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**ATTACHMENTS TO
PREPARED TESTIMONY OF
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**Submitted on Behalf of
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ATTACHMENTS

Description	Page Number(s)
<i>"A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality,"</i> S&P Global, November 9, 2023.	pp. 1 - 13
<i>"Core Earnings: New Data and Evidence,"</i> Harvard Business School Working Paper 20-047.	pp. 14 - 84
<i>"Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand,"</i> S&P Global, October 22, 2024.	pp. 85 - 93
<i>"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"</i> Edison Electric Institute, November 11, 2015.	pp. 94 - 152
<i>"North American Utility Regulatory Jurisdictions Update: Some Notable Developments,"</i> S&P Global, September 24, 2024.	pp. 153 - 161
<i>"Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities,"</i> S&P Global, September 12, 2023.	pp. 162 - 168
<i>"Research Update: Edison International And Subsidiary SoCalEdison Outlooks Revised To Negative From Stable On Potential Risk For Wildfire Fund Depletion: Ratings Affirmed,"</i> S&P Global, February 3, 2025.	pp. 169 - 178
<i>"Research Update: PG&E Corp. And Pacific Gas & Electric Co. Outlooks Revised To Stable On Improving Financial Measures; Ratings Affirmed,"</i> S&P Global, July 18, 2022.	pp. 179 - 188
<i>"Major Energy Rate Case Decisions in the US: January–June 2024,"</i> S&P Global, July 29, 2024.	pp. 189 - 201
<i>"North America Regulated Utilities: Capex and Climate Change Pressures Credit Quality,"</i> S&P Global, January 14, 2025.	pp. 202 - 218
<i>"North America Regulated Utilities: Credit Quality Remains Pressured,"</i> S&P Global, January 9, 2024.	pp. 219 - 232
<i>"Sempra Outlook Revised to Negative, Ratings Affirmed; Southern California Gas Downgraded, Outlook Stable,"</i> S&P Global, January 9, 2025.	pp. 233 - 238
<i>"Slides Published: North American Regulated Utilities Industry Highlights,"</i> S&P Global, May 30, 2025.	pp. 239 - 243
SDG&E Response to DR TURN_001-Q2f-Atch01	LINK
SCG Response to DR TURN_001-Q2a-Atch01	LINK

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A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality

Topic Debt Markets In Transition, Energy & Climate Resilience

Region Americas, EMEA, APAC

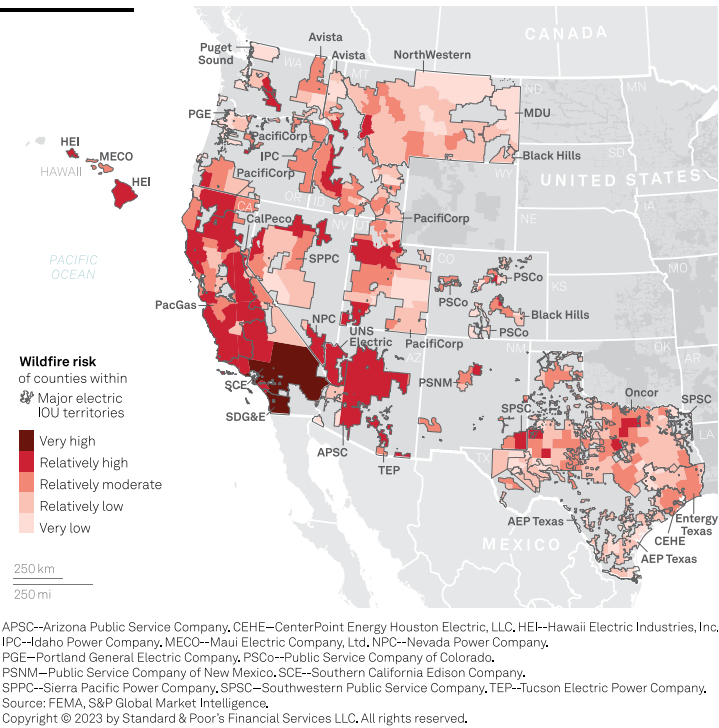
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Key Takeaways

- Climate change is increasing the frequency and severity of storms, hurricanes, wildfires, and other natural disasters, which is escalating infrastructure damage and raising credit risks for North America's investor-owned utilities (IOUs) and publicly owned utilities (POUs).
- To reduce credit risks, we expect IOUs and POU will limit damages from physical events by leveraging already developed and in-use technologies. We also expect that IOUs will likely enhance civil litigation strategies and expand their cost-recovery capabilities.
- Over the past six years, IOU and POU downgrades directly related to physical risks have significantly increased. The credit quality of utilities with physical risk exposure could come under even more pressure if comprehensive risk-reduction strategies are not effectively implemented.

Damages and related costs from physical risks are escalating in North America as regions designated as high-fire risk expand. Climate change is increasing the frequency of extreme and devastating physical events, including hurricanes, storms, and wildfires, which is heightening risks for North America's IOUs and POU. Warmer temperatures increase humidity, leading to stronger winds and devastating tropical storms and hurricanes. In other regions, drier and hotter weather conditions are a primary cause for more intensive and severe wildfires. As temperatures rise and the vegetation dries up, the environment becomes more susceptible to the rapid spread of wildfires. When high winds are added to this combustible environment, the probability of a catastrophic wildfire significantly escalates. As such, areas designated as high fire risk have grown across the Western U.S.

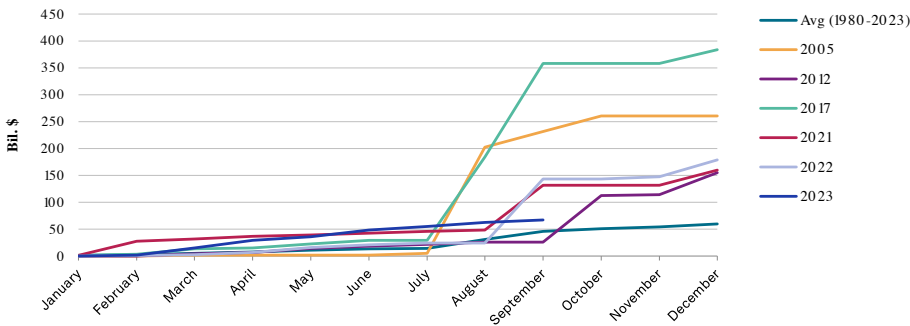
Wildfire risk across western electric service territories



According to the National Oceanic and Atmospheric Administration (NOAA) on an inflation-adjusted basis, 2021 and 2022 represent two of the top five most destructive years for extreme weather events since 1980. Our base case assumes these trends will persist, magnifying physical risks for the IOU and POU industries.

Chart 1

U.S. billion dollar weather disaster year-to-date event cost (CPI-adjusted)



Source: National Oceanic and Atmospheric Administration. Copyright © 2023 by Standard & Poor's Financial Services LLC. All rights reserved.

IOU And POU Downgrades Attributable To Physical Events Have Increased

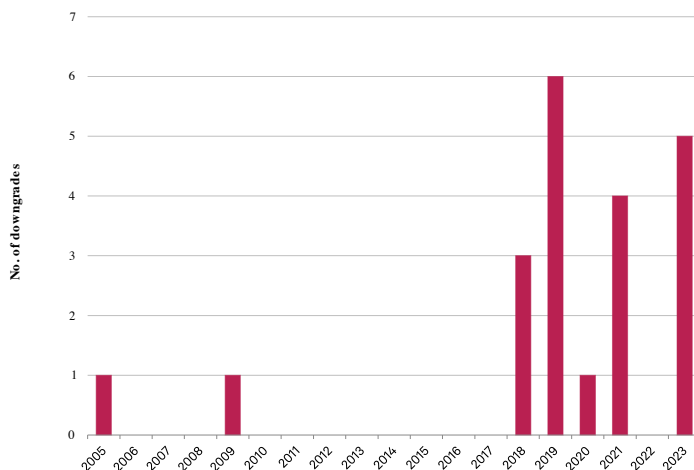
S&P Global Ratings has downgraded more IOUs due to physical events (e.g., hurricanes, storms, and wildfires) over the past six years by nearly 10 times compared with the previous 13 years. From 2005-2017, we only downgraded two North American IOUs because of physical risks, but from 2018-2023 we downgraded 19. Some of the more recent devastating events have led to the latest downgrades, including the 2018 Camp Fire wildfire in California, 2021 Winter Storm Uri, 2021 Hurricane Ida, and the 2023 wildfires in Maui, Hawaii. In addition to the downgrades of PacifiCorp and

Hawaii Electric Light Co. Inc. in 2023, we also revised the rating outlooks to negative on Berkshire Hathaway Energy Co. (BHE), Fortis Inc., and Public Service Co. of Colorado, a subsidiary of Xcel Energy Inc., reflecting their rising exposure to physical risks.

POUs have also been subject to an increasing number of downgrades in recent years stemming from physical risks, including actual wildfire liabilities or elevated wildfire risks, and extreme weather events. We lowered ratings on various POUs in 2019 and 2020 as a result of actual wildfire liabilities or high wildfire risks for California utilities: Trinity Public Utilities District Financing Authority, The City of Glendale's electric system, and Los Angeles Department of Water & Power (power system). Wildfire risks have also limited rating potential for newly assigned ratings in the case of two other California electric utilities the past two years. With regard to extreme weather, of particular note is Winter Storm Uri, whereby sustained extremely cold temperatures and wintry precipitation led to extremely high unbudgeted power and fuel costs resulting in reduced liquidity and higher leverage. We subsequently lowered 13 of our 27 ratings on public power and generation and transmission cooperative electric utilities within the Electric Reliability Council of Texas Inc. (ERCOT), mostly by one notch.

Chart 2

North American IOU downgrades attributed to physical risks



Source: S&P Global Ratings.

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"What We Learn From History Is That People Don't Learn From History" – Warren Buffett

In 2004, four major hurricanes hit Florida in a span of six weeks causing \$1.3 billion in IOU restoration costs alone, not including costs for POUs. In 2005, another seven major hurricanes made landfall in the Southeast U.S., resulting in an incremental \$1 billion in IOU damages. Following these events, utilities and regulators developed and adopted broad recommendations to improve vegetation management, wooden-pole replacement programs, flood monitors, communication efforts, aerial drone usage, and the burying of power lines underground, which is commonly known as undergrounding. Since 2006, Florida Power & Light Co. (FPL), a subsidiary of NextEra Energy Inc., replaced almost all of its wooden transmission structures with concrete and steel structures. Other utilities that weren't as decimated by these hurricanes took some steps to harden their systems, but none incorporated the comprehensive approach taken by FPL. For example, Tampa Electric Co. replaced over 85% of its wooden transmission structures with a goal of reaching 100% by 2029. Over the past several years, because of FPL's initiatives to reduce physical risks, it has more quickly restored electricity service to its customers following major storms or hurricanes.

In 2007, San Diego Gas & Electric Co. (SDG&E) caused several wildfires that destroyed more than 1,100 structures, one of which, at that time, was the largest wildfire caused by a utility. Since these incidents, SDG&E implemented a comprehensive wildfire-prevention plan that helped the utility avoid causing another catastrophic wildfire. Similarly, other utilities implemented some aspects of SDG&E's wildfire-prevention plan, but only SDG&E executed a comprehensive plan. These examples of physical risks typify the challenges for the utility industry. Because costly investments are needed to reduce physical risks, which then pressures the customer bill, utilities usually delay these investments until it is too late, and they are directly impacted by a physical event.

Reducing Physical Risks Before A Catastrophic Event Occurs

As climate change continued to accelerate since 2007, Central and Northern California became increasingly dry, and wildfire risks grew more severe. By 2017, Central and Northern California began to experience wildfires on a more regular basis, culminating with the 2018 Camp Fire in the city of Paradise, causing 85 fatalities and destroying more than 18,000 structures. Following this catastrophic event, all of California's IOUs and POUs were mandated to implement comprehensive wildfire mitigation plans, investing billions on system hardening and technology to reduce physical risks.

Chart 3

Largest California IOUs wildfire mitigation capital spending

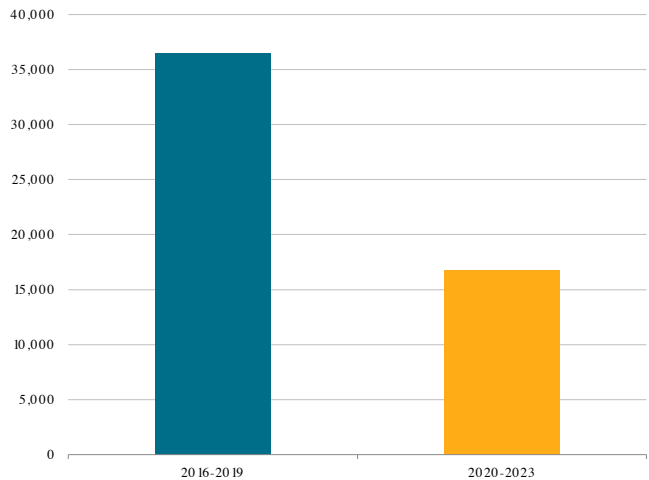


Source: Company documents.
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The number of structures in California destroyed since 2020 has dropped by more than 50% compared to the 2016-2019 period. While weather is an important contributor to this decrease, we also believe California IOUs' and POUs' investments in wildfire mitigation is a key factor.

Chart 4

California structures destroyed by wildfires

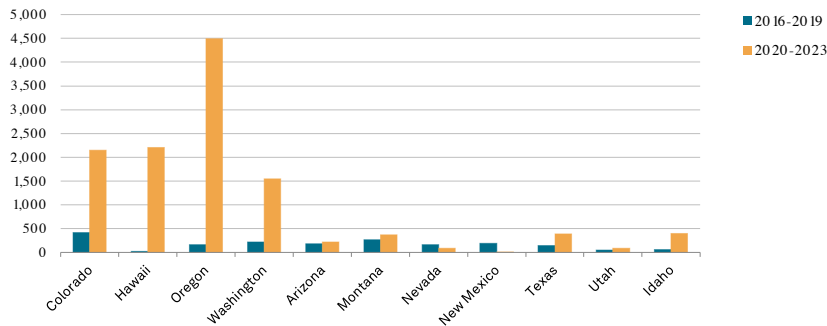


Source: Headwaters Economics and National Fire and Aviation Management FAMWEB.
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While California's IOUs and POUs have implemented comprehensive wildfire mitigation plans, many utilities in other western U.S. states haven't yet adopted such sophisticated strategies. Since 2020, structures destroyed because of wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas have all increased by more than 100% compared to the prior 2016-2019 period. Furthermore, Arizona, Montana, and Utah have each experienced increases of at least 20% over this same timeframe. In light of climate change, we believe it's important for IOUs and POUs in the western U.S. states to implement comprehensive wildfire mitigation plans to reduce physical risks, even though many of these utilities have yet to experience a catastrophic wildfire.

Chart 5

Structures destroyed by wildfires in western states*



*Excludes California. Source: Headwaters Economics and National Fire and Aviation Management FAMWEB.
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Three Key Areas To Reduce Physical Risks

We expect IOUs subject to rising physical risks will develop a three-pronged strategy toward reducing risk. This includes reducing damages from physical events, minimizing litigation risk, and expanding capabilities for cost recovery. POUs are also heavily investing in wildfire mitigation and related technology. While it may take some time and significant investments for the industry to fully implement these strategies, the solutions are nonetheless practical because many are predicated on already developed and in-use technologies.

Reducing Damages From Physical Events

System hardening is an important investment that improves resiliency, reducing damages and risk. Because our modern economy is so dependent on electricity, system hardening also allows for the faster restoration of operations, reducing total economic impacts. While system hardening is often expensive and can take many years to implement, its long-term benefits significantly reduce risk typically outweighing its shorter-term costs. Examples of system hardening include the undergrounding of powerlines, cover conductors--which is the insulation of bare electrical wires with durable long-lived materials that reduce the probability of an electrical fault or spark--and the replacing of wood poles with steel and concrete.

Southern California Edison Co. (SCE) is currently aggressively replacing its overheard distribution lines with covered conductors. The utility expects to replace more than 7,200 miles, or the vast majority of its distribution lines by 2025. Pacific Gas & Electric Co. (PacGas) is currently undertaking a long-term system hardening initiative that includes undergrounding 10,000 miles of its powerlines. POU's are also undergrounding or replacing wood poles with steel poles, including Guam Power Authority (particularly for the typhoons it experiences), Sacramento Municipal Utility District (for its most at-risk power lines in elevated risk zones), Brunswick Electric Membership Corp. in North Carolina, and Seattle City Light. Other POU's such as Anaheim Public Utilities' electric system and Central Florida Tourism Oversight District (formerly Reedy Creek Improvement District) have long had most of their power lines underground.

To reduce the likelihood of causing or contributing to a catastrophic wildfire, many utilities have incorporated weather stations that collect data, which it then uses to forecast weather conditions, including high-wind events. Some utilities have incorporated artificial intelligence (AI) and machine learning into their data analysis, enhancing their forecasting capabilities. Other key tools for wildfire detection include high-definition (HD) cameras, satellite and aerial imaging, remote sensing, and drones. As part of these strategies, utilities have improved communication with state agencies and fire departments, coordinating specific locations that have either encountered or could be highly susceptible to a wildfire. Critical to reducing wildfire risks is the implementation of a public safety power shutoffs (PSPS) program. PSPS is the proactive de-energizing of power lines in extreme weather conditions especially in high-wind events. The decision to de-energize is extraordinarily challenging because it could have serious health and safety ramifications for some customers. Accordingly, it is important that a PSPS program establishes a consistent process for de-energizing power lines and is approved by regulators well in advance of a catastrophic event. We view a PSPS program that establishes such a formal process as a credit-supportive tool that reduces risk for IOUs.

For POU's, in particular, most utilities that have significant wildfire risks have adopted protocols and policies to de-energize power lines in advance of threatening conditions. But some utilities are unlikely to pre-emptively shut off power to avoid wildfire risks because those utilities believe doing so introduces other public safety or health risks, particularly for electric utilities located in large urban areas.

Another crucial component of wildfire prevention is vegetation management, which is the removing or modifying of live and dead vegetation to reduce the potential spread of wildfire ignitions. This ongoing maintenance is essential for reducing the likelihood of debris coming in contact with powerlines, causing a spark that could lead to a wildfire. To further reduce wildfire risks, utilities have implemented enhanced power safety setting systems (EPSS) that automatically shut off power within a tenth of a second if they detect a potential ignition source. Such systems include downed conductor detection, early fault detection, open phase detection, and partial voltage force out.

Because of the different service territories and topographies, we don't expect the strategies implemented by utilities to be uniform. As such, we expect that a utility wildfire mitigation plan will be customized but with the consistent goal of reducing risk.

The table below details aspects of wildfire mitigation strategies that have been implemented by various utilities to reduce physical risks. This table is not comprehensive of each utility's strategies, and generalization is used because of space constraints. For more details regarding each utility's wildfire mitigation plan, please see their website

Ratings

Need a Rating?

Regulated IOU wildfire mitigation plans								
☑ Enacted ☒ Not enacted								
Utility name	Undergrounding	Covered conductor	Poles enhancements/ replacements	Public safety power shutoff programs (PSPS)	Vegetation management	Periodic inspections	Situational awareness and forecasting	Aerial surveillance/ HD cameras
American States Water Company (BVES)	☑	☑	☑	☑	☑	☑	☑	☑
Detail: Data governance, ignition detection sensors and systems, fault monitoring								
FortisAlberta Inc.	☒	☒	☑	☒	☑	☑	☒	☑
Detail: Insulator washing, porcelain switch replacement								
Idaho Power Company	☑	☑*	☑	☑	☑	☑	☑	☑*
Detail: Satellite imagery, shared stewardship								
Liberty Utilities (CalPeco Electric) LLC	☑	☑	☑	☑	☑	☑	☑	☑
Detail: Wildfire, outreach, communication, stakeholder communication, plans to sponsor 8 cameras to the ALERT Wildfire Network in 2023								
Los Angeles Dept. of Water and Power	☒	☑	☑	☒	☑	☑	☑	☑
Detail: LAFD notifies LADWP of NWS Red Flag Warnings, block reclosers in certain situations								
NorthWestern Corporation	☒	☒	☑	☒	☑	☑	☑	☑
NV Energy Inc. (NPC and SPPC)	☑	☑	☑	☑	☑	☑	☑	☑
Detail: AI, FTFM relay settings, installed 65 weather stations and 11 cameras								
PacGas	☑	☑	☑	☑	☑	☑	☑	☑
Detail: EPSS/downed conductor detection, early fault detection sensors, partial voltage force out, satellite IR imaging, HD video, land-based IR cameras								
PacifiCorp	☑	☑	☑	☑	☑	☑	☑	☑*
Detail: Public safety partner portal, AI and machine learning, downed conductor detection, early fault detection, installed 454 weather stations and 25 cameras								
Public Service Company of Colorado	☒	☑	☑	☒	☑	☑	☑	☑
Detail: AI and machine learning, early fault detection, open phase detection, unmanned aerial system and iDAR-equipped helicopter inspection								
Sacramento Municipal Utility District	☑	☑	☑	☑	☑	☑	☑	☑
Detail: Disables reclosers during wildfire season, installed 14 weather stations								
SDG&E	☑	☑	☑	☑	☑	☑	☑	☑
Detail: AI and machine learning, early fault detection, public safety partner portal, weather stations, smoke plume modeling, satellite-based remote sensing cameras, AI smoke detection algorithm								
Southern California Edison Co.	☑	☑	☑	☑	☑	☑	☑	☑
Detail: AI and machine learning, early fault detection, open phase detection, HD cameras, aerial suppression, fast curve relay systems, REFCL technology								

*Piloting program, UAS--Unmanned aerial system, iDAR--ight detection and ranging, LAFD--Los Angeles Fire Dept, LADWP--Los Angeles Dept. of Water and Power, NWS--National weather service, REFCL--Rapid Earth Fault Current Limiter, FTFM--Fast trip fire season mode, NPC--Nevada Power Company, SPPC--Sierra Pacific Power Company, Source: Company documents.
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Assessing Litigation Risks

Because utilities operate under potentially hazardous conditions that include safety as well as environmental risks, they have always been susceptible to litigation. However, in recent years, as the climate changes and wildfires increase, litigation and class action civil lawsuits against utilities have increased. Currently, plaintiffs have pending civil lawsuits against nine utilities because of wildfires.

Major Wildfires Since 2019 In IOU And POU Service Territories					
Year	State	Subsidiary	Weather event	No. of acres burned	No. of structures destroyed
2019	CA	Los Angeles Department of Water & Power	Getty Fire	745	10
2019	CA	Pacific Gas & Electric Co.	Kincade Fire	77,758	374
2019	CA	Southern California Edison Co.	Saddle Ridge Fire	9,000	19
2020	WA	Avista Utilities Inc.	Babb Road Fire	15,000	220
2020	CA	Southern California Edison Co.	Bobcat Fire	116,000	171
2020	CA	Liberty Utilities (CalPeco Electric) LLC	Mountain View Fire	20,879	80
2020	WA	Avista Utilities Inc.	Road 11 Fire	10,000	0

2020	OR	PacifiCorp	2020 wildfires	350,000*	1560*
2020	CA/OR	PacifiCorp	Slater Fire	150,000	440
2020	CA	Pacific Gas & Electric Co.	Zogg Fire	56,338	204
2021	CA	Pacific Gas & Electric Co.	Dixie Fire	963,309	1,311
2021	CO	Public Service Co. of Colorado	Marshall Fire	6,000	1,000
2022	CA	Southern California Edison Co.	Coastal Fire	200	20
2022	CA	Southern California Edison Co.	Fairview Fire	28,000	22
2022	CA	Pacific Gas & Electric Co.	Mosquito Fire	76,788	78
2022	CA	PacifiCorp	McKinney Fire	60,000	185
2023	HI	Maui Electric Co. Ltd.	2023 Hawaii Wildfires	17,000*	2,210*

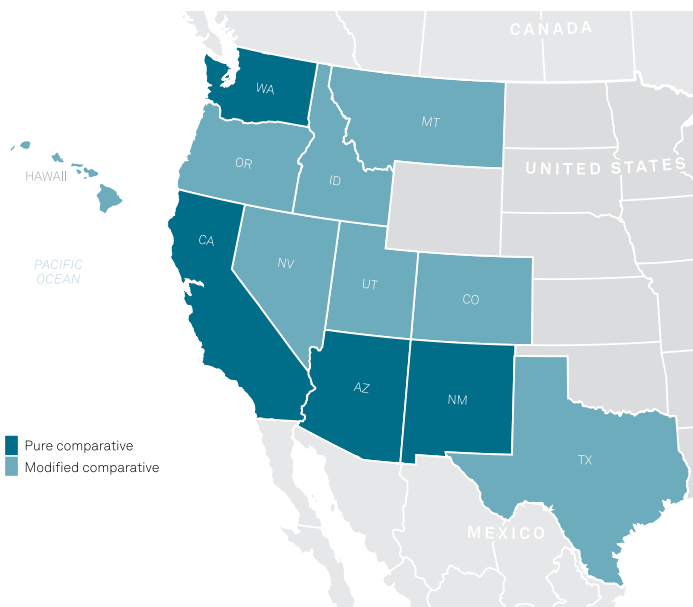
*More than. Source: Company documents and public information.

The degree of litigation risk for a utility depends on the specifics of the statutory law including the standard of negligence, inverse condemnation, caps on damages, and the number of jurors necessary to determine liability.

Standards Of Negligence

The negligence laws for all Western U.S. states require that the plaintiff demonstrates that the defendant is at fault for acting in a deficient manner or for breaching the duty of care. While there are differences between states' standards of negligence, we consider litigation a material credit risk that affects the entire industry. Arizona, California, New Mexico, and Washington operate under a pure comparative negligence standard that can find a defendant liable even if a plaintiff was 99% at fault. Although in such a scenario the defendant's liability is limited to just 1%. Colorado, Hawaii, Idaho, Montana, Nevada, Oregon, Texas, and Utah operate under the modified comparative negligence standard, which limits the defendant's risk. In these states, the defendant can be found liable for damages only if they caused at least 50% of the damages. Because the modified comparative standard of negligence is less onerous on the defendant, we assess utilities that operate in these states as having somewhat lower credit risk.

Comparison of negligence standards by Western state



Source: S&P Global Ratings.
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Inverse Condemnation

In California, IOUs and POUs are held to a higher level of accountability through the state's interpretation of inverse condemnation doctrine--whereby a California utility can be financially responsible for a wildfire if its facilities were a contributing cause of a wildfire, irrespective of negligence. While we assess this interpretation as not correct, to date California remains the only Western U.S. state that supports this interpretation for utilities.

Limiting Damages

For most civil lawsuits, if the defendant is found liable, jurors may assess economic damages, non-economic damages, and punitive damages. Economic damages are the reimbursement of actual monetary losses, while non-economic damages are more subjective and can sometimes include emotional distress, medical expenses, and lost wages. In some instances, punitive damages are assessed if it's determined that the defendant acted in a negligent or gross negligent manner. Punitive damages are essentially a penalty to deter further intentional or reckless behavior.

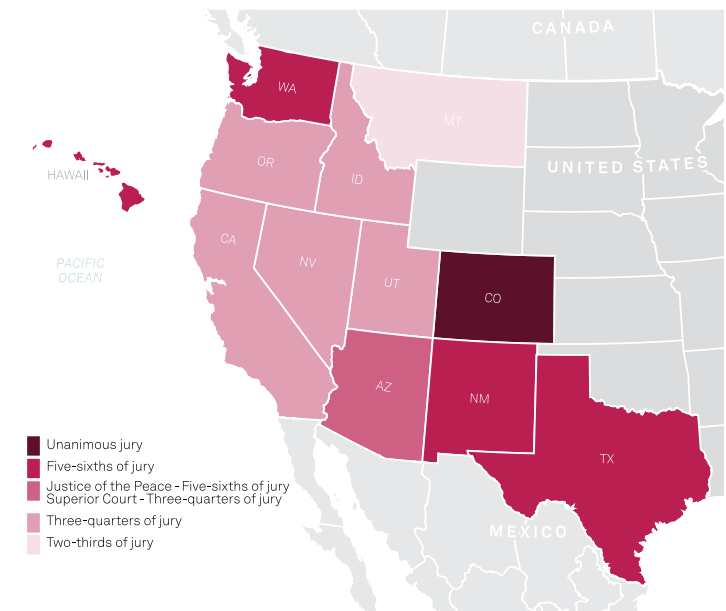
The maximum amounts for non-economic, and punitive damages are sometimes capped by state statutes, and we view these caps as supportive of credit quality, limiting the total potential damages. For example, in Colorado, non-economic damages are capped at about \$614,000, and punitive damages are limited to 1x total damages; however, both of these caps can be increased under various circumstances. Washington state does not allow for punitive damages but does not have a cap on non-economic damages.

Recently, jurors in a class action wildfire lawsuit against PacifiCorp, a subsidiary of BHE, in Oregon assessed economic damages at about \$4 million for 17 plaintiffs but added non-economic and punitive damages of about \$68 million and \$18 million, respectively. This increased total awarded damages to about \$90 million or about \$5.3 million per plaintiff, significantly higher from our base case of about \$1 million per plaintiff, diminishing PacifiCorp's credit quality.

Jurors Necessary For A Liable Verdict

The number of jurors necessary to determine liability is another critical factor to assess litigation risk. When comparing the Western U.S. states, Montana, which requires only two-thirds of the jurors vote to determine liability in a civil lawsuit would represent the highest risk for a utility, while Colorado, which requires a unanimous jury decision is the lowest risk.

Number of jurors required for a liable verdict by Western state



Source: S&P Global Ratings.
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Expanding Cost Recovery Capabilities

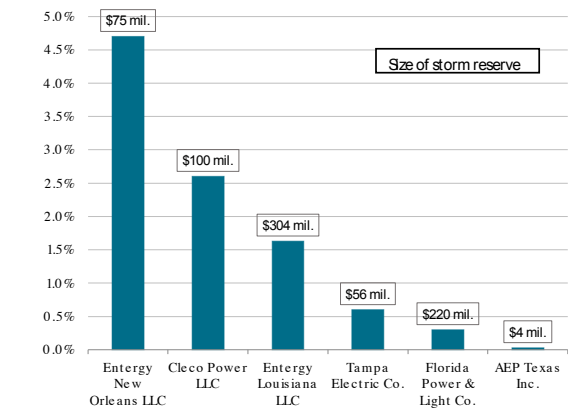
After a utility experiences damages from a physical event or after being found liable for a wildfire, the utility must pay for these costs. We expect that IOUs and POU's will recover most of these costs from ratepayers, which has generally supported the industry's credit quality. However, when the costs become unusually large, regulatory lag increases the difference between when a utility incurs costs and when it's recovered from ratepayers--increases, the balance sheet leverages, and utilities have even experienced significant disallowances that weaken credit quality. In these instances, we believe the industry hasn't contained the credit risk and the industry is short of protective credit capabilities. As such we believe it's important for the IOU industry to significantly increase and broaden recovery capabilities. This includes implementing storm reserves, increasing commercial insurance levels, incorporating self-insurance, participating in a special wildfire fund, and securitization. While expanding cost recovery capabilities would support credit quality, we believe this alone without reducing damages from physical events or minimizing litigation risk, would likely not be sufficient to reduce credit risks. Many POU's carry wildfire liability insurance or maintain self-insurance reserves set aside for potential wildfire liabilities. While POU's may receive federal emergency management agency (FEMA) reimbursement for damage to system infrastructure from wildfires, liabilities aside, FEMA reimbursements often entail considerable lag making internal liquidity or market access critical.

Storm Reserves

Storm reserves allows a utility to prefund from customers storm recovery in advance of a physical event. We view this tool favorably for credit quality because the utility already has the cash reserve that can be immediately used to address the damages following a physical event. We assess a storm reserve as supportive to reduce short-term liquidity needs, minimizes the regulatory lag for IOUs, and reduces balance sheet leverage. Smaller sized utilities with higher exposure to hurricanes and storms such as Entergy New Orleans LLC or Cleco Power LLC typically have a relatively higher storm reserve when compared to their net plant, property, and equipment (PP&E).

Chart 6

Storm reserve as a percentage of PP&E



PP&E--Property, plant and equipment. Source: Company documents. Copyright © 2023 by Standard & Poor's Financial Services LLC. All rights reserved.

Insurance Hurdles

Increasing property and liability insurance coverage decreases a utility's financial exposure to physical risks, and for many years the utility industry has effectively implemented this risk-reduction strategy. However, in recent years, insurance companies have experienced underwriting losses in property lines, driven by a combination of higher inflation

increasing repair costs and more severe weather-related events. Insurers have responded by raising rates and reducing their exposure to residential and commercial property risks in areas exposed to natural catastrophes. This has led to higher insurance premiums and deductibles for policy holders--paying more for less coverage--decreasing the Ratings of this strategy. Need a Rating?

Due to more stringent oversight of homeowners insurance rates by state regulators, it's more difficult to increase rates on homeowners quickly enough to offset higher-loss cost trends and return to profitability. In Florida, this has led several insurance companies to exit the homeowners' market, while in California, several large insurers--including State Farm, Allstate, Farmers and USAA--have reduced or stopped writing new homeowners policies, though they continue to provide coverage for most existing policyholders. For commercial property insurance customers, insurers have been raising rates aggressively to offset higher losses and restore profitability. As noted by PG&E in a 2022 advice letter filed with California Public Utilities Commission, it and the other California IOUs have continued to see increases in the cost of excess liability insurance for wildfires as the number of insurers offering such coverage has decreased, leading to an overall reduction the amount of capacity available.

Given the pressure in the insurance market, some utilities are contemplating greater use of self-insurance. Under the self-insurance model, a utility forms a captive insurer or initiates a fund through a customer charge that it uses to pay losses from physical events. PG&E and SCE currently employing such a strategy through the establishment of a customer funded \$1 billion self-insurance fund that will replace the wildfire liability insurance the company has been purchasing in the commercial market. We view the self-insurance model as supportive of credit quality especially when purchasing adequate liability insurance levels becomes uneconomic or simply not available in the commercial marketplace.

Additionally, in 2020, a special wildfire fund was established under Assembly Bill 1054 by California to decrease physical risks for its IOUs. This special wildfire fund excludes POUs. We view the wildfire fund as highly supportive of credit quality for IOUs. California's largest IOUs (PacGas, Southern California Edison Co. and SDG&E) primarily established the \$21 billion wildfire fund that was equally funded by shareholders and ratepayers. Since its inception, to our knowledge, the fund has not yet been tapped, providing significant financial cushion for California's IOUs.

Utility Securitization

Securitization allows for the issuance of debt secured by a non-by-passable charge to the customer's bill, allowing the utility to fully recover its costs at a lower interest rate for customers. In other words, utilities with regulatory approval, can securitize costs associated with the fallout from storms, other weather-related incidents, energy transition, commodity prices, or other events. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger IOU credit measures and view securitization as supportive of credit quality. The use of securitization has recently increased. Following the 2021 Winter Storm Uri, several states including Texas, Kansas, and Oklahoma passed legislation requiring utilities to issue securitized bonds to fund the high costs of deferred natural gas costs incurred during the storm. In March 2022, Rayburn Country Electric Cooperative (Rayburn) securitized \$900 million of its \$920 million in eligible extraordinary costs resulting from Winter Storm Uri and discharged \$637 million in invoices to the ERCOT that had been unsettled for almost one year. During the storm, Rayburn's electricity demand and power costs surged for almost a week, leading to extremely large invoices from ERCOT that Rayburn lacked sufficient liquidity to pay in full.

Credit Quality Could Suffer As The Climate Changes

We believe it's important for IOUs and POUs exposed to rising physical risks to reduce their credit risks by developing and implementing comprehensive risk mitigation strategies. Although many IOUs and POUs haven't yet been directly exposed to a catastrophic event, it's imperative that the industry remains vigilant as the pace of climate change

S&P Global progresses. While a comprehensive risk reduction strategy does not guarantee that a utility is immune from these rising physical risks, we believe it does significantly reduce much of the risk because the strategy is mostly predicated on already developed and in-use technologies. As climate change progresses, we will continue to monitor physical risk Ratings across North America. Credit quality for IOUs and POUs that have exposure to physical risks **Need a Rating?** proactively implement a comprehensive risk-reduction strategy could be pressured.

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Core Earnings: New Data and Evidence

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Abstract

Using a novel dataset, we show that components of firms' GAAP earnings stemming from ancillary business activities or transitory shocks are significant in frequency and magnitude. These components have grown over time and are dispersed across various sections of the 10-K. Excluding them from GAAP earnings yields a core earnings measure that distinguishes between the recurring and non-recurring components of net income and forecasts future performance. Analysts and market participants are slow to impound these earnings components' implications, particularly the amounts disclosed in footnotes. Trading strategies that exploit non-core earnings produce abnormal returns of 8% per year.

Keywords: Core Earnings; Transitory Earnings; Non-Operating Earnings; Quantitative Disclosures; Fundamental Analysis; Equity Valuation

JEL: C14, G10, G18, M40, M41

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1 Introduction

Financial statements contain a wealth of information about a firm’s net income, an estimate of the net value flow during a period. However, components of earnings differ in their attributes and relevance for future performance. Some components stem from a firm’s central business activities—what we refer to as its “core” earnings. Conversely, other components reflect the results of a firm’s ancillary business activities or transitory shocks. Distinguishing these components to discern core earnings is essential for interpreting, communicating, and forecasting firm performance.

The behavior of sell-side analysts and managers attests to the importance of isolating and identifying components of firms’ earnings. For example, analysts regularly report and forecast firms’ earnings on a non-GAAP basis (“street earnings”) by excluding from GAAP earnings items deemed transitory or not reflective of the central business activities. Similarly, managers commonly report non-GAAP “pro forma” earnings that exclude items they consider unimportant for understanding firm performance.

A concern with metrics such as street or pro forma earnings is that managers and analysts choose the composition of items to include versus exclude in a biased fashion (e.g., [Doyle, Lundholm, and Soliman, 2003](#); [Curtis, Mcvay, and Whipple, 2014](#)). For example, street earnings often exclude stock-based compensation expenses, which result from central business activities and are recurring ([Barth, Gow, and Taylor, 2012](#)). These compositional concerns are compounded by concerns over selection biases stemming from analysts’ and managers’ choices about the firms and fiscal periods for which earnings are modified.

This study addresses three sets of questions designed to enhance financial economists’ understanding of earnings’ properties and their relation to future performance and stock returns. First, how economically significant (e.g., incidence and magnitudes) are non-core-

earnings items and how are they disclosed? Second, how can researchers systematically and impartially measure core earnings in large samples, and how do core earnings relate to future performance? Finally, do market participants understand and impound the distinction between core and non-core earnings in a timely fashion?

In studying these questions, a practical challenge arises from attempting to comprehensively identify revenues, expenses, gains, or losses stemming from transitory shocks or ancillary business activities. Doing so for one firm requires identifying and categorizing items disclosed in the footnotes, management discussion and analysis (MD&A), and cash flow statement sections of firms' 10Ks, which have grown in length (often exceeding 200 pages) and complexity (Loughran and McDonald, 2014). Moreover, correctly categorizing items as core versus non-core is highly context-specific (e.g., it depends on a firm's primary business) and requires judgment. Therefore, measuring core earnings is challenging to scale in the cross-section and over time, and represents a critical hurdle for large-sample studies.

We address these challenges by leveraging data compiled by New Constructs (NC), a financial research firm that identifies and classifies all income-statement-related quantitative disclosures appearing in the 10-K. The data are available for a large sample, covering more than 60,000 firm-year observations from 1998 to 2017. Moreover, NC collects detailed attributes of each quantitative disclosure, allowing us to observe the frequencies and amounts of non-core-earnings items based on their: (i) location of disclosure within the 10-K (e.g., on the face of the income statement, or in the footnotes, MD&A, or cash flow statement and then aggregated into an income-statement line item); (ii) direction of impact on core earnings (e.g., income-increasing or income-decreasing); and (iii) economic category (e.g., acquisition- or restructuring-related).

To measure core earnings, we exclude from GAAP earnings the items NC deems to have resulted from transitory shocks or ancillary business activities. Specifically, our measure

(*Core Earnings*) adds back to GAAP earnings (what we refer to as *Net Income*) net expenses stemming from (1) acquisitions, (2) currency fluctuations, (3) discontinued operations, (4) legal or regulatory events, (5) pension plans, (6) restructuring, (7) gains and losses that companies label as “other” as a separate line item on the income statement, and (8) other gains and losses that NC analysts classify as transitory or ancillary to the central activities. Because an independent research firm produces the underlying data, our measure’s key appeal is that the classification of earnings components is less likely to exhibit systematic biases found in street earnings or pro-forma earnings.

Our first set of analyses highlight the frequency, magnitude, disclosure location, and time trend of the adjustments that reconcile *Net Income* and *Core Earnings*. We find that all firms disclose non-core-earnings items at some point, and they are significant in terms of frequency and magnitude. There are many such disclosures in a 10-K, and increasingly so over the last 20 years: from 1998 to 2017, the average number of non-core-earnings items identified in a 10-K rose more than 30%, from six to eight. The average total non-core-earnings items identified amounts to 19% of average *Net Income*. Moreover, disclosures of non-core-earnings items are dispersed throughout the 10-K, both on and off of the face of the income statement (e.g., in footnotes, MD&A, or cash flow statement). Roughly half of these items, by frequency or magnitude, are disclosed off of the income statement. These findings suggest that individuals seeking to understand the composition of GAAP earnings need to process a large amount of information disclosed in various parts of the 10-K.

Our second set of tests examines the forecasting properties of *Core Earnings*. We begin by examining the persistence properties of *Core Earnings* and *Total Adjustments* (the difference between *Core Earnings* and *Net Income*). By definition, core earnings removes items that result from transitory shocks or ancillary business activities from GAAP earnings. We conceptualize these exclusions as those earnings components that, on a scale-adjusted basis,

are non-recurring either in the short-run (i.e., purely transitory shocks) or over a longer horizon (i.e., ancillary business activities). Under this framing, non-core-earnings items are less likely to persist or scale with fluctuations in the size of the business, and a good core earnings per share measure would distinguish the recurring and non-recurring components of GAAP earnings per share. We show that *Core Earnings* satisfies two key properties: (i) It exhibits a high level of year-over-year persistence, in particular higher than *Net Income* (due to the removal of transitory components of GAAP earnings); and (ii) its adjustments (*Total Adjustments*) exhibits a relatively low degree of year-over-year persistence.¹ Moreover, *Core Earnings* is effective at distinguishing these components of earnings over a five-year horizon.

We also show, consistent with theoretical predictions, that *Core Earnings* offers strong predictive power for firms' *Net Income*, both independently and incrementally to commonly used alternative performance metrics, over a one- to five-year horizon. In addition, *Core Earnings* forecasts other measures of future performance relevant for managers and analysts, such as cash flow from operations, Compustat-defined income-before special items (*IBSPI*), "operating income after depreciation" (*OIADP*), operating income (*OPE*), and street earnings. Finally, we show that the predictive power of *Core Earnings* is attributable to non-core-earnings adjustments stemming from on and off the face of the income statement, as well as from a broad set of economic categories. These findings highlight the importance of distinguishing the core and non-core components of GAAP earnings for understanding current and forecasting future performance.

Finally, we study whether and to what extent market participants understand the implications of the non-core components of *Net Income*. We do so by analyzing the predictive power of the non-core-earnings adjustments made to *Net Income* (*Total Adjustments*) for future revisions in sell-side analysts' earnings forecasts and firms' stock returns.

¹These results hold whether our core earnings measure is scaled by shares outstanding or total assets.

Our evidence suggests that market participants are slow to take into account the implications of non-core earnings. We find *Total Adjustments* positively forecasts revisions in analysts' earnings forecasts in the 12 months following a firm's 10-K filing. Economic and statistical significance are largest for adjustments found in the footnotes, where information tends to be less salient and less structured. These findings are consistent with analysts relying on a subset of adjustments that require lower processing costs in making initial forecasts of earnings, but gradually updating forecasts over time.

Strikingly, *Total Adjustments* also significantly forecasts firms' stock returns in the 12 months following their 10-K filing, even after controlling for characteristics known to explain the cross-section of future returns and other non-core-earnings proxies. In line with our analyst-based tests, the economic and statistical significance of return-predictive ability is largest for adjustments found in the footnotes. A value-weighted trading strategy that buys firms in the highest decile of *Total Adjustments* and sells firms in the lowest decile produces monthly excess returns of 66 basis points per month (8.2% annualized), suggesting that the predictably gradual assimilation of core earnings information into prices applies broadly and is unlikely to be limited to smaller firms.

Collectively, our findings provide three main contributions. First, in documenting the frequency, magnitudes, and varied disclosure location in the 10-K of non-core-earnings items, our findings highlight the importance of financial statement analysis. Moreover, our findings underscore the usefulness of the information disclosed off of the income statement (in footnotes, MD&A, or cash flow statement sections of 10-Ks) for understanding the nuances in earnings. These findings complement evidence in [Bushman, Lerman, and Zhang \(2016\)](#) and [\(Nallareddy, Sethuraman, and Venkatachalam, 2020\)](#), which show that temporal changes in GAAP earnings properties have weakened its ability to forecast firms' future performance. Our results provide direct evidence supporting a prominent explanation posited by [Bushman](#)

et al. (2016), that the changing nature of GAAP earnings is at least in part driven by the growth of one-time items and non-operating items. Our findings also highlight the practical difficulty of measuring core earnings in large samples and point to growing data collection costs as a potential impediment to the timely reflection of earnings information in analysts' forecasts and market prices.

Our paper's second key contribution is analyzing a systematic large-sample approach for measuring firms' core earnings. Our measure is empirically distinct from commonly used alternatives and is less likely to be susceptible to compositional and selection biases found in analysts' and managerial estimates. These data allow for quantifying the magnitude of non-core earnings and identifying where firms disclose them in their financial statements. By distinguishing between the core and non-core components of net income, this novel measure facilitates future-performance forecasting.

Finally, our findings contribute new evidence on the relation between earnings and stock returns (e.g., Abarbanell and Bernard, 1992; Chan, Chan, Jegadeesh, and Lakonishok, 2006; Fama and French, 2006; Da and Warachka, 2011) by showing that analysts and investors inefficiently incorporate the implications of the distinction between core and non-core earnings.² Our findings suggest that the earnings-returns relation depends crucially on the measure of earnings used to reflect firms' economic profitability (e.g., Dechow and Ge, 2006; Novy-Marx, 2013; Ball, Gerakos, Linnainmaa, and Nikolaev, 2015) and underscore the importance of adjusting GAAP earnings to account for non-core-earnings items for forecasting and valuation.

²Prior studies provide mixed evidence on whether market prices reflect the implications of transitory earnings in a timely fashion. For example, while Curtis et al. (2014) provides evidence that a large subset of firms opportunistically uses transitory items in non-GAAP earnings, Doyle et al. (2003) finds that investors do not fully appreciate bias in the exclusions made by managers. By contrast, Gu and Chen (2004) suggests that investors do understand the implications of the items excluded from street earnings. Our analysis is distinct in that we introduce a measure of core earnings whose exclusions from GAAP earnings are more likely to be comprehensive and less likely to be subject to bias. Moreover, our return-prediction results control for the alternative measures of transitory earnings analyzed by these prior studies.

2 Background and Data

This section discusses related research, details our measurement of core earnings, and describes the data used in our main tests.

2.1 Challenges with Measuring Core Earnings

Manually measuring a firm’s core earnings can be challenging and time-consuming. It involves adjusting GAAP earnings for the earnings items (gains and losses) that result from either transitory shocks or ancillary business activities (what we refer to as non-core-earnings items). Because the quantitative information relevant for these adjustments can be disclosed on and off the face of the income statement, comprehensively identifying non-core-earnings items for one firm requires combing through (typically) hundreds of pages of the 10-K, which has grown in length and complexity over time ([Li, 2008](#); [Loughran and McDonald, 2014](#); [Dyer, Lang, and Stice-Lawrence, 2017](#)).

Relying exclusively on computers to automatically process 10-Ks and identify non-core-earnings items on a large scale engenders both semantic and structural challenges. The semantic challenges stem from firms’ use of different terminology to describe similar economic events. For example, the sale of property may be described as “Gains from sales of property,” “(Gain) loss on used rental equipment,” “Gains/losses on investments,” or otherwise. The structural challenge stems from the various sections in which non-core items can be disclosed: as a specific line item on the income statement, or grouped with other revenues and expenses in an aggregated line item and separately disclosed in the footnotes, the MD&A, or the cash flow statement. Moreover, these practices can vary across firms and even across 10-Ks for the same firm over time.

2.2 Data

To overcome practical challenges associated with measuring core earnings for a large sample of firms, we leverage the database compiled by New Constructs (NC), a financial research technology firm. NC was founded with the primary objective of helping investors assess firms' economic earnings (net operating profit after tax in excess of a capital charge) and return on invested capital (ROIC) to facilitate the analyses of intrinsic and market valuations. The computations of these measures involve a complex set of adjustments to the balance sheet and income statement, such as capitalizing off-balance-sheet operating lease obligations (similar to, e.g., [McKinsey & Company, Koller, Goedhart, and Wessels, 2010](#)).

To facilitate data collection and classification efforts, NC designed a process that combines the intelligence and judgment of a human analyst with the processing power of machines. The starting point was a team of analysts who carefully identified all relevant quantitative disclosures and exercised consistent judgment regarding their classification.

Most relevant to this study, as part of its data collection efforts, NC analysts classified into separate categories income statement items deemed to have resulted from transitory shocks or ancillary business activities. To ensure the consistency of classification decisions, NC maintains a shared knowledge base through a training program in finance and accounting that all new analysts must pass.³ It also promotes a culture of open discussion and idea exchange among analysts, particularly regarding the classification of novel quantitative disclosures. NC also maintains a private internal wiki that documents and explains the rationale behind classification decision rules on various types of quantitative disclosures.

To speed and scale up its analysts' efforts, NC developed three technological tools. The first is an internal application that allows analysts to locate, tag, and mark up all relevant

³New analysts are trained on principles covered in *Valuation: Measuring and Managing the Value of Companies* by [McKinsey & Company et al. \(2010\)](#), *Creating Shareholder Value* by [Rappaport \(1998\)](#), *The Quest For Value* by [Stewart \(1991\)](#), and *Expectations Investing* by [Rappaport and Mauboussin \(2001\)](#).

quantitative data points from financial statements, footnotes, and the MD&A. This tool facilitates collecting various attributes of each disclosure, including the surrounding text, data value, units, and specific location in the filing. The second is a taxonomy that allows analysts to assign each collected quantitative number to the appropriate category to facilitate the computation of economic earnings and ROIC. The last is an automation technology, a machine-learning algorithm that learns over time to mimic the collection and classification decisions made by human analysts. When the human analyst classifies certain data points into the same bucket enough times, the machine can learn this pattern and execute it automatically. Whenever the machine comes across a quantitative disclosure that it has not seen an analyst classify in the past, it notifies a human analyst who subsequently tags, marks up, and classifies the disclosure. Analysts' accumulated choices constitute an ever-growing training data set from which machines learn to improve their ability to collect and classify quantitative information disclosed in 10-Ks automatically.

It is worth emphasizing that NC's use of machine learning was not meant to alter or improve analysts' decisions, but rather to mimic them. Most relevant to this paper, NC's machine learning algorithm did not optimize the classification of non-core-earnings items, for example, based on their historical or realized statistical properties. Instead, the machine learned and replicated human analysts' judgments based on their prior decisions. It did so with greater speed and scale to produce a database covering a broad cross-section of firms.

From its database, NC provided to us the non-core-earnings items summarized in various categories of "adjustments" for Russell 3000 firms from 1998 to 2017.⁴ Although NC has an extensive protocol to assure the quality of the data collection and classification decisions, we

⁴Some of the early parts of the data were parsed at a later time. To mitigate concerns about potential look-ahead bias, the Online Appendix (Tables OA.3-OA.5) shows that main inferences are unchanged using a subsample that begins after 2007. The data were parsed and classified on a real-time going-forward basis (with no back-filling) from 2008.

conducted two quality checks on the data.⁵ First, to provide a detailed quality assessment, we hand-checked a sample of roughly 350 unique specific non-core-earnings items NC identified. We compared the name of the item and the value of that item to what was reported in the 10-K. In 100% of instances, we perfectly matched the description, value, and disclosure location of that item in the 10-K. Second, for a broader assessment of quality, we compared the similarity in net income—a field that is not subject to analysts’ classification discretion—as reported by NC and Compustat. We find a correlation of 99% between the two datasets.

2.3 Defining *Core Earnings*

By definition, core earnings removes items from transitory shocks or ancillary business activities from *Net Income*. We conceptualize the former as those earnings items that, on a scale-adjusted basis, are non-recurring in the short-run and the latter as those earnings items that are non-recurring over a longer horizon. Under this framing, non-core-earnings items are less likely to persist or scale with fluctuations in the size of the business. To empirically capture this concept, we utilize NC’s data and adjust GAAP net income for revenues, expenses, gains, and losses identified by NC analysts that fit our definition as being non-core components of earnings. These adjustments fall within eight main economic categories of adjustments, detailed below.⁶

Net Acquisition Expenses equals the total losses minus gains from acquisitions or sales of assets. An example is Yahoo’s net gain of \$4.4 billion in 2012 from selling its Alibaba shares.

Net Currency Expenses equals the total losses minus gains from currency devaluations

⁵For more details on the data collection and quality assurance processes employed by New Constructs, see Wang and Thomas (2018), which was written for class discussion purposes and based on non-public information, including interviews with the organization.

⁶Based on our conceptualization, financing activities and tax consequences of central business activities can belong to core earnings. Thus, while NC analysts also identify interest expense from debt obligations or leases as “non-operating,” we do not include these categories in non-core-earnings adjustments.

or revaluations. An example is Tesla’s foreign-currency-exchange gain of \$12 million in 2013 due to the weakening Japanese Yen, which decreased Tesla’s Yen-denominated liabilities.

Net Discontinued Ops Expenses equals the total losses minus gains from discontinued operations. An example is Pfizer’s 2012 sale of its nutrition business to Nestle, which resulted in \$5.1 billion of revenue.

Net Legal Expenses equals the total losses minus gains arising from legal or regulatory events. An example is Nautilus Group’s \$18 million legal settlement in 2017.

Net Pension Adjustments consists of all net non-service-cost items included in a firm’s net period benefit-cost—the total cost expensed for a firm’s pension or post-retirement plans—minus any service income (negative service costs).⁷ An example is the Accenture 2017 pension settlement charge of \$510 million. Thus, the only pension and post-retirement-plan items included in *Core Earnings* are service costs and amortization of prior service costs.

Net Company-Defined Other Expenses are net losses that the company reports as “other” on the income statement. Items included in this category are those for which the company provides no additional information in the 10-K about the underlying event or transaction.

Finally, *Net Other Expenses* is a catch-all category capturing all other non-core-earnings items. It largely consists of amortization of capitalized interest, unrealized gains or losses related to derivatives and unconsolidated subsidiaries, and real-estate revaluations. It also includes items that adjust for changes in accounting treatments to make the measure compa-

⁷Non-service-cost items include interest cost (increases in the obligation due to the passage of time), expected return on plan assets (typically a credit for deferred expected realized returns on plan assets), settlements and curtailments (non-recurring charges that lower the obligation due to payouts or changes in plan terms), and amortization of actuarial gains or losses (charges that reflect changes in assumptions to explain changes in benefit obligations, amortized from other comprehensive income over time).

NC’s classification treats all net period benefit cost components outside of service cost or amortization of prior service costs as stemming from ancillary activities. This treatment is largely consistent with GAAP’s accounting treatment of these pension components. Specifically, FASB’s pension accounting standards update in 2017 (ASC 715-30) requires firms to report all but the service cost components of net period pension cost as part of the line item “other income/(expense)” in the income statement.

table over time, in particular, goodwill amortization and employee stock options expenses.⁸

Some of the items in each category are reported on a pre-tax basis, while others are reported on an after-tax basis, and they are separately reported by category in the data. To standardize all the adjustments, we estimate and apply an effective tax rate to all pre-tax non-core gains or expenses before aggregating them into the respective categories. We compute the effective tax rate as the ratio of pre-tax income and GAAP net income, and winsorize the measure at 0 and 1. For firms with missing values, we apply the statutory rate of 35%.⁹ Using the after-tax adjustments in each economic category, we construct:

$$\begin{aligned}
 \text{Core Earnings}_{i,t} &= \text{Net Income}_{i,t} + \text{Total Adjustments}_{i,t}, \\
 \text{where Total Adjustments}_{i,t} &= \text{Net Acquisition Expenses}_{i,t} \\
 &+ \text{Net Currency Expenses}_{i,t} \\
 &+ \text{Net Discontinued Ops Expenses}_{i,t} \\
 &+ \text{Net Legal Expenses}_{i,t} \\
 &+ \text{Net Pension Adjustments}_{i,t} \\
 &+ \text{Net Restructuring Expenses}_{i,t} \\
 &+ \text{Net Company-Defined Other Expenses}_{i,t} \\
 &+ \text{Net Other Expenses}_{i,t}.
 \end{aligned} \tag{1}$$

Our data also provide a decomposition of *Total Adjustments* based on the location of disclosure in the 10-K. *Total Adjustments from IS* consists of all net non-core expenses disclosed on the face of the income statement. *Total Adjustments from FN* (*Total Adjustments from MD&A*) consists of net non-core expenses disclosed in the footnotes (MD&A) and not

⁸Before the update of FAS 142 in 2002, companies amortized goodwill annually. Since 2002, companies are no longer required to amortize goodwill annually but are instead subject to an impairment standard. For all firm-years before the rule change, *Net Other Expenses* includes goodwill amortization expense. After 2002, *Net Other Expenses* includes goodwill impairment expense. Similarly, before the update of FAS 123 in 2006, companies were not required to expense stock options. Before 2006, *Core Earnings* are adjusted to reflect the expensing of stock options using data culled from footnote disclosures.

⁹In the Online Appendix (Tables OA.3-OA.5), we show our main results are robust to two alternative tax rate assumptions: a flat statutory rate of 35% applied to all firms and firms' cash effective tax rates computed following [Dyreng, Hanlon, and Maydew \(2008\)](#).

in the income statement. If an item is disclosed in both the footnotes and the MD&A (an uncommon occurrence) it is classified in the location where an analyst deems the information more comprehensively explained (typically footnotes). Finally, *Total Adjustments from CF* consists of net non-core expenses that are disclosed *only* in the cash flow statement.¹⁰ Our empirical examination of *Core Earnings* will analyze the information content of *Total Adjustments* and its location and economic sub-components.

2.4 Alternative Core Earnings Measures

Commonly used academic databases offer alternative metrics that could approximate core earnings for the cross-section of firms. For example, researchers commonly use Compustat-defined adjusted income metrics, such as *IBSPI* (e.g., Bradshaw and Sloan, 2002; Burgstahler, Jambalvo, and Shevlin, 2002), *OIADP* (Bushman et al., 2016), and *OPE* (Doyle, Jennings, and Soliman, 2013) (the definition of each metric is reported in Table A.1). Also, Compustat collects “special” items from economic categories similar to NC’s eight non-core-earnings types.¹¹ As we explain below, differences across these measures likely stem from two main sources: differences in (i) the economic categories of disclosures that data providers collect, and (ii) the data collection rules that data providers apply, even when holding constant the economic category of interest.

Fully reconciling the differences between Compustat’s and NC’s data collection and classification schemes is beyond this paper’s scope because we do not observe the providers’ processes and protocols. Nevertheless, to characterize these differences, we first show sta-

¹⁰One example is Coca Cola in 2017, which disclosed \$1.459 million from “Significant (gains) losses on sales of assets” in its cash flow from operations but not elsewhere in the 10-K.

¹¹The categories collected by Compustat are write-downs (*WDA*), legal and insurance settlements (*SETA*), restructuring costs (*RCA*), gains/losses (*GLA*), impairment of goodwill (*GDWLIA*), acquisitions/mergers (*AQA*), in-process R&D expense (*RDIA*), debt extinguishments (*DTEA*), non-recurring income taxes (*NRTXT*), and other special items (*SPIOA*). These fields are reported on an after-tax basis, and Compustat also reports similar fields on a per-share basis or a pre-tax basis.

tistically that *Total Adjustments* differs significantly from the items identified and excluded from Compustat’s adjusted earnings measures. For example, our Online Appendix (Table OA.1) shows that about 50% to 70% of the variation in *Total Adjustments* is not explained by *IBSPI Adjustments*, *OIADP Adjustments*, or *OPE Adjustments* individually. Moreover, larger values of non-core earnings (either by economic or location categories) identified in the NC data correspond to larger absolute differences between NC and Compustat adjustments, consistent with systematic differences in data collection protocol or quality.

We also studied several examples and, through extensive conversations with S&P Global’s Client Services team, identified three sources of systematic differences between NC and Compustat data. The first stems from how the data providers classify specific economic events, such as actuarial gains and losses or mark-to-market gains and losses on defined benefit plans. Firms aggregate these pension-related items in an operating expenses line item on the income statement, and Compustat typically does not exclude them from their adjusted earnings measures. For example, in 2012, UPS disclosed in the MD&A a mark-to-market loss of \$4.831 billion from its defined benefit plan, which is aggregated as a part of the “Compensation and benefits” expense line item on the income statement. Compustat included this loss as part of its “Cost of Goods Sold” (*COGS*) field, and thus it is included in *IBSPI*, *OIADP*, and *OPE*. Because NC identifies all net non-service-cost items as non-core, this loss is excluded from *Core Earnings*.¹²

The second type of difference stems from classification rules. One example is the “majority rule” that, until recently, was used to determine the contents of Compustat’s “special items” (*SPI*) field. The rule states that if a Compustat analyst cannot determine which income statement line an item is aggregated into for a (dollar value) majority of the iden-

¹²We identified similar examples of pension charges for Federal Express, Honeywell, Boeing, Verizon, and AT&T, all of which included charges of more than \$500 million, and all of which were categorized as operating expenses by both the firm and Compustat but excluded from *Core Earnings*.

tified non-recurring items, then no values are recorded for the *SPI* field (or its relevant sub-components). For example, Compustat analysts identified a total of \$11.9 billion of non-recurring items in Ford’s 2006 10-K footnotes. Because analysts could not identify where \$8.1 billion ($68\% = \$8.1/\$11.9$) of these items were included in the income statement (i.e., the specific line items), the *SPI* field—as well as the economic categories related to its calculation such as write-downs (e.g., *WDA*)—was left blank. Consequently, *IBSPI* and *OIADP* do not fully adjust for these items. However, the majority rule does not impact the calculation of *OPEPS*, which excludes the \$11.9 billion.¹³ No such rule affects NC’s data, which classifies the full \$11.9 billion as non-core.

Another example is the “three-year rule” for determining whether an item is non-recurring. To illustrate the rule, consider GM, which disclosed impairment charges related to property in its footnote from 2011 to 2013. These charges were included in various operating income line items on the income statement, and their magnitudes varied significantly (e.g., \$81 million in 2011 and \$3.8 billion in 2012). In 2011 and 2012, Compustat analysts classified these impairments as special items (part of *SPI*) and excluded them from *IBSPI*, *OIADP*, and *OPE*. However, in 2013 GM recorded another impairment charge related to property (\$901 million). Because this impairment appeared for three consecutive years, triggering the three-year rule, Compustat deemed the 2013 amount as recurring. Compustat does not include the amount in *SPI*—or the economic categories related to its calculation such as restructuring (e.g., *RCA*)—and leaves the charge as part of GM’s 2013 *COGS*, *IBSPI*, *OIADP*, and *OPE*. Moreover, the rule also deems as recurring the 2011 and 2012 amounts, which are retroactively moved from GM’s 2011 and 2012 *SPI* to the respective year’s *COGS*, *IBSPI*, *OIADP*,

¹³Compustat has stopped using the majority rule, although the S&P Global Client Services members we communicated with could not identify the exact year when the rule ceased to be in effect. In our correspondences, an analyst said the rule began being phased out “a few years” after 2006 and was unlikely to be applied after 2013. Compustat did not back-fill data for conformity after it stopped using the rule.

and *OPE*. The three-year rule, which is still in effect, illustrates a source of hindsight bias in Compustat data and an important difference in classification protocol—NC does not use such a rule and identifies all of GM’s charges from 2011 to 2013 as non-core.

A final source of differences is due to data collection oversights. Our examination suggests that, in general, Compustat does a thorough job identifying and collecting income-statement-related data points disclosed in the 10-K. Nevertheless, we identified cases where Compustat did not collect information relating to firms’ income that is useful in assessing core earnings. An example is YUM Brands, which disclosed in 2005 “Store Impairment Charges” of \$62 million in the footnotes. This value was rolled up on the income statement into a “Facility Actions” operating expense line item totaling \$19 million. Compustat did not collect the \$62 million impairment charge and included the entire \$19 million “Facility Actions” expense in its *SG&A* field as well as *IBSPI*, *OIADP*, and *OPE*. NC identified the \$62 million and classified it as a non-core expense.

Researchers also frequently use street earnings reported by IBES, which has been extensively studied by the prior literature. Street earnings can systematically differ from *Core Earnings* both because of sample coverage and the nature of the adjustments. Street earnings data are limited to the subset of firms with analyst coverage. Also, street earnings adjustments are not necessarily complete or comparable across firms. Prior research suggests they can systematically exclude certain operating and recurring items such as stock compensation expense (Barth et al., 2012) and may be biased due to managerial incentives.¹⁴

Although we explain why our data measure can differ significantly, and potentially offer improvement upon, commonly used adjusted earnings measures, it is ultimately an empirical

¹⁴Bentley, Christensen, Gee, and Whipple (2018) finds that, for a large majority of firms, manager-reported non-GAAP earnings are identical to the street earnings reported in IBES, which suggests general agreement between analysts and managers on how to adjust GAAP earnings to reflect core operating performance. This consensus raises the possibility that managerial bias that could be reflected in pro forma earnings (Curtis et al., 2014) is also reflected in street earnings, for which Doyle et al. (2013) provides empirical evidence.

question to what extent *Core Earnings* and *Total Adjustments* provide incremental information for forecasting purposes. For example, other data providers' classification rules could be more relevant, or NC data could embed some oversights. Therefore, to establish incrementality, our analyses of forecasting properties below will include Compustat or IBES adjusted earnings measures as controls.

3 Summary Statistics and Time-Series Trends

In this section, we characterize the adjustments that separate *Net Income* and *Core Earnings*. In doing so, we show that these adjustments are frequent, economically large, dispersed across sections of firms' 10-Ks, and growing over time.

We begin by examining to what extent firms disclose non-core-earnings items over their histories and, when they do, the frequency and magnitude of these disclosures. For comparability, we report summary statistics using the sample of 60,135 observations and 5,088 unique firms for which we have non-missing *Core Earnings* and Compustat adjusted earnings measures examined in our analyses (*IBSPI*, *OIADP*, *OPE*).

Table 1, Panel A, examines the likelihood of observing a non-core-earnings item in a given firm over its history in our 20-year sample. For each of the 5,088 firms, we compute and summarize indicator variables for the presence of non-core-earnings disclosures overall ($\mathbb{I}[\textit{All Adjustments over Firm History}]$), on the face of the income statement ($\mathbb{I}[\textit{On IS over Firm History}]$), off of the income statement ($\mathbb{I}[\textit{Off IS over Firm History}]$), in the MD&A ($\mathbb{I}[\textit{MD\&A over Firm History}]$), in the footnotes ($\mathbb{I}[\textit{FN over Firm History}]$), and in the cash flow statement ($\mathbb{I}[\textit{CF over Firm History}]$).

Our results suggest that nearly all firms disclose non-core-earnings items at some point in their history, both on and off the income statement. More than 99% of firms disclose

non-core-earnings items over our sample period. Similarly, more than 99% disclose one such item on the face of their income statement. Further, 83% disclose a non-core-earnings item off of the income statement over their histories, either in the footnotes (72%), MD&A (55%), or cash flow statement (60%) sections of their 10-Ks.

Table 1, Panel B, further examines the incidence and magnitudes of the various categories (location, economic type, and direction) of disclosed non-core-earnings items. When they are disclosed, firms report numerous non-core-earnings items on and off the face of the income statement. On average, there are 4.0 such items on the face of the income statement and 4.6 off the income statement. Similarly, net non-core-earnings items reported on the face of the income statement are similar in magnitude (on average \$19 million when a firm discloses one such item) to those reported off the income statement (on average \$23 million when a firm discloses one such item). Among the latter, MD&A and footnote disclosures are more economically significant than those from the cash flow statement. Given the substantial lower frequency of non-core-earnings disclosures in the MD&A, these summary statistics suggest that such disclosures in the MD&A tend to involve large losses.

Panel B also shows that, among the different economic categories of non-core-earnings items, the most common are restructuring-related: 41,869 firm-year observations (70% of the sample) report a non-core earnings item relating to restructuring activities. By contrast, the least typical non-core-earnings items stem from legal or regulatory events (9% of the sample). When a firm discloses a non-core-earnings item of a particular economic category, we observe, on average, only one such disclosure. Notable exceptions are pension and restructuring items, which average 5.8 and 2.3 among firms that disclose them. The mean values of the non-core-earnings items vary significantly across categories. For example, net expenses from *Restructuring* are \$36 million on average, whereas net expenses from *Company-Defined Other* are \$-1.76 million on average.

Finally, Panel B shows that income-increasing (i.e., that increase *Core Earnings* relative to *Net Income*) items are more significant in terms of frequency and magnitudes than income-decreasing (i.e., that decrease *Core Earnings* relative to *Net Income*) items. On average, when they are disclosed, four income-increasing items are identified in the 10-K versus an average of three income-decreasing items. Similarly, income-increasing items on average are larger in magnitude (on average \$130 million when a firm discloses one such item) than income-decreasing items (on average \$86 million when a firm discloses one such item). (For ease of comparison, income-increasing and income-decreasing items are summarized in absolute values). These patterns could be consistent with accounting conservatism. For example, U.S. GAAP does not allow for write-ups. The greater frequency of non-core expenses is likely also attributable to the nature of business conditions. For example, unexpected sources of expense outnumber unexpected sources of income. This tendency is reflected in the structure of the income statement, which typically provides only one line for revenue and sometimes a second line for “other income” but specifies numerous ways to spend the money that a company earns.

Table 2, Panel A, reports distributional statistics for *Core Earnings* per share and *Total Adjustments* per share for the full sample of firms, where we set the value in a particular economic category to 0 in the absence of identified non-core-earnings items. For much of our empirical analysis, we measure performance on a per-share basis for interpretability (e.g., because market participants are interested in earnings per share) and to account for scaling effects (e.g., Barth and Clinch, 1998, 2009). For comparison, we also report the distributional statistics of GAAP earnings (*Net Income*), other adjusted earnings measures from Compustat and IBES (*IBSPI*, *OIADP*, *OPE*, and *Street Earnings*) as well as *Cash Flow from Operations*, and their adjustments (*IBSPI Adjustments*, *OIADP Adjustments*, *OPE Adjustments*, *Total Accruals*, and *Street Earnings Adjustments*). All variables are winsorized at the top and

bottom 0.5% of the cross-sectional distribution and defined in Table A.1.

Of particular interest is that, across the full sample, average non-core earnings adjustments (*Total Adjustments*) amounts to an 18-cents-per-share increase in a firm's *Net Income*. These magnitudes are significant: average *Total Adjustments* represents 19% of average *Net Income* and about 16% of average *Core Earnings*.

Next, we analyze the time-series patterns. To facilitate comparisons across time, our analysis focuses on the sub-sample of 2,074 unique firms for which the NC data contain their full histories back to 1998. Figure 1 displays the average annual dollar value per share of *Total Adjustments*, *Core Earnings*, and *Net Income* from 1998 to 2017. All three series have increased in value over time. Notably, this figure demonstrates that non-core-earnings adjustments smooth out net income, consistent with these adjustments removing earnings shocks from transitory or ancillary business activities.

Figure 2 and 3 further illustrate how non-core-earnings items disclosed in the 10-K have evolved over time. Figure 2, Panel A, shows the average number of such items was six in 1998 and increased by 33% to an average of eight in 2017. This increase is driven by adjustments identified from the face of the income statement, which averaged 2.7 in 1998 and 4.2 in 2017 (a 56% increase). Off-income-statement non-core earnings disclosures saw a more modest increase over this period, from an average of 3.3 in 1998 to 3.8 in 2017 (a 15% increase). Nevertheless, the 2017 numbers suggest that about half of the total number of non-core-earnings items are reported off of the face of the income statement.

Figure 2, Panel B, shows that off-income-statement non-core-earnings items are most commonly disclosed in the footnotes, which averaged 3.1 in 1998 and 2.9 in 2017 (a 6.5% decline). Interestingly, the growth of off-income-statement items is mostly due to MD&A items, increasing from an average of 0.1 in 1998 to 0.5 in 2017 (500%).

Figure 3, Panel A, shows that average value per share of total, on-income-statement, and

off-income-statement non-core-earnings adjustments have grown significantly over time. It also shows that adjustments from the face of the income statement are much more volatile than those off of the income statement. This could be consistent with large transitory shocks more likely to be disclosed on the face of the income statement. Nevertheless, the average non-core-earnings values from footnotes often represent a significant percentage of total adjustments: In 11 of the 20 years in our sample, they exceed 35%. Moreover, Figure 3, Panel B, shows that disclosures in footnotes and the MD&A drove the growth in the average value of off-income-statement non-core-earnings items over our sample. Footnotes adjustments averaged \$0 per share in 1998 and \$0.035 in 2017. Similarly, MD&A adjustments averaged \$0.007 per share in 1998 and \$0.036 in 2017.

The summary statistics presented in this section attest to the economic importance, diversity, and complexity of non-core-earnings information in firms' 10-Ks. Nearly all firms disclose non-core-earnings items at some point, and they often make such disclosures off the income statement. Moreover, when a firm discloses a non-core-earnings item, both the total number and magnitudes of the adjustments are significant.

Taken together, our results illustrate the importance of the quantitative information disclosed off the income statement, in terms of their frequency and magnitude, and their different and evolving properties. Therefore, capturing and understanding the nature of core earnings requires the collection, synthesis, and analysis of quantitative information disclosed throughout the filings. Consequently, these findings also highlight the practical difficulty of measuring core earnings in large samples and point to growing data collection costs as a potential impediment to the timely reflection of earnings information in analysts' forecasts and market prices.

4 Forecasting Properties

This section examines properties of *Core Earnings* and *Total Adjustments* in terms of forecasting the future values of itself, *Net Income*, and other performance measures.

4.1 Persistence

We begin by examining how well *Core Earnings* distinguishes between the recurring and non-recurring components of *Net Income* (all measured on a per-share basis). A performance measure that effectively separates the recurring and non-recurring components of *Net Income* should display two fundamental properties. First, by removing the non-recurring components, such a measure should exhibit relatively high persistence, notably higher than that of *Net Income*. Second, the adjustments made (i.e., the difference between *Net Income* and the measure) should exhibit relatively low persistence.

The first property alone is not sufficient to assess how effectively a measure distinguishes between the recurring and non-recurring components of *Net Income*. In our sample, the cross-sectional persistence for revenues per share over a one-year horizon is 0.98 (untabulated). Clearly, revenues do not adequately reflect core earnings because they exclude components of operating profits that are persistent and part of firms' central activities. Not surprisingly, the difference between *Net Income* and revenues is also highly persistent. Similarly, the second property alone is insufficient because an ineffective core earnings measure could retain a large portion of transitory earnings items by excluding only a small subset of them from *Net Income*. In such a case, both the measure and its adjustments will exhibit relatively low persistence.

We begin with the persistence properties of *Core Earnings* over a one-year horizon. Table 2, Panel B, reports the distribution of the time-series AR(1) parameter for *Core Earnings*

and *Total Adjustments*, estimated by regressing the one-year-ahead measure on the current-period measure at the firm level. As a benchmark, we also report the persistence of *Net Income*. Because our database consists of only 21 years of data, we use the sample of (1,768) firms with at least 15 years of data to mitigate small-sample concerns.

The mean time-series AR(1) parameter for *Core Earnings* (0.59) is 30% larger than than for *Net Income* (0.45). Similarly, the mean AR(1) parameter for *Core Earnings* is 3.5 times as large as *Total Adjustments*, consistent with *Core Earnings* distinguishing the more and less persistent components of *Net Income*.

We next examine the *cross-sectional* persistence of *Core Earnings*, which is more relevant for many asset-pricing contexts. We estimate ϕ from the following regression:

$$Performance_{i,t+1} = \alpha + \phi \times Performance_{i,t} + \eta_t + \epsilon_{i,t+1}, \quad (2)$$

where η_t are year-fixed effects, and ϕ capture the extent to which differences in performance *between* firms in one year forecast differences in performance the following year.

Table 3, Panel A, reports a cross-sectional persistence parameter of 0.637 for *Net Income* (column 1) and 0.810 for *Core Earnings* (column 2), which is about 30% higher than *Net Income* and 4.5 times the persistence of *Total Adjustments* (0.178 in column 3). Consistent with the time-series results, these findings show *Core Earnings* is effective at excluding the less persistent components of *Net Income*.

As a GAAP benchmark, columns 4 and 5 report the cross-sectional persistence of *Cash Flow from Operations* and its adjustments (*Total Accruals*). Although *Cash Flow from Operations* is relatively persistent (0.785), it is only 1.7 times as persistent as *Total Accruals*. At 0.459, *Total Accruals* is 2.6 times as persistent as *Total Adjustments*, suggesting that *Cash Flow from Operations* excludes a significant amount of persistent earnings items.

For comparison, Table 3, Panel B, reports analogous tests of *IBSPI*, *OIADP*, and *OPE*, and their adjustments. Overall, *OIADP* exhibits the highest cross-sectional persistence (0.861), about 6% higher than *Core Earnings*. However, *OIADP* is only 1.4 times as persistent as *OIADP Adjustments*. At 0.612, *OIADP Adjustments* is nearly as persistent as *Net Income*. Like *Cash Flow from Operations*, *OIADP* is not particularly effective at excluding the less persistent components of *Net Income*. Both *IBSPI* and *OPE* are more effective at doing so, with *OPE*'s persistence properties being the most similar to those of *Core Earnings*: *Core Earnings* exhibits 3% higher persistence than *OPE*, but *Total Adjustments* is also 3% more persistent than *OPE Adjustments*. Moreover, *OPE* is about 4.5 times as persistent as *OPE Adjustments*, similar to the relation between *Core Earnings* and *Total Adjustments*. These results suggest that *Core Earnings* and *OPE* perform best in distinguishing the persistent and transitory components of *Net Income* over a one-year horizon.

We also examine the persistence properties of *Core Earnings* and other adjusted earnings measures over a longer horizon. Figure 4 reports the ratio of persistence parameters between *Core Earnings* and *Total Adjustments* over a five-year horizon, where we estimate the T -period persistence from an equation similar to Eq., (2) but with $Performance_{i,t+T}$ as the dependent variable. We also report persistence ratios of other adjusted earnings measures for comparison.

Figure 4 shows the persistence ratio of *Core Earnings* is growing over the five-year horizon and is generally higher than the persistence ratio of all other adjusted earnings measures. In year five, for example, *Core Earnings* continues to exhibit substantially higher persistence than *Net Income* (0.64 versus 0.46 or 30% higher), while the persistence of *Total Adjustments* is only 0.04, the lowest among all the adjustments considered. The diminishing persistence of *Total Adjustments* suggests that certain components of non-core earnings, such as those gains or losses that are not a part of central activities, could exhibit some degree of recurrence

in the short run but diminishingly so over a longer horizon. Our evidence overall suggests that *Core Earnings* is effective at excluding non-recurring components of earnings, which we show below aids in forecasting future performance.

4.2 Forecasting Future Performance

Next, we examine whether *Core Earnings* contains incremental information about firms' future performance. A measure that effectively distinguishes the persistent and transitory components of *Net Income* should, in theory, help to forecast future *Net Income*. To see this, consider the following stylized model of earnings (e_t) which contains a persistent (z_t) and a transitory (v_t) component:

$$\begin{aligned} e_{t+1} &= z_{t+1} + v_{t+1}, \text{ and} \\ z_{t+1} &= z_t + u_{t+1}, \end{aligned}$$

where u_{t+1} and v_{t+1} are iid and mean-zero innovations with finite variances. This implies only the persistent component of current-period earnings is relevant for forecasting future earnings: $e_{t+1} = z_t + u_{t+1} + v_{t+1}$. Isolating the persistent component of e_t should therefore improve upon its forecasting power for e_{t+1} . However, in general, the ability to exclude the transitory portions of earnings need not be the *only* property that could lead to greater predictive power for future earnings. Other relevant properties include the ability to distinguish the influence of earnings management or identify longer-term strategic changes, which are outside the scope of our analyses.

To assess how well *Core Earnings* forecasts future *Net Income*, Panel C of Table 2 reports the cross-sectional mean-squared errors (MSE) from forecasting one-year-ahead *Net Income* using current-period *Net Income* and current-period *Core Earnings*. Our results show the time-series-average MSE produced by *Core Earnings* is 20% lower than that produced by

Net Income: i.e., *Core Earnings* is a significantly better forecaster of future *Net Income* than current-period *Net Income*.

Table 4, column 1, provides a more general assessment of the incremental forecasting ability of *Core Earnings* for one-year-ahead *Net Income*, using multivariate OLS:

$$\begin{aligned}
 \text{Net Income}_{i,t+1} = & \gamma_0 + \gamma_{AE} \times \text{Core Earnings}_{i,t} + \gamma_{NI} \times \text{Net Income}_{i,t} \\
 & + \gamma_{CFO} \times \text{Cash Flow from Operations}_{i,t} + \gamma_{IBSPI} \times \text{IBSPI}_{i,t} \\
 & + \gamma_{OIADP} \times \text{OIADP}_{i,t} + \gamma_{OPE} \times \text{OPE}_{i,t} + \eta_t + \epsilon_{i,t+1},
 \end{aligned} \tag{3}$$

where η_t are year-fixed effects as before.

Our results show that *Core Earnings* contains information for future *Net Income* that is incremental to contemporaneous *Net Income*, as well as other adjusted earnings measures. The coefficient on *Core Earnings* is positive and the largest both in economic magnitude and statistical significance (at the 1% level).

For comparison, in Table 4, columns 2-6, we assess the incremental predictive ability of *Core Earnings* for other measures of one-year-ahead performance. In particular, we estimate a specification similar to Eq., (3) but use as the dependent variable one-year-ahead *Cash Flow from Operations*, *Core Earnings*, *IBSPI*, *OIADP*, or *OPE*.

Although our main focus is on forecasting *Net Income*, these additional results are descriptively interesting because the alternative performance measures represent a set of accrual- and cash-flow-based operating performance measures that could be important to managers' and investors' decision contexts. Thus, the additional tests provide a broader assessment of the incremental usefulness of *Core Earnings* for understanding firms' prospects. Table 4 shows that, in each case, *Core Earnings* contains incremental information about future performance: The coefficient on *Core Earnings* is positive and statistically significant at the

1% level. The results also suggest that the variation in *Total Adjustments* is incremental to Compustat’s adjustments for future performance.

In our Online Appendix (Table OA.2), we examine the predictive ability of *Core Earnings* for future performance over a longer horizon. We repeat the analysis of Table 4, but use two- to five-year-ahead variants of each performance measure. For each of the performance measures considered, we continue to find incremental predictive ability in *Core Earnings*, consistent with *Core Earnings* effectively distinguishing the recurring and non-recurring components of *Net Income*.

4.3 Future Performance and *Total Adjustments* Components

To provide a deeper understanding of different non-core-earnings items’ information content, we also examine the sub-components of *Total Adjustments* and firms’ future performance. Table 5, Panel A, reports results from regressing measures of one-year-ahead performance on *Net Income* and the net adjustment amounts that stem from the income statement, footnotes, MD&A, and cash flow statement sections of the 10-K. The categories of adjustment that help drive the observed predictive relations will exhibit a positive slope coefficient.

Generally, net adjustments identified from the income statement, footnotes, and MD&A are strongly predictive of future performance. Although adjustments from the cash flow statement generally exhibit a positive relation with future performance, it obtains statistical significance only in forecasting *Cash Flow from Operations*. We expect weaker statistical significance for these adjustments because, compared to the net adjustments derived from different parts of the 10-K, adjustments from the cash flow statement are the least significant in frequency, magnitudes, and variation (e.g., Table 1, Panel B).

Table 5, Panel B, repeats the analysis above for the eight economic categories of *Total*

Adjustments (Eq., (1)). Except for *Net Currency Expenses* and *Net Company-Defined Other Expenses*, the coefficients on each economic category are positive and statistically significant at the 5% level, suggesting that the predictive content of *Total Adjustments* for future performance is present across categories. The coefficients on *Net Currency Expenses* and *Net Company-Defined Other Expenses* are positive in all but one case. However, their statistical significance is generally weak, probably because they are the least significant in terms of frequency, magnitudes, and variation (e.g., Table 1, Panel B).

To better understand the relation between the non-core-earnings categories and future performance, Table 6 reports the persistence parameters for each adjustment category over a one-year horizon, following Table 3. Panel A, column 1, reports the persistence parameters of net adjustments stemming from the income statement, footnotes, MD&A, and cash flow statement sections of the 10-K, and Panel B, column 1, reports the persistence parameters of net adjustments from each of the eight economic categories of *Total Adjustments*. Although there is variation in the persistence across categories, in each case the persistence parameter is significantly lower than *Net Income* and *Core Earnings* (Table 3 columns 1 and 2).

In columns 2 and 3 of Table 6, we further decompose the persistence of each non-core-earnings type into their income-increasing (i.e., when there are net expenses) and income-decreasing (i.e., when there are net gains) parts. Generally, we find a lower level of persistence in the income-decreasing components of net adjustments.

Although some categories of adjustments exhibit higher degrees of persistence over a one-year horizon, we find that the persistence parameters for all categories decline significantly over time, consistent with these items being less persistent over a longer horizon (results untabulated). For example, the persistence parameters of *Acquisitions*, *Pension*, and *Restructuring* decline to 0.09, 0.30, and 0.06 by year five, declines of 50% to 75%.

4.4 Robustness: *Core Earnings* and *Street Earnings*

Our final analysis of the forecasting properties of *Core Earnings* examines whether its predictive power for future *Net Income* and other performance measures is incremental to *Street Earnings*, a non-GAAP income measure provided by IBES that is commonly used and analyzed in the literature.¹⁵ This measure also can serve as a proxy for managers' non-GAAP earnings, as Bentley et al. (2018) finds the two overlap in a majority of instances. Because about 20% of our sample does not have analyst forecast data from IBES, we conduct this analysis separately using a subsample of observations with non-missing *Street Earnings*.

Table 7 reports results analogous to Table 4, but includes *Street Earnings* as an additional contemporaneous control in each specification. We also add a specification (in column 3) that considers one-year-ahead *Street Earnings* as the dependent variable of interest. Table 7 shows that *Core Earnings* contains information about future performance that is incremental to *Street Earnings*: In each specification, the coefficient on *Core Earnings* is positive and statistically significant at the 5% level.

Together, Tables 3-7 provide novel evidence on the predictive and persistence properties of non-core-earnings components of GAAP net income. Our empirical evidence suggests that non-core-earnings components are informative of future performance. However, information about them is dispersed across various parts of the 10-K (both on and off the income statement). Given the increasing complexity and length of financial reports, our findings highlight the increasing processing costs market participants face in obtaining value-relevant information from 10-Ks. Our analyses also suggest that the predictive ability of *Core Earnings* stems, at least in part, from its ability to distinguish the recurring and non-recurring

¹⁵Compustat provides a variable, "S&P Core Earnings," that makes eight adjustments to net income to better measure core earnings: impairment of goodwill, settlements, implied option expense, gain/loss on sale, restructuring charge, pension adjustments, and retirement adjustments. We do not examine this variable because it is sparsely populated.

components of *Net Income*. Nevertheless, by weighting or selectively excluding certain adjustment categories, it may be possible to improve upon *Core Earnings* in terms of its ability to forecast future performance. To the extent that is so, our results can be considered conservative.

5 Market Processing of Non-Core Earnings

We proceed to analyze whether market participants grasp the subtleties of earnings components and impound the implications of the distinction between core and non-core earnings.

5.1 Future Analyst Forecast Revisions

We begin by examining how analysts respond to non-core-earnings items. To the extent that analysts respond promptly, their earnings forecast revisions in the year following a 10-K filing would not be systematically related to the sign and magnitude of non-core earnings.

Table 8 reports the results from pooled cross-sectional regressions of *Forecast Revisions* on *Total Adjustments*, where *Forecast Revisions* is the average monthly difference in mean analyst earnings-per-share forecasts over the 12 months after 10-K filing date. Column 1 shows that higher *Total Adjustments*—that is, understatement of *Net Income* as a measure of core earnings due to non-core expenses—forecasts increases in analysts' earnings-per-share forecasts during the 12 months following the 10-K filing. The coefficient on *Total Adjustments* is positive and significant at the 5% level. This result is robust to the inclusion of the following controls: *Earnings Surprise* and *Lagged Forecast Revisions* in column 2, *Size* and *Book-to-Market* in column 3, and the adjustments embedded in other adjusted earnings measures in column 4. Notably, column 4 shows that *IBSPI Adjustments*, *OIADP Adjustments*, *OPE Adjustments*, and *Street Adjustments* are not statistically significantly

(at the 10% level) associated with analysts' future forecast revisions; only *Total Adjustments* and *Total Accruals* exhibit statistically significant relations.

Table 8, column 5, further examines how forecast revisions respond to the non-core-earnings items from the different parts of the 10-K. We replicate the specification of column 4 but replace *Total Adjustments* with *Total Adjustments from IS*, *Total Adjustments from FN*, *Total Adjustments from MD&A*, and *Total Adjustments from CF*. We find a positive and statistically significant coefficient on both *Total Adjustments from IS* and *Total Adjustments from FN*, with the statistical significance and economic magnitude of the coefficient being the largest for the non-core-earnings items stemming from the footnotes.

These findings suggest analysts are not efficient in incorporating the implications of non-core earnings into their forecasts, particularly those disclosed in the footnotes of the 10-K. These findings are consistent with behavioral biases or with incentive-misalignment problems among analysts (see, e.g., [Kothari, So, and Verdi, 2016](#), for a review), as well as the footnotes being a less structured and less salient section of the 10-K.

5.2 Stock Market Returns

Our final tests examine whether market prices impound the implications of non-core-earnings items efficiently. We begin with portfolio-level average returns. Table 9 divides firm-years into deciles, based on the magnitude of *Total Adjustments* relative to the distribution from the prior calendar year. Firms in the highest decile have the highest dollar value of income-increasing adjustments; those in the lowest decile have the highest dollar value of income-decreasing adjustments.

To the extent that investors under-appreciate the implications of non-core-earnings items, for example, due to underreacting to low-salience earnings signals (e.g., [Sloan, 1996](#)) or

overweighting analysts' forecasts (e.g., [So, 2013](#)), we expect the stock returns of the highest decile portfolio to outperform those in the lowest decile. The intuition is that firms' core earnings in the highest decile are relatively high compared to GAAP earnings and vice versa for the lowest decile firms. As investors learn about firms' core earnings over time, stock prices adjust gradually.

Table 9 summarizes the value-weighted returns to each decile of total adjustments scaled by assets. Value weights are based on firms' market capitalization in the month before the 10-K filing. The first column summarizes average 12-month raw returns: firms in decile 10 have a value-weighted average annual return of 11.9%, and firms in decile 1 have an average return of 3.5%. The 8.4% spread in raw returns is both statistically and economically significant. The spread in raw returns concentrates among the lowest decile, suggesting investors are particularly slow at pricing adjustments that overstate GAAP relative to core earnings (e.g., large non-recurring gains). These findings dovetail nicely with [Curtis et al. \(2014\)](#), which shows that managers are less likely to recognize non-recurring gains in their non-GAAP earnings disclosures. Jointly, these results are consistent with investors being less likely to efficiently incorporate into price the implications of less salient earnings items.

The remaining columns in Table 9 report factor loadings and abnormal monthly returns from a calendar-time portfolio trading strategy. We estimate and report abnormal returns (ALPHA) for each decile portfolio and for the long-short portfolio (decile 10 minus decile 1) using the Fama-French three-factor model—with a market factor (MKTRF), a size factor (SMB), and a value factor (HML)—augmented with the momentum factor (UMD). We find the mean difference in monthly abnormal returns between the tenth-decile and first-decile value-weighted portfolios to be 0.66%. These monthly excess returns are both statistically and economically significant, equating to an annualized difference of 8.2%. These figures are particularly impressive in light of the fact that they are produced by a fairly low-turnover

portfolio-trading strategy, since each firm files only one 10-K per year.¹⁶

We complement the portfolio-based findings in Table 9 by examining the link between future returns and *Total Adjustments* in multivariate tests. Table 10 reports the results of regressing firms' market-adjusted returns during the 12 months following the 10-K filing date on *Total Adjustments* and several control variables.

Column 1 reports the regression counterpart of Table 9, using the same underlying sample of observations with no controls. Columns 2-5 then incrementally add control variables. In columns 1-3, the coefficients on *Total Adjustments* are positive and significant and incremental to a set of standard control variables known to explain the cross-section of returns: firm size, book-to-market, momentum, gross profit, and share turnover. These findings suggest that our results are unlikely driven by well-known asset pricing factors.¹⁷

In column 4, the coefficient on *Total Adjustments* remains positive and significant after controlling for analyst dispersion and coverage, which prior research links to the cross-section of returns (e.g., Kothari et al., 2016; Lee and So, 2017). These results mitigate concerns that our results stem from the pricing of information asymmetries or investor disagreement stemming from complexity in the financial reporting process.

Column 5 controls for the alternative earnings adjustments considered in this paper, in particular the adjustments embedded in *Cash Flow from Operations*, *IBSPI*, *Street Earnings*, *OIADP*, and *OPE*. As with *Total Adjustments*, we scale each of these adjustments by

¹⁶In untabulated results, we find qualitatively similar results using equal-weighted portfolios. For example, the mean difference in monthly abnormal returns between the tenth-decile and first-decile equal-weighted portfolios is 0.57%, or 7.1% annualized.

¹⁷In our return-prediction tests, *Total Adjustments* is scaled by total assets to neutralize the potential effects of firm size on stock returns, which is a standard approach common to asset pricing studies focused on firms' profits (e.g., Sloan, 1996; So, 2013; Novy-Marx, 2013) and facilitates interpretability in these regressions. Our Online Appendix (Table OA.5) shows that we obtain similar inferences when scaling by shares outstanding. It also shows (Tables OA.3-OA.4) that our main results on the persistence and forecasting properties of *Core Earnings* remain similar if we instead scale the adjusted earnings and adjustment measures by total assets. Thus, our main findings are robust to the use of a consistent deflator.

total assets. Of particular note, we find the inclusion of these variables decreases the significance of *Total Adjustments*, which is consistent with the findings in (Dechow and Ge, 2006) that investors overestimate the persistence of Compustat-identified special or unusual items. Nonetheless, with the inclusion of these controls, we find that the coefficient on *Total Adjustments* remains positive and statistically significant, indicating that the measure captures information distinct from alternative earnings adjustments studied in prior research.

Finally, in column 6, we examine how the return-predictive relation of *Total Adjustments* varies based on the location of disclosure in the 10-K. We replicate the specification of column 5, but replace *Total Adjustments* with *Total Adjustments from IS*, *Total Adjustments from FN*, *Total Adjustments from MD&A*, and *Total Adjustments from CF*. Consistent with our findings with analyst forecast revisions, we find a positive and statistically significant coefficient on both *Total Adjustments from IS* and *Total Adjustments from FN*, with the statistical significance and economic magnitude of the coefficient being the largest for the adjustments stemming from the footnotes. The incremental significance of these adjustment measures when controlling for *IBSPI* and *OIADP* suggests that the predictive power of our measures for returns stems from identifying less obvious items that are not reflected in Compustat *Special Items* or non-operating earnings.

Overall, the results of Table 8, 9, and 10 suggest that market participants are inefficient in impounding the implications of non-core earnings, especially those stemming from the footnotes of the 10-K, into stock prices. One explanation is that the information in the footnotes is less structured and less salient compared to the information disclosed on the face of the income statement or in the MD&A.

6 Conclusion

This paper shows that disclosures of income-statement items stemming from ancillary business activities or transitory shocks are frequent and economically significant, and increasingly so over the last 20 years. A significant proportion of these items, in terms of frequency and magnitude, is disclosed off the income statement in less structured or salient parts of the 10-K. Using a novel database that comprehensively identifies these items for public firms, we find that adjusting GAAP earnings to exclude these items produces a measure of core earnings that possesses several desirable properties. For example, it distinguishes the persistent and transitory components of *Net Income*, and forecasts future *Net Income* and a variety of other performance measures relevant to managers' and investors' decision contexts. However, we find that analysts and other market participants are slow to impound the implications of the distinction between core and non-core earnings, especially those disclosed from the footnotes section of the 10-K.

The implications of these findings are potentially far-reaching for investors and researchers. Our results highlight the importance of detailed financial statement analysis, including the information disclosed off of the income statement, for understanding, measuring, and forecasting firms' performance. At the same time, our analyses can inform regulators and policymakers. In particular, our findings attest to the large and growing computational costs of processing information in firms' 10-Ks. These costs point to the potential for increasing inequities in the usefulness of financial statements for sophisticated versus unsophisticated investors who differ in their technological capabilities for processing 10-K information. Recognition of these issues has led standard setters to explore when and how to better disaggregate and classify line items on the financial statements (e.g., IASB's ongoing "Primary Financial Statements project"). Our findings highlight a potential hidden downside asso-

ciated with more granular disclosures and point to potential gains from standardizing and making more easily accessible their location and format to reduce processing costs.

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Table A.1.
Description of Variables

This table defines variables used in our analysis. Accounting variables are retrieved from New Constructs and Compustat, as described below. Where Compustat (IBES) {CRSP} variables are used, the variable abbreviation is reported in brackets (parentheses){curly brackets}.

Variable	Description	Computation
<i>Book-to-Market</i>	Natural log of the book-to-market ratio	Calculated as $1 + \text{Book value of Equity [CEQ]} / (\text{Shares Outstanding \{SHROUT\}} \times \text{Share Price \{PRC\}})$ from five days prior to the 10-K filing
<i>Cash Flow from Operations</i>	Annual net operating cash flow	$(\text{Net Operating Cash Flow [OANCF]} - \text{Extraordinary Items and Discontinued Operations [XIDOC]}) / \text{Common Shares Outstanding [CSHO]}$
<i>Core Earnings</i>	Annual core earnings estimated using NC data	$(\text{Net Income [NI]} + \text{Net Acquisition Expenses} + \text{Net Currency Expenses} + \text{Net Discontinued Ops Expenses} + \text{Net Legal Expenses} + \text{Net Pension Adjustments} + \text{Net Restructuring Expenses} + \text{Net Company-Defined Other Expenses} + \text{Net Other Expenses}) / \text{Common Shares Outstanding [CSHO]}$
<i>Coverage</i>	Analyst coverage	Natural log of the total number of analysts covering the firm (NUMEST)
<i>Dispersion</i>	Analyst forecast dispersion	$1 + \text{the natural log of the standard deviation of analysts' earnings forecasts (STDEV)}$
<i>Earnings Surprise</i>	Difference between <i>Street Earnings</i> and mean analyst earnings estimate	$\text{Street Earnings (ACTUAL)} - \text{Mean Analyst Estimate (MEANEST)}$
<i>Forecast Revisions</i>	Average monthly change in analysts' consensus earnings-per-share estimate for the following year	Month-over-month change in the mean analyst estimate (MEANEST)
<i>Gross Profit</i>	Annual gross profit	$(\text{Revenue [REVT]} - \text{COGS [COGS]}) / \text{Total Assets [AT]}$
<i>IBSPI</i>	(Income before special items	$(\text{Net income [NI]} - \text{Special Items [SPI]}) / \text{Common Shares Outstanding [CSHO]}$
<i>IBSPI Adjustments</i>	Special items	$(\text{IBSPI} - \text{Net Income [NI]}) / \text{Common Shares Outstanding [CSHO]}$
<i>Momentum</i>	Stock return from prior 12 months	12-month cumulative buy-and-hold returns RET during the 12 months ending 10 days before 10-K filing
<i>Net Acquisition Expenses</i>	Annual non-core net expenses due to acquisitions	Net acquisition-related transactions that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]

Table A.1 Continued.

Variable	Description	Computation
<i>Net Company-Defined Other Expenses</i>	Annual net expenses from company-defined “other” expenses	Net transactions that impact <i>Net Income</i> that the company defines as “other” on the income statement/Common Shares Outstanding [CSHO]
<i>Net Currency Expenses</i>	Annual non-core net expenses due to foreign currency fluctuations	Net foreign-currency-related transactions that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Net Discontinued Ops Expenses</i>	Annual non-core net expenses due to discontinued operations	Net transactions related to discontinued operations that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Net Income</i>	Annual net income	GAAP Earnings [NI]/Common Shares Outstanding [CSHO]
<i>Net Legal Expenses</i>	Annual non-core net expenses due to legal, regulatory, and insurance events	Net transactions related to legal, regulatory, or insurance events that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Net Other Expenses</i>	Annual non-core net expenses that do not belong to other categories	All other net transactions that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Net Pension Expenses</i>	Annual non-core net expenses due to pension plans	Net pension-related transactions that impact <i>Net Income</i> and that are deemed non-core by NC/Common Shares Outstanding [CSHO]
<i>Net Restructuring Expenses</i>	Annual non-core net expenses due to restructuring	Net restructuring-related transactions that impact <i>Net Income</i> and that are deemed non-core by NC/Common Shares Outstanding [CSHO]
<i>OIADP</i>	Operating income	Operating income after depreciation [OIADP]/Common Shares Outstanding [CSHO]
<i>OIADP Adjustments</i>	Non-operating income	(<i>OIADP</i> [OIADP] - <i>Net Income</i> [NI])/Common Shares Outstanding [CSHO]
<i>OPE</i>	Earnings from operations	Earnings per share from operations [OPEPS] $\times$ Common shares used to calculate earnings per share basic [CSHPRI]/Common Shares Outstanding [CSHO]
<i>OPE Adjustments</i>	Earnings not from operations	(<i>OPE</i> - <i>Net Income</i> [NI])/Common Shares Outstanding [CSHO]

Table A.1 Continued.

Variable	Description	Computation
<i>Ret</i>	Market-adjusted annual return	Calculated as firm return {RET} minus market return (using the CRSP value-weighted index {VWRETD}) for the 12 months beginning three months after the fiscal-year end
<i>Share Turnover</i>	Trading volume	Daily Trading Volume {VOL} / Daily Shares Outstanding {SHROUT}, averaged over the six months prior to the 10-K filing date
<i>Size</i>	Natural log of market capitalization	Log(Shares Outstanding {SHROUT} from five days prior to the 10-K filing $\times$ Share Price {PRC} from five days prior to the 10-K filing)
<i>Special Items</i>	Special items	Special items [SPI]/Common Shares Outstanding [CSHO]
<i>Street Earnings</i>	Adjusted earnings per share as compiled by IBES	Street earnings per share (ACTUAL)
<i>Street Adjustment</i>	Difference between <i>Street Earnings</i> and <i>Net Income</i>	(Street earnings per share (ACTUAL) $\times$ Shares outstanding used for street EPS (SHOUT) - <i>Net Income</i> [NI])/Common Shares Outstanding [CSHO]
<i>Total Accruals</i>	Total accruals	(<i>Net Income-Cash flow from Operations</i>)/Common Shares Outstanding [CSHO]
<i>Total Adjustments</i>	Net expenses from income-statement items that are transitory or stem from ancillary business activities	(<i>Net Acquisition Expenses</i> + <i>Net Currency Expenses</i> + <i>Net Discontinued Ops Expenses</i> + <i>Net Legal Expenses</i> + <i>Net Pension Adjustments</i> + <i>Net Restructuring Expenses</i> + <i>Net Company-Defined Other Expenses</i> + <i>Net Other Expenses</i>)/Common Shares Outstanding [CSHO]
<i>Total Adjustments from CF</i>	Annual non-core net expenses reported in the cash flow statement	Total net expenses reported in the cash flow statement that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Total Adjustments from FN</i>	Annual non-core net expenses reported in the footnotes	Total net expenses reported in the footnotes that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Total Adjustments from IS</i>	Annual non-core net expenses reported on the income statement	Total net expenses reported on the face of the income statement that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]
<i>Total Adjustments from MD&A</i>	Annual non-core net expenses reported in the MD&A	Total net expenses reported in the MD&A that impact <i>Net Income</i> and that are deemed to be non-core by NC/Common Shares Outstanding [CSHO]

Fig. 1. Average Total Adjustments, GAAP Earnings, and Core Earnings

This figure displays time-series patterns in non-core-earnings adjustments across the sample period. The blue line is the average core earnings per share, the dashed line is the GAAP earnings per share, and the red line is the average total adjustments per share.

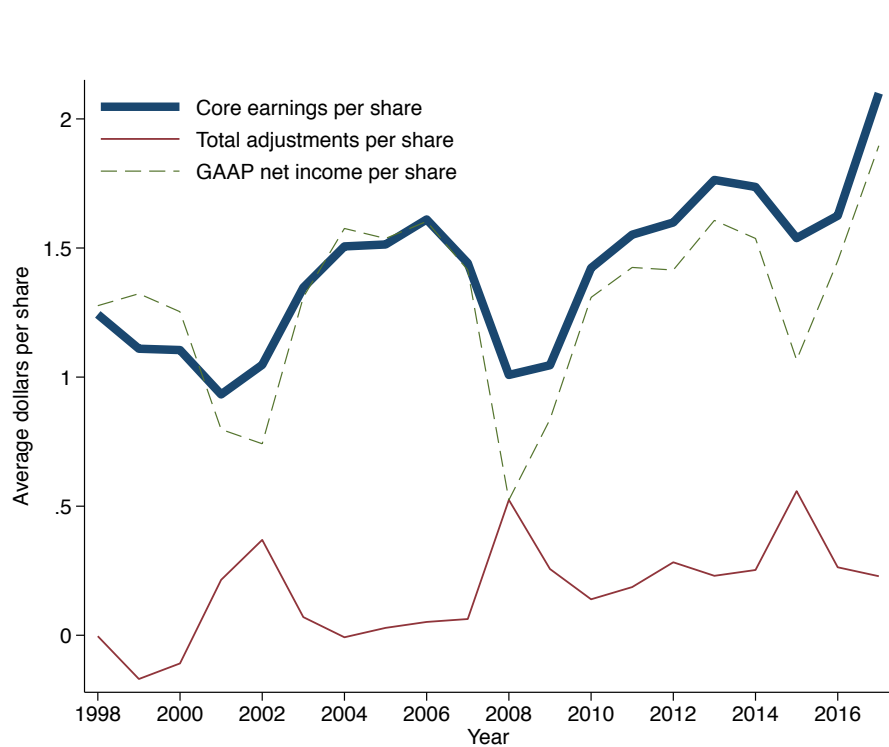


Fig. 2. Average Annual Number of Non-Core Earnings Adjustments by 10-K Disclosure Location

This figure displays time-series patterns in the frequency of non-core-earnings items from 1998 to 2017. Panel A shows the average number of items identified in firms' 10-Ks (Total) as well as the average number of items disclosed on (IS) and off (Off-IS) the income statement. Panel B decomposes off-income-statement non-core-earnings items and displays the average number of items disclosed in the footnotes (FN), cash flow statement (CF), and MD&A sections of the 10-K.

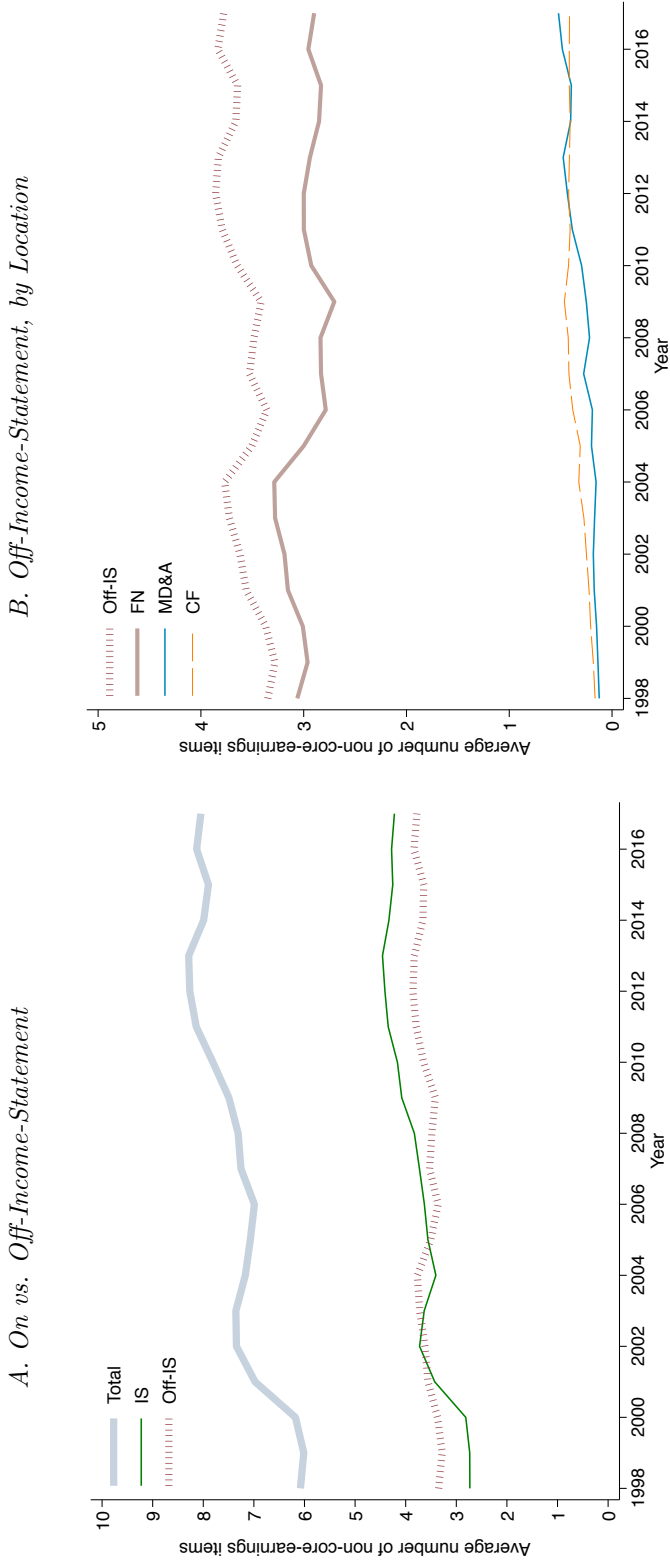
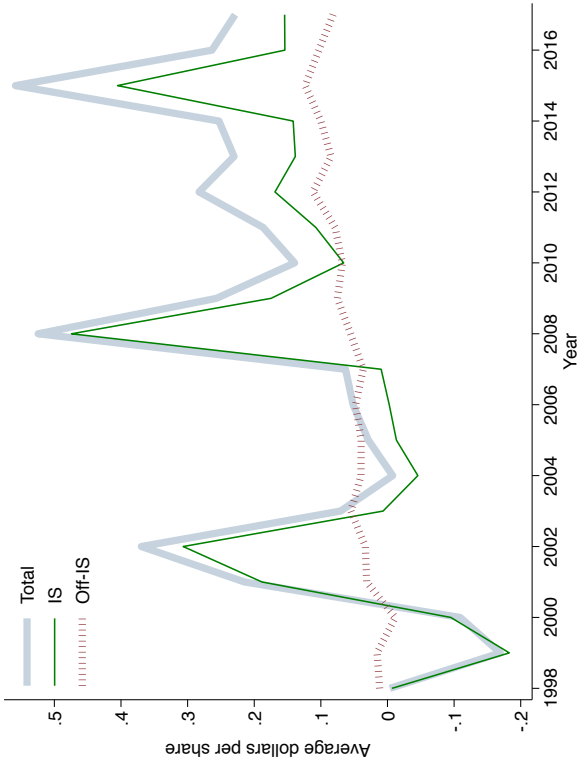


Fig. 3. Average Value per Share of Non-Core Earnings Adjustments by 10-K Disclosure Location

This figure displays time-series patterns in the per-share value of non-core-earnings items from 1998 to 2017. Panel A shows the average per-share value of items identified in firms' 10-Ks (Total) as well as the average per-share value of items disclosed on (IS) and off (Off-IS) the income statement. Panel B decomposes off-income-statement non-core-earnings items and displays the average per-share value of items disclosed in the footnotes (FN), cash flow statement (CF), and MD&A sections of the 10-K.

A. *On vs. Off-Income-Statement*



B. *Off-Income-Statement, by Location*

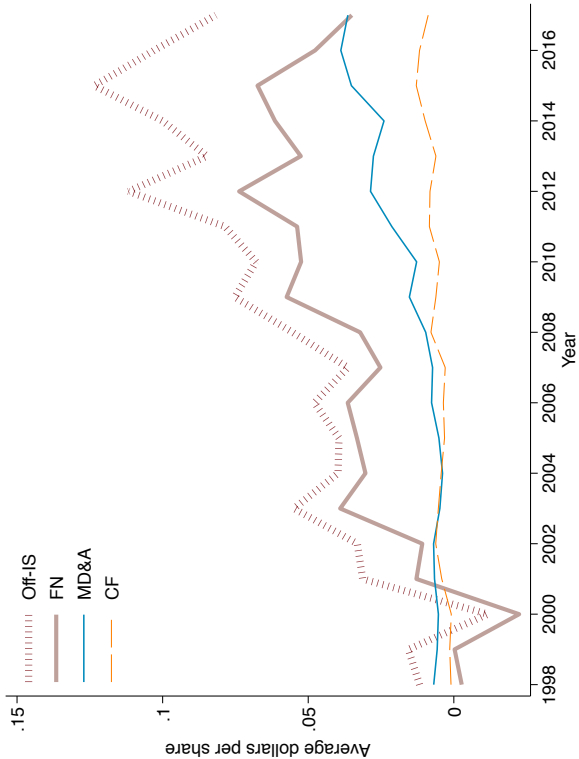


Fig. 4. Persistence Ratio of Earnings and Adjustments

This figure displays the persistence ratio of adjusted earnings measures and their adjustments to *Net Income* over a five-year horizon. The ratio is calculated as the persistence parameter from regressing the adjusted earnings measure in year $t + T$ on the measure in year t (analogous to Eq., (2)), divided by the persistence parameter over the same horizon for the adjustments used to calculate the earnings measure (i.e., GAAP net income – adjusted earnings measure). The figure reports the persistence ratio for *Core Earnings*, *IBSPI*, *OIADP*, and *OPE*. Variables are defined in Table A.1.

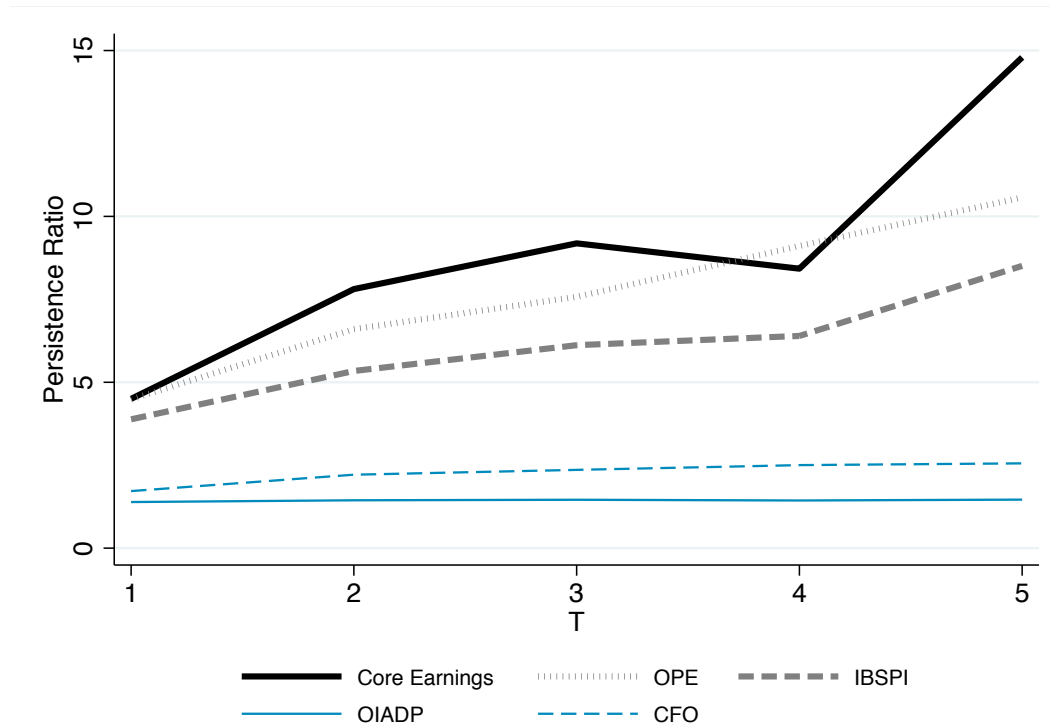


Table 1.
Likelihood, Frequency, and Magnitude of Non-Core-Earnings Disclosures

This table reports descriptive statistics—non-missing-value count (N), average ($Mean$), median ($p50$), and standard deviation (SD)—for non-core-earnings items disclosed in firms' 10-Ks. Panel A reports the likelihood of a non-core-earnings item being disclosed by a firm over our sample period. $\mathbb{I}[All\ Adjustments\ over\ Firm\ History]$, $\mathbb{I}[On\ IS\ over\ Firm\ History]$, $\mathbb{I}[Off\ IS\ over\ Firm\ History]$, $\mathbb{I}[MD\&A\ over\ Firm\ History]$, $\mathbb{I}[FN\ over\ Firm\ History]$, and $\mathbb{I}[CF\ over\ Firm\ History]$ are indicators equal to 1 if a firm disclosed such an item in the 10-K, on the face of the income statement, off of the income statement, in the footnotes, in the MD&A, or in the cash flow statement. Panel B reports the distributional statistics of the frequencies and magnitudes (in \$ millions) of each non-core-earnings adjustment type, by location or economic category, in the subsample with at least one adjustment in that category. For ease of comparison, income-increasing and income-decreasing items are summarized in absolute values. All variables reporting magnitudes are winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1.

Panel A: Likelihood of Non-Core-Earnings Items over a Firm's History				
	N	$Mean$	$p50$	SD
$\mathbb{I}[All\ Adjustments\ over\ Firm\ History]$	5,088	0.99	1.00	0.07
$\mathbb{I}[On\ IS\ over\ Firm\ History]$	5,088	0.99	1.00	0.12
$\mathbb{I}[Off\ IS\ over\ Firm\ History]$	5,088	0.83	1.00	0.38
$\mathbb{I}[FN\ over\ Firm\ History]$	5,088	0.72	1.00	0.45
$\mathbb{I}[MD\&A\ over\ Firm\ History]$	5,088	0.55	1.00	0.50
$\mathbb{I}[CF\ over\ Firm\ History]$	5,088	0.60	1.00	0.49

Panel B: Frequency and Magnitudes of Non-Core-Earnings Items, Adjustment Sample							
	N	Frequency			Magnitudes		
		$Mean$	$p50$	SD	$Mean$	$p50$	SD
<i>On IS</i>	53,403	3.98	3.00	3.17	18.72	0.03	213.08
<i>Off IS</i>	32,525	4.55	3.00	3.90	22.83	0.89	116.72
<i>FN</i>	23,400	4.94	4.00	3.77	19.92	0.98	96.76
<i>MD&A</i>	8,214	1.62	1.00	1.12	15.12	2.08	48.81
<i>CF</i>	15,588	1.23	1.00	0.50	3.39	0.08	19.38
<i>Acquisition</i>	9,013	1.22	1.00	0.61	11.14	1.86	29.16
<i>Currency</i>	6,785	1.06	1.00	0.26	3.44	0.11	21.54
<i>Discontinued Operations</i>	8,730	1.17	1.00	0.43	-7.72	0.14	80.38
<i>Legal or Regulatory</i>	5,211	1.12	1.00	0.38	11.35	1.05	37.58
<i>Pension</i>	14,877	5.78	6.00	2.85	5.69	0.51	45.35
<i>Restructuring</i>	41,869	2.30	2.00	1.62	36.02	1.29	196.63
<i>Company-Defined Other</i>	30,599	1.05	1.00	0.25	-1.76	-0.07	22.05
<i>Other</i>	29,210	1.90	1.00	1.32	5.19	0.00	80.96
<i>Income-Increasing</i>	49,698	4.47	3.00	3.64	129.86	8.73	505.75
<i>Income-Decreasing</i>	45,299	3.05	2.00	2.52	85.80	4.18	342.65
<i>All Adjustments</i>	56,727	6.35	5.00	5.39	32.31	0.50	250.81
<i>Net Income</i>	56,727	—	—	—	247.62	22.22	1,135.36

Table 2.

Descriptive Statistics: Core Earnings, Total Adjustments, and Additional Performance Measures

This table reports descriptive statistics—count (N), average ($Mean$), median ($p50$), and standard deviation (SD)—for the non-core-earnings adjustments and our main variables of interest. Panel A reports distributional statistics on *Core Earnings*, *Total Adjustments*, *Net Income*, and additional adjusted earnings measures and their adjustments from *Net Income* for the full sample of firms. Panel B reports the summary statistics for the time-series AR(1) parameter for *Net Income*, *Core Earnings*, and *Total Adjustments* for the subset of firms with at least 15 years of available data. Panel C reports time-series distributional statistics on the cross-sectional average squared forecast errors (MSE) from forecasting one-year-ahead *Net Income*. The first two rows of this panel report the distributional statistics of MSEs using as forecasters current-period *Net Income* and *Core Earnings*; the last row reports the distributional statistics of the difference between the MSE from *Core Earnings* and the MSE from *Net Income*. All variables are scaled by shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1.

<i>Variable</i>	<i>N</i>	<i>Mean</i>	<i>p50</i>	<i>SD</i>
Panel A: Core Earnings, Non-Core Earnings, and Other Earnings Measures (\$ per share)				
<i>Core Earnings</i>	60,026	1.0916	0.7643	2.4010
<i>Total Adjustments</i>	60,026	0.1786	0.0070	1.1216
<i>Net Income</i>	60,026	0.9560	0.7610	2.7816
<i>IBSPI</i>	60,026	1.1391	0.8454	2.5603
<i>OIADP</i>	60,026	1.4972	1.0194	2.3948
<i>OPE</i>	60,026	1.1030	0.8177	2.3297
<i>Street Earnings</i>	49,946	1.3298	1.0251	2.1933
<i>Cash Flow from Operations</i>	60,026	2.4084	1.6066	3.7019
<i>IBSPI Adjustments</i>	60,026	0.1852	0.0062	0.7267
<i>OIADP Adjustments</i>	60,026	0.5541	0.2088	1.7520
<i>OPE Adjustments</i>	60,026	0.1566	0.0041	1.1413
<i>Street Earnings Adjustments</i>	49,946	0.2540	0.0019	1.4875
<i>Total Accruals</i>	60,026	-1.4883	-0.8098	3.1687
Panel B: Persistence of Performance and Adjustment Measures				
<i>Net Income</i>	1,768	0.4474	0.4551	0.3350
<i>Core Earnings</i>	1,768	0.5850	0.5886	0.3151
<i>Total Adjustments</i>	1,768	0.1656	0.1209	0.3425
Panel C: Mean Squared Errors from Forecasting $Net\ Income_{t+1}$				
<i>Net Income</i>	19	5.7432	4.7796	3.3416
<i>Core Earnings</i>	19	4.5454	3.4770	2.8952
<i>MSE Difference</i>	19	-1.1978	-0.6827	1.2540

Table 3.
Cross-Sectional Persistence of Performance Measures and their Adjustments

This table reports the OLS estimation results from regressing a measure of performance (or their adjustments of *Net Income*) from the next fiscal year on the same measure for the current fiscal year, following Eq., (2). In Panel A, the measures are *Net Income* (column 1), *Core Earnings* (column 2), *Total Adjustments* (column 3), *Cash Flow from Operations* (column 4), *Total Accruals* (column 5). In Panel B, the measures are *IBSPI* (column 1), *IBSPI Adjustments* (column 2), *OIADP* (column 3), *OIADP Adjustments* (column 4), *OPE* (column 5), and *OPE Adjustments* (column 6). All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

Panel A					
	(1)	(2)	(3)	(4)	(5)
<i>Net Income</i>	0.6366*** (0.043)				
<i>Core Earnings</i>		0.8100*** (0.028)			
<i>Total Adjustments</i>			0.1780*** (0.027)		
<i>Cash Flow from Operations</i>				0.7845*** (0.021)	
<i>Total Accruals</i>					0.4585*** (0.040)
Year FE	Yes	Yes	Yes	Yes	Yes
Observations	54,228	54,228	54,228	54,228	54,228
Adjusted R^2	0.3879	0.6075	0.0586	0.5991	0.2211

Panel B						
	(1)	(2)	(3)	(4)	(5)	(6)
<i>IBSPI</i>	0.7499*** (0.028)					
<i>IBSPI Adjustments</i>		0.1898*** (0.040)				
<i>OIADP</i>			0.8612*** (0.024)			
<i>OIADP Adjustments</i>				0.6121*** (0.051)		
<i>OPE</i>					0.7853*** (0.028)	
<i>OPE Adjustments</i>						0.1734*** (0.028)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Observations	54,228	54,228	54,228	54,228	54,228	54,228
Adjusted R^2	0.5218	0.0546	0.7304	0.3701	0.5865	0.0421

Table 4. Predicting One-Year-Ahead Performance

This table reports OLS estimation results from regressing one-year-ahead firm performance on measures of performance from the current fiscal year, similar to Eq., (3). The measures of future performance are *Net Income* (column 1), *Cash Flow from Operations* (column 2), *Core Earnings* (column 3), *IBSPI* (column 4), *OIADP* (column 5), and *OPE* (column 6). All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	Forward Net Income (1)	Forward Cash Flow from Operations (2)	Forward Core Earnings (3)	Forward IBSPI (4)	Forward OIADP (5)	Forward OPE (6)
<i>Core Earnings</i>	0.3062*** (0.040)	0.2255*** (0.060)	0.5058*** (0.038)	0.2826*** (0.036)	0.1597*** (0.041)	0.2592*** (0.053)
<i>Net Income</i>	0.0542* (0.029)	-0.1114*** (0.039)	-0.0847*** (0.028)	-0.0682*** (0.023)	-0.0026 (0.027)	-0.0729*** (0.020)
<i>Cash Flow from Operations</i>	0.0579** (0.022)	0.5704*** (0.023)	0.0763*** (0.016)	0.0718*** (0.022)	0.0354** (0.017)	0.0498** (0.020)
<i>IBSPI</i>	0.0610 (0.055)	0.0324 (0.069)	0.0284 (0.071)	0.1903** (0.068)	-0.0959* (0.053)	-0.0294 (0.047)
<i>OIADP</i>	0.1757** (0.071)	0.3128*** (0.057)	0.1661** (0.061)	0.1864*** (0.063)	0.8164*** (0.052)	0.1298** (0.061)
<i>OPE</i>	0.1817** (0.080)	0.0072 (0.048)	0.1521** (0.060)	0.1919** (0.083)	-0.0483 (0.041)	0.4839*** (0.079)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Observations	54,228	54,228	54,228	54,228	54,228	54,228
Adjusted R^2	0.4718	0.6355	0.6360	0.5753	0.7351	0.6120

Table 5. Predicting One-Year-Ahead Performance Using Core Earnings Components

This table reports OLS estimation results from regressing one-year-ahead performance on *Net Income* and the sub-components of *Core Earnings* from the current fiscal year. Panel A examines the location categories of non-core earnings adjustments. Panel B examines the economic categories of non-core earnings adjustments. The measures of future performance are *Net Income* (column 1), *Cash Flow from Operations* (column 2), *Core Earnings* (column 3), *IBSPI* (column 4), *OIADP* (column 5), and *OPE* (column 6). Each regression is estimated using year-fixed effects and a sample of 54,228 observations, as in Table 4. All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	<i>Forward Net Income</i>	<i>Forward Cash Flow from Operations</i>	<i>Forward Core Earnings</i>	<i>Forward IBSPI</i>	<i>Forward OIADP</i>	<i>Forward OPE</i>
	(1)	(2)	(3)	(4)	(5)	(6)
Panel A: By Location Category						
<i>Net Income</i>	0.7621*** (0.027)	0.9561*** (0.040)	0.7505*** (0.024)	0.7697*** (0.027)	0.7204*** (0.029)	0.7091*** (0.024)
<i>Total Adjustments from IS</i>	0.7175*** (0.034)	1.2667*** (0.058)	0.8281*** (0.032)	0.7799*** (0.034)	0.8394*** (0.043)	0.7159*** (0.040)
<i>Total Adjustments from FN</i>	0.8163*** (0.138)	2.4177*** (0.318)	1.2751*** (0.147)	1.0784*** (0.142)	1.3535*** (0.187)	0.8328*** (0.168)
<i>Total Adjustments from MD&A</i>	0.5685 (0.382)	2.8424*** (0.356)	1.1803*** (0.261)	1.1353** (0.332)	1.8446*** (0.236)	1.1874*** (0.270)
<i>Total Adjustments from CF</i>	-0.2896 (0.883)	4.4026*** (0.745)	1.0476 (0.616)	0.2449 (0.851)	0.4498 (0.641)	0.1618 (0.608)
Adjusted R^2	0.4470	0.4270	0.5841	0.5349	0.5488	0.5430
Panel B: By Economic Category						
<i>Net Income</i>	0.7504*** (0.027)	0.9644*** (0.041)	0.7433*** (0.024)	0.7597*** (0.028)	0.7148*** (0.028)	0.6999*** (0.024)
<i>Net Acquisition Expenses</i>	0.6307** (0.217)	3.3949*** (0.439)	1.3492*** (0.119)	1.6541*** (0.204)	2.3346*** (0.169)	1.2853*** (0.252)
<i>Net Currency Expenses</i>	0.8341 (1.055)	3.6563* (1.695)	1.7086 (0.896)	1.8455 (0.928)	1.9248* (0.828)	1.7808* (0.756)
<i>Net Discontinued Ops Expenses</i>	1.0178*** (0.095)	1.5432*** (0.134)	1.0917*** (0.072)	0.9684*** (0.097)	1.1539*** (0.078)	1.0364*** (0.064)
<i>Net Legal Expenses</i>	1.0709** (0.309)	1.9937*** (0.475)	1.4165*** (0.208)	1.4265*** (0.209)	2.2522*** (0.223)	1.6182*** (0.257)
<i>Net Pension Adjustments</i>	0.9228** (0.310)	2.2554** (0.618)	1.4394*** (0.346)	1.0802** (0.317)	1.2110** (0.356)	0.6684 (0.391)
<i>Net Restructuring Expenses</i>	0.7252*** (0.059)	1.5639*** (0.087)	0.8914*** (0.048)	0.8258*** (0.056)	0.9131*** (0.066)	0.7414*** (0.060)
<i>Net Company-Defined Other Expenses</i>	0.5076 (0.281)	-0.2040 (0.421)	0.5338* (0.247)	0.4996 (0.249)	0.4385 (0.273)	0.5372* (0.244)
<i>Net Other Expenses</i>	0.6454*** (0.060)	0.9806*** (0.075)	0.8315*** (0.062)	0.6993*** (0.040)	0.7820*** (0.037)	0.6044*** (0.074)
Adjusted R^2	0.4391	0.4303	0.5773	0.5270	0.5433	0.5338

Table 6. Persistence of Adjustment Categories

This table reports the slope coefficient from OLS regressions of the non-core adjustments from a given category of *Core Earnings* in the next fiscal year on the adjustments from the same category in the current fiscal year. Following Table 3, these regressions also include year-fixed effects. Column 1 slope coefficients are estimated using the Net Adjustments from a given category. In column 2 slope coefficients are estimated using the sum of income-increasing adjustments in a given category. In column 3 the slope coefficients are estimated using only the sum of income-decreasing adjustments in a given category. Panel A reports the persistence of location categories of adjustments. Panel B reports the persistence of economic categories of adjustments. All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	(1) Net Adjustments	(2) Income-Increasing Net Adjustments	(3) Income-Decreasing Net Adjustments
Panel A: By Location Category			
<i>IS</i>	0.1551*** (0.023)	0.2037*** (0.038)	0.2151*** (0.029)
<i>MD&A</i>	0.3067*** (0.021)	0.3248*** (0.021)	0.3067*** (0.071)
<i>FN</i>	0.4654*** (0.051)	0.5292*** (0.046)	0.3964*** (0.071)
<i>CF</i>	0.3559*** (0.036)	0.3863*** (0.040)	0.3486*** (0.038)
Panel B: By Economic Category			
<i>Acquisitions</i>	0.3773*** (0.020)	0.3987*** (0.020)	0.2757*** (0.039)
<i>Currency</i>	0.2023* (0.110)	0.4327*** (0.114)	0.3147*** (0.036)
<i>Discontinued Operations</i>	0.1127*** (0.011)	0.1732*** (0.012)	0.1604*** (0.016)
<i>Legal and Regulatory</i>	0.1643*** (0.023)	0.1976*** (0.025)	0.1988*** (0.035)
<i>Pension</i>	0.5195*** (0.118)	0.6749*** (0.077)	0.5624*** (0.155)
<i>Restructuring</i>	0.2049*** (0.038)	0.2295*** (0.047)	0.2008*** (0.027)
<i>Company-Defined Other</i>	0.4002*** (0.031)	0.4011*** (0.047)	0.4975*** (0.034)
<i>Other</i>	0.2320** (0.093)	0.1984* (0.107)	0.3850*** (0.073)

Table 7. Incremental Predictive Ability of *Core Earnings* Relative to *Street Earnings*

This table reports OLS estimation results from regressing one-year-ahead firm performance on measures of performance from the current fiscal year, similar to Table 4. The main difference is that this table adds *Street Earnings* as an additional explanatory variable. The measures of future performance are *Net Income* (column 1), *Cash Flow from Operations* (column 2), *Street Earnings* (column 3), *Core Earnings* (column 4), *IBSPI* (column 5), *OIADP* (column 6), and *OPE* (column 7). All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	Forward Net Income (1)	Forward Cash Flow from Operations (2)	Forward Street Earnings (3)	Forward Core Earnings (4)	Forward IBSPI (5)	Forward OIADP (6)	Forward OPE (7)
<i>Core Earnings</i>	0.2387*** (0.048)	0.1175** (0.050)	0.0989** (0.035)	0.4199*** (0.045)	0.2113*** (0.037)	0.1245*** (0.040)	0.2323*** (0.048)
<i>Net Income</i>	0.0785* (0.039)	-0.1062*** (0.034)	-0.0704*** (0.017)	-0.0743*** (0.021)	-0.0619*** (0.021)	-0.0209 (0.017)	-0.0770*** (0.017)
<i>Cash Flow from Operations</i>	0.0410 (0.025)	0.5826*** (0.027)	0.0421** (0.016)	0.0631*** (0.017)	0.0525** (0.024)	0.0259 (0.016)	0.0308 (0.022)
<i>Street Earnings</i>	0.1883*** (0.041)	0.1703*** (0.036)	0.6462*** (0.078)	0.1970*** (0.023)	0.2334*** (0.036)	0.1357*** (0.023)	0.2475*** (0.031)
<i>IBSPI</i>	0.0365 (0.062)	0.0634 (0.055)	0.0108 (0.044)	0.0105 (0.053)	0.1958** (0.080)	-0.0585* (0.031)	0.0243 (0.042)
<i>OIADP</i>	0.1402* (0.073)	0.3380*** (0.055)	0.0675 (0.044)	0.1423** (0.063)	0.1547** (0.068)	0.8487*** (0.065)	0.1264* (0.066)
<i>OPE</i>	0.1426 (0.096)	-0.0921* (0.050)	0.0824 (0.058)	0.1216 (0.076)	0.1065 (0.105)	-0.1569** (0.062)	0.2821*** (0.081)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Observations	43,380	43,380	43,380	43,380	43,380	43,380	43,380
Adjusted R ²	0.4805	0.6442	0.7062	0.6554	0.5915	0.7453	0.6395

Table 8. Earnings Adjustments and Future Forecast Revisions

This table reports OLS estimation results from regressing analysts' future forecast revisions on net non-core earnings adjustments. The dependent variable, *Forecast Revisions*, is the average monthly revision of mean analyst earnings-per-share forecasts in the 12 months after the release of the 10-K. *Total Adjustments* is the net value of all non-core earnings adjustments. *Total Adjustments on IS* is the net value of non-core earnings adjustments identified from the face of the income statement. *Total Adjustments in FN*, *Total Adjustments in MD&A*, *Total Adjustments in CF* are the net value of non-core earnings adjustments identified from the footnotes, MD&A, and cash flow statement sections of the 10-K, respectively. All variables are scaled by shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. Variables are defined in Table A.1. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	<i>Forecast Revisions</i>				
	(1)	(2)	(3)	(4)	(5)
<i>Total Adjustments</i>	0.0012** (0.001)	0.0013*** (0.000)	0.0013*** (0.000)	0.0015** (0.001)	
<i>Total Adjustments from IS</i>					0.0012* (0.001)
<i>Total Adjustments from FN</i>					0.0056*** (0.002)
<i>Total Adjustments from MD&A</i>					0.0031 (0.002)
<i>Total Adjustments from CF</i>					0.0015 (0.005)
<i>Earnings Surprise</i>		-0.0012 (0.002)	-0.0014 (0.002)	-0.0012 (0.002)	-0.0013 (0.002)
<i>Lagged Forecast Revision</i>		0.0594 (0.044)	0.0578 (0.043)	0.0596 (0.044)	0.0594 (0.044)
<i>Size</i>			0.0000 (0.000)	-0.0001 (0.000)	-0.0001 (0.000)
<i>Book-to-Market</i>			-0.0009 (0.001)	-0.0010 (0.001)	-0.0010 (0.001)
<i>Total Accruals</i>				-0.0007** (0.000)	-0.0007** (0.000)
<i>IBSPI Adjustments</i>				0.0002 (0.001)	0.0001 (0.001)
<i>OIADP Adjustments</i>				-0.0005 (0.001)	-0.0005 (0.001)
<i>OPE Adjustments</i>				-0.0005 (0.001)	-0.0004 (0.001)
<i>Street Adjustments</i>				0.0004 (0.001)	0.0004 (0.001)
Year FE	Yes	Yes	Yes	Yes	Yes
Observations	42,645	42,645	42,645	42,645	42,645
Adjusted R^2	0.0306	0.0348	0.0352	0.0388	0.0391

Table 9. Future Returns across Deciles of Total Adjustments

This table reports value-weighted average returns in the 12 months following the month in which a firm files its 10-K. Value weights are based on firms' market capitalization in the month prior to their 10-K filings. We summarize these average returns among firms that filed a 10-K in each calendar quarter by deciles of *Total Adjustments* scaled by total assets per share. We also summarize the difference in average returns between the top and bottom deciles ("High – Low"). Decile assignments are made by comparing each firm's scaled *Total Adjustments* to the decile breakpoints computed using the prior calendar year's cross-sectional distribution. The first column summarizes value-weighted average 12-month raw returns. The remaining columns report factor loadings and abnormal monthly returns from a calendar-time value-weighted portfolio trading strategy. We form, update, and rebalance portfolios when firms file 10-Ks. We assign a firm that files a 10-K in a particular month to a decile portfolio by comparing its *Total Adjustments* to the decile breakpoints computed using the prior calendar year's cross-sectional distribution of *Total Adjustments*. Abnormal returns (ALPHA) are estimated using the Fama-French three-factor model—with a market factor (MKTRF), a size factor (SMB), and a value factor (HML)—augmented with the momentum factor (UMD). We report *T*-statistics based on the time-series of 12 month returns across calendar quarters in parentheses.

	Annual Returns	Factor-Adjusted Alphas and Factor Loadings				
	Raw	ALPHA	MKTRF	SMB	HML	UMD
10 (High Adjustments)	11.927 (3.71)	0.157 (0.78)	0.937 (18.46)	0.188 (2.97)	0.078 (1.19)	-0.225 (-5.63)
9	9.825 (4.34)	0.197 (1.55)	0.921 (28.75)	-0.058 (-1.45)	0.190 (4.63)	-0.091 (-3.59)
8	11.532 (4.23)	0.360 (2.53)	0.944 (26.34)	-0.154 (-3.45)	0.255 (5.54)	-0.081 (-2.87)
7	8.886 (4.62)	0.110 (0.87)	0.957 (30.24)	-0.230 (-5.85)	0.219 (5.41)	-0.043 (-1.70)
6	10.568 (4.63)	0.023 (0.17)	0.964 (28.01)	-0.143 (-3.34)	0.262 (5.95)	-0.069 (-2.56)
5	10.875 (4.57)	-0.251 (-1.67)	1.050 (27.75)	-0.104 (-2.22)	0.268 (5.52)	0.017 (0.58)
4	9.060 (3.85)	0.058 (0.37)	1.089 (27.76)	0.040 (0.82)	0.370 (7.35)	-0.054 (-1.73)
3	11.149 (2.90)	0.443 (2.41)	1.012 (21.83)	0.054 (0.94)	-0.125 (-2.10)	-0.099 (-2.71)
2	9.390 (2.90)	-0.108 (-0.58)	1.083 (23.11)	0.107 (1.83)	-0.544 (-9.06)	-0.101 (-2.73)
1 (Low Adjustments)	3.529 (1.27)	-0.504 (-1.80)	1.224 (17.37)	0.130 (1.49)	-0.725 (-8.02)	-0.248 (-4.45)
High – Low	8.398 (2.74)	0.661 (1.94)	-0.287 (-3.34)	0.057 (0.54)	0.802 (7.30)	0.022 (0.33)

Table 10. Cross-Sectional Annual-Return Regressions

This table reports OLS estimation results from regressing firms' cumulative returns over the 12 months following their 10-K filing dates on the net value of non-core-earnings adjustments identified in an entire 10-K (columns 1-5) or their disclosure location sub-components (column 6). Sample sizes differ across columns based on the availability of control variables. Cross-sectional-fixed effects, based on the year and month of the 10-K filing, are included throughout. *Total Adjustments* is the net value of all non-core earnings adjustments. *Total Adjustments on IS* is the net value of non-core earnings adjustments identified from the face of the income statement. *Total Adjustments in FN*, *Total Adjustments in MD&A*, *Total Adjustments in CF* are the net value of non-core earnings adjustments identified from the footnotes, MD&A, and cash flow statement sections of the 10-K. Variables are defined in Table A.1; however, *Total Adjustments*, its disclosure location sub-components, *Gross Profit*, *Total Accruals*, *Special Items*, *OIADP Adjustments*, *OPE Adjustments*, and *Street Adjustments* are all scaled by total assets in this table. All explanatory variables are winsorized at the 1% level. *T*-statistics, reported in parentheses, are based on two-way-cluster robust standard errors, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	(1)	(2)	(3)	(4)	(5)	(6)
<i>Total Adjustments</i>	86.365*** (3.04)	70.718*** (2.87)	69.372*** (2.91)	83.799*** (3.10)	66.723** (2.20)	
<i>Total Adjustments from IS</i>						65.493** (2.26)
<i>Total Adjustments from FN</i>						296.983*** (2.94)
<i>Total Adjustments from MD&A</i>						19.320 (0.15)
<i>Total Adjustments from CF</i>						-148.725 (-0.48)
<i>Size</i>		-4.940*** (-3.45)	-4.750*** (-3.15)	-6.153*** (-3.55)	-5.511*** (-3.50)	-5.541*** (-3.52)
<i>Book-to-Market</i>		2.174 (1.25)	2.254 (1.51)	1.849 (1.33)	2.311 (1.55)	2.324 (1.54)
<i>Momentum</i>			-0.035 (-0.76)	-0.032 (-0.68)	-0.035 (-0.72)	-0.034 (-0.72)
<i>Gross Profit</i>			8.575*** (2.74)	1.835 (0.57)	3.722 (1.33)	3.702 (1.32)
<i>Share Turnover</i>			-0.205 (-1.07)	-0.222 (-1.36)	-0.250 (-1.63)	-0.252* (-1.66)
<i>Dispersion</i>				-6.641*** (-7.15)	-7.120*** (-7.67)	-7.152*** (-7.74)
<i>Coverage</i>				5.083*** (3.51)	4.244*** (3.07)	4.276*** (3.09)
<i>Total Accruals</i>					-27.469** (-2.53)	-27.872** (-2.58)
<i>IBSPI Adjustments</i>					-59.205* (-1.96)	-58.328* (-1.93)
<i>Street Adjustments</i>					3.698 (0.16)	3.576 (0.16)
<i>OIADP Adjustments</i>					-37.856* (-1.94)	-37.592* (-1.83)
<i>OPE Adjustments</i>					2.501 (0.07)	3.632 (0.10)
Filing Year-Month FE	Yes	Yes	Yes	Yes	Yes	Yes
Observations	60,294	60,294	60,292	50,055	49,442	49,442
Adjusted R^2	0.0553	0.0671	0.0684	0.0720	0.0738	0.0738

Core Earnings: New Data and Evidence

Online Appendix

Abstract

This Online Appendix contains supplementary results for the paper “Core Earnings: New Data and Evidence.” We document significant differences between *Total Adjustments* and the adjustments embedded in commonly used measures of adjusted earnings from Compustat. We also provide evidence that *Core Earnings* offers incremental predictive power for firms’ future performance over a two- to five-year horizon. Lastly, we establish the robustness of our main findings to alternative implementations and assumptions. Specifically, we show our main findings are qualitatively similar when (i) limiting our sample to post-2007 data, (ii) estimating tax effects using cash effective tax rates and statutory tax rates, and (iii) using alternative scaling for all variables.

1 Overview

In this Online Appendix, we document significant differences between *Core Earnings* adjustments and the adjustments embedded in commonly used Compustat measures of adjusted earnings. We also establish the robustness of the main findings in the paper “Core Earnings: New Data and Evidence” to alternative implementations and assumptions. These tests reinforce our main findings and mitigate concerns that our findings are sensitive to the particular implementation used in our paper.

1.1 Differences in Performance Measurements

Table OA.1 examines the relation between the non-core earnings items identified by NC (*Total Adjustments*) and the adjustments made by Compustat to calculate *IBSPI*, *OIADP*, and *OPE*. Panel A reports the results of regressing *Total Adjustments*, as defined by New Constructs, on the three adjustment measures used to calculate Compustat’s measures of earnings. While all three Compustat measures of adjustments are positively related to *Total Adjustments*, individually, each Compustat adjustment explains 26% to 53% of the variation in *Total Adjustments*. Jointly they explain 57%, leaving a significant amount of the variation in *Total Adjustments* unexplained.

Panel B further examines the sources of the differences between *Total Adjustments* and Compustat adjustments. We regress the absolute difference between *Total Adjustments* and each of the Compustat adjustments on sub-components of *Total Adjustments*. Columns 1-3 examine the location sub-categories of *Total Adjustments*, and columns 4-6 examine the economic sub-categories of *Total Adjustments*. In general, larger dollar values of non-core earnings identified in the NC data correspond to larger absolute differences between NC and Compustat adjustments across economic and location categories, consistent with systematic differences in data collection protocol or quality.

1.2 Long-horizon predictive power of *Core Earnings*

Table OA.2 examines the predictive power of *Core Earnings* for future performance over a five-year horizon. It reports the results from regressing measures of performance in years $t+2$ to $t+5$ (in panels A through D) on *Core Earnings* in year t . This test uses a specification analogous to Eq. (3) of the paper, and includes as control variables *Net Income*, *Cash Flow from Operations*, *IBSPI*, *OIADP*, and *OPE* measured in year t , as well as year fixed effects. For simplicity of presentation, we only report the coefficients and standard errors for *Core Earnings*, which is statistically significant across all specifications. *Core Earnings* offers incremental predictive power for forecasting future performance over a five-year horizon.

1.3 Robustness Tests

The next set of tables in this appendix re-estimate three sets of analyses central to our paper. In the first, we re-examine the cross-sectional persistence of core earnings and non-

core-earnings adjustments (Table OA.3). In the second set of analyses, we re-examine core earnings’ usefulness for forecasting measures of one-year-ahead performance (Table OA.4). Finally, in our third set of analyses below, we re-examine the ability of non-core-earnings adjustments to forecast firms’ future returns (Table OA.5).

Within each set of analyses, we implement and test four alternative measures of core earnings and/or total adjustments denoted by the parenthetical appended to the original variable name. For example, the variables *Core Earnings (Post-2007)* and *Total Adjustments (Post-2007)* correspond to the same variable used in our main paper but are limited to firm-years from 2008 to 2017. This subsample covers the years after the last major change in the data provider’s data parsing and classification processes. Beginning in 2008, the data were parsed and classified on a real-time going-forward basis (with no back-filling). These subsample tests help to mitigate concerns related to potential look-ahead bias in our results.

We also consider two alternative sets of measures that alter the assumed corporate tax rate (and the after-tax impact of the non-core-earnings adjustments). *Core Earnings (Cash ETR)* and *Total Adjustments (Cash ETR)* adjust our main measures by using the cash effective tax rate to measure tax expenses. Following Dyreng, Hanlon, and Maydew (2008), we calculate the cash effective tax rate as total cash taxes paid divided by total pre-tax income over the prior 10 years, where we assign a tax rate of 35% for missing observations. Similarly, *Core Earnings (Statutory)* and *Total Adjustments (Statutory)* adjust our main measures by using the statutory tax rate of 35%. These tests help mitigate concerns that our main findings are driven by, and/or sensitive to, measurement errors associated with the estimation of tax implications associated with the non-core-earnings adjustments.

Finally, we scale all variables by total assets in the Tables OA.3 and OA.4 (corresponding to Tables 3 and 4 of the paper), and by shares outstanding in Table OA.5 (corresponding to Table 10 of the paper). These tests confirm that our main results are robust to the use of a consistent deflator for *Core Earnings* and *Total Adjustments*.

References

Dyreng, S. D., M. Hanlon, and E. L. Maydew (2008). Long-run corporate tax avoidance. *Accounting Review* 83(1), 61–82.

Table OA.1. Differences in Earnings Adjustments

This table examines the relation between the non-core earnings items used to calculate *Total Adjustments* and the items used to calculate *IBSPI Adjustments*, *OIADP Adjustments*, and *OPE Adjustments*. Panel A reports the slope coefficient from OLS regressions of *Total Adjustments* on the three measures of Compustat adjustments. Following Table 3 of the main paper, these regressions also include year-fixed effects. Panel B reports the results from regressing the absolute differences between *Core Earnings* and each of the three Compustat adjustment variables on the location (columns 1-3) and economic (columns 4-6) sub-categories of non-core earnings items identified by NC. All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. See the main text for additional variable descriptions. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

Panel A: Explaining <i>Total Adjustments</i>				
	(1)	(2)	(3)	(4)
<i>IBSPI Adjustments</i>	1.0460*** (0.031)			0.3954*** (0.110)
<i>OIADP Adjustments</i>		0.2296*** (0.026)		0.0569*** (0.010)
<i>OPE Adjustments</i>			0.7356*** (0.029)	0.4676*** (0.077)
Year FE	Yes	Yes	Yes	Yes
Observations	55,677	55,677	55,677	55,677
Adjusted R^2	0.4739	0.2604	0.5316	0.5736

Table OA.1. [Continued]

Panel B: Explaining Absolute Differences in Adjustments					
	(1)	(2)	(3)	(4)	(5)
	<i>IBSPI</i>	<i>OIADP</i>	<i>OPE</i>	<i>IBSPI</i>	<i>OIADP</i>
	<i>Adjustments</i>	<i>Adjustments</i>	<i>Adjustments</i>	<i>Adjustments</i>	<i>Adjustments</i>
<i>Total Adjustments from IS</i>	0.5050*** (0.071)	0.4433*** (0.029)	0.4230*** (0.063)		
<i>Total Adjustments from MD&A</i>	0.5006*** (0.107)	1.2339*** (0.129)	0.5802*** (0.086)		
<i>Total Adjustments from FN</i>	0.5699*** (0.093)	0.8532*** (0.088)	0.8990*** (0.112)		
<i>Total Adjustments from CF</i>	0.8011*** (0.171)	1.1782*** (0.226)	1.1294*** (0.225)		
<i>Net Acquisition Expenses</i>				0.3101* (0.152)	0.7784*** (0.167)
<i>Net Currency Expenses</i>				0.4408 (0.394)	0.3301 (0.404)
<i>Net Discontinued Ops Expenses</i>				1.3887*** (0.063)	0.1463** (0.051)
<i>Net Legal Expenses</i>				-0.0262 (0.074)	0.3073** (0.114)
<i>Net Pension Expenses</i>				0.4503** (0.164)	1.0524*** (0.175)
<i>Net Restructuring Expenses</i>				0.3501*** (0.071)	0.4915*** (0.072)
<i>Net Company-Defined Other Expenses</i>				0.6736*** (0.127)	1.0383*** (0.174)
<i>Net Other Expenses</i>				0.8456*** (0.070)	0.5072** (0.203)
Year FE	Yes	Yes	Yes	Yes	Yes
Observations	55,677	55,677	55,677	55,677	55,677
Adjusted R ²	0.3643	0.1836	0.2882	0.4014	0.1883
					0.3068

Table OA.2. Predicting Performance in Years $t + 2$ to $t + 5$

This table reports OLS estimation results from regressing firm performance in years $t + 2$ to $t + 5$ on measures of performance from the current fiscal year. The measures of future performance are *Net Income* (column 1), *Cash Flow from Operations* (column 2), *Core Earnings* (column 3), *IBSPI* (column 4), *OIADP* (column 5), and *OPE* (column 6). Panels A through D measure the dependent variable in years $t+2$ through $t+5$. As in Table 4 of the paper, all specifications include year-fixed effects and current fiscal year *Net Income*, *Cash Flow from Operations*, *IBSPI*, *OIADP*, and *OPE*. For simplicity, we report only the coefficients and standard errors for *Core Earnings*. All variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. See the main text for additional variable descriptions. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	<i>Forward Net Income</i>	<i>Forward Cash Flow from Operations</i>	<i>Forward Core Earnings</i>	<i>Forward IBSPI</i>	<i>Forward OIADP</i>	<i>Forward OPE</i>
	(1)	(2)	(3)	(4)	(5)	(6)
Panel A: Year $t + 2$						
<i>Core Earnings</i>	0.3251*** (0.060)	0.2243*** (0.076)	0.4511*** (0.043)	0.3197*** (0.061)	0.2070*** (0.068)	0.2799*** (0.078)
Adjusted R^2	0.3518	0.5564	0.4992	0.4424	0.5978	0.4736
Panel B: Year $t + 3$						
<i>Core Earnings</i>	0.2672*** (0.045)	0.2461** (0.100)	0.3961*** (0.059)	0.2606*** (0.044)	0.1537** (0.056)	0.2044*** (0.052)
Adjusted R^2	0.3050	0.5001	0.4405	0.3887	0.5393	0.4146
Panel C: Year $t + 4$						
<i>Core Earnings</i>	0.1775*** (0.048)	0.1781* (0.084)	0.3192*** (0.056)	0.1692*** (0.044)	0.1250* (0.068)	0.1375** (0.056)
Adjusted R^2	0.2514	0.4446	0.3705	0.3198	0.4618	0.3403
Panel D: Year $t + 5$						
<i>Core Earnings</i>	0.1760*** (0.053)	0.1837* (0.102)	0.2804*** (0.060)	0.1746*** (0.053)	0.1612* (0.079)	0.1725** (0.072)
Adjusted R^2	0.2234	0.4039	0.3245	0.2842	0.4129	0.2934

Table OA.3.

Cross-Sectional Persistence of *Core Earnings* and *Total Adjustments*, Robustness Tests

This table reports the OLS estimation results from regressing alternative measures of *Core Earnings* and *Total Adjustments* from the next fiscal year on the same measure for the current fiscal year. *Core Earnings (Post-2007)* and *Total Adjustments (Post-2007)* examine all firm-years from 2008 to 2017. *Core Earnings (Cash ETR)* and *Total Adjustments (Cash ETR)* recalculate the *Core Earnings* and *Total Adjustments* measures by estimating the tax effects of adjustments using the cash effective tax rate, calculated as cash taxes paid divided by pre-tax income. *Core Earnings (Statutory)* and *Total Adjustments (Statutory)* recalculate the *Core Earnings* and *Total Adjustments* measures by estimating the tax effects of adjustments using the statutory tax rate of 35%. *Core Earnings (Scaled by Total Assets)* and *Total Adjustments (Scaled by Total Assets)* scale the *Core Earnings* and *Total Adjustments* by total assets, as opposed to shares outstanding. All other variables are scaled by total shares outstanding and winsorized at the top and bottom 0.5% of the cross-sectional distribution. See the main text for additional variable descriptions. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<i>Core Earnings (Post-2007)</i>	0.8237*** (0.039)							
<i>Total Adjustments (Post-2007)</i>		0.1761*** (0.029)						
<i>Core Earnings (Cash ETR)</i>			0.8209*** (0.027)					
<i>Total Adjustments (Cash ETR)</i>				0.1914*** (0.029)				
<i>Core Earnings (Statutory TR)</i>					0.8124*** (0.028)			
<i>Total Adjustments (Statutory TR)</i>						0.1893*** (0.029)		
<i>Core Earnings (Scaled by Total Assets)</i>							0.7641*** (0.030)	
<i>Total Adjustments (Scaled by Total Assets)</i>								0.1417*** (0.016)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Observations	26,433	26,433	54,734	54,734	54,734	54,734	54,734	54,734
Adjusted R ²	0.6211	0.0456	0.6251	0.0653	0.6125	0.0635	0.6084	0.0479
F-Stat	20.69		44.75		46.11		61.89	
p-Value	0.00		0.00		0.00		0.00	

Table OA.4. Predicting One-Year-Ahead Performance, Robustness Tests

This table reports OLS estimation results from regressing one-year-ahead firm performance on measures of performance from the current fiscal year. The measures of future performance are *Net Income* (Panel A), *Cash Flow from Operations* (Panel B), *Core Earnings* (Panel C), *IBSPI* (Panel D), *OIADP* (Panel E), and *OPE* (Panel F). *Core Earnings (Post-2007)* examines the subsample of firm-years from 2008 to 2017. *Core Earnings (Cash ETR)* recalculates the *Core Earnings* measure by estimating the tax effects of adjustments using the cash effective tax rate, calculated as cash taxes paid divided by pre-tax income. *Core Earnings (Statutory)* recalculates the *Core Earnings* measure by estimating the tax effects of adjustments using the statutory tax rate of 35%. *Core Earnings (Scaled by Total Assets)* scales the *Core Earnings*, as well as all other variables in the regression, by total assets, as opposed to shares outstanding (i.e., in columns 1-3). As in Table 4 of the paper, all specifications include year-fixed effects and current fiscal year *Net Income*, *Cash Flow from Operations*, *IBSPI*, *OIADP*, and *OPE*. For simplicity, we report only the coefficients and standard errors for *Core Earnings* variants. All variables are at the top and bottom 0.5% of the cross-sectional distribution. See the main text for additional variable descriptions. Standard errors, reported in parentheses, are two-way-cluster robust, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

	(1)	(2)	(3)	(4)
Panel A: Forward Net Income				
<i>Core Earnings (Post-2007)</i>	0.3213*** (0.047)			
<i>Core Earnings (Cash ETR)</i>		0.3016*** (0.047)		
<i>Core Earnings (Statutory TR)</i>			0.3097*** (0.044)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.3328*** (0.081)
Adjusted R^2	0.5108	0.4720	0.4716	0.5198
Panel B: Forward Cash Flow from Operations				
<i>Core Earnings (Post-2007)</i>	0.2827** (0.087)			
<i>Core Earnings (Cash ETR)</i>		0.2442*** (0.056)		
<i>Core Earnings (Statutory TR)</i>			0.2360** (0.066)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.1582*** (0.034)
Adjusted R^2	0.6576	0.6361	0.6356	0.6278

Table OA.4 Continued.

	(1)	(2)	(3)	(4)
Panel C: Forward Core Earnings				
<i>Core Earnings (Post-2007)</i>	0.4855*** (0.044)			
<i>Core Earnings (Cash ETR)</i>		0.5299*** (0.039)		
<i>Core Earnings (Statutory TR)</i>			0.5332*** (0.040)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.5157*** (0.054)
Adjusted R^2	0.6597	0.6501	0.6395	0.6339
Panel D: Forward IBSPI				
<i>Core Earnings (Post-2007)</i>	0.3128*** (0.046)			
<i>Core Earnings (Cash ETR)</i>		0.2808*** (0.044)		
<i>Core Earnings (Statutory TR)</i>			0.2858*** (0.040)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.2536*** (0.063)
Adjusted R^2	0.6040	0.5756	0.5751	0.5866
Panel E: Forward OIADP				
<i>Core Earnings (Post-2007)</i>	0.2221** (0.048)			
<i>Core Earnings (Cash ETR)</i>		0.1695** (0.048)		
<i>Core Earnings (Statutory TR)</i>			0.1683** (0.049)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.1228** (0.036)
Adjusted R^2	0.7456	0.7356	0.7352	0.6588
Panel F: Forward OPE				
<i>Core Earnings (Post-2007)</i>	0.3404*** (0.065)			
<i>Core Earnings (Cash ETR)</i>		0.2591*** (0.056)		
<i>Core Earnings (Statutory TR)</i>			0.2595*** (0.055)	
<i>Core Earnings (Scaled by Total Assets)</i>				0.2736*** (0.053)
Adjusted R^2	0.6319	0.6125	0.6117	0.6240

Table OA.5. Cross-Sectional Annual-Return Regressions, Robustness Tests

This table reports OLS estimation results from regressing firms' cumulative returns over the 12 months following their 10-K filing dates on the net value of non-core-earnings adjustments identified in the 10-K and firm-level controls. Cross-sectional-fixed effects, based on the year and month of the 10-K filing, are included in all specifications. Panel A examines different variations *Total Adjustments*. *Total Adjustments (Post-2007)* examines the subsample of firm-years from 2008 to 2017. *Total Adjustments (Cash ETR)* recalculate the *Total Adjustments* measure by estimating the tax effects of adjustments using the cash effective tax rate, calculated as cash taxes paid divided by pre-tax income. *Total Adjustments (Statutory)* recalculates the *Total Adjustments* measures by estimating the tax effects of adjustments using the statutory tax rate of 35%. *Total Adjustments (Per Share)* scales *Total Adjustments*, as well as all other control variables in the regression, by total shares outstanding, as opposed to total assets, as is the case for the rest of the tests in this table. Panel B uses a similar naming convention, examining total adjustments by their disclosure location in the 10-K, and, for simplicity, we report the coefficients and standard errors only for *Total Adjustments* variants. All explanatory variables are winsorized at the top and bottom 0.5% of the cross-sectional distribution. See the main text for additional variable descriptions. *T*-statistics, reported in parentheses, are based on two-way-cluster robust standard errors, clustering at the firm and year levels. Significance levels are indicated by *, **, *** for 10%, 5%, and 1% respectively.

Table OA.5 Continued.

	<i>Panel A: Total Adjustments</i>			
	(1)	(2)	(3)	(4)
<i>Total Adjustments (Post-2007)</i>	73.879*			
	(1.67)			
<i>Total Adjustments (Cash ETR)</i>		67.687**		
		(2.31)		
<i>Total Adjustments (Statutory TR)</i>			70.523**	
			(2.30)	
<i>Total Adjustments (Per Share)</i>				3.263**
				(2.47)
<i>Size</i>	-3.686**	-5.508***	-5.504***	-6.828***
	(-2.11)	(-3.50)	(-3.50)	(-3.91)
<i>Book-to-Market</i>	1.381	2.294	2.300	1.652
	(0.71)	(1.54)	(1.54)	(1.37)
<i>Momentum</i>	-0.125	-0.035	-0.035	-0.027
	(-1.20)	(-0.73)	(-0.73)	(-0.56)
<i>Gross Profit</i>	-0.018	3.766	3.748	0.067
	(-0.01)	(1.35)	(1.34)	(0.68)
<i>Share Turnover</i>	-0.206	-0.249	-0.249	-0.275*
	(-1.50)	(-1.61)	(-1.62)	(-1.84)
<i>Dispersion</i>	-7.973***	-7.135***	-7.131***	-7.227***
	(-6.19)	(-7.65)	(-7.66)	(-7.23)
<i>Coverage</i>	3.815*	4.246***	4.241***	5.284***
	(1.72)	(3.08)	(3.07)	(3.48)
<i>Total Accruals</i>	-42.220***	-27.856**	-27.871**	-0.627**
	(-2.67)	(-2.57)	(-2.57)	(-2.52)
<i>IBSPI Adjustments</i>	-68.734*	-55.826*	-57.948*	-3.224*
	(-1.87)	(-1.84)	(-1.91)	(-1.78)
<i>Street Adjustments</i>	-10.241	1.663	2.809	0.424
	(-0.53)	(0.07)	(0.12)	(0.53)
<i>OIADP Adjustments</i>	-43.359	-38.588**	-38.691**	21.439*
	(-1.47)	(-2.01)	(-1.99)	(1.72)
<i>OPE Adjustments</i>	51.105	3.060	1.881	-1.276
	(1.05)	(0.09)	(0.05)	(-1.20)
Filing Year-Month FE	Yes	Yes	Yes	Yes
Observations	25,741	49,442	49,442	49,442
Adjusted R^2	0.0773	0.0739	0.0739	0.0738

Table OA.5 Continued.

	<i>Panel B: Adjustments by location</i>			
	(1)	(2)	(3)	(4)
<i>Total Adjustments from IS (Post-2007)</i>	75.541** (2.25)			
<i>Total Adjustments from FN (Post-2007)</i>	192.668** (2.07)			
<i>Total Adjustments from MD&A (Post-2007)</i>	39.913 (0.28)			
<i>Total Adjustments from CF (Post-2007)</i>	-430.776 (-1.25)			
<i>Total Adjustments from IS (Cash ETR)</i>		65.949** (2.38)		
<i>Total Adjustments from FN (Cash ETR)</i>		242.970*** (2.66)		
<i>Total Adjustments from MD&A (Cash ETR)</i>		55.194 (0.41)		
<i>Total Adjustments from CF (Cash ETR)</i>		-139.109 (-0.47)		
<i>Total Adjustments from IS (Statutory TR)</i>			68.310** (2.33)	
<i>Total Adjustments from FN (Statutory TR)</i>			208.482* (1.90)	
<i>Total Adjustments from MD&A (Statutory TR)</i>			67.501 (0.45)	
<i>Total Adjustments from CF (Statutory TR)</i>			-144.895 (-0.45)	
<i>Total Adjustments from IS (Per Share)</i>				2.675** (2.53)
<i>Total Adjustments from FN (Per Share)</i>				8.488*** (3.29)
<i>Total Adjustments from MD&A (Per Share)</i>				-4.397 (-0.84)
<i>Total Adjustments from CF (Per Share)</i>				-9.451 (-1.12)
Filing Year-Month FE	Yes	Yes	Yes	Yes
Controls	Yes	Yes	Yes	Yes
Observations	25,741	49,442	49,442	49,442
Adjusted R^2	0.0768	0.0737	0.0736	0.0738

22-Oct-2024 | 12:28 EDT

Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand

Topic **Energy & Climate Resilience, Debt Markets In Transition**

Region **Americas, EMEA, APAC**

[View Analyst Contact Information](#)

Key Takeaways

- Data center electricity demand should boost revenues at North America's investor-owned regulated utilities and provide modest support for the industry's credit quality.
- S&P Global Ratings' base case assumes that annual electricity sales growth at about 1% for several decades will transform an industry used to stagnation but won't fully meet the tech industry's needs.
- Contracts and rates for data centers should be structured to shield existing customers from price hikes related to meeting new demand.
- Resulting increases in capital spending and cash flow deficits will necessitate careful and consistent funding that supports credit quality.

Data center electricity demand should spark sales growth in the long-stagnant North American investor-owned regulated utilities sector.

Why it matters: Regulated utilities will be called on to meet the fast growing electricity demands of data centers. The significant time required to expand generation capacity is likely to prove a limiting factor in data center growth.

What we think and why: Increased electricity demand from data centers should prove generally supportive of regulated utilities' credit quality. It will also introduce new risks, notably related to funding and pressures on billing, which will have to be structured to protect existing clients from cost increases related to data center driven growth.

Utilities Should Benefit From Data Centers' Power Requirements

The rising number of data centers is generally supportive of the North America investor-owned regulated utility industry's credit quality. We expect the growth will drive electricity sales and enable the industry to spread its fixed costs over a wider base of ratepayers.

There are credit risks associated with that growth. Meeting new demand will require increased capital spending and may result in significant increases to customer bills, if the challenges are not effectively managed. Yet we believe these risks are still preferable to the sector's two-decade experience of flat to negative electricity sales growth.

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And the benefits should prove lasting. We expect electricity sales growth will persist over the next several decades, providing modest tail winds for the industry's credit quality.

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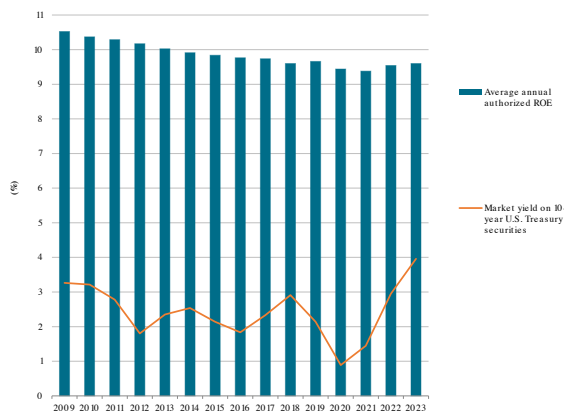
No Growth In Recent History Brings Higher Credit Risk

North America's investor-owned regulated utility industry has spent the past two decades being squeezed by successful efforts to improve energy efficiency. Resultant flat electricity sales, over much of the past two decades, focused the industry on efficient cost management and cost recovery with minimal regulatory lag (the delay between a utility incurring costs and recovering them from ratepayers) as the primary means to maintain credit quality.

During that period of stagnation, the industry's authorized return on equity decreased (see chart 1). Moreover, it failed to rebound in line with the more recent uptick in interest rates, with the result being increased pressure on the industry's key credit risk measures.

Chart 1

U.S. electric utilities' return on equity has lagged rate changes



*U.S. regulated electric utilities. ROE—Return on equity.
Sources: Federal Reserve Economic Data, Regulatory Research Associates; a group within S&P Global Commodity Insights.
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Utilities sort to reduce some of that risk by improving their track record of credit supportive rate case orders (regulator-approved rate increases) and by minimizing regulatory lag--notably by implementing forward-looking test years, multiyear rate cases, formula rates, and additional regulatory riders. For example, Michigan and Pennsylvania moved to fully forecasted test years in 2019 and 2012, respectively. Despite these efforts, the industry's ability to effectively manage regulatory risk and maintain credit quality proved challenging due to rising capital spending and the lack of growth (see "

American Electric Power Co. Inc. Downgraded To 'BBB+' On Weak Financial Measures, Outlook Negative,"

March 4, 2024; "

Alliant Energy Corp. Outlook Revised To Negative On Weak Financial Performance, 'A-' Rating Affirmed," March

1, 2024; and "

Eversource Energy Ratings Placed On CreditWatch Negative Following Offshore Wind Impairment," January 11, 2024).

Data Centers Should Deliver A Return To Growth

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We expect that data centers' near term proliferation will prove the catalyst for North America investor-owned regulated utilities' return to electricity sales growth. Our base-case forecast is for electricity sales to increase at a compound growth rate (CAGR) of about 1.1%.

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We note that there is significant divergence of opinion around that forecast, with some experts forecasting sales growth as high as a 3% CAGR. Our forecast of about 1% CAGR reflects our view that systematic and careful planning across the investor-owned utility sector will likely limit its realistic capability to grow at a substantially faster pace. Furthermore, most of the sector's current capital spending plans do not yet incorporate much of the growth associated with data centers, which has largely emerged over the past year. As such, most of the incremental infrastructure capital spending associated with data centers will take considerable time, even just to complete the planning phase, and will therefore likely be implemented at a slow pace.

The expansion of utility infrastructure assets is a long-term planning process that requires permitting and siting, and is typically done at a methodical pace, not least due to regulatory approvals that often take many filings and considerable time. We expect that the pace of utility infrastructure investments will not likely fully meet the energy growth needs of the tech industry, and could therefore become a limiting factor on its longer-term growth rate.

Our U.S. technology analysts don't see power curbing cloud and AI platform revenue growth through 2025, but expect it could become a constraint later this decade. Even if that materializes, it may not affect our view on the credit quality of U.S. technology issuers, because we don't view them as dependent on cloud and AI units maintaining current growth rates. Indeed, we recently outlined our view that larger tech companies could maintain their credit worthiness even in the event of a meaningful deceleration in cloud- and AI-related revenue growth (see "

U.S. Tech Earnings: Cloud Titans Bet Big On AI As Traditional Players Lag," Aug. 12, 2024).

However, even a 1% CAGR for electricity sales will likely prove transformative for the utility industry. In particular the growing number of data centers will allow the industry to spread its fixed costs over a wider base. We anticipate this will provide some cushion for the industry to effectively manage regulatory risk and maintain credit quality without necessarily requiring that every rate case order is highly supportive of credit quality.

Furthermore, while we assume moderate electricity sales CAGR, we also expect that growth rate will prove durable (see chart 2). We expect growth in data center numbers will support most of the industry's growth through to 2030, while the following decade's growth will also be supported by increased onshoring of manufacturing and wider spread adoption of electric vehicles. We also believe that a slower pace of growth over a longer timeframe will be welcomed as it should prove supportive of the industry's long-term credit quality.

Chart 2



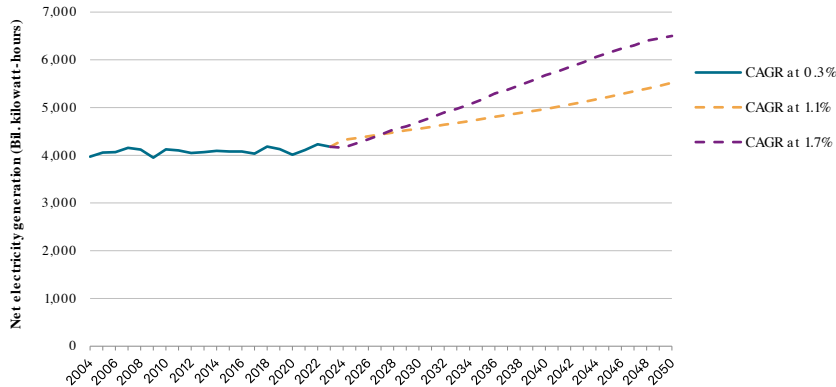
Growth will be transformative for utilities used to stagnation
Electricity demand: U.S. regulated electric utilities

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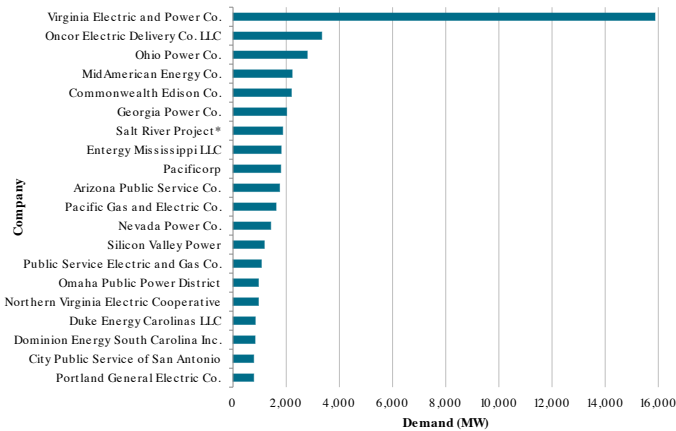
Data as of June 2024. CAGR—Compound annual growth rate.
Source: U.S. Energy Information Administration (historical and 1.1% CAGR), S&P Global Commodity Insights (1.7% CAGR).
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Data Center Demand Will Not Be Uniform

While data center energy demand will prove a boon for much of the North America regulated utility industry, it will not uniformly affect all utilities. We expect that the data center- driven demand growth will predominantly be in the Southeast, Midwest, and Western U.S. The greatest concentration of data centers is likely to be around the Washington D.C. metro area, primarily benefiting Dominion Energy's subsidiary, Virginia Electric and Power & Co. (see chart 3).

Chart 3

Data center demand by utility subsidiary



Data as of May 10, 2024. Demand is assumed for about the next decade. Utility is the primary utility in a data center's zip code. Data c when the actual figure is unknown. Renewable project counts toward a utility's total if the utility is listed as interconnected utility, owner, operator or power purchase agreement counterparty. Utilities include subsidiaries of investor-owned utilities, municipalities i
*Salt River Project Agricultural Improvement and Power District, Arizona. MW—Megawatt.
Sources: S&P Global Market Intelligence 451 Research, S&P Global Market Intelligence.
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Sales Growth Comes With Credit Risks

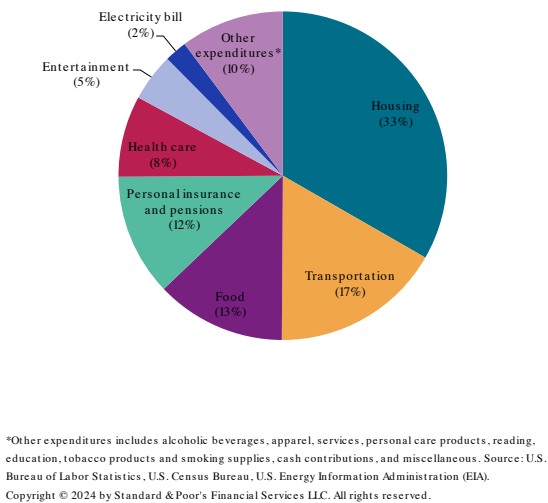
While the expansion of data centers represents a growth opportunity for the regulated utility industry, the industry must structure these new customer rates and contracts to ensure that the new data center customers are paying for their share of electricity costs.

Meeting the demands of relatively few but very large data center customers will require that the utility industry significantly increases its capital spending and infrastructure investments. Simply assigning a significant portion of data center-related infrastructure costs to existing residential customers would result in increased customer bills and likely Rating pressure on the industry's ability to effectively manage regulatory risk. Increases to customer bills ty Need a Rating? more customer complaints, which pressures regulators to limit further rate case increases, which, in turn, can negatively affect the industry's ability to effectively manage regulatory risk.

We therefore expect that increased capital expenditure associated with the growth of data centers will be primarily recovered from data center customers over decades. Such a plan comes with its own risks. For example, a technological breakthrough that reduces or eliminates the need for data centers, could eventually shift the recovery of these long-term infrastructure investments onto residential customers.

The average monthly U.S. electric bill is about \$138, representing about 2.2% of U.S. median household income. We believe at such levels, the customer bill represents good value for customers relative to other typical household bills (see chart 4).

Chart 4
Electricity bills are relatively small but politically sensitive
U.S. consumer expenditures in 2022



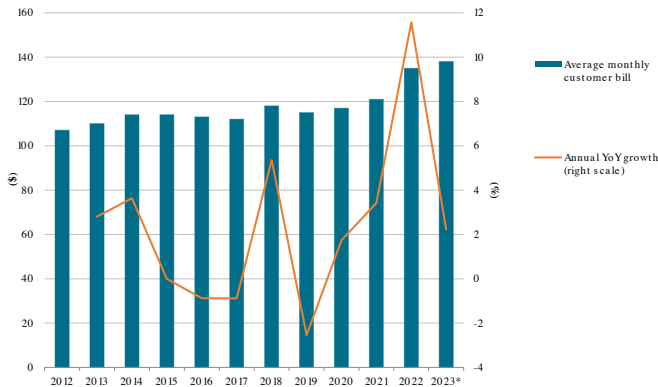
We consider that the industry's effective management of regulatory risk requires that electricity-customer bills are maintained at less than 2.5% of household income, and that annual energy bill increases are kept at less than 3%. Average bill increases were about 2.1% over the past decade, despite the spike in commodity prices in 2022 (see chart 5). Sharing data center-related infrastructure costs with existing residential customers would likely disrupt this paradigm, potentially leading to regulatory setbacks that could weigh on the industry's credit quality.

Chart 5
S&P Global
U.S. monthly electric bill for residential customers
CAGR at 2.1%

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*2023 data is preliminary and is subject to revision. YoY--Year-over-year.
Source: U.S. Energy Information Administration (EIA).
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Faster growth in electricity demand, and the resulting demand for increased investment, could also test credit quality by straining the industry's key financial metrics. Currently, we expect investor-owned U.S. electric utility sector's capital spending to be at about \$140 billion, with cash flow deficits of \$40 billion-\$60 billion. We forecast capital spending for data centers to increase the sector's annual robust capital spending by about 10%-15% per year for the next several decades (see chart 6), potentially leading to an increase in the industry's leverage and a deterioration in related financial measures.

More than 20% of the utility industry is already subject to a negative outlook on credit ratings. Also, about one-third of the industry is actively managing financial measures with only minimal financial cushion above our downgrade thresholds. We consider that for the industry to maintain credit quality it will need to finance increasing capital spending in a credit-supportive manner.

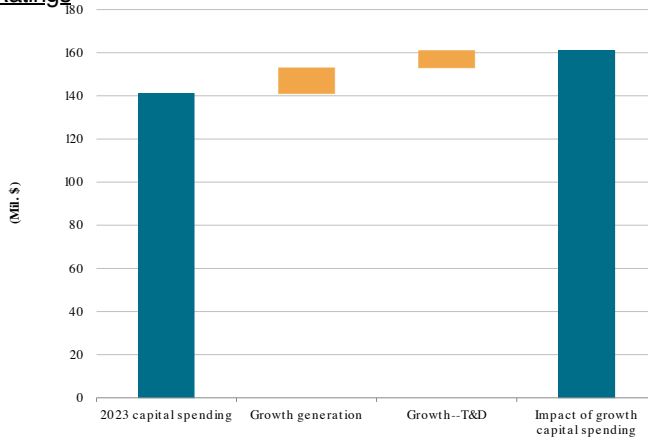
Chart 6

S&P GlobalGrowth will increase annual capital spending by about 14 %
Capital spending at U.S. regulated electric utilities

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T&D--Transmission and distribution. Source: S&P Global Ratings.
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Data Center Demand Should Prove A Net Positive

Overall, we expect growing demand for electricity, and resulting industry growth, due to data centers will support credit quality. There will clearly be risks that the industry must effectively come to terms with. We believe these risks are manageable, though unforeseen events remain a possibility. Therefore, we anticipate the industry's credit quality is poised to benefit from the emergence of electricity sales growth for the first time in nearly two decades.

Editor: Paul Whitfield

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Alternative Regulation for Emerging Utility Challenges: 2015 Update

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Contents

I. Introduction.....	1
II. Cost Trackers	6
III. Relaxing the Link Between Revenue and System Use.....	17
A. Lost Revenue Adjustment Mechanisms	17
B. Revenue Decoupling	17
C. Fixed/Variable Pricing	21
IV. Forward Test Years	31
V. Multiyear Rate Plans	34
VI. Formula Rates	47
VII. Marketing Flexibility	52
VIII. Conclusions	56

I. Introduction

Investor-owned electric utilities in the United States are buffeted today by varied and rapid changes in the business conditions they face. For vertically integrated electric utilities (“VIEUs”) and utility distribution companies (“UDCs”) alike, the traditional cost of service approach to rate regulation is often not ideal for helping utilities cope with these changes. Alternative approaches to regulation (“Altreg”) can often help utilities secure better outcomes for their customers and shareholders.

The changing business climate stems primarily from three root causes. One is pressure, from policymakers and many customers, for the power industry to lighten its environmental footprint. In addition to evolving renewable portfolio standards at the state level, utilities must comply with an array of federal initiatives such as the Environmental Protection Agency’s Clean Power Plan. Demand-side management (“DSM”) programs and tightening building codes and appliance standards encourage energy efficiency. Some customers seek power from greener sources than the increasingly clean portfolios of utilities. Self generation from rooftop solar is one means to this end, and its cost is falling. Customer-sited distributed generation (“DG”) must be accommodated, and utilities must purchase power surpluses that these facilities generate at regulated rates.

A second force for change is technological progress in metering and distribution. Advanced metering infrastructure and other smart grid technologies can improve reliability and facilitate integration of intermittent renewables. Time-sensitive pricing can encourage customers to use the grid in less costly ways. New value-added optional products and services can be offered which benefit customers.

A third force for change is increased concern about the reliability and resiliency of grid service. Some facilities are approaching advanced age, and some need more protection from severe weather. Many customers seek better quality service.

These forces are having important practical effects on utilities. Growth in the demand for their traditional services has slowed, and utilities face competition from distributed energy resources (“DERs”). Nevertheless, some utilities need capital expenditures (“capex”) for cleaner generating capacity, smart grid facilities, increased resiliency, and replacement of aging assets. Many new facilities don’t automatically trigger revenue growth. Increased marketing flexibility is needed to meet competitive challenges and complex, changing customer needs.

Under traditional regulation, the base rates that compensate utilities for costs of non-energy inputs are reset only in general rate cases with historical test years. These lengthy proceedings require a detailed review of all costs and their allocation amongst the utility’s retail services. Revenue from secondary sources (e.g., off-system sales) is imputed against the revenue requirement.

Most base rate revenue is drawn from volumetric and other usage charges. Since the cost of base rate inputs is driven more by capacity than system use in the short run, a utility’s finances are sensitive between rate

cases to the gap between growth in system use and capacity. A convenient proxy for this gap is the growth in use per customer (aka “average use”). The need for rate cases increases when average use declines.

Traditional regulation is ill-suited for addressing many of today’s challenges. Growth in average use was once positive, and the resulting incremental revenues helped utilities finance rising cost without rate cases. Today, growth in the average use of residential and commercial customers is typically static and often negative. Utilities needing normal or high capital expenditures are then compelled to file rate cases more frequently. These involve high regulatory cost and are nonetheless frequently uncompensatory when they involve historical test years. Frequent rate cases also reduce utility opportunities to increase earnings from improved cost containment and marketing. Traditional regulation also does not allow for many value-added or optional rates and services. Improved utility performance is thus discouraged at a time when it is increasingly needed to respond to competitive pressures.

Increased financial attrition has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

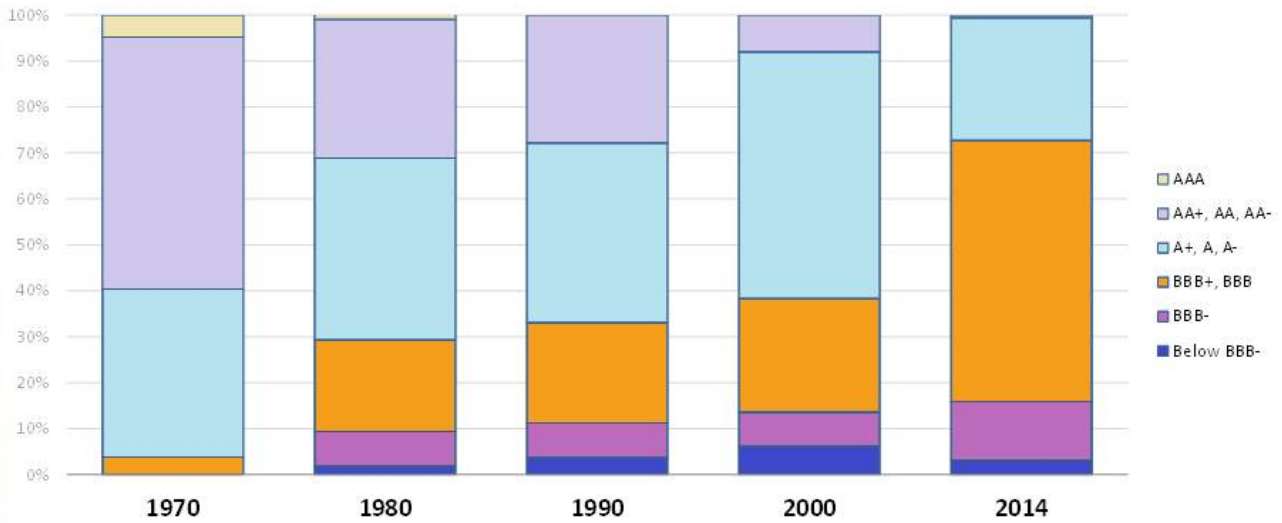
Alternative approaches to regulation have been developed which handle today’s business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, can involve sweeping regulatory change. Others, like revenue decoupling and cost trackers, target specific challenges.

This survey, now updated to include precedents through mid-2015, explains Altreg options and details precedents in the regulation of retail electric utility rates. A summary of states that currently use these approaches is featured in Table 1. Information is also provided on precedents for gas and water distributors and for energy utilities in Australia, Canada, and Britain. This year’s survey also discusses marketing flexibility, a new Altreg area of growing interest to EEI members.

Figure 1

U.S. Electric IOUs Rating History

1970 – 2014



The current average company rating is BBB+, improved from the BBB average rating in 2000



Source: EEI Finance Department, Standard & Poor's, Macquarie Capital, SNL Financial

Table 1

Alternative Regulation Tools: An Overview of Current Precedents

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans ¹	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Alabama	Electric & Gas					Electric & Gas	Yes
Alaska							
Arizona	Electric, Gas, & Water	Gas only	Electric & Gas		Electric only		
Arkansas	Electric & Gas	Gas only	Electric & Gas				
California	Electric & Gas	Electric & Gas			Electric & Gas		Yes
Colorado	Electric & Gas				Electric only		
Connecticut	Electric, Gas, & Water	Electric & Gas	Gas only	Electric & Gas			Yes
Delaware	Electric, Gas, & Water						
District of Columbia	Electric & Gas	Electric only					
Florida	Electric & Gas			Gas only	Electric only		Yes
Georgia	Electric & Gas	Gas only		Gas only	Electric only	Gas only	Yes
Hawaii	Electric only	Electric only			Electric only		Yes
Idaho	Electric only	Electric only					
Illinois	Gas & Water	Gas only		Electric & Gas		Electric only	Yes
Indiana	Electric, Gas, & Water	Gas only	Electric only		Gas only		
Iowa	Gas only			Gas only	Electric only		
Kansas	Gas only		Electric only	Gas only			
Kentucky	Electric & Gas		Electric & Gas	Gas only			Yes
Louisiana	Electric only		Electric only		Electric only	Electric & Gas	Yes
Maine	Electric, Gas, & Water	Electric only		Gas only	Gas only		Yes
Maryland	Electric & Gas	Electric & Gas					
Massachusetts	Electric & Gas	Electric & Gas	Electric & Gas		Gas only		
Michigan	Gas only	Gas only					Yes

Table 1 continued

State	Capital Cost Trackers	Measures that Relax the Use/Revenue Link			Multiyear Rate Plans ¹	Retail Formula Rate Plans	Forward Test Years
		Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing			
Minnesota	Electric & Gas	Electric & Gas					Yes
Mississippi	Electric & Gas		Electric & Gas	Electric only		Electric & Gas	Yes
Missouri	Gas & Water			Gas only			
Montana	Electric & Gas		Gas only				
Nebraska	Gas only			Gas only			
Nevada	Gas only	Gas only	Electric only				
New Hampshire	Electric, Gas, & Water			Gas only	Electric & Gas		
New Jersey	Electric, Gas, & Water	Gas only					
New Mexico							Yes
New York	Gas & Water	Electric & Gas	Gas only	Electric & Gas	Electric & Gas		Yes
North Carolina	Gas & Water	Gas only	Electric only				
North Dakota	Electric only			Gas only	Electric only		Yes
Ohio	Electric, Gas, & Water	Electric only	Electric only	Gas only	Electric only		
Oklahoma	Electric only		Electric only	Electric & Gas		Gas only	
Oregon	Electric & Gas	Electric & Gas	Electric & Gas				Yes
Pennsylvania	Electric, Gas, & Water			Gas only			Yes
Rhode Island	Electric & Gas	Electric & Gas					Yes
South Carolina	Electric only		Electric only			Gas only	
South Dakota	Electric only						
Tennessee	Gas only	Gas only		Gas only		Gas only	Yes
Texas	Electric & Gas			Gas only		Gas only	
Utah	Gas only	Gas only					Yes
Vermont				Gas only			
Virginia	Electric & Gas	Gas only		Gas only	Electric only		
Washington	Gas only	Electric & Gas			Electric & Gas		
West Virginia	Electric only						
Wisconsin				Gas only			Yes
Wyoming	Electric only	Gas only	Electric & Gas	Electric & Gas			Yes

¹ This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers

A cost tracker is a mechanism for expedited recovery of specific utility cost (e.g., outside of a rate case). Balancing accounts are typically used to track unrecovered costs. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are more practical than rate cases for addressing particular costs. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent rate cases and materially impact utility risk. Other volatile expenses that are sometimes addressed with trackers include those for pensions, severe storms, and uncollectible bills.

A second use of trackers is for costs incurred due to policies of government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agencies to consider the impact of their policies on customer bills.

Trackers are also used to compensate utilities for costs that are rapidly rising and don't otherwise trigger new revenue, whether or not they are volatile or mandated. This encourages needed expenditures and reduces risk and the frequency of rate cases. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in large measure to their rapid growth include those for health care.

Trackers for some costs have multiple rationales. DSM expenses, for example, are often sizable and sometimes grow rapidly.¹ Utility DSM programs are often mandated. Additionally, DSM can slow growth in the average use of power and reduce the need for plant additions, important sources of earnings growth for utilities. Tracking DSM expenses helps to balance utility incentives to embrace DSM.

Capital cost trackers typically address the accumulating depreciation, return on asset value, and taxes that result from the capex.² Capital costs can qualify for tracker treatment on several grounds. Major plant additions are volatile. Capex might be necessitated by highway construction or changes in government safety, reliability, or environmental standards. Capex is sometimes large enough to cause brisk cost growth that would otherwise occasion frequent rate cases.

An early use of capital cost trackers in the electric utility industry was to address construction costs of large power plants. These plants can take years to construct. An allowance in rates for a return on funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery of the allowance strains utility cash flow, increases financing expenses, and induces more rate "shock" when the value of the plant and construction financing is finally added to the rate base.

¹ This survey only documents capital cost trackers. Trackers for DSM expenses are ubiquitous so that there is less need for documentation.

² Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Many commissions have addressed these problems by making a return on construction work in progress (“CWIP”) eligible for immediate recovery. Capital cost trackers have often been used in lieu of frequent rate cases to obtain CWIP recovery.

Capital costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for large generation units, and construction of specific assets usually takes less than a year. However, the capex can still be sizable and doesn’t automatically trigger new revenue when completed. A tracker for accelerated modernization costs can help a company modernize its grid and improve its services without frequent rate cases.

Capital costs of generation emissions controls are often accorded tracker treatment. These controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities typically become used and useful each year over a series of years.

There are varied treatments of costs in approved capital trackers. Regulators often approve tracked capex budgets in advance, usually after considerable deliberation. Procedures for reviewing the need for generation plant additions are especially well established. Once a budget is set, the treatment of variances between actual and budgeted cost becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (e.g., 50-50) between the utility and its customers. Utilities are also permitted sometimes to share in the benefits of capex underspends. The prudence of tracked capex is often subject to a final review when the cost is added to rate base, a step that usually occurs in the next rate case.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are numerous and continue to grow. This is the most widely used Altreg tool in the United States. For electric utilities, trackers for emissions controls, generation capacity, advanced metering infrastructure, and general system modernization have been especially common in recent years. Trackers for gas distributors typically address the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common for accelerated modernization.

Figure 2: Recent Capital Cost Tracker Precedents by State: Energy Utilities

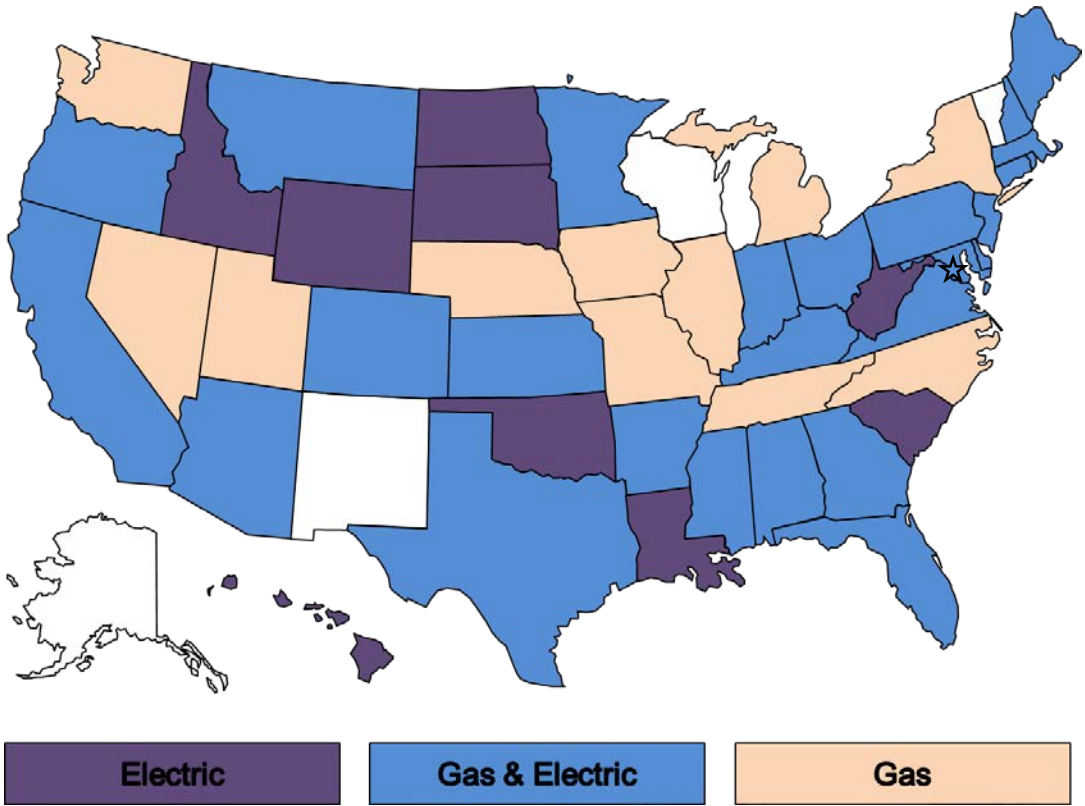


Figure 3: Recent Capital Cost Tracker Precedents by State: Water Utilities



Table 2

Recent Capital Cost Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	Arkansas Oklahoma Gas	Gas	Act 310 Surcharge	Relocations of pipelines mandated by government agencies	Docket 12-088-U (July 2013)
AR	Arkansas Oklahoma Gas	Gas	System Safety Enhancement Rider	Replacement of bare steel mains, mains on low pressure systems, mains that are subject of an advisory notice by government that company deems to be unsatisfactory	Docket 13-078-U (July 2014)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket 10-108-U (March 2011)
AR	Empire District Electric	Electric	Alternative Generation Environmental Recovery Rider	Environmental	Docket 15-010-U (August 2015)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket 10-109-U (August 2011)
AR	SourceGas Arkansas	Gas	At-Risk Meter Relocation Program Rider	Installation of new services for meters relocated due to motor vehicle collision risk	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Main Replacement Program Rider	Replacement of bare steel and coated steel mains, mains that are subject of an advisory notice by government that company deems to be unsatisfactory, and associated services	Docket 13-079-U (July 2014)
AR	SourceGas Arkansas	Gas	Act 310 Surcharge	Bare steel and cast iron pipeline replacement, in-line inspection project, emissions controlling catalysts for compressor station engines, greenhouse gas monitoring of some regulator stations, highway relocation projects	Docket 13-072-U (April 2014)
AR	SWEPSCO	Electric	Alternative Generation Recovery Rider	New generation	Docket 09-008-U (November 2009)
AR	SWEPSCO	Electric	Rider Environmental Compliance Surcharge	Environmental	Docket 15-021-U (October 2015)
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket E-01345A-08-0172
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket E-01345A-11-0224 (May 2012)
AZ	Arizona Public Service	Electric	Four Corners Rate Rider Surcharge	Generation	Docket E-01345A-11-0224 (December 2014)
AZ	Arizona Water Company	Water	Arsenic Cost Recovery Mechanism	Investments to reduce arsenic in water supply	Various (operating regions have separate decisions approving ACRMs)
AZ	Arizona Water Company - Eastern Group	Water	System Improvement Benefits Mechanism	Replacement of leak prone mains and related services, meters, and hydrants, replace meters that do not have lead free brass, other replacements for mains, services, meters, and hydrants that are at the end of their useful life	Decision 73938 (June 2013)
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket G-01551A-10-0458 (January 2012)
AZ	Tucson Electric Power	Electric	Environmental Compliance Adjustor	Miscellaneous environmental projects	Decision 73912 (June 2013)
CA	Pacific Gas & Electric	Electric	Smart Grid Memorandum Account	Smart grid projects that received DOE matching funds	Decision 09-09-029 (September 2009)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	Pacific Gas & Electric	Electric	Smart Grid Pilot Deployment Project Balancing Account	Pilot programs for smart grid line sensors, volt/VAR optimization, detection and location of distribution line outages and faulted circuits, and information technology investments to improve short term demand forecasting for power procurement	Decision 13-03-032 (March 2013)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	Energy Storage Balancing Account	Projects to store solar energy	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	San Diego Gas & Electric	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced metering infrastructure project	Decision 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CA	Southern California Gas	Gas	Post-2011 Distribution Integrity Management Program Balancing Account	DIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas	Transmission Integrity Management Program Balancing Account	TIMP related costs	Decision 13-05-010 (May 2013)
CA	Southern California Gas	Gas Transmission	Safety Enhancement Capital Cost Balancing Account	Replacement of mains that fail pressure tests or that cannot be pressure tested	Decision 14-06-007 (June 2014)
CO	Black Hills Colorado Electric	Electric	Transmission Cost Adjustment Rider	Transmission projects	Docket 09-014E, Decision C09-0271 (March 2009)
CO	Black Hills Colorado Electric	Electric	Clean Air Clean Jobs Act Rider	Gas-fired generation	Docket 14AL-0393E, Decision C14-1504 (December 2014)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket 07A-339E, Decision C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket 10-AL-963G (August 2011)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
CO	Public Service Company of Colorado	Electric	Clean Air Clean Jobs Act Rider	Miscellaneous environmental projects including gas-fired generation, scrubbers	Proceeding 14A-680E, Decision C15-0292 (March 2015)
CO	Rocky Mountain Gas	Gas Transmission	System Safety and Integrity Rider	TIMP, DIMP, and other safety regulatory compliance projects	Docket 13AL-0046G, Decision R14-0114 (February 2014)
CT	Aquarion Water Company of Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-06-21W101 (December 2008)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket 12-07-06 (January 2013)
CT	Connecticut Natural Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Connecticut Natural Gas	Gas	DIMP True-Up Mechanism	Cast iron and bare steel main replacement	Docket 13-06-08; (January 2014)
CT	Connecticut Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 08-10-15W101 (March 2009)
CT	Southern Connecticut Gas	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
CT	Torrington Water	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17W101 (December 2009)
CT	United Water Connecticut	Water	Water Infrastructure and Conservation Adjustment	Replacement of infrastructure including mains, valves, services, meters, and hydrants that have reached the end of their useful life or are no longer able to function as intended	Docket 09-06-17W101 (December 2009)
CT	Yankee Gas Services	Gas	System Expansion Reconciliation Mechanism	System expansion	Docket 13-06-02 (November 2013)
DC	Potomac Electric Power	Electric	Underground Project Charge	Undergrounding of specific feeders	Formal Case 1116 (November 2014)
DC	Washington Gas Light	Gas	Plant Recovery Adjustment	Remediation/replacement of mechanical couplings	Formal Case 1027 (December 2009)
DC	Washington Gas Light	Gas	Accelerated Pipe Replacement Plan Adjustment	Replacement of cast iron mains, bare steel mains and services and "black plastic" services	Formal Case 1115 (January 2015)
DE	Artesian Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-474 (December 2001)
DE	Delmarva Power & Light	Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 12-546 (October 2013)
DE	Delmarva Power & Light	Electric	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	Docket 13-115 (August 2014)
DE	Sussex Shores Water	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-470 (December 2001)
DE	Tidewater Utilities	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 03-210 (May 2003)
DE	United Water Delaware	Water	Distribution System Improvement Charge	Replacement of infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-481 (December 2001)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Florida City Gas	Gas	Safety and Access Verification Expedited Program	Replacement of unprotected steel mains, relocation of certain gas mains in rear lot easements	Docket 150116-GU (September 2015)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket 120015-EI (December 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 930613-EI (January 1994)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 050078-EI (September 2005)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Generation Base Rate Adjustment	Generation	Docket 130208 (November 2013)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Miscellaneous environmental projects	Docket 960688-EI (August 1996)
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 29950 as STRIDE tracker in 2009
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Surcharge	Pre-1985 plastic mains and services replacement, planned customer expansions, and infrastructure improvements that sustain reliability and operational flexibility	Docket 8516-U and 29950 (October 2009 and August 2013)
GA	Atmos Energy (now Liberty Utilities)	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket 12509-U (December 2000)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Docket 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket 27800, Senate Bill 31
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket 2007-0416 (December 2009)
IA	Black Hills Energy	Gas	System Safety Maintenance Adjustment	Replacement of steel and pvc pipe, relocations mandated by local governments	Docket RPU-2012-0004 (March 2013)
ID	PacifiCorp	Electric	Energy Cost Adjustment Mechanism	Lake Side II generation facility	Case PAC-E-13-04 (October 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
IL	Ameren Illinois	Gas	Rider Qualifying Infrastructure Plant	Replacement of prone to leak distribution and transmission pipe, installation of AMI and communications infrastructure, replacing or installing transmission or distribution facilities to establish over-pressure protection, replacement of difficult to locate mains and services, replacement of high pressure transmission pipelines without a recorded maximum allowable operating pressure, replacements to facilitate an upgrade from a low pressure system to a high pressure system	Docket 14-0573 (January 2015)
IL	Consumers Illinois Water Company (Kankakee, Vermilion, Woodhaven Districts)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 01-0561 (December 2001)
IL	Illinois-American Water (Chicago Metro Division)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 09-0251 (March 2010)
IL	Illinois-American Water (Single Tariff Pricing Zone)	Water	Qualifying Infrastructure Plant Surcharge Rider	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 04-0336 (December 2004)
IL	Northern Illinois Gas	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast iron pipe, non-cast iron pipe, and copper services; relocation of meters from inside customers' premises; upgrading of system from low pressure to medium pressure; replacement or installation of regulator stations, regulators, valves and associated facilities to establish over-pressure protection	Docket 14-0292 (July 2014)
IL	Peoples Gas Light & Coke	Gas	Rider Qualifying Infrastructure Plant	Replacement of cast and ductile iron, relocation of meters from inside customers' premises, upgrading of system from low pressure to medium pressure, replacement of high pressure transmission pipelines at higher risk of failure or lacking records, installation of regulator stations to establish over-pressure protection	Docket 13-0534 (January 2014)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Miscellaneous environmental projects	Cause 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Revenue Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket 43114 (November 2007)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Miscellaneous environmental projects	Cause 43636 (June 2009)
IN	Indiana Water Service	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42743 DSIC-1 (December 2004)
IN	Indiana-American Water	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Cause 42351 DSIC-1 (February 2003)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Miscellaneous environmental projects	Cause 42170 (November 2002)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Miscellaneous environmental projects	Cause 42150 (November 2002)
IN	Northern Indiana Public Service	Electric	Transmission, Distribution & Storage System Improvement Charge	Investments to maintain the capacity deliverability of system and replacement of aging infrastructure, economic development	Cause 44370 and 44371 (February 2014)
IN	Northern Indiana Public Service	Gas	Distribution System Improvement Charge	Gas system deliverability and system integrity projects, rural main extensions	Cause 44403 TDSIC 1 (January 2015)
IN	Utility Center Inc.	Water	Distribution System Improvement Charge	Replacement of non-revenue producing infrastructure (e.g., existing mains, services, meters, and hydrants)	Docket 42416 DSIC-1 (June 2003)
IN	Vectren Energy Delivery (Indiana Gas and Southern Indiana Gas & Electric)	Gas	Compliance and System Improvement Adjustment	System and pressure improvements, storage operations, instrumentation and communications equipment, public improvement projects, service replacements, and economic development	Cause 44429 (August 2014)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 08-AQLG-852-TAR (July 2008)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 10-KGSG-155-TAR (December 2009)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket 09-MDWE-722-TAR (May 2009)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocations	Docket 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Docket 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Miscellaneous environmental projects	Case 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Projects to be determined in subsequent filings to Commission	Docket U-30689 and U-32779 (October 2010 and June 2014)
LA	Entergy Gulf States Louisiana	Electric	Formula Rate Plan-3	Acquisition of generating facility, new generating facility or refurbishment of existing generating facility if the revenue requirement related to the project exceeds \$10 million	Docket U-32707 (December 2013)
LA	Entergy Louisiana	Electric	Formula Rate Plan 7	Cost of Ninemile 6 natural gas generating facility; New generating facility, acquisition of a generating facility, or refurbishment of existing generating facility if the revenue requirement related to the project exceeds \$10 million	Docket U-32708 and 31971 (January 2014 and April 2012)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Bay State Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, service tie-ins, encroached pipe, and meters	DPU 14-134
MA	Berkshire Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron mains and associated services, encroached pipe, and meter sets composed of non-cathodically protected steel, cast iron or copper	DPU 14-131
MA	Fitchburg Gas & Electric Light	Gas	Gas System Enhancement Adjustment Factor	Replacement of cast main and unprotected steel mains and services and encroached pipe	DPU 14-130

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MA	Massachusetts Electric	Electric	Net CapEx Factor	Potentially all distribution investments	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Massachusetts Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Smart Grid Adjustment Provision	Pilot smart grid investments including AMI, high speed communications network, in-home energy management devices, distribution automation, advanced capacitor control, advanced grid monitoring, remote fault indicators	DPU 11-129
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-132
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	New England Gas	Gas	Gas System Enhancement Adjustment Factor	Replacement of non-cathodically protected steel, cast iron, and wrought iron mains and associated services, inside services, service tie-ins, encroached pipe, and meters	DPU 14-133
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	Smart Grid Adjustment Factor	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MD	Baltimore Gas & Electric	Electric	Electric Reliability Investment Surcharge	Upgrades to improve poorest performing feeders, selective undergrounding, expanded recloser development on 13kV and 34 kV lines, diverse routing of 34 kV supply circuits	Case 9326 (December 2013)
MD	Baltimore Gas & Electric	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel mains and services, cast iron mains, copper services, and pre-1982 plastic "Ski Bar" risers	Case 9331 (January 2014)
MD	Columbia Gas of Maryland	Gas	Strategic Infrastructure Development and Enhancement Program	Replacement of bare steel and cast iron mains and bare steel services	Case 9332 (August 2014)
MD	Delmarva Power & Light	Electric	Grid Resiliency Charge	Feeder hardening	Case 9317 (September 2013)
MD	Potomac Electric Power	Electric	Grid Resiliency Charge	Feeder hardening	Case 9311 (July 2013)
MD	Washington Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program Rider	Replacement of bare and unprotected steel mains and services, targeted copper and pre-1975 plastic services, mechanically coupled pipe main and services, and cast iron mains	Case 9335 (May 2014)
ME	Central Maine Power	Electric	Customer Relationship Management & Billing Rate Adjustment	Customer relationship management & billing system replacement	Docket 2015-00040 (October 2015)
ME	Maine Water Company	Water	Water Infrastructure Charge	Replacement of stationary physical plant assets needed to operate a water system	Various orders separately issued for operating divisions
ME	Northern Utilities	Gas	Targeted Infrastructure Recovery Adjustment	Cast iron, bare steel, and unprotected coated steel mains and services replacements, replacement of farm tap regulators	Docket 2013-00133 (December 2013)
MI	Consumers Energy	Gas	Enhanced Infrastructure Replacement Program	Cast iron replacements	Case U-17643 (January 2015)
MI	Michigan Consolidated Gas (now DTE Gas)	Gas	Infrastructure Recovery Mechanism	Replacement of cast iron mains, replacement of indoor meters with outdoor meters, pipeline integrity projects designed to comply with federal and state safety standards	Case U-16999 (April 2013)
MI	SESCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 and U-17824 (January 2011 and June 2015)
MN	Interstate Power & Light	Electric	Renewable Energy Recovery Adjustment	Renewable generation	Docket M-10-312 (December 2013)
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Miscellaneous environmental projects	Docket M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Rider for Boswell Unit 4 Emission Reduction	Miscellaneous environmental projects	Docket M-12-920 (November 2013)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Miscellaneous environmental projects	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-06-1103 (November 2006)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket M-08-261 (November 2008)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Miscellaneous environmental projects	Docket M-09-847 (November 2009)
MN	Otter Tail Power	Electric	Renewable Resource Cost Recovery Rider	Renewable generation	Docket M-08-119 (August 2008)
MN	Otter Tail Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-09-881 (January 2010)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Case GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2007-0208 (July 2007)
MO	Missouri American Water	Water	Infrastructure System Replacement Surcharge	Replacement of mains, associated valves and hydrants, main cleaning and relining projects	Case WO-2004-0116 (December 2003)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components or relocations	Docket GR-2009-0355 (February 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
MS	Atmos Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new industrial customers for economic development	Docket 2013-UN-23 (July 2013)
MS	Centerpoint Energy	Gas	Supplemental Growth Rider	Extraordinary service expansions to new commercial and industrial customers for economic development	Docket 13-UN-214 (October 2013)
MS	Mississippi Power	Electric	Environmental Compliance Overview Plan Rate	Miscellaneous environmental projects	Docket 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket D2012.3.25 (November 2012)
NC	Aqua North Carolina	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-218, Sub 363 (May 2014)
NC	Aqua North Carolina	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-218, Sub 363 (May 2014)
NC	Carolina Water Service	Water	Water System Improvement Charge	Replacement of distribution system mains, valves, services, meters, and hydrants, main extensions, projects to comply with primary drinking water standards, unreimbursed facility relocation costs due to highways	Docket W-354, Sub 336 (March 2014)
NC	Carolina Water Service	Water	Sewer System Improvement Charge	Replacement of pumps, motors, blowers, and other mechanical equipment, collection main extensions designed to implement solutions to wastewater problems, improvements necessary to reduce inflow and infiltration to the collection systems as required by state and federal law and regulations, unreimbursed costs of highway relocations	Docket W-354, Sub 336 (March 2014)
NC	Piedmont Natural Gas	Gas	Integrity Management Rider	Investments driven by federal pipeline safety and integrity requirements	Docket G-9, Sub 631 (December 2013)
ND	Montana-Dakota Utilities	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-85 (December 2013)
ND	Montana-Dakota Utilities	Electric	Generation Resource Recovery Rider Tariff	New Generation	Case PU-14-108 (August 2014)
ND	Northern States Power- MN	Electric	Transmission Cost Rider	Transmission projects	Case PU-12-813 (February 2014)
ND	Northern States Power- MN	Electric	Renewable Energy Rider	North Dakota based renewable generation	Case PU-12-813 (February 2014)
ND	Otter Tail Power	Electric	Renewable Resource Rider	Renewables	Case PU-06-466 (May 2008)
ND	Otter Tail Power	Electric	Transmission Facility Cost Recovery Tariff	Transmission investments required to serve retail customers	Case PU-11-682 (April 2012)
ND	Otter Tail Power	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Case PU-13-84 (December 2013)
NE	Black Hills Nebraska Gas Utility	Gas	Infrastructure System Replacement Recovery Charge	Non-revenue increasing projects to replace existing assets	Application NG-0074
NE	SourceGas Distribution	Gas	Pipeline Replacement Charge	Projects entering service before May 2014 that are installed to comply with safety requirements as replacements for existing facilities, projects that will extend the useful life of existing assets or enhance pipeline integrity, facility relocations	Application NG-0072 (June 2013)
NE	SourceGas Distribution	Gas	System Safety and Integrity Rider	Projects entering service after April 2014 that comply with federal regulations including transmission and distribution integrity management plans or are facility relocations costing \$20,000 or more	Application NG-0078 (October 2014)
NH	Aquarion Water of New Hampshire	Water	Water Infrastructure and Conservation Adjustment Charge	Projects to upgrade or replace non-revenue producing assets including main, valve, and hydrant replacement, main cleaning and relining, and non-reimbursable relocations	Docket DW 08-098 (September 2009)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Miscellaneous environmental projects	DE 11-250 (April 2012)
NH	Public Service Company of New Hampshire	Electric	Reliability Enhancement Plan	Reliability improvements	DE 09-035, DE 11-250, and DE 14-238 (June 2015)
NJ	Elizabethtown Gas	Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort	System hardening	Docket GO13090826 (July 2014)
NJ	New Jersey American Water	Water	Distribution System Improvement Charge	Incremental non-revenue water main replacement, rehabilitation, or mandated relocation projects, service line replacements, valve and hydrant replacement	Docket WR12070669 (October 2012)
NJ	New Jersey Natural Gas	Gas	New Jersey Reinvestment in System Enhancement	Storm hardening projects	Docket GR13090828 (July 2014)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket EO09020125 (August 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Dockets G009010050, EO11020088, GO10110862 (April 2009 and July 2011)
NJ	Public Service Electric and Gas	Electric & Gas	Energy Strong Adjustment Mechanism	Electric: substation flood mitigation, gird reconfiguration strategies, and smart grid; Gas: Metering and regulating station flood mitigation, replacement of utilization pressure cast iron in flood prone areas	Docket EO13020155, GO13020156 (May 2014)
NJ	South Jersey Gas	Gas	Storm Hardening and Reliability Program	Replacement of low pressure mains and services with high pressure mains and services, removal of regulator stations, installation of excess flow valves in coastal areas	Docket GO13090814 (August 2014)
NJ	United Water New Jersey	Water	Distribution System Improvement Charge	Repair, replace, and/or clean mains, replace valves, hydrants, and service lines	Docket WR12080724 (October 2012)
NV	Southwest Gas	Gas	Gas Infrastructure Replacement Mechanism	Early vintage pipe replacements, conversion of master metered customers to individual meters	Docket 14-10002 (December 2014)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
NY	Corning Natural Gas	Gas	Safety and Reliability Charge	Replacement of leak prone pipe and ancillary costs to maintain a safe and reliable system	Case 11-G-0280 (October 2015)
NY	Keyspan Energy Long Island	Gas	Leak Prone Pipe Surcharge	Accelerated leak prone pipe removal program	Case 12-G-0214 (December 2014 and March 2015)
NY	Long Island American Water	Water	System Improvement Charge	Iron removal, storage tank rehabilitation, suction well rehabilitation at selected plants, customer information system	Case 11-W-0200 (March 2012)
NY	United Water New Rochelle	Water	Long Term Main Renewal Project	Cleaning and relining of mains	Case 99-W-0948 (August 2000)
NY	United Water New York	Water	Underground Infrastructure Renewal Program	Replacement of infrastructure including mains, valves, services, meters, and hydrants	Case 06-W-0131 (December 2006)
NY	United Water New York	Water	New Water Supply Source Surcharge	Projects to provide new sources of water in the short and long term	Case 06-W-0131 (December 2006)
OH	Aqua Ohio	Water	System Infrastructure Improvement Surcharge	Replacement of service lines, mains, hydrants, valves, main extensions to resolve documented water supply problems	Case 04-1824-WW-SIC (March 2005)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case 10-388-EL-SSO (August 2010)
OH	Columbia Gas	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Cases 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case 09-1036-GA-RDR (April 2010)
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services and faulty risers	1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Cases 07-0589-GA-AIR, 07-0590-GA-ALT, and 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Cases 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Duke Energy Ohio	Electric	Distribution Capital Investment Rider	Distribution capital investments not recovered through other trackers	Case 14-841-EL-SSO (April 2015)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Bare steel and cast iron pipelines & faulty riser replacements	Case 08-169-GA-ALT (October 2008)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMR	Cases 07-0829-GA-AIR and 06-1453-GA-UNC (October 2008); Case 09-38-GA-UNC (May 2009); Case 09-1875-GA-RDR (May 2010)
OH	Ohio American Water	Water	System Improvement Charge	Non-revenue producing service lines, hydrants, mains, valves, main extensions that improve supply problems, main cleaning	Case 05-577-WW-SIC (August 2005)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net distribution capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Cases 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Cases 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause PUD 20080387, Order 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	System Reliability Rider	Grid resiliency projects	Cause PUD 201300202 (January 2014)
OK	Public Service Company of Oklahoma	Electric	Advanced Metering Infrastructure Tariff	Advanced metering infrastructure deployment	Cause PUD 201300217 (April 2015)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, transmission integrity management program, distribution integrity management program	Docket UM 1406, Order 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	Lake Side 2 Tariff Rider	Generation	Docket UE 263, Order 13-474 (December 2013)
OR	PacifiCorp	Electric	M2O Transmission Rider	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Orders 12-493 and 13-195 (December 2012 and May 2013)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	Columbia Gas	Gas	Distribution System Improvement Charge	Replacement of cast iron, bare steel, and first generation plastic mains and services, install excess flow valves, install or relocate automated meters, and replace risers, meter bars, and service regulators	P-2012-2338282 (March 2013)
PA	Columbia Water Company	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-00021979
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket M-2009-2123948 (April 2010)
PA	Equitable Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2342745 (July 2013)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket M-2009-2123944 (April 2010)
PA	PECO	Electric	Distribution System Improvement Charge	Storm hardening and resiliency measures, underground cable replacement, substation retirements, and facility relocations	Docket P-2015-2471423 (October 2015)
PA	PECO	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2347340 (September 2015)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania-American Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-000961031 (August 1996)
PA	Peoples Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344596 (May 2013)
PA	Peoples TWP	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2344595 (May 2013)
PA	Philadelphia Gas Works	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2012-2337737 (April 2013)
PA	Philadelphia Suburban Water	Water	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-000961035 (August 1996)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket M-2009-2123945 (January 2010)
PA	PPL Electric Utilities	Electric	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., poles, wires)	Docket P-2012-2325034 (May 2013)
PA	UGI Central Penn Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2398835 (September 2014)
PA	UGI Penn Natural Gas	Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects (e.g., mains, meters, services)	Docket P-2013-2397056 (September 2014)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Previous accelerated capital replacement program investments plus main and service replacements and reliability investments	Docket 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Miscellaneous environmental projects	Docket EL11-001
SD	Black Hills Power	Electric	Phase in plan rate	Gas-fired generation	Docket EL12-062 (September 2013)
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL07-026 (January 2009)
SD	Northern States Power- MN	Electric	Transmission Cost Recovery Tariff	Transmission	Docket EL07-007 (January 2009)
SD	Northern States Power- MN	Electric	Infrastructure Rider	Generation	Docket EL 12-046 (April 2013)
SD	Otter Tail Power	Electric	Transmission Cost Recovery Tariff	Retail sales portion of specific transmission projects	Docket EL 10-015 (November 2011)
SD	Otter Tail Power	Electric	Environmental Quality Cost Recovery Tariff	Miscellaneous environmental projects	Docket EL 14-082 (December 2014)
TN	Piedmont Natural Gas	Gas	Integrity Management Rider	Distribution and transmission integrity management planning as required by the US Department of Transportation	Docket 13-00118 (May 2014)
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Gas Utilities Dockets 9615 and 10640
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity including mains replacement	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket 35620 (August 2008)
TX	Centerpoint Energy Houston Electric	Electric	Distribution Cost Recovery Factor	Change in net distribution rate base since last rate case	Docket 44572 (August 2015)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Miscellaneous environmental & reliability projects	Docket PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Miscellaneous environmental projects	Case PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case PUE-2011-00049 (November 2011)
VA	Roanoke Gas Company	Gas	SAVE Rider	Replacement of cast iron mains, bare steel mains and services and pre-1973 plastic pipe	Case PUE-2012-00030 (August 2012)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case PUE-2011-00073 (March 2012)
VA	Virginia Electric Power	Electric	Rider BW	Brunswick County Power Station (natural gas combined cycle generating station)	Case PUE-2012-00128 (August 2013)

Table 2 continued

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
VA	Virginia Natural Gas	Gas	SAVE Rider	Replacement of first generation plastic mains, cast and wrought iron mains, bare and ineffectively coated steel mains, and service lines installed prior to 1971	Case PUE-2012-00012 (June 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and pre-1975 plastic services	Cases PUE-2010-00087 and PUE-2012-00096 (April 2011 and November 2012)
WA	Cascade Natural Gas	Gas	Pipeline Replacement Program Cost Recovery Mechanism	Replacement of bare steel and poorly coated pipelines and distribution systems	Docket PG-131838 (October 2013)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WV	Monongahela Power	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Potomac Edison	Electric	Vegetation Management Surcharge	Capitalized distribution vegetation management expenses	Case 14-0702-E-42T (February 2015)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, environmental	Case 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket 20003-123-ET-12 (November 2012)

III. Relaxing the Link Between Revenue and System Use

Policymakers are increasingly interested in relaxing the link between the revenues utilities realize, and the kWh and kW of system use by customers. This reduces the financial attrition that results from slowing growth in system use (given legacy rate designs) more efficiently than frequent rate cases. In addition, utilities have more incentive to embrace DSM. Three approaches to relaxing the revenue/usage link are well established: lost revenue adjustment mechanisms (“LRAMs”), revenue decoupling, and fixed/variable pricing.

A. Lost Revenue Adjustment Mechanisms

LRAMs keep utilities whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also DG). Recovery usually is effected through a special rate rider. Estimates of load losses are needed.

LRAMs encourage utilities to embrace DSM that is eligible for LRAM treatment. They do not provide recovery for the revenue impact of external forces, like DSM programs managed by independent agencies, which slow load growth. Estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. When usage charges are high, the utility remains at risk for revenue fluctuations in volumes and peak load due to weather, local economic activity, and other volatile demand drivers.

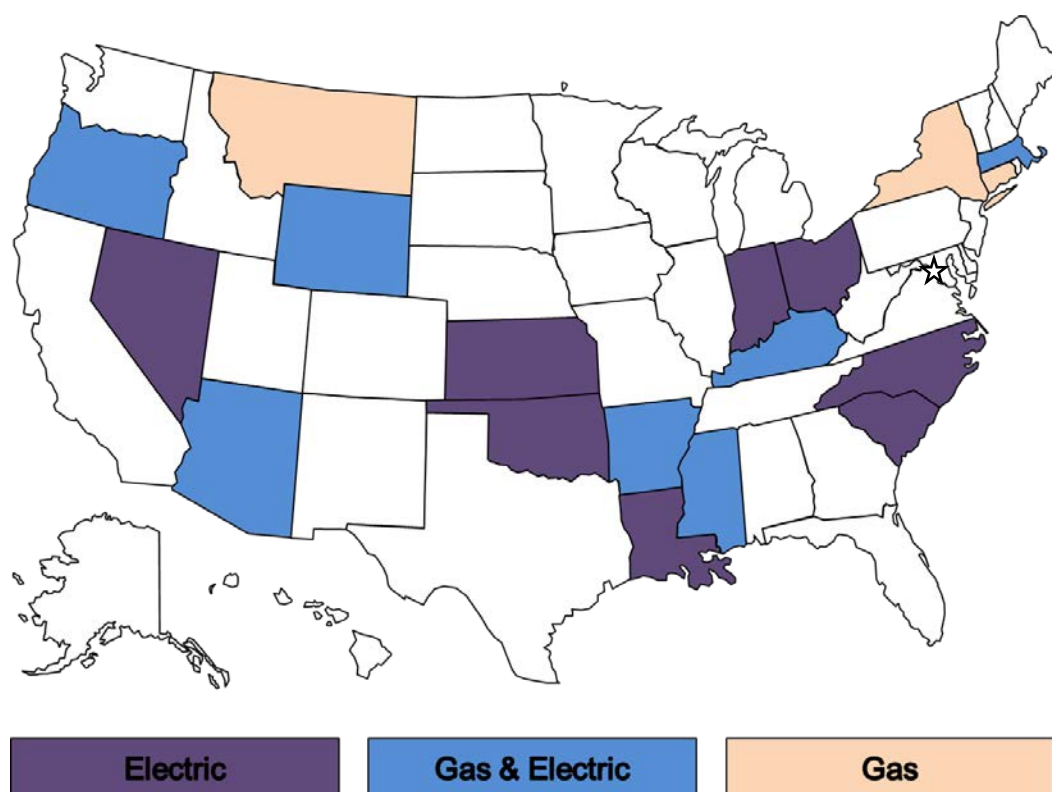
Precedents for LRAMs are detailed in Table 3 and Figure 4 below.³ LRAMs are currently the most popular means of relaxing the link between revenue and system use in the US electric utility industry. Since our 2013 survey, LRAMs have been adopted for electric utilities in Arizona, Louisiana, and Mississippi. A few utilities have LRAMs that address DG. LRAMs are less popular for gas distributors since the declining average use they have typically experienced for many years is due chiefly to external forces that LRAMs don’t address. Some utilities have LRAMs for some services and revenue decoupling for others. In New York, for example, some natural gas distributors have decoupling for residential and commercial customers and LRAMs for some large load customers.

B. Revenue Decoupling

Revenue decoupling adjusts a utility’s rates periodically to help its actual revenue track its allowed revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism (“RDM”) and a revenue adjustment mechanism (“RAM”). The RDM tracks variances between actual and allowed revenue and adjusts rates to reduce them. The RAM escalates allowed revenue to provide relief for growing cost pressures.

³ Some mechanisms similar to LRAMs are excluded from this survey.

Figure 4: Current LRAMs by State



RDMs can make true ups annually or more frequently. More frequent adjustments cause actual revenue to track allowed revenue more closely so that rate adjustments are smaller. The size of the rate adjustment that is permitted in a given year is sometimes capped. A “soft” cap permits utilities to defer for later recovery account balances that cannot be drawn down immediately. A “hard” cap does not.

RDMs vary in the scope of services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor’s base rate revenue and are often the primary focus of DSM programs. RDMs also vary in terms of the services for which revenues are pooled for true up purposes. In some plans all services are placed in the same “basket.” Other plans have multiple baskets, and these insulate customers of services in each basket from changes in revenue for services in other baskets.

Some RDMs are “partial” in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between allowed revenue and weather normalized actuals. An RDM that instead accounts for *all* sources of demand variance is called a “full” decoupling mechanism.

Table 3

Current LRAM Precedents¹

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket 07-075-TF, Order 26
AR	SourceGas Arkansas	Gas	June 2011	Docket 07-078-TF, Order 26
AR	Southwestern Electric Power	Electric	June 2011	Docket 07-082-TF, Orders 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket E-01345A-11-0224, Decision 73183
AZ	Tucson Electric Power	Electric	June 2013	Docket E-01933A-12-0291; Decision 73912
AZ	UNS Electric	Electric	September 2013	Docket E-04204A-12-0504; Decision 74235
AZ	UNS Gas	Gas	May 2012	Docket G-04204A-11-0158 Decision 73142
CT	Southern Connecticut Gas	Gas	August 1995	Docket 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Causes 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Cases 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case 2004-00389
KY	Kentucky Power	Electric	December 1995	Case 95-427
KY	Kentucky Utilities	Electric	May 2001	Case 2000-0459
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case 93-150
LA	Cleco Power	Electric	October 2014	Docket R-31106
LA	Entergy Gulf States Louisiana	Electric	October 2014	Docket R-31106
LA	Entergy Louisiana	Electric	October 2014	Docket R-31106
LA	Southwestern Electric Power	Electric	October 2014	Docket R-31106
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128

Table 3 (cont'd)

State	Company	Services	Approval Date	Case Reference
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MS	Atmos Energy	Gas	August 2014	Docket 2014-UA-017
MS	Centerpoint Energy	Gas	August 2014	Docket 2014-UA-007
MS	Entergy Mississippi	Electric	September 2014	Docket 2009-UN-064
MS	Mississippi Power	Electric	March 2015	Docket 2014-UN-10
MT	Montana-Dakota Utilities	Gas	October 2006	Docket D2005.10.156; Order 6697c
NC	Duke Energy Carolinas	Electric	February 2010	Docket E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket E-22, Sub 464
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
NY	Keyspan Long Island	Gas	December 2009	Case 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case 06-G-1185; Currently effective for all customers not in RDM
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket 08-1094-EL-SSO
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007 and August 2012	Dockets 06-0091-EL-UNC and 11-4393-EL-RDR; Effective for classes not included in RDM
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket 08-935-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause PUD 200900196; Order 572836
OR	Cascade Natural Gas	Gas	April 2006	Order 06-191; UG 167 Effective for classes not included in RDM
OR	Portland General Electric	Electric	September 2001	Order 01-836; UE 79 Effective for classes not included in RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Duke Energy Carolinas	Electric	January 2010	Docket 2009-226-E Order 2010-79
SC	Progress Energy Carolinas	Electric	June 2009	Docket 2008-251-E Order 2009-373
SC	South Carolina Electric & Gas	Electric	July 2010	Docket 2009-261-E, Order 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Dockets 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket 20004-65-ET-06

¹ LRAMs listed here include only those mechanisms that compensate utilities for actual revenues lost due to DSM and DG.

The great majority of decoupling systems have a RAM since, if allowed revenue is static, the utility will experience financial attrition as its costs inevitably rise. Utilities that do not have RAMs in their decoupling systems often file frequent rate cases or are allowed to use capital cost trackers to address attrition. The more important issue in a proceeding to consider decoupling is therefore the design of the RAM rather than the need for one.

Most RAMs escalate allowed revenue only for customer growth. Escalation for customer growth is sensible because it is an important driver of cost and also highly correlated with other drivers such as peak demand. The need for rate cases is thereby reduced but is rarely eliminated since cost has other drivers such as input price inflation. When RAMs are escalated only for customer growth, utilities usually retain the freedom to file rate cases to address other cost factors and often do. Some RAMs are “broad-based” in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can materially reduce the need for rate cases and provide a foundation for a multiyear rate plan.

Revenue decoupling compensates utilities for declining average use even if it is driven in part by external forces such as independently administered DSM programs. The lost revenue disincentive is removed for a wide array of utility initiatives to encourage DSM without requiring load impact calculations or rate designs that discourage DSM. To the extent that recovery of allowed revenue is ensured, utilities can use rate designs with usage charges more aggressively to foster DSM. This makes environmental intervenors strong supporters of decoupling. Controversy over billing determinants in rate cases with future test years is reduced.

Revenue decoupling is a popular means of relaxing the link between a utility’s revenue and customers’ kWh consumption. States that have tried gas and electric revenue decoupling are indicated on the maps below in Figures 5a and 5b, respectively. Revenue decoupling precedents in the United States and Canada are detailed in Table 4. In the electric utility industry, decoupling has been favored in states that strongly support DSM. Since our 2013 survey, decoupling has been adopted for electric utilities in Connecticut, Maine, Minnesota, and Washington state. Decoupling is the most widespread means of relaxing the revenue/usage link for gas distributors. This reflects the fact that gas distributors often experience declining average use and that this has been driven chiefly by external forces. Table 4 indicates the kinds of RAMs chosen in approved decoupling systems. Note that RAMs for electric utilities are frequently broad-based.

C. Fixed/Variable Pricing

Fixed/variable pricing is an approach to rate design that uses fixed charges (charges that do not vary with the actual sales volume or peak demand) to compensate utilities for fixed costs of service. For residential and small commercial services, customer charges (a flat monthly fee per customer) are the most common fixed charge used. Base revenue thus tends to grow at the gradual pace of customer growth. A *straight* fixed/variable (“SFV”) rate design recovers *all* base revenue through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed/variable pricing.

Expired Plan

Current Plan

Expired Plan **Current Plan**

Table 4
Revenue Decoupling Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current					
United States					
AR	Arkansas Oklahoma Gas	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-078-U
AR	CenterPoint Energy	Gas	2008-2016	No RAM but multiple capital cost trackers	Dockets 06-161-U, 11-088-U, 12-057-TF, and 13-114-TF
AR	SourceGas Arkansas (Arkansas Western)	Gas	2014-open	No RAM but multiple capital cost trackers	Docket 13-079-U
AZ	Southwest Gas	Gas	2012-open	Customers	Docket G-01551A-10-0458
CA	Bear Valley Electric Service	Electric	2013-2016	Stairstep	Decision 14-11-002
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2014-2016	Stairstep	Decision 14-08-032
CA	San Diego Gas & Electric	Gas & Electric	2012-2015	Stairstep	Decision 13-05-010
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2012-2015	Stairstep	Decision 13-05-010
CA	Southwest Gas	Gas	2014-2018	Stairstep	Decision 14-06-028
CT	Connecticut Light & Power	Electric	2014-open	No RAM	Docket 14-05-06
CT	Connecticut Natural Gas	Gas	2014-open	No RAM	Docket 13-06-08
CT	United Illuminating	Electric	2013-open	Stairstep until July 2015, No RAM thereafter	Docket 13-01-19
DC	Potomac Electric Power	Electric	2010-open	Customers	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	Dockets 2008-0274, 2008-0083, 2013-0141
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0164, 2013-0141
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163, 2013-0141
ID	Idaho Power	Electric	2012-open	Customers	Cases IPC-E-11-19, IPC-E-14-17
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM but broad-based capital cost tracker	Case 11-0281
IN	Citizens Gas	Gas	2007-open	Customers	Cause 42767
IN	Indiana Gas	Gas	2011-2015	Customers	Cause 44019
IN	Indiana Gas	Gas	2016-2019	Customers	Cause 44598
IN	Indiana Natural Gas	Gas	2014-open	Customers	Cause 44453
IN	Vectren Southern Indiana	Gas	2011-2015	Customers	Cause 44019
IN	Vectren Southern Indiana	Gas	2016-2019	Customers	Cause 44598
MA	Bay State Gas	Gas	2015-2018	Revenue per Customer Stairstep	DPU 15-50
MA	Boston-Essex Gas	Gas	2010-open	Customers	DPU 10-55
MA	Colonial Gas	Gas	2010-open	Customers	DPU 10-55
MA	Fitchburg Gas & Electric	Gas	2011-open	Customers	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capital cost tracker	DPU 09-39
MA	New England Gas	Gas	2011-open	Customers	DPU 10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MD	Baltimore Gas & Electric	Electric	2008-open	Customers	Letter Orders ML 108069, 108061
MD	Baltimore Gas & Electric	Gas	1998-open	Customers	Case 8780
MD	Chesapeake Utilities	Gas	2006-open	Customers	Order 81054
MD	Columbia Gas of Maryland	Gas	2013-open	Customers	Order 85858
MD	Delmarva Power & Light	Electric	2007-open	Customers	Order 81518
MD	Potomac Electric Power	Electric	2007-open	Customers	Order 81517
MD	Washington Gas Light	Gas	2005-open	Customers	Order 80130
ME	Central Maine Power	Electric	2014-open	Customers	Docket 2013-00168

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
United States (cont'd)					
MI	Consumers Energy	Gas	2015-open	No RAM	Case U-17643
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case U-16999
MI	Michigan Gas Utilities	Gas	2015-open	No RAM	Case U-17273
MN	CenterPoint Energy	Gas	2015-2018	Customers	GR-13-316
MN	Minnesota Energy Resources	Gas	2013-2016	Customers	GR-10-977
MN	Northern States Power - MN	Electric	2016-2018	Customers	GR-13-868
NC	Piedmont Natural Gas	Gas	2008-open	Customers	Docket G-9, Sub 550
NC	Public Service Co of NC	Gas	2008-open	Customers	Docket G-5, Sub 495
NJ	New Jersey Natural Gas	Gas	2014-open	Customers	Docket GR13030185
NJ	South Jersey Gas	Gas	2014-open	Customers	Docket GR13030185
NV	Southwest Gas	Gas	2009-open	Customers	D-09-04003
NY	Central Hudson G&E	Gas & Electric	2015-2018	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	Gas	2014-2016	Revenue per Customer Stairstep	Case 13-G-0031
NY	Consolidated Edison	Electric	2014-2016	Stairstep	Case 13-E-0030
NY	Corning Natural Gas	Gas	2015-2017	Customers	Case 11-G-0280
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery New York	Gas	2013-2014	Revenue per Customer Stairstep through 2014, Customers After 2014	Case 12-G-0544
NY	National Fuel Gas	Gas	2013-2015	Customers	Case 13-G-0136
NY	New York State Electric & Gas	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0715
NY	New York State Electric & Gas	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0716
NY	Niagara Mohawk	Gas	2013-2016	Optional Revenue per Customer Stairstep	Case 12-G-0202
NY	Niagara Mohawk	Electric	2013-2016	Optional Stairstep	Case 12-E-0201
NY	Orange & Rockland Utilities	Gas	2015-2018	Revenue per Customer Stairstep	Case 14-G-0494
NY	Orange & Rockland Utilities	Electric	2015-2017	Stairstep	Case 14-E-0493
NY	Rochester Gas & Electric	Gas	2010-2013	Revenue per Customer Stairstep through 2013, Customers thereafter	Case 09-E-0717
NY	Rochester Gas & Electric	Electric	2010-2013	Stairstep through 2013, No RAM thereafter	Case 09-G-0718
NY	St. Lawrence Gas	Gas	2010-open	Revenue per Customer Stairstep through 2012, Customers thereafter	Case 08-G-1392
OH	AEP Ohio	Electric	2012-2018	Customers	Cases 11-351-EL-AIR, 13-2385-EL-SSO
OH	Duke Energy Ohio	Electric	2015-open	Customers	Case 14-841-EL-SSO
OR	Cascade Natural Gas	Gas	2013-2015	Customers	Order 13-079
OR	Northwest Natural Gas	Gas	2012-open	Customers	Order 12-408
OR	Portland General Electric	Electric	2014-2016	Customers	Order 13-459
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capital cost tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	Customers	Docket 4206
TN	Chattanooga Gas	Gas	2013-open	Customers	Docket 09-0183
UT	Questar Gas	Gas	2010-open	Customers	Docket 09-057-16
VA	Columbia Gas of Virginia	Gas	2013-2015	Customers	Case PUE-2012-00013
VA	Virginia Natural Gas	Gas	2013-2016	Customers	Case PUE-2012-00118
VA	Washington Gas Light	Gas	2013-2016	Customers	Case PUE-2012-00138
WA	Avista	Gas & Electric	2015-2019	Customers	Dockets UE-140188 and UG-140189
WA	Puget Sound Energy	Gas & Electric	2013-2016	Revenue per Customer Stairstep	Dockets UE-121697 and UG-121705
WY	Questar Gas	Gas	2012-open	Customers	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	Customers	Docket 30022-148-GR-10

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Current (cont'd)					
Canada					
BC	BC Hydro	Electric	2015-2016	Stairstep	Order G-48-14
BC	FortisBC	Electric	2014-2019	Indexing	Order G-139-14
BC	FortisBC Energy	Gas	2014-2019	Indexing	Order G-138-14
BC	Pacific Northern Gas	Gas	2003-open	Customers	N/A
ON	Enbridge Gas Distribution	Gas	2014-2018	Stairstep	EB-2012-0459
ON	Union Gas	Gas	2014-2018	Indexing	EB-2013-0202
Historic					
United States					
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2008-2013	No RAM	Docket 07-078-TF
CA	Bear Valley Electric Service	Electric	2009-2012	Stairstep	Decision 09-10-028
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Gas	Gas	1979-1980	No RAM	Decision 89710
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1983-1984	Hybrid	Decision dated December 8, 1982
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CO	Public Service Company of Colorado	Gas	2008-2011	Customers	Decision C07-0568
CO	Public Service Company of Colorado	Electric	2012-2014	Stairstep	Decision C12-0494
CT	United Illuminating	Electric	2009-2013	Stairstep until 2011/No RAM for 2011 onwards	Docket 08-07-04
FL	Florida Power Corporation	Electric	1995-1997	Customers	Docket 930444
ID	Idaho Power	Electric	2007-2009	Customers	Case IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	Customers	Case IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	Customers	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	Customers	Case 07-0242
IN	Citizens Gas	Gas	2007-2011	Customers	Cause 42767
IN	Vectren Energy	Gas	2007-2011	Customers	Cause 43046
IN	Vectren Southern Indiana	Gas	2007-2011	Customers	Cause 43046
MA	Bay State Gas	Gas	2009-open	Customers	DPU 09-30
ME	Central Maine Power	Electric	1991-1993	Customers	Docket 90-085
MI	Consumers Energy	Electric	2009-2011	Customers	Case U-15645
MI	Consumers Energy	Gas	2010-2012	Customers	Case U-15986
MI	Detroit Edison	Electric	2010-2011	Customers	Case U-15768
MI	Michigan Consolidated Gas	Gas	2010-2012	Customers	Case U-15985
MI	Michigan Gas Utilities	Gas	2010-2013	Customers	Case U-15990
MI	Upper Peninsula Power	Electric	2010-2011	Customers	Case U-15988
MN	CenterPoint Energy	Gas	2010-2013	Customers	Docket GR-08-1075
MT	Montana Power Company	Electric	1994-1998	Customers	Docket 93.6.24

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
United States (cont'd)					
NC	Piedmont Natural Gas	Gas	2005-2008	Customers	Docket G-44 Sub 15
ND	Northern States Power - MN	Electric	2012	Not Applicable, plan only 1 year in duration	Case PU-11-55
NJ	New Jersey Natural Gas	Gas	2007-2010	Customers	Docket GR05121020
NJ	New Jersey Natural Gas	Gas	2010-2013	Customers	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	Customers	Docket GR05121019
NJ	South Jersey Gas	Gas	2010-2013	Customers	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	Customers	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009	No RAM	Case 08-E-0887
NY	Central Hudson G&E	Gas & Electric	2010-2013	Revenue per Customer Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Central Hudson G&E	Gas & Electric	2013-open	Customers for Gas, No RAM for Electric	Case 12-M-0192
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion 92-8
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2010-2013	Revenue per Customer Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Corning Natural Gas	Gas	2012-2015	Revenue per Customer Stairstep	Case 11-G-0280
NY	Keyspan Energy Delivery - New York	Gas	2010-open	Revenue per Customer Stairstep	Case 06-G-1185
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion 92-8
NY	National Fuel Gas	Gas	2008-open	Customers	Case 07-G-0141
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Niagara Mohawk	Gas	2009-open	Customers	Case 08-G-0609
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Orange & Rockland Utilities	Gas	2012-2015	Customers	Case 08-G-1398
NY	Orange & Rockland Utilities	Gas	2009-2012	Revenue per Customer Stairstep	Case 08-G-1398
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion 93-19
OH	Duke Energy Ohio	Electric	2012-2014	Customers	Case 11-5905-EL-RDR
OH	Vectren Energy	Gas	2007-2009	Customers	Case 05-1444-GA-UNC
OR	Cascade Natural Gas	Gas	2007-2012	Customers	Order 06-191
OR	Northwest Natural Gas	Gas	2002-2005	Customers	Order 02-634
OR	Northwest Natural Gas	Gas	2005-2009	Customers	Order 05-934
OR	Northwest Natural Gas	Gas	2009-2012	Customers	Order 07-426
OR	PacifiCorp	Electric	1998-2001	Indexing	Order 98-191
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order 95-0322
OR	Portland General Electric	Electric	2009-2010	Customers	Order 09-020
OR	Portland General Electric	Electric	2011-2013	Customers	Order 10-478
TN	Chattanooga Gas	Gas	2010-2013	Customers	Docket 09-0183
UT	Questar Gas	Gas	2006-2010	Customers	Docket 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	Customers	Case PUE-2008-00060
VA	Washington Gas Light	Gas	2010-2013	Customers	Case PUE-2009-00064
WA	Avista	Gas	2007-2009	Customers	Docket UG-060518
WA	Avista	Gas	2009-2012	Customers	Docket UG-060518
WA	Avista	Gas	2013-2014	Revenue per Customer Stairstep	Docket UG-120437
WA	Cascade Natural Gas	Gas	2005-2010	Customers	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	Customers	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	Customers	Docket D-6690-UR-119
WI	Wisconsin Public Service	Gas & Electric	2013	Not Applicable, plan only 1 year in duration	Docket 6690-UR-121
WY	Questar Gas	Gas	2009-2012	Customers	Docket 30010-94-GR-08

Table 4 (cont'd)

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
Historic (cont'd)					
Canada					
BC	BC Gas	Gas	1994-1995	Hybrid	Order G-59-94
BC	BC Gas	Gas	1996-1997	Hybrid	N/A
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Hydro	Electric	2009-2010	Hybrid	Order G-16-09
BC	BC Hydro	Electric	2011	Not Applicable, plan only 1 year in duration	Order G-180-10
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	Terasen Gas	Gas	2010-2011	Hybrid	Order G-141-09
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
ON	Enbridge Gas Distribution	Gas	2008-2012	Revenue per Customer Indexing	Docket EB-2007-0615
ON	Union Gas	Gas	2008-2012	Indexing	Docket EB-2007-0606

Fixed/variable pricing relaxes the revenue/usage link with low administrative cost since it requires neither decoupling true ups nor load impact calculations. When average use is declining, base revenue will grow more rapidly with fixed/variable pricing so that rate cases tend to be less frequent even if the decline is largely driven by external forces. Base revenue grows more slowly than under conventional rate designs if average use is rising. The short term disincentive is removed to embrace various DSM initiatives. However, fixed/variable pricing reduces a utility's ability to use usage charges as a tool for promoting DSM. For example, it does not encourage customers with electric vehicles to charge these vehicles at night. Note also that the principle of rate design gradualism often discourages regulators from immediately adopting SFV pricing.

SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed/variable pricing in retail ratemaking are listed below on Table 5 and Figure 6. It can be seen that fixed/variable pricing has to date been considerably more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced, and the fact that the decline has been driven largely by external forces. Since our 2013 survey, fixed/variable pricing has been implemented for an electric utility in Oklahoma.

In addition to the precedents listed here, utilities in Wisconsin and several other states have in recent years made sizable steps in the direction of fixed/variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than are utilities in the United States. Most fixed/variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 6: Fixed/Variable Pricing Precedents by State

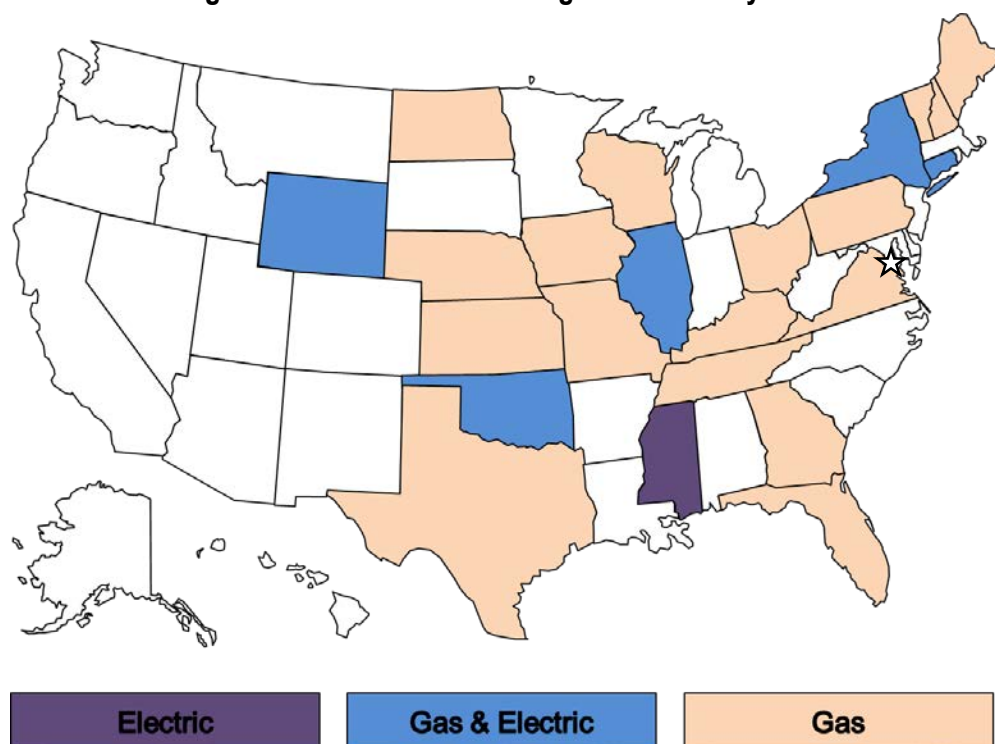


Table 5

Fixed Variable Residential Pricing Precedents¹

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Connecticut Natural Gas	Gas	2014-open	Docket 13-06-08
CT	United Illuminating	Electric	Occurred over period of years	No specific case
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Liberty Utilities	Gas	2015-open	Docket 34734
IA	Black Hills Energy	Gas	2009-open	Docket RPU-08-3
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Ameren Illinois	Electric	Occurred over period of years	No specific case
IL	Commonwealth Edison	Electric	2011-2013	Case 10-0467
IL	Mt. Carmel Public Utilities	Gas	2013-open	Case 13-0079
IL	North Shore Gas	Gas	2008-open	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case 07-0242
KS	Atmos Energy	Gas	2010-open	Docket 10-ATMG-495-RTS
KS	Black Hills Energy (formerly Aquila)	Gas	2007-open	Docket 07-AQLG-431-RTS
KS	Kansas Gas Service	Gas	2012-open	Docket 12-KGSG-835-RTS
KY	Atmos Energy	Gas	2014-open	Case 2013-00148
KY	Columbia Gas	Gas	2013-open	Case 2013-00167
KY	Delta Natural Gas	Gas	2007-open	Case 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case 2009-00202
ME	Maine Natural Gas	Gas	Occurred over period of years	Docket 2009-00067
ME	Northern Utilities	Gas	2014-open	Docket 2013-00133
MO	AmerenUE	Gas	2007-open	Case GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
NE	SourceGas Distribution	Gas	2012-open	Docket NG-0067
NH	Liberty Utilities (EnergyNorth Natural Gas)	Gas	Occurred over period of years	No specific case
NH	Northern Utilities	Gas	2014-open	DG 13-086
NY	Central Hudson Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
NY	Consolidated Edison	Electric & Gas	Occurred over period of years	No specific case
NY	Corning Gas	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - Long Island	Gas	Occurred over period of years	No specific case
NY	Keyspan Energy Delivery - New York	Gas	Occurred over period of years	No specific case
NY	National Fuel Gas	Gas	Occurred over period of years	No specific case

Table 5 (cont'd)

Jurisdiction	Company Name	Services	Years in Place	Case Reference
NY	New York State Electric & Gas	Electric	Occurred over period of years	No specific case
NY	Niagara Mohawk	Electric & Gas	Occurred over period of years	No specific case
NY	Orange & Rockland	Electric & Gas	Occurred over period of years	No specific case
NY	Rochester Gas & Electric	Electric & Gas	Occurred over period of years	No specific case
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Arkansas Oklahoma Gas	Gas	2013-open	Cause PUD 201200236
OK	Centerpoint Energy	Gas	2010-open	Cause PUD 201000030
OK	Oklahoma Natural Gas	Gas	2004-open	Causes PUD 200400610, PUD 201000048, PUD 200900110
OK	Public Service Company of Oklahoma	Electric	2015-open	Cause PUD 201300217
PA	Columbia Gas	Gas	2013-open	Docket R-2012-2321748
TN	Atmos Energy	Gas	2012-open	Docket 12-00064
TN	Piedmont Natural Gas	Gas	2012-open	Docket 11-00144
TX	Atmos Energy - Mid-Tex Division	Gas	Occurred over period of years	No specific case
TX	Atmos Energy - West Texas Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Houston Division	Gas	Occurred over period of years	No specific case
TX	Centerpoint Energy Beaumont/East Texas Division	Gas	Occurred over period of years	No specific case
VA	Columbia Gas of Virginia	Gas	Occurred over period of years	No specific case
VT	Vermont Gas Systems	Gas	Occurred over period of years	No specific case
WI	Madison Gas & Electric	Gas	2015-open	Docket 3270-UR-120
WI	Wisconsin Public Service	Gas	2015-open	Docket 6690-UR-123
WY	SourceGas Distribution	Gas	2011-open	Docket 30022-148-GR-10
WY	PacifiCorp (d/b/a Rocky Mountain Power)	Electric	2009-open	Docket 20000-333-ER-08

¹ Fixed variable pricing precedents include power and gas distributors that have a customer charge equal to or in excess of \$15 (or \$20 for vertically integrated electric utilities).

IV. Forward Test Years

General rate cases involve “test years” in which revenue requirements and billing determinants (e.g., the residential delivery volume) are jointly considered in ratesetting. A historical test year ends before the rate case is filed. A forward (a/k/a “fully forecasted”) test year (“FTY”) begins after the rate case is filed. An FTY typically begins about the time the rate case is expected to end and new rates take effect. Two-year forecasts may be required in this event which span both the year of the rate case and the rate effective year.⁴ In between forward and historical test years is the option of a “partially forecasted” test year in which some months of historical data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historical test years tend to be uncompensatory when cost is growing faster than billing determinants. Annual rate cases with historical test years can alleviate but not eliminate underearning under these conditions. The effect on credit metrics can be material.⁵ Where historical test years are used, there are thus added advantages to implementing other Altreg innovations discussed in this survey.

Forward test years can fully compensate utilities when cost growth exceeds growth in billing determinants. If this imbalance is chronic, however, FTYs do not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, such as cost trackers or multiyear rate plans.

Many approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalize data for an historical reference period, adjusted for known and measurable changes, and then use indexing and other statistical methods to extend projections. A mixture of forecasting methods is common. For example, index-based forecasting may be used only for O&M expenses.

FTYs were adopted in many jurisdictions during the 1970s and 1980s, when rapid inflation and major plant additions coincided with oil shock-induced slowdowns in the growth of average use. Several additional states have recently moved in the direction of FTYs. Some of these states are in the West, where comparatively rapid economic growth has required more rapid buildout of utility infrastructure.

Current state policies concerning test years are summarized below in Figure 7 and Table 6. In many jurisdictions the use of partially or fully-forecasted test years is not standardized. For example, in some jurisdictions, including Illinois and North Dakota, utilities are allowed to select their type of rate case test year. Test year selection may also be made part of the rate case (e.g., Utah). A few jurisdictions allow forward test years to be used in rate cases or formula rate plans, but not both (e.g., Illinois and Arkansas).

⁴ A forward test year can in principle be the rate case year, and thereby not require two-year forecasts. Proposed rates can be established on an interim basis shortly after the filing.

⁵ For evidence see “Forward Test Years for US Electric Utilities” by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, Edison Electric Institute, 2010.

The ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total. Since our 2013 survey, electric utilities in Pennsylvania have successfully used FTYs and utilities in Arkansas and Indiana have received legislative authorization for their use.⁶⁷ Forward test years are the norm in Canadian regulation.

Historical Test Year **Forward Test Year** **Other**

⁷ FTYs in Arkansas can only be used in formula rate plans.

Table 6

Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted Test Years Commonly Used (15)	
Alabama	Utilities operate under forward-looking formula rate plans Rate cases use forward test years but some formula rate plans use historical test years
California	
Connecticut	
FERC	
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Fully-Forecasted Test Years Occasionally Used (9)	
Illinois	Utilities use various test years including forward test years ("FTYs")
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Mississippi	Both electric utilities operate under forward-looking formula rate plans. Gas formula rate plans rely on historical test years ("HTYs").
New Mexico	A recently passed law allows for use of FTYs, and at least one rate increase based on FTY evidence has been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have traditionally been the norm. However, a law allowing fully-forecasted test years passed in 2012 and several electric utility rate increases based on FTY evidence have been approved.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Partially-Forecasted Test Years Commonly or Occasionally Used (8)	
Arkansas	Utilities have typically used partially forecasted test years in rate cases. However, a recent bill authorized the use of formula rates with either historical or forecasted test periods. Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings PEPCO has filed rate cases using both hybrid and historical test years recently Utilities use various test years excluding FTYs Utilities have the option to file partially-forecasted test years
Delaware	
District of Columbia	
Idaho	
Maryland	
Missouri	
New Jersey	
Ohio	
Historical Test Years Commonly Used (20)	
Alaska	Utilities have filed FTY evidence. However, no FTY rates have yet been approved but a recent case made extraordinary HTY adjustments. A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has been approved for an energy utility to date

V. Multiyear Rate Plans

Multiyear rate plans (“MRPs”) are designed to reduce regulatory cost, while increasing the utility incentive for efficient operation. Rate cases are held infrequently, most often at three to five year intervals. Between rate cases, rate escalations are based on a combination of automatic attrition relief mechanisms (“ARMs”) and cost trackers. The rate adjustments provided by ARMs are largely “external” in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth.

The “externalization” of ratemaking that ARMs and rate case moratoria achieve gives utilities more opportunity to profit from improved performance. Benefits of better performance can be shared between the utility and its customers. Performance incentives are strengthened despite streamlined regulation. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs can cap growth in rates (e.g., customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster customer use of the grid. Revenue caps are usually combined with revenue decoupling mechanisms, and are often favored where utilities must cope with declining average use and/or policymakers strongly encourage DSM.

Several approaches to ARM design are well-established. These include multiyear cost forecasts, indexing, and hybrids. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in other cost drivers like the number of customers served. A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue.

The indexing approach to ARM design has been more common for UDCs because their cost growth is relatively gradual and predictable. Hybrid and forecasted ARMs have historically been more common for vertically integrated electric utilities because occasional major plant additions have given their cost trajectories more of a “stairstep” pattern. However, this pattern is becoming less common in an era when demand growth is slower and fewer large power plants are under construction. Some VIEUs operating under MRPs have separate ARMs for generation and distribution.

Cost trackers are often used in MRPs to address changes in business conditions that are difficult to address using ARMs. A tracker that recovers a large portion of a utility’s capex cost can sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. MRPs with “tracker/freeze” provisions for vertically integrated utilities often accord tracker treatment to costs of new or refurbished generating plants.⁸ Trackers also address *force majeure* events like severe storms and changes in tax rates that affect costs.

Many MRPs feature earnings sharing mechanisms (“ESMs”) that automatically share earnings surpluses and/or deficits that result when the rate of return on equity (“ROE”) deviates from its regulated target. Some MRPs feature “off-ramps” that permit plan suspension when earnings are unusually high or low.

⁸ A good example is the Generation Base Rate Adjustment in the current MRP of Florida Power & Light.

Plans often feature performance incentive mechanisms that are linked to the utility's service quality. With stronger cost containment incentives, there is a greater need for a link between revenue and service quality. Many MRPs combine revenue decoupling, the tracking of DSM expenses, and performance incentives for DSM. The stronger incentive to contain cost that MRPs provide then becomes a "fourth leg" for the DSM stool.

MRPs have long been used to regulate utilities where market-responsive rates and services are a priority. Infrequent rate cases reduce the regulatory cost of allocating the revenue requirement between a complex and changing mix of market offerings and lessen concerns about cross-subsidization. These benefits of MRPs can be enhanced by designing other plan provisions in ways that insulate core customers from potentially adverse consequences of marketing flexibility.

For example, in the early 1990s, Maine's electric utilities were still vertically integrated and needed flexibility in marketing power to paper and pulp customers, some of whom had cogeneration options. The commission, under the chairmanship of Thomas Welch (a former telecom industry lawyer) approved a succession of price cap plans for Central Maine Power which facilitated marketing flexibility. As a result, the company had more freedom to enter into special contracts. The stronger incentives the company had to offer the right discounts to customers at risk of bypass was acknowledged by the commission when costs were allocated in later rate cases.

MRPs were first widely used in the United States to regulate railroad, oil pipeline, and telecommunications companies. A major attraction was the ability of MRPs to afford utilities flexibility in serving markets with diverse competitive pressures and complex, changing customer needs. US and Canadian precedents for MRPs in the electricity and gas utility industries are indicated in Table 7 and Figures 8a and 8b.⁹ In the US, MRPs have traditionally been most common in California and the Northeast. MRPs have been adopted by well-known VIEUs in Florida, North Dakota, and Virginia since our 2012 survey. A number of states have, additionally, experimented with "mini-MRPs" with terms of only two years. The forecast and tracker/freeze approaches to ARM design are most common currently in the US. The Federal Energy Regulatory Commission ("FERC") uses MRPs with index-based ARMs to regulate oil pipelines.

Canada is moving towards MRPs with index-based ARMs for gas and electric power distribution in all four populous provinces. In advanced economies overseas, MRPs are more the rule than the exception for utility regulation. Australia, Britain, and New Zealand are long time practitioners.

⁹ Rate freezes without extensive supplemental funding from capital cost trackers are excluded from Table 7 and Figures 8a and 8b.

Figure 8a: Recent US Multiyear Rate Plan Precedents by State

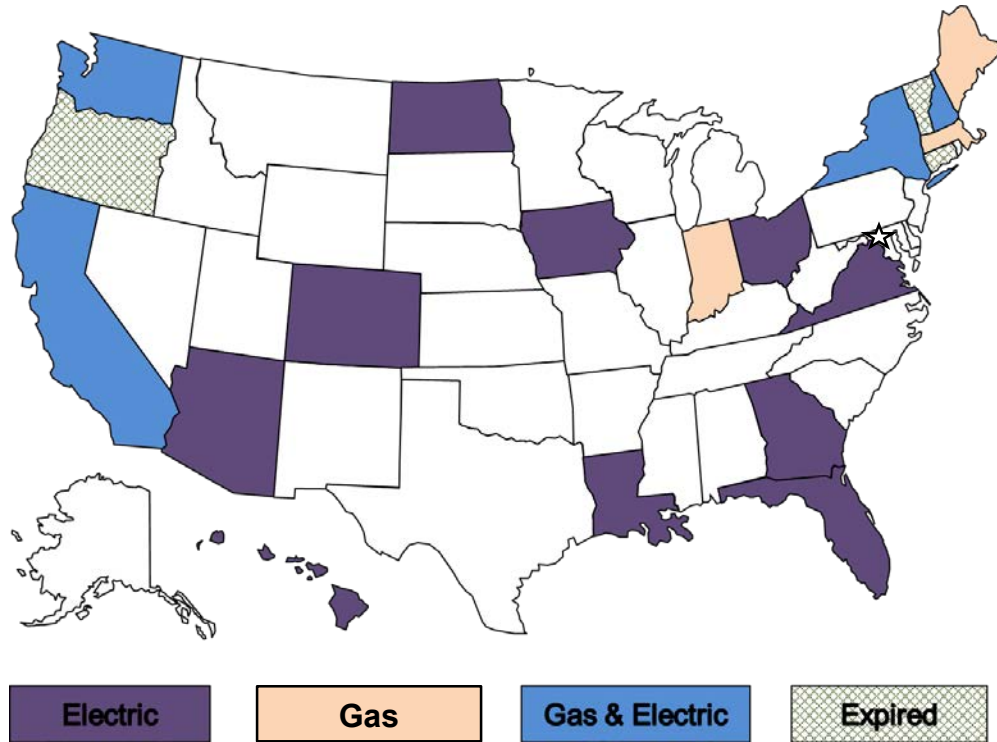


Figure 8b: Recent Canadian Multiyear Rate Plan Precedents by Province

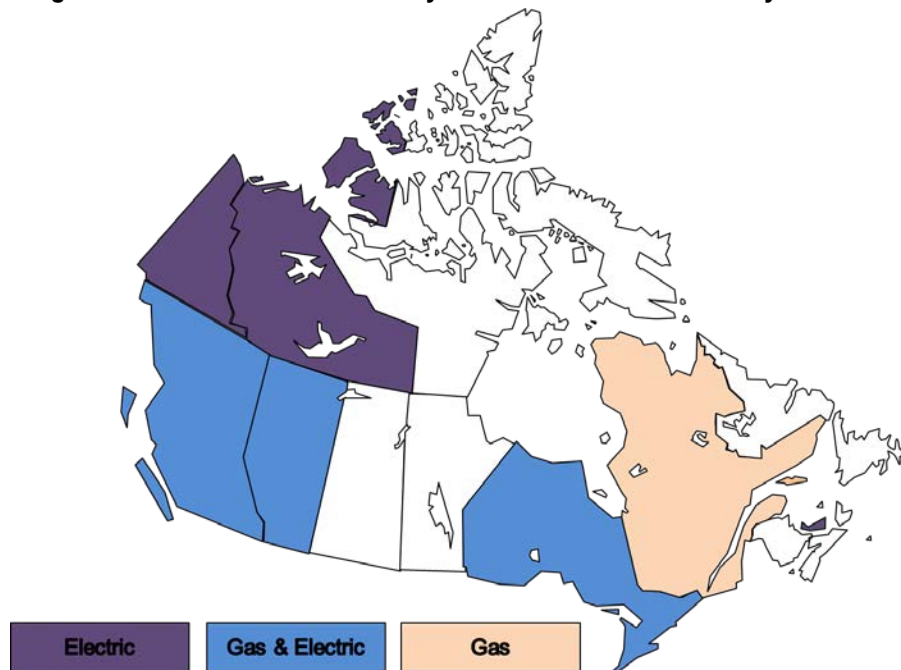


Table 7

Multiyear Rate Plan Precedents ¹

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current						
United States						
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate Freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capital and other cost trackers, LRAM	None	Decision 73183; May 2012
CA	Bear Valley Electric Service	2013-2016	Power distribution	Revenue Cap Stairstep	None	Decision 14-11-002; November 2014
CA	California Pacific Electric	2013-2015	Power distribution	Revenue Cap Index	None	Decision 12-11-030; November 2012
CA	Pacific Gas & Electric	2014-2016	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 14-08-032; August 2014
CA	PacifiCorp	2011-2013, extended through 2016	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings	None	Decision 10-09-010; September 2010
CA	San Diego Gas & Electric	2012-2015	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southern California Gas	2012-2015	Gas	Revenue Cap Stairstep	None	Decision 13-05-010; May 2013
CA	Southwest Gas	2014-2018	Gas	Revenue Cap Stairstep	None	Decision 14-06-028; June 2014
CO	Public Service of Colorado	2015-2017	Bundled power service	Rate Freeze with multiple capital cost trackers	Sharing of overearnings only up to earnings cap	Decision C15-0292; March 2014
FL	Florida Power & Light	2013-2016	Bundled power service	Rate Freeze with multiple capital and other cost trackers	None	Docket 120015-EI; December 2012
FL	Gulf Power	2014-June 2017	Bundled power service	Price Cap Stairstep through 2015, Rate Freeze beyond	None	Docket 130140-EI; December 2013
FL	Duke Energy Florida (formerly Progress Energy Florida)	2012-2016, extended through 2018	Bundled power service	Rate Freeze with one step plus capital and other cost trackers	None	Dockets 120022-EI and 130208-EI; 2012 and November 2013
FL	Tampa Electric	2013-2017	Bundled power service	Revenue Cap Stairstep	None	Docket 130040-EI
GA	Georgia Power	2014-2016	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with deadband	Docket 36989; December 2013
HI	Hawaiian Electric Company	2012-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2008-0083
HI	Hawaiian Electric Light Company	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0164
HI	Maui Electric	2013-open	Bundled power service	Revenue Cap Hybrid	Sharing of overearnings only without deadband, multiple sharing levels	Dockets 2008-0274 & 2009-0163
IA	MidAmerican Energy	2014-2017	Bundled power service	Revenue Cap Stairstep for 2014-2016, Rate Freeze for 2017	Sharing of overearnings only with deadband up to earnings cap	RPU-2013-0004
IN	Northern Indiana Public Service Company	2015-2020	Gas	Rate Freeze with capital and other cost trackers, possible reopening in 2017	Earnings cap implemented if company overearns since last rate case or prior 59 months, whichever is less	Cause 43894 and 44403 TDSIC 1 (August 2013 and January 2015)
LA	Cleco Power	2014-2017	Bundled power service	Rate Freeze with capital and other cost trackers	Sharing of overearnings only with deadband up to earnings cap	Docket U-32779; June 2014
MA	Bay State Gas	2015-2018	Gas	Revenue Cap Stairstep for 2015, 2016, Revenue Freeze through October 2018	None	DPU 15-150; October 2015
ME	Summit Natural Gas of Maine	2013-2022	Gas	Price Cap Indexing: 75% of change in GDPPPI	None until company has 1,000 or more customers, then sharing of under/overearnings evenly with deadband	Docket 2012-258; January 2013
NH	Northern Utilities	May 2014 - April 2017	Gas	Revenue Cap Stairstep for 2014-2015, Rate Freeze in 2016	Sharing of overearnings only with deadband up to earnings cap	DG 13-086; April 2014
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	Sharing of overearnings only with deadband	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Revenue Cap Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	Sharing of overearnings only with deadband	DE 10-055

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
United States (cont'd)						
NY	Central Hudson Gas & Electric	2015-2018	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Cases 14-E-0318, 14-G-0319
NY	Consolidated Edison	2014-2016	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 13-G-0031
NY	Corning Natural Gas	2012-2015	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-G-0280
NY	Orange & Rockland Utilities	November 2015-October 2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple sharing bands	Case 14-G-0494
ND	Northern States Power - Minnesota	2013-2016	Bundled power service	Revenue Cap Stairstep for 2013-2015, Rate Freeze in 2016	Sharing of overearnings only without deadband, earnings adjusted for effects of weather	Case PU-12-813
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Cases 11-388-EL-SSO, 12-1230-EL-SSO
US	All	2011-2016	Oil pipelines	Price Cap Index: PPI-Finished Goods + 2.65%	None	Docket RM10-25-000; December 2010
VA	Appalachian Power	2014-2017	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
VA	Virginia Electric Power	2015-2019	Bundled power service	Rate Freeze supplemented by capital and other cost trackers	None	Senate Bill 1349
WA	Puget Sound Energy	2013-2016	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, equal sharing between company and customers	Dockets UE-121697 and UG-121705
Canada						
Alberta	Altgas Utilities and ATCO Gas	2013-2017	Gas	Revenue per Customer Indexing: Input price index - 1.16%, + capital cost trackers	None	Decision 2012-237
Alberta	ATCO Electric, EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, + capital cost trackers	None	Decision 2012-237
British Columbia	FortisBC	2014-2018	Bundled power service	Revenue Cap Index: I-Factor - 1.03%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698719, Decision; September 2014
British Columbia	FortisBC Energy	2014-2018	Gas	Revenue Cap Index: I-Factor - 1.1%, + capital cost tracker for CPCN projects	Symmetric without deadband	Project #3698715, Decision; September 2014
Ontario	All unless company opts out	2014-2018	Power distribution	Price Cap Index: Input price index - (0%+stretch); stretch factor reassigned annually, + capital cost tracker option available	None	EB-2010-0379 Report of the Board; November 2013
Ontario	Horizon Utilities	2015-2019	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2014-0002; December 2014
Ontario	Hydro One Networks	2015-2017	Power distribution	Revenue Cap Stairstep	None	EB-2014-0247; March 2015
Ontario	Enbridge Gas Distribution	2014-2018	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	EB-2012-0459, Decision with Reasons; July 2014
Ontario	Union Gas Limited	2014-2018	Gas	Revenue Cap Index: 40% of growth in GDP-IPI	Sharing of overearnings only with deadband, multiple sharing ranges	EB 2013-0202 Decision; October 2013
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Price Cap Stairstep: Bill defines rates for each year.	Earnings cap set at allowed ROE, no floor	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act
Quebec	Gazifere	2011-2015	Gas distribution	Price Cap Index	Sharing of overearnings only without deadband and multiple sharing bands up to earnings cap	D-2010-112; August 2010
Yukon Territory	Yukon Electrical Company, Limited	2013-2015	Bundled power service	Revenue Cap Stairstep	None	Board Order 2014-06; April 2014

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Great Britain						
Great Britain	All	2013-2021	Gas and power transmission	British-Style Hybrid	Not reviewed	RIIO-T1 Final Proposals, April and December 2012
Great Britain	All	2013-2021	Gas distribution	British-Style Hybrid	Not reviewed	RIIO-GD1 Final Proposals, December 2013
Great Britain	All	2015-2023	Power distribution	British-Style Hybrid	Variances of cost from budgets shared through Information Quality Incentive Mechanism	RIIO-ED1 Final Proposals, December 2014
Australia/New Zealand						
Australia	ActewAGL	2015-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	Final Decision ActewAGL distribution determination 2015-16 to 2018-19; April 2015
Australia	Ausgrid	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ausgrid distribution determination 2015-16 to 2018-19; April 2015
Australia	Directlink	2015-2020	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision Directlink transmission determination 2015-16 to 2019-20; April 2015
Australia	Endeavour Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Endeavour Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Energex	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Energex determination 2015-16 to 2019-20
Australia	Ergon Energy	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Ergon Energy determination 2015-16 to 2019-20
Australia	Essential Energy	2015-2019	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision Essential Energy distribution determination 2015-16 to 2018-19; April 2015
Australia	Jemena Gas Networks	2015-2020	Gas distribution	Australian-Style Hybrid	Not reviewed	Final Decision Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20; June 2015
Australia	SA Power Networks	2015-2020	Power distribution	Australian-Style Hybrid	Not reviewed	Final Decision SA Power Networks determination 2015-16 to 2019-20
Australia	TasNetworks	2015-2019	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TasNetworks transmission determination 2015-16 to 2018-19; April 2015
Australia	TransGrid	2015-2018	Power transmission	Australian-Style Hybrid	Not reviewed	Final Decision TransGrid transmission determination 2015-16 to 2017-18; July 2015
Australia	Power & Water	2014-2019	Power transmission & distribution	Australian-Style Hybrid	Not reviewed	2014 Networks Price Determination Final Determination Part-A Statement of Reasons; April 2014
Australia	All Queensland Distributors	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for Qld Gas Network, Final Decision; June 2011
Australia	Energex and Ergon Energy	2010-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Queensland Distribution Determination 2011-11 to 2014-15 (Final Decision)
Australia	Envestra	2011-2016	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Proposal for the SA Gas Network, Final Decision; June 2011
Australia	All Victorian Distributors	2013-2017	Gas distribution	Australian-Style Hybrid	Not reviewed	Access Arrangement Final Decision; March 2013

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Current (cont'd)						
Australia/New Zealand (cont'd)						
Australia	CitiPower	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	CitiPower Pty Distribution Determination 2011-2015; September 2012
Australia	Powercor	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Powercor Australia Ltd Distribution Determination 2011-2015; October 2012
Australia	Jemena Electricity Networks	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	Jemena Electricity Networks (Victoria) Ltd Distribution Determination 2011-2015; September 2012
Australia	SP AusNet	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	SPI Electricity Pty Ltd Distribution Determination 2011-2015; August 2013
Australia	United Energy Distribution	2011-2015	Power distribution	Australian-Style Hybrid	Not reviewed	United Energy Distribution Distribution Determination 2011-2015; September 2012
New Zealand	All but Orion Electric	2015-2020	Power distribution	Revenue Cap Index: CPI-0% for most companies	None	Project no. 14.07/14118; November 2014
New Zealand	All	2013-2017	Gas distribution	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
New Zealand	All	2013-2017	Gas transmission	New Zealand-Style Hybrid	Not reviewed	Project no. 15.01/13199
Historic						
United States						
CA	Bear Valley Electric Service	2009-2012	Power distribution	Revenue Cap Stairstep	None	Decision 09-10-028; October 2009
CA	Pacific Gas & Electric	2011-2013	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 11-05-018; May 2011
CA	Pacific Gas & Electric	2007-2010	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 07-03-044; March 2007
CA	Pacific Gas & Electric	2004-2006	Gas & bundled power service	Revenue Cap Index	None	Decision 04-05-055; May 2004
CA	Pacific Gas & Electric	1993-1995	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 92-12-057; December 1992
CA	Pacific Gas & Electric	1990-1992	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 89-12-057; December 1989
CA	Pacific Gas & Electric	1987-1989	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 86-12-092; December 1986
CA	Pacific Gas & Electric	1984-1986	Gas & bundled power service	Revenue Cap Hybrid	None	Decisions 83-12-068; December 1983 and 85-12-076; December 1985
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	None	Decisions 06-12-011; December 2006 and 09-04-017; April 2009
CA	PacifiCorp	1994-1996	Bundled power service	Price Cap Index	None	Decision 93-12-106; December 1993
CA	PacifiCorp	1984-1987	Bundled power service	Revenue Cap Hybrid	None	Decisions 84-07-150; July 1984 and 85-12-076; December 1985
CA	San Diego Gas & Electric	2008-2011	Gas & bundled power service	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	San Diego Gas & Electric	2005-2007	Gas & bundled power service	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	San Diego Gas and Electric	1999-2002	Gas & power distribution	Price Cap Index	Sharing of overearnings only above deadband with multiple sharing bands	Decision 99-05-030; May 1999

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
CA	San Diego Gas & Electric	1994-1999	Gas & bundled power service	Revenue Cap Hybrid	Sharing of overearnings only with deadband and multiple sharing bands up to an earnings cap	Decision 94-08-023; August 1984
CA	San Diego Gas & Electric	1989-1993	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 88-12-085; December 1988
CA	San Diego Gas & Electric	1986-1988	Gas & bundled power service	Revenue Cap Hybrid	None	Decision 85-12-108; December 1985
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	None	Decision 09-10-041; October 2009
CA	Sierra Pacific Power	1990-1992	Bundled power service	Revenue Cap Hybrid	None	Decision 90-07-060; July 1990
CA	Southern California Edison	2012-2014	Bundled power service	Revenue Cap Hybrid	None	Decision 12-11-051; November 2012
CA	Southern California Edison	2009-2011	Bundled power service	Revenue Cap Stairstep	None	Decision 09-03-025; March 2009
CA	Southern California Edison	2006-2008	Bundled power service	Revenue Cap Hybrid	None	Decision 06-05-016; May 2006
CA	Southern California Edison	2004-2006	Bundled power service	Revenue Cap Hybrid	None	Decision 04-07-022; July 2004
CA	Southern California Edison	1997-2001	Power distribution	Price Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 96-09-092; September 1996
CA	Southern California Edison	1986-1991	Bundled power service	Revenue Cap Hybrid	None	Decision 85-12-076; December 1985
CA	Southern California Gas	2008-2011	Gas	Revenue Cap Stairstep	None	Decision 08-07-046; July 2008
CA	Southern California Gas	2005-2007	Gas	Revenue Cap Index	Sharing of overearnings only with deadband and multiple sharing bands	Decision 05-03-025; March 2005
CA	Southern California Gas	1998-2003	Gas	Revenue Cap Index	Sharing of over/underearnings outside deadband with multiple sharing bands	Decision 97-07-054; July 1997
CA	Southern California Gas	1990-1993	Gas	Revenue Cap Hybrid	None	Decision 90-01-016; January 1990
CA	Southern California Gas	1985-1989	Gas	Revenue Cap Hybrid	None	1984, 85-12-076; December 1985, and 87-05-027; May 1987
CA	Southwest Gas	2009-2013	Gas	Revenue Cap Stairstep	None	Decision 08-11-048; November 2008
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband, multiple sharing bands up to earnings cap	Decision C12-0494
CT	Connecticut Light & Power	2004-2007	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 03-07-02
CT	United Illuminating	2006-2008	Power distribution	Revenue Cap Stairstep	Even sharing of overearning without deadband	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capital and other cost trackers	None	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate Freeze with 1 step to reflect generation brought in-service and multiple capital and other cost trackers	None	Docket 050078-EI
GA	Georgia Power	2011-2013	Bundled power service	Revenue Cap Stairstep; Rate increases permitted for DSM and major generation plant additions	Sharing of overearnings only with deadband	Docket 31958
IA	MidAmerican Energy	2001-2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capital and other cost trackers	Sharing of overearnings only in multiple sharing bands, deadband not applicable due to no allowed ROE	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco Power	2009-2014	Bundled power service	Rate Freeze with capital cost tracker	Sharing of overearnings only with deadband up to earnings cap	Order U-30689
MA	Bay State Gas	2006-2015, terminated in 2009	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 05-27
MA	Berkshire Gas	February 2002-January 2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	None	Docket D.T.E. 01-56

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket D.P.U. 96-50-C (Phase I); May 1997
MA	Boston Gas (II)	2004-2013, Terminated in 2010	Gas distribution	Price Cap Index	75-25 shareholders-ratepayers sharing around deadband	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Even sharing of earnings above/below deadband	Docket D.T.E. 04-79
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Deadband with 50-50 sharing of over and underearnings	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas distribution	Price Cap Index	Even sharing of overearnings only. No allowed ROE established for company and no determination of a deadband.	Docket 970795; June 1998
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	50/50 sharing around deadband	Docket 97-116; March 1998
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Even sharing of earnings above/below deadband	Docket 92-345 Phase II; January 1995
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	50-50 sharing below deadband	Docket 99-666; November 2000
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate capital cost tracker for AMI	50-50 sharing above 11% ROE	Docket 2007-215
ME	Maine Natural Gas	2010-2012	Gas	Revenue Cap Stairstep with steps conditioned on company earnings	None	Docket 2009-67
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband	Case 90-G-0981, Opinion 91-21; October 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Sharing of overearnings only without deadband and multiple sharing bands	Case 93-G-0941, Opinion 94-22; October 1994
NY	Central Hudson Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings with deadband and multiple sharing bands	Case 09-E-0588
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Gas & power distribution	Price Cap Stairstep	Sharing of overearnings only with deadband, multiple sharing bands up to earnings cap	Case 05-E-0934 & Case 05-G-0935; July 2006
NY	Consolidated Edison	2010-2013	Gas	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-G-0795
NY	Consolidated Edison	2007-2010	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband, sharing threshold adjustable depending on work with DSM program administrator for first year only	Case 06-G-1332
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 93-G-0996, Opinion 94-2; October 1994
NY	Consolidated Edison	2010-2013	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 09-E-0428
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Price Cap Stairstep	Sharing of overearnings only with multiple bands. No allowed ROE approved.	Case 04-E-0572; March 2005
NY	Consolidated Edison	1992-1995	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings with varying allowed ROE and no deadband	Opinion 92-8
NY	Keyspan Energy Delivery - Long Island	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1185
NY	Keyspan Energy Delivery - New York	2010-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands, sharing threshold adjustable for good DSM performance	Case 06-G-1186
NY	Long Island Lighting Company	December 1, 1993 - November 30, 1996	Gas	Revenue Cap Stairstep	Even sharing of overearnings only with deadband	Case 93-G-002, Opinion 93-23; December 1993
NY	Long Island Lighting Company	1992-1994	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only without deadband	Opinion 92-8

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Attrition Relief Mechanism	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
United States (cont'd)						
NY	New York State Electric & Gas	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0715
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Bundled power service	Revenue Cap Stairstep	Sharing of overearnings only with annually varying deadbands	Case 94-M-0349, Opinion 95-27; September 1995
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas & bundled power service	Revenue Cap Stairstep	Even sharing of overearnings only above deadband	Case 92-G-1086, Opinion 93-22; November 1993
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas & bundled power service	Revenue Cap Stairstep	Sharing of overearnings only without deadband up to earnings cap	Case 29327, Opinion 89-37; June 1991
NY	Orange & Rockland Utilities	2009-2012	Gas	Revenue Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 08-G-1398
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Price Cap Stairstep	Sharing of overearnings only beyond deadband and multiple sharing bands	Case 05-G-1494; October 2006
NY	Orange & Rockland Utilities	November 1, 2003 - October 31, 2006	Gas	Price Cap Stairstep	Even sharing of overearnings only without deadband	Case 02-G-1553; October 2003
NY	Orange & Rockland Utilities	2012-2015	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband and multiple bands	Case 11-E-0408
NY	Orange & Rockland Utilities	2008-2011	Power distribution	Revenue Cap Stairstep	Sharing of overearnings only above deadband with multiple sharing bands	Case 07-E-0949
NY	Orange & Rockland Utilities	1991-1993	Bundled power service	Revenue Cap Stairstep	Even sharing of overearnings above deadband	Case 89-E-175
NY	Rochester Gas & Electric	2010-2013	Gas & power distribution	Revenue Cap Stairstep	Sharing of overearnings only with deadband that varies annually and multiple sharing bands	Case 09-E-0717
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas & bundled power service	Revenue Cap Stairstep	Earnings cap only	Case 92-G-0741, Opinion No. 93-19; August 1993
OH	AEP-Ohio	2012-2015	Power distribution	Rate Freeze supplemented by capital and other cost trackers	Company subject to Significantly Excessive Earnings Test conducted annually	Case No. 11-346-EL-SSO; August 2012
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Price Cap Stairstep	Company subject to Significantly Excessive Earnings Test conducted annually	Case 08-920-EL-SSO
OR	PacifiCorp	1998-2001	Power distribution	Revenue Cap Index	Sharing of over/underearning outside deadband in multiple sharing bands	Order No. 98-191
US	All	2006-2011	Oil pipelines	Price Cap Index: PPI-Finished Goods + 1.3%	None	RM05-22-000
US	All	2001-2006	Oil pipelines	Price Cap Index: PPI-Finished Goods + 0%	None	RM00-11-000
US	All	1995-2001	Oil pipelines	Price Cap Index: PPI-Finished Goods - 1%	None	RM93-11-000
VT	Green Mountain Power	2007-2010	Bundled power service	Revenue Cap Stairstep	Earnings cap for overearnings above deadband; Multiple sharing bands for earnings apply if actual ROE below deadband (earnings floor of the deadband also applies)	Docket No. 7176
WA	Puget Sound Energy	1997-2001	Bundled power service	Price Cap Stairstep	None	Docket UE-960195
Australia/New Zealand						
Australia	Jemena Gas Networks	2010-2015	Gas distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement Proposal for NSW Gas Networks, Final Decision; June 2010
Australia	All New South Wales distributors	2009-2014	Power distribution	Australia-Style Hybrid	Not reviewed	New South Wales Distribution Determination 2009-10 to 2013-14 Final Decision
Australia	ElectraNet	2008-2013	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; April 2008
Australia	ElectraNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1094
Australia	Powerlink	2007-2012	Power transmission	Australia-Style Hybrid	Not reviewed	Final Decision; June 2007

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
Australia	Powerlink	2002-2007	Power transmission	Australia-Style Hybrid	Not reviewed	File No: 2000/659
Australia	Snowy Mountains	1999-2004 (terminated in 2002 due to merger with Transgrid)	Electric transmission	Australia-Style Hybrid	Not reviewed	File No: C1999/62
Australia	SPI PowerNet	2003-2008	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1093
Australia	Transend	2009-2014	Power transmission	Australia-Style Hybrid	Not reviewed	Transend Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transend	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No: C2001/1100
Australia	Transgrid	2009-2014	Electric transmission	Australia-Style Hybrid	Not reviewed	Transgrid Transmission Determination 2009/10-2013/14 (Final Decision)
Australia	Transgrid	2004-2009	Power transmission	Australia-Style Hybrid	Not reviewed	File No. M2003/287
Australia	Transgrid	1999-2004	Power transmission	Australia-Style Hybrid	Not reviewed	File No: CG98/118
Australia - New South Wales	Country Energy Gas	2006-2010	Gas distribution	Australia-Style Hybrid	Not reviewed	Revised Access Arrangement for Country Energy Gas Network, Final Decision; November 2005
Australia - New South Wales	AGL Gas Networks	1999-2004	Gas transmission & distribution	Australia-Style Hybrid	Not reviewed	Access Arrangement for AGL Gas Networks Limited, Final Decision; July 2000
Australia - New South Wales	All	2004-2009	Power distribution	Australia-Style Hybrid	Not reviewed	File No: S2004/138
Australia - New South Wales	All	1999-2004	Power distribution	Australia-Style Hybrid	Not reviewed	NEC Determination 99-1
Australia - Northern Territory	Power & Water	2000-2003	Power transmission & distribution	Australia-Style Hybrid	Not reviewed	Revenue Determinations document; June 2000
Australia - Northern Territory	Power & Water	2009-2014	Power transmission & distribution	Price Cap Index: CPI + 0.85%	Not reviewed	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Australia - Northern Territory	Power & Water	2004-2009	Power transmission & distribution	Price Cap Index: CPI - 2%	Not reviewed	Final Determination Networks Pricing: 2004 Regulatory Reset; February 2004
Australia - Victoria	All	2008-2012	Gas distribution	Australia-Style Hybrid	Not reviewed	Gas Access Arrangement Review 2008, 2012, Final Decision; March 2008
Australia - Victoria	All	2003-2007	Gas distribution	Australia-Style Hybrid	Not reviewed	Review of Gas Access Arrangements, Final Decision; October 2002
Australia - Victoria	All	2006-2010	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Review 2006-2010 (Final Decision Volume 1)
Australia - Victoria	All	2001-2005	Power distribution	Australia-Style Hybrid	Not reviewed	Electricity Distribution Price Determination 2001-2005 (Final Decision Volume 1)
New Zealand	All	2010-2015	Power distribution	Revenue Cap Index: CPI - 0%	None	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Australia/New Zealand (cont'd)						
New Zealand	All	2004-2009	Power distribution	Revenue Cap Index: CPI - 0.86% (Average across firms)	None	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Canada						
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	50-50 for excess earnings above deadband	Decision 2009-035
Alberta	Northwestern Utilities	1999-2002, reopened for 2001-2002	Gas distribution	Revenue Cap Stairstep; at reopener replaced with rate freeze	Sharing of earnings above/below deadband with multiple bands for overearnings; at reopener simplified to 50/50 sharing of overearnings with deadband	Decision U98060; March 1998 and Decision 2000-85; December 2000
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	None	City of Edmonton Distribution Tariff Bylaw 12367; August 2000
Northwest Territory	Northland Utilities	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 17-2011; November 2011
Northwest Territory	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Revenue Cap Stairstep	None	Decision 13-2011; August 2011
Ontario	All Ontario Distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	None	EB-2007-0673; July 2008, September 2008, and January 2009
Ontario	All Ontario Distributors	2006-2009	Power distribution	Price Cap Index	None	EB-2006-0089; December 2006
Ontario	All Ontario Distributors	2000-2003	Power distribution	Price Cap Index	50-50 sharing of excess earnings without deadband	RP-1999-0034; January 2000
Ontario	Enbridge Gas Distribution	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI * 53%	50-50 sharing of excess earnings above deadband	EB-2007-0615; February 2008
Ontario	Union Gas	2008-2012	Gas distribution	Revenue Cap Index: GDP-IPI -1.82%	Sharing of overearnings only with deadband and multiple sharing bands	EB-2007-0606; January 2008
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	50-50 sharing around deadband	RP-1999-0017; July 2001
Great Britain						
Great Britain	All	2008-2013	Gas distribution	British-Style Hybrid	Not reviewed	Review- Final Proposals; Published December 2007
Great Britain	All	2002-2007, extended to 2008	Gas distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2007-2012	Gas transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Great Britain	All	2002-2007	Gas transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	1998-2002	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1994-1997	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
Great Britain	All	1992-1994	Gas transmission & distribution	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.444
England & Wales	All	1995-2000	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Great Britain	All	2010-2015	Power distribution	British-Style Hybrid	Variances of cost from budgets shared through Information Quality Incentive Mechanism	Ofgem Distribution Price Control Review 5
Great Britain	All	2005-2010	Power distribution	British-Style Hybrid	Not reviewed	Ofgem Distribution Price Control Review 4

Table 7 (cont'd)

Jurisdiction	Company	Plan Term	Services Covered	Rate Escalation Provisions	Earnings Sharing Provisions	Case Reference
Historic (cont'd)						
Great Britain (cont'd)						
Great Britain	All	2000-2005	Power distribution	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	2001-2006, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	OECD Reviews of Regulatory Reform
England & Wales	National Grid	1997-2001	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
England & Wales	National Grid	1993-1997	Power transmission	British-Style Hybrid	Not reviewed	Energy Law Journal Volume 23 No. 2 p.452
Great Britain	All	2007-2012	Power transmission	British-Style Hybrid	Not reviewed	Transmission Price Control Review; Published December 2006
Scotland	All	2000-2005, extended to 2007	Power transmission	British-Style Hybrid	Not reviewed	"RPI - X @ 20." Ofgem Publication
Scotland	All	1995-2000	Power transmission	British-Style Hybrid	Not reviewed	1995 Report by Monopolies and Mergers Commission

¹ Rate freezes without extensive supplemental funding from capital cost trackers are excluded from this table.

VI. Formula Rates

A cost of service formula rate plan (“FRP”) is essentially a wide-scope cost tracker designed to help a utility’s revenue track its cost of service. Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated. Regulatory cost is contained by limiting review of costs and revenues.

The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target. Both approaches can keep the utility whole for the time value of money.

Earning true up mechanisms often include a deadband in which variances don’t trigger a rate adjustment. Once the variance exceeds the deadband, however, earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between the earnings true up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans.

Formula rates do not always address major plant additions. In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is often recovered through a separate tracker.

Mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its O&M expenses may be limited by a formula tied to an inflation index. FRPs in several states that include Illinois and Mississippi contain a number of targeted performance incentive mechanisms.

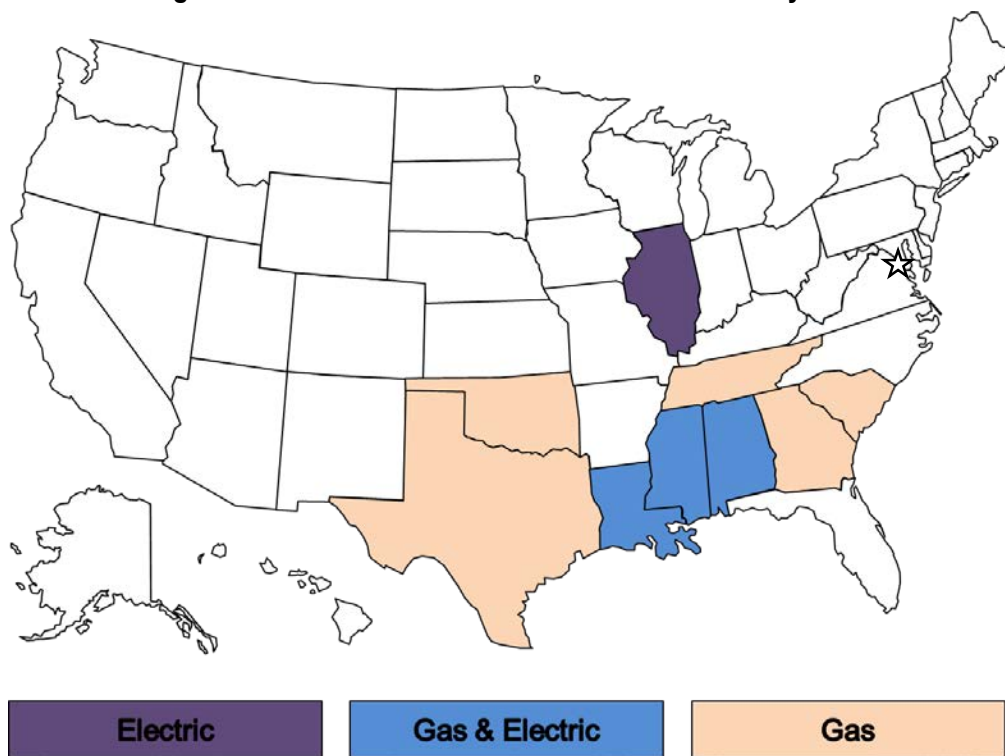
Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of energy utilities for decades. Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 8 and Figure 9.¹⁰ It can be seen that FRPs for retail utility services are most common in the Southeast and South Central states. Alabama was an early innovator, approving “Rate Stabilization and Equalization”

¹⁰ Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition. These usually take the form of ESMs that may or may not protect the utility from underearning.

plans for Alabama Power and Alabama Gas in the early 1980s.¹¹ Formula rates are now used to regulate electric utilities in Illinois, some gas and electric utilities in Louisiana and Mississippi, and some gas utilities in Georgia, Oklahoma, South Carolina, Tennessee, and Texas. Most of the recent approvals of formula rates have been for gas distribution, as this is one means to avoid the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized legislatively for electric utilities in Arkansas.

Figure 9: Current Retail Formula Rate Precedents by State



¹¹ For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 8

Retail Formula Rate Plan Precedents¹

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2013-open	Dockets 18117 and 18416 (August 2013)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2014-2018	Dockets 18406 and 18328 (December 2013)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2013-2017	Docket 28101 (August 2013)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017, extended through 2019	Case 12-0001 (September 2012) and Public Act 098-1175
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017, extended through 2019	Case 11-0721 (May 2012) and Public Act 098-1175
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Clause	2014-open	Docket U-32987 (June 2014)
LA	Southwestern Electric Power	Electric	Formula Rate Plan	2013-2016	Docket U-32220 (July 2014)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2011-present	Docket 05-UN-0503 (April 2011)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2014-open	Docket 2014-UN-060 (May 2014)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 6 (FRP-6)	2015-open	Docket 2014-UN-132 (December 2014)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Cause PUD 201000030 (July 2010)
OK	Arkansas Oklahoma Gas	Gas	Performance Based Rate of Change Plan	2013-open	Cause PUD 201200236 (July 2013)
SC	Piedmont Gas	Gas	NA	2005-open	Docket 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-open	Docket 2005-113-G (October 2005)
TN	Atmos Energy	Gas	Annual Review Mechanism	2015-open	Docket 14-00146 (May 2015)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2013-2017	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2007
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2014-open	Various Resolutions/Ordinances across cities in service territory including City of Tulia Ordinance 2014-03
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2012-open	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-2013	Dockets 18117 and 18416 (October 2005)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014, later changed to 2013	Dockets 18406 and 18328 (December 2007)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets 18046 and 18328 (June 2002)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-2014	Docket U-21484 (May 2006)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket U-21484 (January 2001)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-2014	Dockets U-28814 and U-28588 and U-28587 (May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket UD-08-03 (April 2009)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-2011	Docket 05-UN-0503 (December 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy	Gas	Rate Regulation Adjustment Rider	2012-2014	Docket 12-UN-139 (May 2012)

Table 8 (cont'd)

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Historic (cont'd)					
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-2012	Docket 07-UN-548 (December 2007)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP-5)	2010-2014	Docket 2009-UN-388 (March 2010)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP-1)	1995	Docket 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Cause PUD U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Cause PUD 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Cause PUD 200400187 (November 2004)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2014	Docket 200800348 (April 2009)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - varying end dates	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Centerpoint Energy - Beaumont East Texas Gas Division	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - Rio Grande Service Area	Gas	Cost of Service Adjustment	2009-2011	Various Resolutions/Ordinances across cities in service territory

¹ Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

VII. Marketing Flexibility

This is a new section, added since the last survey. We've added it because we (and EEI) believe that marketing flexibility is a growing, strategic issue for EEI members. Several trends in business conditions are driving the need for more flexibility. The growth of distributed energy resources, for example, is a competitive challenge but also brings new service opportunities related to the development of distributed energy assets (e.g., designing, financing, procuring, building, fueling, and maintaining). Grid modernization is providing new functional capabilities to the grid which also create new service opportunities.¹² Examples include new reliability, network management, and transaction management services. Residential and commercial customers also have a growing interest in plug-in electric vehicles, and all retail customers have shown an interest in green power packages that can be supplied from grid-accessed resources.

New services will tend to be optional services that all customers will not want. Customers must be able to decline them; and if they do, not to incur associated costs. Competitive alternatives will be available for many of these services, and customers may have special needs that are difficult to address with standard tariffs. Thus, utilities will need to be able to respond quickly to the market. They will often be price “takers,” as opposed to price “makers.”

To date, regulatory precedent allowing investor-owned electric utilities to offer many of these services has been limited. This chapter is, in effect, a place holder for expected future electricity precedent.

Why Electric Utilities Need Marketing Flexibility

Of course, electric utilities have always needed flexibility in some of the markets they serve:

- Utility assets have uses in markets other than those for retail electric services. Most notably, surplus generating capacity of VIEUs can be used for sales in bulk power markets. These markets are competitive and price-volatile. Land in transmission corridors can be well-suited for nurseries. Prices utilities charge in competitive markets like these are largely decontrolled. Margins earned in these markets are shared with customers of retail electric services.
- The demand of large-load retail customers is often sensitive to the rates and other terms of service utilities offer because these customers have power-intensive technologies and/or options to cost-competitively cogenerate or operate at alternative locations, or are economically marginal. Customers of this kind are especially important to vertically integrated utilities. Discounts or special contracts for such customers are traditionally allowed but often require specific approval. Commission reviews of special contracts can take months.

¹² For an overview of modernization, see: EPRI, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 2014.

Marketing Flexibility Remedies

Marketing flexibility runs the gamut from greater commission effort to approve new rates and services by traditional means to “light handed” regulation and outright decontrol. Light handed regulation typically takes the form of expedited approval of market offerings. These offerings may be subject to further scrutiny at a later date (e.g., in the next rate case).

Flexibility is most commonly granted for rates and services with certain characteristics. Light handed regulation of optional rates and services, for example, is based on the grounds that customers are protected by their freedom not to take the service, their continued access to service under standard tariffs, and the availability of alternatives in unregulated markets. Optional offerings include tariffs open to all qualifying customers, special contracts, and discretionary value-added services. Decontrol is typically permitted only for offerings to markets where vigorous competition reigns.

Marketing Flexibility Examples: Electric Utilities

Marketing flexibility is not extensive in the electric utility industry today but there are nonetheless notable examples such as the following.

- Four Florida electric utilities have “Commercial/Industrial Service Rider” (“CISR”) tariffs that allow them to negotiate contract service agreements (“CSAs”) that outline discounts on the base energy and/or demand charges for large load customers who can show that they have viable alternatives to utility-provided electric service.¹³ The discounted rate must cover the incremental cost of service provision and provide a contribution to fixed costs. CSAs do not need commission approval but the commission has the option to conduct a prudence review of any signed contract.
- Duke Energy offers large North Carolina customers an optional Green Source Rider service. The program allows customers that have added at least 1 MW of new load since June 2012 to apply for an annual amount of renewable energy (and the associated renewable energy certificates) over a specific term (between 3-15 years). Customers may request a particular renewable resource in their application. Duke would then negotiate a purchased power agreement on behalf of the customer or attempt to source the energy from its own assets.

¹³ Florida Public Service Commission (2014), Order Approving Commercial/Industrial Service Rider Tariff, Order No. PSC-14-0110-TRF-EI.

Marketing Flexibility in Other Regulated Industries

Regulators and electric utilities considering new forms of marketing flexibility can learn from other utility industries that have experienced technological change, increased competition, and/or complex and changing customer needs. We provide here brief overviews of experience in the telecommunications, gas distribution, gas transmission, and railroad industries.

Telecommunications

Local telephone companies (aka incumbent local exchange carriers or "ILECs") control the traditional distribution networks connecting residences and businesses. The "last mile" services they provide include the interconnection needed for long-distance, data, security, paging, and mobile telephone services as well as local telephone calling. ILECs have in the last 30 years confronted extensive competition, rapid technological change, and new marketing opportunities. Challenges they have faced have many parallels to those emerging for electric utilities.

The Federal Communications Commission ("FCC") regulates interstate access services of ILECs. Other ILEC services are regulated by state commissions. In the 1980s, ILECs were still regulated using cost-of-service regulation with complex reporting and compensation schemes. This was succeeded by multiyear rate plans, often called "price cap" plans since they capped rate escalation but permitted some discounts to encourage greater system use. Price caps were often escalated using inflation – X formulas where the X factor reflected an estimate of the telecommunication industry productivity trend. Prices were separately capped for several baskets of services. This insulated customers in each service basket from discounts offered to other baskets. Insulation was heightened by the infrequency (or elimination) of rate cases and the common lack of earnings sharing. The FCC instituted price caps for interstate access services of ILECs in the early 1990s. Price caps also became commonplace in state ILEC regulation.

Marketing flexibility for ILECs has been most relevant in the following two areas.

Competition in Traditional Service Markets Some services ILECs offered became subject to mounting competitive pressure that varied with the location where service was offered. For example, by the late 1990s, competitive access providers like MFS were constructing high-speed fiber optic networks connecting office buildings in metropolitan areas. These networks allowed businesses and long-distance carriers to connect to customers while bypassing ILEC data facilities. They could also be used to transmit voice traffic, avoiding ILEC voice access charges. High regulated prices were uncompetitive in high-traffic locations where facilities-based competitors entered the market. For services subject to competitive challenges, price cap plans in many states permitted discounts to standard tariffs within certain bands (e.g., rates could rise by 5% less than the price cap index) and/or subject to pricing floors that discouraged predation and cross-subsidization. In markets where pronounced competition could be demonstrated, ILEC rates were sometimes effectively decontrolled.

Innovative Services Technological change gave rise to innovative new services [e.g., Voicemail, Centrex and high-speed data (e.g., digital subscriber loop or "DSL")] which utilize essential network assets of ILECs

and cannot not practically be performed by affiliates.¹⁴ Many of these services were deemed “information” services and were regulated by the FCC. Regulators ultimately permitted ILECs to provide a host of these services and allowed considerable pricing flexibility.

Gas Distribution

Natural gas distributors also need flexibility to address some markets that they serve. Like VIEUs, many large-load customers of gas distributors have price sensitive demands and special needs. Distributors have frequently obtained light handed regulation to respond to these challenges. Nicor Gas, for example, offers a contract service for customers taking delivery near interstate gas pipelines. Contracts are submitted to state regulators for informational purposes and are treated on a proprietary basis. Nicor has similar flexibility to enter into custom contracts with electric power generators. The Company must document to the regulator that revenues from such service exceed the incremental cost of service, thereby ensuring a positive contribution to fixed cost recovery.

Interstate Gas Transmission

Interstate pipeline companies need marketing flexibility for many reasons. Demand for a pipeline’s services can be sensitive to the terms it offers due to competition from other pipelines, dual-fuel capabilities of large volume customers, the extreme variability of need for service, and other special needs. It is difficult to design standard tariffs that meet the needs of all customers. Pipelines also have their own needs, such as an interest in signing anchor shippers to long-term contracts before constructing new facilities. Since 1996, the FERC has engaged in light handed regulation of negotiated pipeline rates to individual customers who have recourse to service under a standard tariff. The FERC gives a quick turnaround to most requests for negotiated contracts. A sizable share of pipeline service is conducted under negotiated rates. A remarkable variety of rate designs have been employed.¹⁵

Railroads

In the railroad industry, MRPs were permitted under the terms of the Staggers Railroad Act of 1980. Railroads were given a freer hand to respond to competition from truckers, waterborne carriers, and other railroads. The railroads also used marketing flexibility to offer discounts to customers that reduced their cost by assembling their own unit trains and not requesting pickups or deliveries in remote locations.

MRPs are less common today in the railroad and telecom industries. However, marketing flexibility continues under new regulatory systems that share with MRPs the attribute of protecting core customers without linking a carrier’s rates closely to its own cost. Railroads have recently used this flexibility to compete for traffic from new oil field developments.

¹⁴ Centrex service, which provided businesses features like call-waiting, auto attendant, voicemail, 4-digit extension dialing and conference calling, could also be sourced by purchasing or leasing a private branch exchange ("PBX"), a private network platform that enabled these features.

¹⁵ See, for example, Comments of the Interstate Natural Gas Association of America in FERC Docket PLO2-6-000, September 2002.

VIII. Conclusions

Regulation of North American energy utilities is evolving to better meet the needs of utilities and their customers in a rapidly changing world. Innovation continues, while some older forms of Altreg such as multiyear rate plans are having a renaissance.

The variety of Altreg approaches that have been established reflects the varied circumstances of utilities. Some are vertically integrated, while others are more specialized wire companies. Capex needs and trends in average use vary greatly. Regulatory traditions also vary across the US and other advanced industrial countries.

No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying challenges increases the chance that an approach has already been tried that would work well, with some adjustments, in new situations. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to achieve compensatory rates of return while making needed investments, improving efficiency, and developing more market-responsive rates and services. Regulation can be streamlined, and utilities can be encouraged to embrace cost-effective DERs. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which kinds of Altreg might work best in their situation.

24-Sep-2024 | 16:51 EDT

North American Utility Regulatory Jurisdictions Update: Some Notable Developments

Topic **Energy & Climate Resilience, Debt Markets In Transition**

Region **Americas, EMEA, APAC**

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Key Takeaways

- Since S&P Global Ratings last reported on North American utility regulatory jurisdictions in March 2024 there have been numerous developments that could have credit implications for rated utilities.
- Developments in California show promise for the recovery of wildfire claims and an undergrounding initiative.
- Several states may move forward to limit natural gas consumption while encouraging further electrification.
- Legislation in Utah will help mitigate the financial impact of wildfire claims.
- Virginia and Wyoming passed credit-supportive legislation regarding nuclear and coal generation, respectively.

As part of our ongoing surveillance of rated U.S. and Canadian regulated utilities, S&P Global Ratings monitors regulatory developments that could have ratings implications. Since **our last report**, published in March 2024, key developments include pending rate cases, grid modernization plans, and initiatives related to energy transition. Other important developments include storm recovery costs (New York), merger and acquisition (M&A) proceedings (Minnesota and Wisconsin), and wildfire mitigation efforts (California and Utah). We have also noted the uncertainties around recovery of capital spending, wildfire litigation, and clean energy and electrification initiatives.

We incorporate regulatory advantage into our analysis of a regulated utility's business risk profile. We make regulatory advantage determinations in rating committees for approximately 220 U.S. and 30 Canadian utilities. Utility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile and generally underpins our ratings. One significant aspect of it that influences credit quality is the regulatory environment in the jurisdictions where a utility operates. Therefore, we monitor many different regulatory jurisdictions and incorporate any regulatory or legislative actions that support, or do not support, a rated utility's credit quality. Our analysis covers

quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation. (See [Sector-Specific Corporate Methodology](#), published April 4, 2024, for more details on each category.)

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Notable Regulatory Developments

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California

On Aug. 29, 2024, Edison International (Edison) subsidiary Southern California Edison Co. (SCE) reached a settlement agreement with the California Public Advocates Office on its cost recovery application related to the 2017/2018 Thomas Fire, Koenigstein Fire, and Montecito Mudslides (TKM). If approved by the California Public Utilities Commission (CalPUC), SCE will be authorized to recover 60%, or approximately \$1.6 billion of approximately \$2.7 billion of losses, including approximately \$1.3 billion of uninsured claims, and about \$300 million of legal and financing costs paid as of May 31, 2024. SCE will also be authorized to recover 60% of losses paid after May 31, 2024, except for about \$125 million of such costs previously waived under a prior agreement with the CalPUC's Safety and Enforcement Division. If approved, SCE may issue securitization bonds to recover such amounts.

Overall, we view this development as supportive of credit quality. Should the CalPUC approve the TKM settlement, it potentially signals a precedent for the recovery of prudent third-party wildfire claims to be recovered from ratepayers, which could lead us to a more favorable view of California's regulatory construct.

Separately, in March 2024 CalPUC adopted a resolution following the passage of Senate Bill 884 in 2023 that authorizes electric utilities serving 250,000 or more customers within the state to participate in an expedited utility undergrounding program. Participating utilities must submit a 10-year distribution infrastructure undergrounding plan to the Office of Energy Infrastructure Safety (OEIS). The OEIS may approve such plan after the utilities demonstrate that their plans' substantially increase reliability by reducing use of public safety power shutoffs, enhanced powerline safety settings, de-energization events, and other outage programs, and that the plan substantially reduces wildfire risk. Upon OEIS approval, the utilities may seek cost recovery from CalPUC, subject to several provisions, including utilities not exceeding approved cost caps for each specific year during the plan, ongoing progress report filings with both the OEIS and the CalPUC, and use of an independent monitor to assess utilities' compliance for each year the undergrounding plan is in effect.

Overall, while the implementation may introduce regulatory risk that participating utilities must effectively manage, we believe the resolution indicates California's proactiveness towards addressing wildfire risk, which is supportive of credit quality.

Colorado

Colorado continues to be a challenging environment for natural gas investor-owned regulated utilities (IOUs). In Public Service Co. of Colorado's (PSCo; a subsidiary of Xcel Energy Inc.) current rate proceeding, the staff of the Colorado Public Utilities Commission (CoPUC) proposed a 7.5% equity return on capital spending related to new business and capacity expansion projects, and a 9% equity return on safety-related spending. We therefore view the staff's recommendation as negative for credit quality as it creates greater uncertainty regarding regulatory outcomes for natural gas IOUs going forward, while also weakening the ability of the regulatory framework to attract long-term capital for gas IOUs operating in the state, which include PSCo, Atmos Energy Corp., and Black Hills Corp. Overall, we believe this situation demonstrates the more challenging regulatory environment gas distribution IOUs face in a state transitioning away from fossil fuels on an accelerated basis.

On the electric side, electrification and decarbonization reduction goals continue to frame energy policy for Colorado's electric IOUs. Senate Bill 24-218, enacted during the most recent legislative session, establishes a rider for qualifying grid modernizing distribution spending deemed supportive of the state's goals. We believe this rider supports credit quality as it reduces regulatory lag and adds to the availability of recovery mechanisms in the state, which is a transmission rider.

The new law also requires IOUs to file plans with CoPUC by Jan. 1, 2025, to underground utility distribution infrastructure. Undergrounding distribution lines may help mitigate wildfires being started by utility equipment.

Connecticut

Earlier in 2024, Connecticut's Superior Court opined in favor of the Public Utilities Regulatory Authority (PURA) concerning the unfavorable rate case decision for Aquarion Co. The company appealed the Superior Court's decision to the Connecticut Supreme Court, where we expect further developments later this year or early next year. Furthermore, following the Superior Court's decision in the Aquarion case, Connecticut Light & Power Co. (CL&P) and The United Illuminating Co. (UIL) both initially paused their participation in the state's electric vehicle rebate program given concerns over their ability to recover related costs in a timely manner, but subsequently resumed their participation. Additionally, CL&P's parent Eversource Energy cut its capital spending plans for its electric and gas distribution operations in Connecticut by \$500 million between 2024 and 2028.

Separately, in July 2024, Connecticut Water Co. (CWC) was authorized to raise its base rates by \$6.4 million, based on a 9.4% return on equity (ROE) and 53% equity layer. Although PURA also authorized CWC to earn an additional \$1.1 million if it achieves certain performance targets, the total potential rate increase for the company was less than one-half of the \$21.4 million rate increase request.

We will continue to monitor these and other regulatory proceedings, including the pending rate cases for Southern Connecticut Gas Co. and Connecticut Natural Gas Corp. Notably, these proceedings will be decided under a new commission, as a new commissioner was recently appointed. We expect a final outcome to them by the end of November 2024. The steady erosion in cost recovery through rate increases could weaken the credit quality of certain regulated utilities.

District of Columbia

Recently, the Public Service Commission of the District of Columbia voted against the Washington Gas Light Co. (WGLC) proposed accelerated pipe replacement plan, citing misalignment with the city's climate goals. Overall, the city is primarily focused on minimizing its carbon footprint by limiting the growth of the gas distribution business. Currently we do not believe this materially weakens the D.C. regulatory environment, because in the coming months we expect WGLC to refile its plan with modifications. We will continue to monitor the proceeding regarding the refiled plan before the commission.

Federal Energy Regulatory Commission

In June 2024, The Federal Energy Regulatory Commission (FERC) issued a show cause order, finding that the existing open access transmission tariff (OATT) of certain regional transmission operators (RTOs) and independent system operators—including Midcontinent Independent System Operator Inc. (MISO), PJM Interconnection LLC (PJM), Southwest Power Pool Inc. (SPP), and ISO New England Inc. (ISO-NE)--appear to be unjust, unreasonable, and unduly discriminatory or preferential based on the transmission owner's initial funding provisions. These provisions allow transmission owners to initially fund capital costs for transmission network upgrades for interconnection service, and then subsequently recover such costs through a return on, and of, such investments. Furthermore, the order finds

that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated. The order implies that such initial funding rules could be increasing interconnection costs without corresponding improvements to that service, potentially leading to barriers to interconnection and resulting in undue discrimination among interconnection customers.

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From a credit perspective, we view the OATT as a key component of the FERC rate-setting process, which allows transmission utilities to earn a regulated return on their investments, supporting cash flows. As such, we will continue to monitor potential implications of these developments, including as it relates to the predictability and consistency of the rate-setting process.

Florida

A recent regulatory outcome appears to be constructive for credit quality. In August 2024, the Florida Public Service Commission (FPSC) authorized a \$470 million multiyear base rate increase over the 2025-2027 period for Duke Energy Florida LLC. The increase is based on a midpoint of 10.3% ROE that we view as supportive of the company's credit quality since the ROE is modestly above the industry averages. The multiyear rate increase is about 60% of what the company had requested.

In addition, we are monitoring Tampa Electric Co.'s (TEP) pending multiyear rate case. TEP is seeking a rate increase of about \$295 million in 2025, \$95 million in 2026, and \$69 million in 2027, and an 11.5% ROE (the company's current ROE is 9.95%). In June 2024, the Office of Public Counsel filed testimony supporting an increase in electric base rates of about \$75 million in 2025, \$60 million in 2026, and \$24 million in 2027, based on an ROE of 9.5%. We expect a final order before year-end 2024.

Illinois

We continue to follow developments related to Commonwealth Edison Co.'s (a subsidiary of Exelon Corp.) and Ameren Illinois Co.'s (a subsidiary of Ameren Corp.) grid plans that each company refiled in March 2024. Although both utilities are operating under approved multiyear rate plans, the ultimate impact on their revenue requirements for the next four years could fluctuate depending on the Illinois Commerce Commission's (ICC) decisions regarding refiled grid plans. We anticipate the companies' approved rate base values and revenue requirements for use in each year of their plans would be updated once that process is completed. We expect ICC decisions in December 2024.

Louisiana

The Louisiana Public Service Commission (LPSC) has approved a stipulation under which it will extend Entergy Louisiana LLC's (ELL) formula rate plan (FRP) for three years and increase the company's base rates by \$120 million effective September 2024, with a \$140 million cap for the 2024 and 2025 test years. The rate case decision also includes a 9.7% ROE and continuation of ELL's transmission and distribution recovery mechanisms, but with certain caps. In addition, the stipulation includes a one-time refund of about \$184 million over two years, mostly reflecting the benefits from IRS tax audits and a reconciliation of the prior years' FRPs.

We view the LPSC's continued adoption of FRPs as supportive for credit quality because we believe such mechanisms enhance utilities' cash flow visibility and predictability. Furthermore, they reduce regulatory risk because the companies receive periodic rate increases without having to adjudicate a full rate case.

The LPSC also announced it has approved a settlement agreement with Entergy Corp.'s subsidiary System Energy Resources Inc. (SERI) regarding multiple proceedings pending before the FERC. If adopted, we would view this as credit supportive because it will resolve substantially all proceedings against SERI. These proceedings have been

pending for multiple years and could have had a significant negative credit impact on SERI.

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Massachusetts

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Several House and Senate bills (including HB-3237, HB-3203, SB-2105, and HB-3227) were recently introduced in Massachusetts to support the state's goal of being carbon neutral by 2050. The proposed bills include plans to prevent utilities from adding natural gas to municipalities that do not already have it, prohibiting state regulators from approving proposals to build new pipelines until at least 2026, redefining gas utilities to include thermal energy, and allowing cities and towns to prohibit fossil fuel use in new construction or major renovations. Overall, these developments suggest that future growth of gas distributions companies could be constrained, increasing the challenges for the state's natural gas local distribution companies. We will continue to monitor related developments.

Minnesota

In May 2024, ALLETE Inc. announced it had agreed to be acquired by two infrastructure funds, the Canada Pension Plan Investment Board and Global Infrastructure Partners. Regulatory approvals are required, including the Minnesota Public Utilities Commission (MPUC), which has authority over utility M&A in the state. Pursuant to state statutes, when reviewing proposed M&A deals, MPUC must consider whether the transaction is consistent with the public interest. There is no statutory time frame for MPUC to act on a merger application and we will continue to monitor the proceeding. ALLETE's credit quality could weaken if MPUC orders a significant ratepayer benefit as part of this transaction because ALLETE already has higher capital spending requirements to decarbonize its generation fleet in line with state energy policy goals, which could weaken financial performance if largely debt funded.

New Mexico

In June 2024, Public Service Co. of New Mexico (PNM) filed for a rate increase of \$174 million comprising about \$92 million of non-fuel costs and about \$82 million of pass-through fuel costs. This rate case will be important for S&P Global Ratings to determine PNM's ability to manage its regulatory risk in New Mexico and will help us determine our view of New Mexico's credit supportiveness. Under its last rate case, which we viewed as less than credit supportive, there were unique factors in the case that made it difficult to establish a definitive long-term view of New Mexico's credit supportiveness.

New York

New York has enacted the New York Utility Corporation Securitization Act, which would allow electric utilities in the state to petition the New York Public Service Commission (NYPSC) to issue storm recovery bonds. We view this as a credit supportive development as it could expedite recovery of such costs, strengthening financial measures. In August 2024, Avangrid Inc. subsidiaries New York State Electric & Gas Corp. (NYSEG) and Rochester Gas & Electric Corp. (RG&E) petitioned for storm-recovery financing as of July 1, 2024, including upfront financing costs. NYSEG and RG&E have requested total securitization amounts of about \$707 million and \$75 million, respectively. We will monitor these proceedings.

Oregon

Several cities in Oregon are exploring building electrification policies. This follows a July 2023 ruling by the U.S. Court of Appeals for the 9th Circuit, which caused lawmakers in Eugene to repeal an ordinance prohibiting gas use in new low-rise construction while also prompting other cities to back away from similar gas policy plans. In particular, the city of Ashland voted to direct its Climate and Environment Policy Advisory Committee to refine possible policies aimed at advancing electrification within the city through different legal approaches. Overall, we view such overtures as indicative

of energy transition risk that the affected gas local distribution utility companies (LDCs) must manage to maintain credit quality. As such, we will continue to monitor potential implications on credit quality for affected gas LDCs should legislation or policies aimed at restricting natural-gas growth gain momentum.

Ratings

Pennsylvania

Pennsylvania's Act 12 (Fair market value legislation), passed in 2016, supports investor-owned water utilities' acquisitions of municipal water and sewer system. Recently it has been criticized by certain lawmakers in the state, with a proposal to repeal the law. A primary issue with the original law has largely focused on the impact on customer rates after municipal water systems are eventually acquired. Although the law remains in effect, in July 2024 the Pennsylvania Public Utility Commission (PPUC) finalized new criteria for reviewing the sale of public water and wastewater systems. This includes enhanced rate notification for customers, standardizing valuation methods, and a reasonable review ratio that assesses the fairness of acquisition prices. This new criteria has resulted in termination of previously announced transactions, including the August 2024 termination of the proposed sale of the Towamencin Township wastewater system to Pennsylvania American Water, a subsidiary of American Water.

Overall, we view this development as neutral for credit quality in the near to intermediate time frame. However, enhanced regulatory scrutiny of the process to acquire municipal water and wastewater systems or a repeal of Act 12 could make future acquisitions of such systems more onerous to execute, affecting growth prospects of investor-owned water utilities in Pennsylvania.

Texas--PUCT

We continue to surveil matters regarding CenterPoint Energy Houston Electric LLC (CEHE; a subsidiary of CenterPoint Energy Inc.) before the Public Utilities Commission of Texas (PUCT). In July 2024 the governor of Texas directed PUCT to open an investigation into CEHE's preparation and restoration efforts, following the Category 1 hurricane that led to power outages for about 80% of the utility's 2.6 million electric customers. The governor requested PUCT deliver findings by Dec. 1, 2024. There is no immediate credit impact regarding CEHE but if there are negative findings, including any penalties levied, this could be negative for CEHE's credit quality.

In conjunction with its restoration efforts and accelerated resiliency spending program, CEHE requested to withdraw its pending rate case before PUCT, even though regulation requires Texas transmission and distribution utilities' rates to be reviewed within 48 months of their most recent rate case. CEHE's previous rate case ended March 2020, so the company filed its latest rate case in March 2024. Although CEHE initially requested a rate increase, multiple intervenors proposed rate reductions. PUCT's final determination regarding the rate case will be necessary to assess the credit impact. Regardless of the PUCT determination, we do not anticipate the outcome modifying our view on the credit supportiveness of PUCT.

Lastly, in August 2024 the lieutenant governor of Texas requested that PUCT disallow costs associated with CEHE's leased mobile generation, which the company was authorized to recover through regulatory proceedings. We believe a disallowance of already authorized costs could negatively affect our view of PUCT credit supportiveness.

Utah

In March 2024, Senate Bill 224 (SB224) established a fund for electric utilities in Utah with over 200,000 retail customers (such as PacifiCorp), to help pay claims arising from a fire caused by the utility. The fund will mostly be funded by a Utah commission-approved surcharge that the utility may charge its customers for a set period, plus investment income earned on fund assets. The utility with a fund can access it regardless of whether they are deemed

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negligent but must pay a \$10 million deductible. Any party may challenge the amount of a disbursement, although the burden of proof is on the challenger. The commission can also order the company to reimburse the fund for any imprudent disbursement amounts, up to 10% of its Utah rate base.

Ratings

SB224 also clarified that wildfire damage claims against an electric utility must be brought within two years of the ignition of the event, and, importantly, SB224 also defined limitations of liability if an electric utility has an approved wildland fire protection plan in place and the commission determines that the utility complies with this plan. These caps were set at \$450,000 for non-economic damages for parties with a physical injury, \$100,000 for other non-economic damages, and the lesser of replacement cost or the difference between pre-post fire fair market value for economic damages. Caps still do not apply for wrongful death claims.

Overall, we view this legislation as favorable for credit quality because it provides the ability to establish a supplemental fire fund, and provides liability caps for electric utility caused wildfire damages aside from wrongful deaths. The new law has not yet been tested in practice and we will continue to monitor related developments.

Virginia

In April 2024, a law was passed that provides Virginia Electric Power Co. and Appalachian Power Co. the ability to seek Virginia State Corporation Commission approval to recover costs associated with a small modular nuclear reactor (SMR) facility of up to 500 megawatts through a limited-issue rate adjustment clause. In general, we view the building of SMRs as negative for credit quality since it entails potential construction risk due to its first-of-its kind technology. Developing new nuclear power plants is a highly complex project characterized by extensive timelines, significant capital investments, and inherent execution risks that can lead to significant cost overruns and delays. Furthermore, given our negative credit view of SMRs, we assess a regulatory framework that provides adequate and timely cost recovery for such costs as only very partially mitigating some of these risks.

Wisconsin

In April 2024, WEC Energy Group Inc.'s Wisconsin subsidiaries filed with the Public Service Commission of Wisconsin (PSCW) for electric and natural gas rate cases for a cumulative increase of approximately \$825 million. The multiyear rate cases at subsidiaries Wisconsin Electric Power Co., Wisconsin Gas LLC, and Wisconsin Public Service Corp. are primarily directed towards funding investments, particularly towards transitioning the generation fleets from coal to renewables as well as reliability and safety spending. If authorized as proposed, the increase in rates will bolster financial measures. We continue to view Wisconsin as strongly credit supportive of utilities, and will continue to monitor developments around the rate cases. We expect decisions by year-end 2024.

In May 2024, ALLETE Inc. entered into a definitive agreement to be acquired by the Canada Pension Plan Investment Board and Global Infrastructure Partners, subject to certain regulatory approvals, including by the PSCW. The PSCW has authority over mergers involving Wisconsin utilities. We will monitor the proceeding and any potential impacts to ALLETE's credit quality related to the transaction.

Wyoming

In March 2024, Wyoming modified a law enacted in 2020 requiring a specified percentage of electricity to be dispatchable, reliable, and low-carbon by July 1, 2030. The modification revises the compliance year to 2033 and redefines the statutory definition of low carbon. In addition, the revised compliance standard limits it to only those utilities serving more than 10,000 electric customers, whereas previously it applied to any public utility in the state. Furthermore, the utilities must generate low-carbon electricity from an existing coal-fired generation unit or an equivalent new coal-fired generation facility.

Overall, while these developments are neutral for credit quality in the near term, longer-term energy transition risks could arise should more stringent federal environmental regulations aimed at coal-fired generation facilities result in higher costs for affected utilities.

Ratings

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12-Sep-2023 | 18:06 EDT

Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities

Region [Americas](#), [EMEA](#), [APAC](#)

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Key Takeaways

- Cash flow quality metrics are a key factor in determining credit risk for regulated utilities.
- Most investor-owned utilities generate negative discretionary cash flow from operations during periods of normal operations and offset this deficit with reliable access to the capital markets for financing.
- This balance may be tested as utilities take advantage of the ever-increasing opportunities to grow rate base through record capital spending, while in the process potentially eroding credit quality.
- So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill ever-deepening discretionary cash shortfalls.

S&P Global Ratings has long focused on cash flow quality metrics when determining credit risk for the investor-owned utilities that it rates. The historical and projected generation of cash flow from operations, adjusted to deduct capital spending, dividends paid, and share repurchases, is a key input into the calculation of discretionary cash flow. Given the capital-intensive nature of the utilities sector, and the consistency of dividend payments that management teams are loath to trim, we focus on the utilities' ability to manage discretionary cash flow from operations and external funding to maintain credit quality.

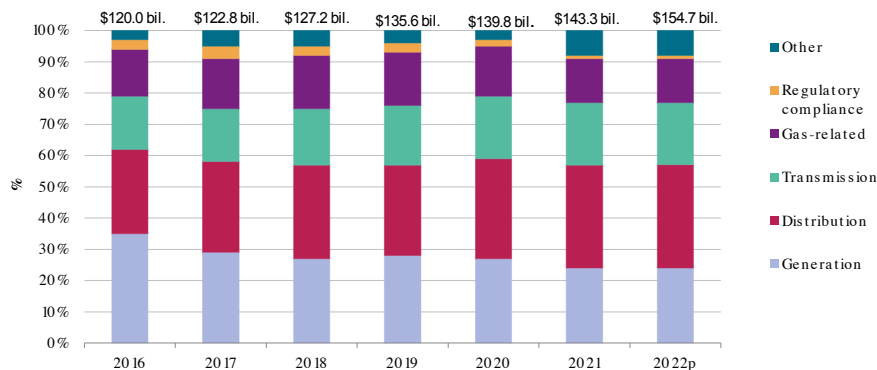
In practice, the majority of utilities generate negative discretionary cash flow from operations during periods of normal operations, which they offset with steady access to the capital markets for both debt and equity financing. During periods of healthy growth, funds from operations increases to offset higher debt balances that result from discretionary cash flow deficits. This allows utilities to maintain credit metrics at acceptable levels. However, ever-increasing opportunities to grow rate base through record capital spending, together with limited equity issuance, may test this balance in the years to come. Here we focus on emerging capital spending trends and opportunities facing the sector and why we think key cash flow metrics may come under pressure.

Record Capital Spending Trends Not Likely To Abate Soon

Transformative change is now well under way within the generation portfolio that North American utilities use to produce power, with increasing focus on low-carbon generation including new investments in wind and solar assets and battery storage. At the same time, traditional carbon-intensive units are either facing retirement or substantial capital requirements to comply with increasingly stringent air quality mandates or to address climate change, important to investors or other stakeholders. Other large-scale capital projects are aimed at hardening the grid against increasingly severe physical risks and climate events while others are geared to accommodate more diverse and intermittent power sources. Further, aging infrastructure is a pervasive issue that requires persistent management, replacement, and improvement, a trend that is fueling investments across electric, gas, and water systems from coast to coast.

Chart 1

U.S. investor-owned electric utilities' capital expenditures by use



p--Projected. Source: Edison Electric Institute, EEI member utilities as of September 2022. S&P Global Ratings. Copyright © 2023 by Standard & Poor's Financial Services LLC. All rights reserved.

Utilities Find Abundant Rate Base Growth Opportunities In Regulated Businesses

The aforementioned trends are playing a key role in fueling record levels of spending in 2023. This pattern is not new, as total capital spending for the universe of utilities we rate increased from about \$100 billion to \$200 billion in little more than a decade. S&P Global Ratings generally views capital spending contained within the regulated utility business model as favorable from a business risk perspective. This spending typically heightens the company's reliance on lower-risk growth as compared to investments into higher-risk unregulated adjacent businesses.

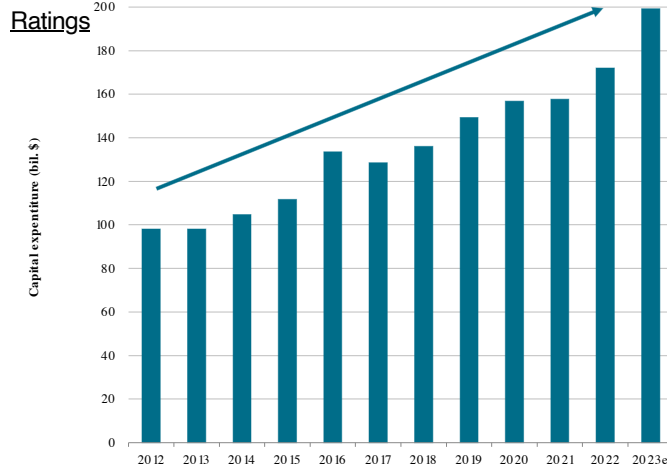
Capital spending provides rate base expansion which in turn drives earnings gains even during periods of negative volume growth in electricity sales. (Sales volumes have been flat to negative for most of the last decade due to consistent efforts toward conservation, energy efficiency, distributed generation, and technology advancements.) Policymakers also promote higher capital spending through legislation that includes incentives to address long-range climate change objectives, as is evident in the Biden Administration's recent passage of the Inflation Reduction Act (IRA) that allows for tax credit transferability to encourage investments in renewable power generation among other incentives. The combined effect of all of these factors supports the view that the sector's appetite for ever-increasing annual capital spending is not going to end soon.

Chart 2
Long-range capital spending of rated investor-owned utilities

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e--Estimate. Source: S&P Global Ratings, as of Aug. 22, 2023.
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And without some material economic disruption or rate pressures that test the will of customers and regulators, we believe that these trends are durable and will likely persist for at least the next 10 years. It also appears evident, looking at the multi-year strategic focus of the management teams we interact with that the focus on regulated utility spending (and by extension the diminished focus on other adjacent operations) has helped reduce the reliance on higher risk businesses. From a credit perspective, this is favorable in terms of our assessments of business risk, and potentially financial risk as well, assuming that management teams commit to maintain financial policies that manage any strains on balance sheets from reduced discretionary cash flows because of a greater reliance on debt.

How Utilities Account For Capital Expenditures And Rate Base Growth

Through the utility's rate case filings, the state utility regulatory commissions determine the revenue requirement necessary for the utility to recover its operating costs, taxes, debt service, and its depreciation expense (necessary to return capital deployed into its physical assets to investors). Investor-owned utilities are also authorized to earn profits on the equity rate base invested by shareholders to support operations. Rate base growth occurs through the deployment of capital into new investments and by effective regulatory management. Thus, there is an incentive and expectation that utility management teams will pursue prudent capital investments that are necessary to serve the rate payers.

While this is part of effective management, the current environment is presenting utility management teams with an expanding strategic opportunity to both strengthen the physical grid and to realize healthy profits and growth for many years to come.

Financial Policy Will Weigh Heavily On The Direction Of Credit Quality

The essential nature of utility services, and the strength of the regulatory frameworks across North America breeds a level of confidence that enables utility management teams to dial-in financial policy with a good deal of precision. They are accustomed to running with negative discretionary cash flow, and many have adopted policies that target a level of financial leverage that is just above the downgrade thresholds we communicate in our research reports. This is typically manageable but persistently high capital spending has begun to test the ability of management teams to maintain ratings while pursuing historically higher growth spending.

Chart 3

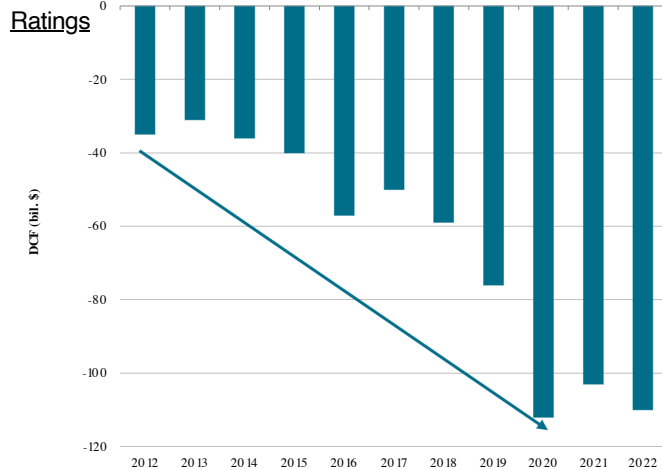
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Long-range discretionary cash flow of rated investor-owned utilities

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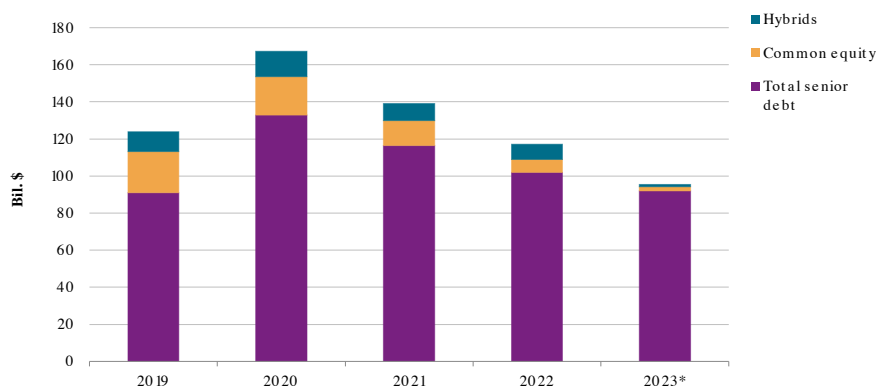


DCF—Discretionary cash flow. Source: S&P Global Ratings, as of Aug. 22, 2023.
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Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill ever-deepening discretionary cash flow shortfalls, but time will tell.

Chart 4

North America investor-owned utilities' capital markets issuance



Senior debt includes first-mortgage bonds and senior unsecured. Hybrids includes junior subordinated debt, preferreds, subordinated debt, and equity units. *YTD as of September 2023. Sources: S&P Global Ratings, S&P Market Intelligence.
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Most utility management teams maintain the ability to pull levers to target financial outcomes. While this is true in any sector to some extent, utilities' operating stability supports a greater degree of precision when managing financial risk against other stakeholder objectives. The capacity and willingness to take actions to offset the potential deterioration of the balance sheet will therefore be a key focal point if capital spending continues to grow. Companies will have to consider tough tradeoffs between good capital projects, shareholder rewards, and balance sheet strength.

Could Regulators Constrain Spending To Reduce Customer Rate Pressures?

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Key determinant of how durable these trends prove to be over the long term will be utilities' careful management of capital spending growth so that customer rates do not rise to the point where bills are viewed as burdensome or out of sync with the value proposition of the utility services. Most utilities manage this issue very well and here [Need a Rating?](#) argued that the value provided through their services is high and leaves room to execute current plans.

Management teams take great care to manage the regulatory relationships with the state utility commissions to strike the appropriate balance between effective grid updates and the costs to achieve these objectives. Well-run utilities place great emphasis on operations and maintenance cost management to reduce the burden on rate payers and proceed with new projects. Nonetheless, elevated spending, particularly in an inflationary environment, is likely to add further strain to regulatory proceedings.

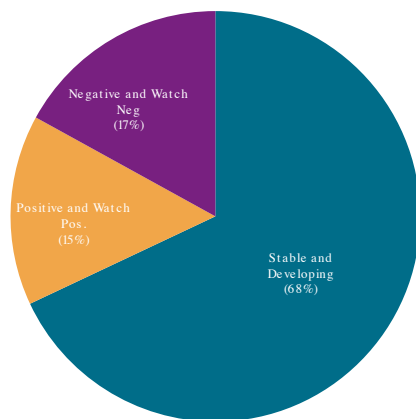
Load growth, something we have not seen for many years, and potentially bolstered by electrification trends, new investments related to green hydrogen or energy-intensive technologies, and the future of electric vehicle growth, can also help to offset this pressure at the margin in some service territories. The more likely scenario is that modest load growth will continue to be offset by efficiency gains and the unwavering increase in capital spending has the potential to bring higher rates to many customers. This will require prudent management to ensure rate pressures remain reasonable so as not to strain the utility's regulatory relationship.

Stable Outlooks Could Turn Negative As The Capital Spending Boom Persists

Earlier in 2023, S&P Global Ratings noted that its outlook for the industry as a whole is stable, supported by the percentage of utilities with a stable outlook, lower natural gas prices, and a slowing of inflation. Even now, about 68% of outlooks in the sector are stable, with negative and positive outlooks at 17% and 15%, respectively. These data points suggest a period of ratings stability for the next year or so following a step down in credit quality during 2022.

Chart 5

Regulated utilities' outlooks YTD 2023



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Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of deterioration in discretionary cash

flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the Ratings ratings.

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03-Feb-2025 | 09:24 EST

Research Update: Edison International And Subsidiary SoCalEdison Outlooks Revised To Negative From Stable On Potential Risk For WildFire Fund Depletion: Ratings Affirmed

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Rating Action Overview

- On Jan. 27, 2025, Edison International (Edison) subsidiary Southern California Edison Co. (SCE) submitted an interim update to the California Public Utilities Commission (CPUC) following its previously filed Electric Safety Incident report (ESIR), both in relation to the Eaton wildfire event that occurred in early January.
- The Los Angeles County Fire Department (County), the lead agency investigating the origin and cause of the Eaton fire has identified a preliminary area of origin for the Eaton fire, an area where SCE has three transmission towers.
- SCE's preliminary analysis shows that a fault detected on a geographically distant line at certain of its substations caused a momentary and expected increase in the current on SCE's transmission system, including on four energized lines, even though such increase remained within SCE's design limits, not triggering system protection on the lines.
- Furthermore, the California Department of Forestry and Fire Protection (Cal Fire) has confirmed that the Eaton fire (99% contained) burned over 14,000 acres, destroyed over 9,000 structures, damaged over 1,000 structures, and resulted in 17 fatalities, making this fire far more destructive than the 2017/2018 wildfires which occurred in SCE's service territory.
- Overall, while the investigations are ongoing, we believe that the California wildfire fund, designed as a material source of liquidity and financial support for participating California investor-owned utility is at risk of a material depletion.
- As such, we are revising our outlooks on Edison and subsidiary Southern California Edison to negative from stable, while maintaining our 'BBB' issuer credit ratings on these entities.
- The negative outlooks on Edison and SCE reflect the potential that the California wildfire fund could materially deplete given the significant number and value of structures that have been damaged or destroyed (over 10,000) due to the Eaton fire, and the possibility that SCE's equipment may be linked to the fire. The negative outlooks also reflect the potential for a more-challenging operating environment going forward for Edison and SCE due to wildfire risk, which could weaken credit quality.

Rating Action Rationale

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Our outlook revisions to negative on both Edison and subsidiary SCE reflects the possibility that the

California Wildfire Fund could materially deplete. This reflects the number of structures that have been destroyed (over 10,000) due to the Eaton fire, and the possibility that SCE's equipment may be linked to the fire. In addition, we analyzed cases from two previous fires in SCE's history (Thomas & Woolsey) which occurred around the 2017/2018 period, looking at several factors such as the number of structures damaged or destroyed, the total number of plaintiffs involved in those cases, the total amount of damages demanded by claimants, and the total amount paid by SCE to settle claims. Our preliminary analysis indicates that the value of potential liabilities related to the Eaton fire could be significant. We note that the investigations are ongoing, and SCE has not been determined to be the cause of the Eaton wildfire. That said, if SCE is found to have contributed to the wildfire, third parties would likely file significant claims against the utility because of the inverse condemnation doctrine in California - whereby a California utility can be financially responsible for a wildfire if its facilities were a contributing cause of the fire irrespective of negligence, putting the sufficiency of the fund at risk. Furthermore, the \$21 billion wildfire fund does not have an automatic replenishing mechanism and is fully available to other participating California investor-owned utilities, including Pacific Gas & Electric and San Diego Gas & Electric.

Taken together, these factors suggest risk of the wildfire fund eventually being depleted. If the fund is depleted, SCE loses the credit benefit of using the fund as a source of liquidity and more importantly, loses the credit protection of the liability cap. As such, as the wildfire fund materially declines, Edison and SCE's credit quality could become more exposed to risk, supporting our negative outlook on both entities.

We view the Thomas Fire, Koenigstein Fire, and Montecito Mudslides (TKM) cost recovery approval as positive for Edison's credit quality. The CPUC approved SCE's settlement agreement with the California Public Advocates Office on its cost recovery application related to the 2017/2018 TKM events. SCE will be authorized to recover 60%, or approximately \$1.6 billion of approximately \$2.7 billion of losses incurred related to these events and will seek to recover such amounts by issuing securitized bonds. Overall, we view this development as supportive of credit quality because it potentially sets a precedent for how the CPUC may approach recovery of prudent third-party wildfire claims in the event the wildfire fund is depleted. Furthermore, we expect Edison's consolidated funds from operations (FFO) to debt to improve by about 70 basis points because of this CPUC decision. SCE has since similarly filed a cost recovery application for the Woolsey Fire (2018), requesting recovery for approximately \$5.4 billion. The outcome of this application is pending.

Our assessment of business risk profile of Edison is unchanged at strong. Our assessment of Edison's business risk profile reflects the company's larger size, lower-risk, rate-regulated electric utility business, and effective regulatory risk management, incorporating several constructive cost recovery mechanisms. These include the use of a forward-looking test year during rate-setting, attrition rates, decoupling, and various balancing accounts that support cash flow recovery. Partially offsetting Edison's business risk is its physical risk exposure due to wildfires, and California courts' interpretation of the legal doctrine of inverse condemnation, which is partially mitigated by the availability of the \$21 billion wildfire fund, and Edison's approximately \$1 billion wildfire-specific insurance coverage. On other regulatory matters, SCE filed for its 2025 general rate case (GRC) in May 2023 with the CPUC, requesting a rate increase of approximately \$1.9 billion effective Jan. 1, 2025. As part of this GRC, the company also requested increases of approximately \$600 million for 2026, \$700 million for 2027, and \$700 million for 2028. The CPUC decision for this rate case is pending.

We assess Edison's financial risk profile as significant. We assess Edison's financial risk profile using our media volatility financial benchmark table, reflecting the company's lower-risk, regulated utility business and effective regulatory risk management. We expect the company's FFO to debt to improve in 2025, reflecting increased cash

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collections from several balancing accounts, new rate increases, and our expectation of constructive regulatory decisions on SCE's 2025 rate request. Under our base-case scenario, we expect annual capital expenditures to average just about \$7 billion annually over our forecast period. Our base case also assumes manageable operating expense levels, steady use of SCE's regulatory mechanism that support cash flow, manageable litigation and dividends averaging about \$1.4 billion over our forecast period. Furthermore, our base case assumes negative discretionary cash flow, reflecting the company's capital spending and dividend payments. Overall, we anticipate Edison's financial measures will reflect FFO to debt of 16%-18% for the 2025-2027 period.

Outlook

The negative outlooks on Edison and SCE reflect the uncertainty that the California wildfire fund could materially deplete given the number and value of the structures that have been damaged or destroyed (over 10,000) due to the Eaton fire, and the possibility that SCE's equipment may be linked to the fire. The negative outlooks also reflect potential for a more challenging operating environment going forward for Edison and SCE due to wildfire risk, which could weaken credit quality.

Downside scenario

We could lower our ratings on Edison and subsidiary SCE over the next 12 to 24 months if;

- Edison's consolidated financial measures weaken, reflecting FFO to debt of less than 14%;
- We believe the California's wildfire fund will deplete at an accelerated pace, without sufficient countermeasures, if SCE or another participating investor-owned utility in the fund experience wildfire-related liability payments that prompt material drawdowns from the fund.
- We conclude that the company's wildfire mitigation strategies are insufficient to consistently protect the company against severe wildfire losses.

Upside scenario

We could revise the ratings outlook back to stable over the next 12 to 24 months following confirmation that the wildfire fund is sufficient to support Edison's credit quality, and the company maintains consolidated FFO to debt consistently above 14% without an increase in business risk.

Company Description

Edison is a holding company that, through regulated utility subsidiary SCE, has more than 3,000 megawatts of owned electric generation capacity and serves more than 5 million customers in Central, Coastal, and Southern California.

Liquidity

As of Sept. 30, 2024, we assess Edison's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and we expect sources will cover uses even if forecast consolidated EBITDA declines by 10%. We believe the predictable regulatory framework for Edison provides a manageable level of cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. In addition, we believe Edison has the ability to absorb high-impact, low-probability events because the company maintains about \$4.85 billion in committed credit facilities through May 2028. Additionally, we believe the company can lower its high capital spending (averaging about \$7 billion annually) during stressful periods, indicative of a limited need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management, sound

S&P Global relationships with its banks and a satisfactory standing in the credit markets. Overall, we believe the company will be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations.

The company has long-term debt maturities in 2025 totaling about \$2 billion, and we expect the company to proactively address these maturities well in advance of their scheduled due date.

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Principal liquidity sources

- Cash and liquid investments of \$200 million;
- Credit facilities of \$4.85 billion;
- Cash FFO of about \$6.4 billion; and
- Working capital inflows of \$130 million.

Principal liquidity uses

- Long-term debt maturities of about \$2.5 billion;
- Total short-term debt outstanding of \$568 million;
- Assumed maintenance capex of \$3.5 billion; and
- Dividends of about \$1.2 billion.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of Edison, reflecting above-average physical risk compared with peers due to its exposure to California wildfires, including 27% of its service territory designated as high-risk fire area. Catastrophic wildfires caused by Edison's equipment in 2017 and 2018 have constrained credit quality. That said, we believe the company's ongoing focus on its wildfire mitigation practices, which include grid hardening, vegetation management, use of technology and proactive surveillance, maintenance of a valid safety certificate, and continued access to the wildfire funds partially mitigates this risk. Furthermore, while communities' susceptibility to wildfires is relevant, Edison has implemented PSPS measures to proactively deenergize power lines that may be at risk of causing a wildfire. That said the Eaton fire event highlights how challenging the operating environment is for Edison.

Issue Ratings--Subordination Risk Analysis

Capital structure

Edison has about \$35 billion in total debt in its capital structure, of which \$29 billion consists of first-mortgage bonds and secured debt at SCE.

Analytical conclusions

- We rate Edison's unsecured debt issues one notch lower than our issuer credit rating on the company. This is due to the significant proportion of priority debt at the company's subsidiary.
- We rate Edison's preferred stock and junior subordinated debt two notches below our issuer credit rating to reflect the instruments' subordination and deferability features.
- We base our commercial paper and short-term rating on our long-term issuer credit rating of the company.

Rating Component Scores

Rating Component Scores

Edison International

 Foreign currency issuer credit rating BBB/Negative/A-2 Search EN Support	
Local currency issuer credit rating	BBB/Negative/A-2 Need a Rating?
Business risk	Strong
Country risk	Very low risk
Industry risk	Very low risk
Competitive position	Satisfactory
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	bbb
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	bbb
Rating Component Scores	
Southern California Edison Co.	
Foreign currency issuer credit rating	BBB/Negative/A-2

Local currency issuer credit rating		BBB/Negative/A-2	EN	Support
Business risk		Strong	Need a Rating?	
Country risk		Very low		
Industry risk		Very low		
Competitive position		Satisfactory		
Financial risk		Significant		
Cash flow/leverage		Significant		
Anchor		bbb		
Diversification/portfolio effect		Neutral (no impact)		
Capital structure		Neutral (no impact)		
Financial policy		Neutral (no impact)		
Liquidity		Adequate (no impact)		
Management and governance		Neutral (no impact)		
Comparable rating analysis		Neutral (no impact)		
Stand-alone credit profile		bbb		
Group credit profile		bbb		
Entity status within group		Core (No impact on SACP)		

Environmental, social, and governance (ESG) credit factors for this change in credit rating/outlook and/or CreditWatch status:

— Physical risk

Related Criteria

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Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024

Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024

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- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Related Research

- Southern California's Historic Wildfire Destruction Puts Heat On North America Investor-Owned Utilities' Credit Quality, Jan. 15, 2025
- Bulletin: Edison International And Subsidiary Southern California Edison Actively Monitored Amid Wildfire-Related Incident Reports, Jan. 13, 2025
- Tear Sheet: Edison International Actively Monitored Amid Significant Wildfires, Jan. 8, 2025
- Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions, Nov. 6, 2024
- Tear Sheet: TKM Settlement Agreement Is Potentially Supportive For Edison International's Credit Quality, Sept. 9, 2024

Ratings List

Ratings list

Ratings Affirmed; Outlook Action		
	To	From
Edison International		
Southern California Edison Co.		
Issuer Credit Rating	BBB/Negative/A-2	BBB/Stable/A-2

Foreign Currency

S&P Global

BBB/Negative/A-2

Search

EN

Support

BBB/Stable/A-2

SCE Trust VI

Ratings

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SCE Trust VII

SCE Trust VIII

Issuer Credit Rating

BBB/Negative/--

BBB/Stable/--

Foreign Currency

BBB/Negative/--

BBB/Stable/--

Ratings Affirmed

Edison International

Senior Unsecured

BBB-

Junior Subordinated

BB+

Edison International

SCE Trust VII

Southern California Edison Co.

Preferred Stock

BB+

Edison International

Southern California Edison Co.

Commercial Paper

A-2

SCE Trust II

SCE Trust III

SCE Trust IV

SCE Trust V

SCE Trust VI

SCE Trust VIII

Southern California Edison Co.

Preference Stock

BB+

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Southern California Edison Co.

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18-Jul-2022 | 16:55 EDT

Research Update: PG&E Corp. And Pacific Gas & Electric Co. Outlooks Revised To Stable On Improving Financial Measures; Ratings Affirmed

[View Analyst Contact Information](#)

Rating Action Overview

- Pacific Gas & Electric Co. (Pac Gas), the subsidiary of PG&E Corp., recently completed the issuance of about \$3.9 billion of securitization bonds after already completing an issuance of about \$3.6 billion of securitization bonds in May 2022.
- The company will use the securitization proceeds to pay or reimburse for wildfire claims cost associated with prior California wildfires. In total, we expect that the company will retire of about \$6.5 billion of debt during 2022, improving its financial measures.
- We revised our outlooks on PG&E and subsidiary Pac Gas to stable from negative and affirmed the ratings, including the 'BB-' issuer credit ratings on PG&E and Pac Gas. We also affirmed the 'BB-' rating on PG&E's senior unsecured debt (the recovery rating remains '3'; 65% estimated recovery). In addition, we affirmed the 'BBB-' rating on Pac Gas' senior secured first-mortgage bonds (the recovery rating remains '1+'; 150% estimated recovery).
- The stable outlooks on PG&E and Pac Gas reflect our expectations of continued gradual financial improvement, such that PG&E's consolidated funds from operations (FFO) to debt will consistently be greater than 13% and the company is not the cause of a catastrophic wildfire.

Rating Action Rationale

The outlook revision reflects our expectations of improving financial measures, without a weakening of business risk. We view the issuance of \$3.9 billion of securitization bonds as supportive of credit quality. The company expects to use the proceeds to mostly retire utility debt, which will improve financial measures. The recent issuance is in addition to the May 2022 securitization issuance of about \$3.6 billion, where the company used proceeds primarily to retire debt. In total, the company will benefit from the securitization issuance of about \$7.5 billion in 2022, which we assess as supportive of credit quality. We expect that securitization issuances and subsequent debt reduction will improve the company's consolidated FFO to debt by about 200 basis points in 2022.

Securitization typically contains an irrevocable, non-bypassable charge with periodic true-ups and an absolute transfer and first-priority security interest in transition property; we often deconsolidate such debt, resulting in stronger credit measures and improving credit quality.

Ratings

For PG&E, while in the short term, we view the securitization as supportive of credit quality because the near-term debt reduction strengthens PG&E's financial measures, over the long term we assess the \$7.5 billion of securitization as mostly credit neutral. As part of the California Public Utilities Commission's (CPUC) approval of the \$7.5 billion of securitization, PG&E will be reducing its future cash flows (from net operating losses) to fund an equivalent customer credit to avoid a material increase to the customer bill. As such, we expect PG&E's longer-term financial measures will be somewhat weaker and therefore we assess the \$7.5 billion of securitization as credit neutral over the longer term.

Also supporting the company's financial measures is the recovery of about \$1.7 billion of wildfire-related costs through various balancing accounts in 2022. For 2023 to 2026, we expect even further financial improvement predicated on the company's 2023 electric and gas general rate cases. In February 2022, the company revised its rate case filing, requesting a combined multi-year revenue increase of about \$3.4 billion for 2023, \$1 billion for 2024, \$750 million for 2025, and \$550 million for 2026. We expect a rate case order from the CPUC by about midyear 2023, but we believe the determination will be retroactive to early 2023. The relatively large rate case filings primarily reflects rising capital spending, and we expect that the company will effectively manage regulatory risk, resulting in reasonable rate case orders that will lead to consistently improved financial measures.

Under our base case, we also expect that the company's robust capital spending totaling about \$53 billion through 2026, will consistently result in negative discretionary cash flow. Overall, we expect that PG&E's 2023 consolidated FFO to debt will improve to the 12.5%-13.5% range from about 10.9% in 2021. We also expect that subsequent financial performance will improve, reflecting FFO to debt of 13%-16% for 2023-2026 period.

We assess PG&E's business risk profile as satisfactory. Our assessment of PG&E's business risk profile, which we assess at the lower end of the range for its category, reflects the company's larger-size regulated utility operations that mostly consists of transmission and distribution (T&D) assets, and also incorporates the significant risks of catastrophic wildfires in its service territory. Because of climate change, dry conditions in Northern California have become common, increasing the susceptibility that a smaller wildfire can grow into a catastrophic one. Also, a large percentage of the company's service territory operates within high fire-threat districts, which considerably increases the risks for PG&E compared with peers. The risk of causing a wildfire in California has considerably higher legal risks compared to utilities in other states because of California's inverse condemnation doctrine--whereby a California utility can be financially responsible for a wildfire if its facilities were a contributing cause of a wildfire, irrespective of negligence.

Offsetting some of these risks is assembly bill (AB) 1054 that established an approximate \$21 billion wildfire fund, allows for a predetermined cap that limits liability, and provides for a revised standard for determining a utility's reasonable conduct, placing the initial burden of proof on the intervenor. Furthermore, PG&E is reducing risk through the continued implementation of technology, identifying high-wind conditions, effective utilization of public safety power shut events, decreasing fire ignitions through enhanced powerline safety settings, and increasing system hardening, including undergrounding.

Despite the company's advancements to reduce wildfire risks, we expect that wildfire risks will continue to remain challenging for the foreseeable future. In 2022, the California Department of Forestry and Fire Protection determined that the 2021 Dixie Fire was caused by a tree contacting electrical distribution lines owned and operated by Pacific Gas & Electric. Despite the devastation of the Dixie Fire, which burned nearly 1 million acres and caused a fatality, we did not view the Dixie Fire as catastrophic. Because of California's recent risk reducing measures including system hardening, effective use of technology, and the wildfire fund, S&P Global Ratings assesses a catastrophic wildfire for a

California investor-owned utility, as one that damages or destroys more than 4,000 structures, which we use as a proxy for \$4 billion in wildfire claims. The Dixie wildfire, while destructive, only damaged or destroyed less than 1,500 structures. PG&E's credit quality would be negatively affected if it is the cause of a catastrophic wildfire.

Ratings

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Outlook

The stable outlooks on PG&E and Pac Gas reflect our expectations of continued gradual financial improvement, such that PG&E's consolidated FFO to debt will consistently be greater than 13% and the company is not the cause of a catastrophic wildfire.

Downside scenario

We could downgrade PG&E and Pac Gas over the next 12 months if the company receives its general rate case orders and consolidated FFO to debt remains below 13%. We could also lower ratings if risks increased, such as the company causes a catastrophic wildfire, its management of regulatory risk weakens, business risk increases, or any of California's investor-owned electric utilities are found to be the cause of a catastrophic wildfire, thereby increasing the probability the wildfire fund could be depleted sooner than expected.

Upside scenario

We could raise our rating on PG&E and Pac Gas over the next 12 months if:

- PG&E's consolidated FFO to debt improves to consistently greater than 15%;
- The company is not found to be the cause of a catastrophic wildfire;
- The company effectively manages regulatory risk;
- The company improves its track record of safety and reliability;
- California's other investor-owned electric utilities are not found to be the cause of a catastrophic wildfire, thereby depleting the wildfire fund sooner than expected;
- PG&E maintains its safety certification; and
- There is no further weakening of business risk.

Company Description

PG&E Corp. is a San Francisco-based utility holding company. Its wholly owned utility subsidiary is Pacific Gas & Electric Co. (Pac Gas), which operates in northern and central California. Pac Gas generates revenues through the sale and delivery of electricity and natural gas to 5.5 million electric and 4.5 million gas customers and has about 7,700 MW of generation capacity. The utility is regulated by the CPUC, Federal Energy Regulatory Commission, and the Nuclear Regulatory Commission.

Our Base-Case Scenario

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- The company issues \$7.5 billion of securitized debt in 2022 and retires \$6.5 billion of debt.
- Robust capital spending of about \$53 billion over the next five years.
- PG&E and California's other investor-owned electric utilities are not found to be the cause of a catastrophic wildfire.
- PG&E maintains its safety certification, consistent with meeting the requirements under AB 1054.
- Negative discretionary cash flow, resulting in external funding needs that we assume will be funded largely with debt.

Liquidity

As of March 31, 2022, we assess PG&E's liquidity as adequate because we believe its liquidly sources will likely be more than 1.1x its uses over the next 12 months, and PG&E will meet its outflows even if its consolidated EBITDA declines 10%. Additionally, our assessment also reflects the company's sound relationships with banks and its likely ability to absorb high-impact, low-probability events with limited need for refinancing, as evidenced by the company's access the wildfire fund.

Principal liquidity sources

- Cash on hand of about \$250 million;
- Credit facility availability of about \$2.95 billion; and
- Cash FFO of about \$5.9 billion.

Principal liquidity uses

- Short-term debt and long-term debt maturities of about \$800 million over the next 12 months; and
- Maintenance capital expenditures of about \$6 billion.

Covenants

Compliance expectations

PG&E's revolving credit facility has a debt- to- capital limit of 70% and Pac Gas' revolving credit facility has a debt- to- capital limit of 65%. We expect the companies to consistently be in compliance with these covenants and have at least 15% financial covenant headroom.

Environmental, Social, And Governance

ESG credit indicators: E-5, S-5, G-5

ESG factors are the same for both entities.

Environmental, social, and governance factors are very negative considerations in our credit rating analysis of Pacific Gas & Electric. Climate change has increased the frequency of wildfires in northern California and environmental factors have become an integral part of our credit analysis of the company.

Social risks are also high, reflecting its communities' susceptibility to wildfires and the potential for higher customer bills due to ongoing significant investments in wildfire mitigation, system hardening, and technology. [Search](#) [EN](#) [Support](#)

Governance factors are also a very negative consideration. The company is the only North American re [Need a Rating?](#) file for bankruptcy protection twice over the past two decades and has a history of confrontational relationships with regulatory authorities, which, in our view, are beyond isolated episodes and outside industry norms. This has adversely affected the company's reputation, representing a significant risk to the company.

Issue Ratings - Subordination Risk Analysis

Capital structure

As of March 31, 2022, PG&E has about \$38 billion of long-term debt. About \$5 billion consists of senior notes at PG&E and approximately \$33 billion of senior secured debt at Pac Gas that are backed by first-mortgage bonds (FMB).

Issue Ratings - Recovery Analysis

Key analytical factors

- Our '1+' recovery rating on Pac Gas' senior secured FMBs and secured revolving credit facility reflects that the substantial value of the company's regulated utility assets is sufficiently larger than its secured debt, limited priority claims, and other liabilities. For our recovery analysis, we treat the accounts receivable (AR) securitization facility as a priority claim due to its senior claim to the value of the company's revenue (via its AR) and the structural protections of this financing structure. Conversely, we do not treat the securitization of incremental charges related to wildfire recovery costs as priority.
- The recovery rating indicates our highest expectation for full recovery and results in an issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.
- We view the secured debt at PG&E as effectively unsecured because it is not guaranteed by Pac Gas and is essentially the junior-most debt liability in PG&E's consolidated capital structure, behind unsecured liabilities and preferred equity interests at Pac Gas. As such, we cap the recovery rating on this debt at '3' (consistent with our approach to rating unsecured debt issued by companies we rate 'BB-' or higher), although the implied coverage is substantially higher at more than 400%.
- A default could stem from sudden liquidity pressure amid unpredictable weather, cost, or market conditions outside the company's control, consistent with the conditions of past utility defaults. Furthermore, it could reflect significant litigation exposure, consistent with the company's previous default.
- We expect Pac Gas would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is roughly \$72 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): \$71.5 billion
- Valuation split (PG&E/Pac Gas): 0%/100%

Simplified waterfall**S&P Global**[Search](#)[EN](#)[Support](#)**Ratings**[Need a Rating?](#)

- Net recovery value after administrative costs (5%): \$68 billion
- Priority claims at Pac Gas (AR securitization): \$1 billion
- Remaining Pac Gas value available: \$67 billion
- Secured debt claims at Pac Gas (FMBs and bank debt): \$41 billion
- --Recovery expectations: 100% (coverage exceeding 150%)
- Residual value available to Pac Gas equity: \$26 billion
- Pac Gas preferred stock claims: \$250 million
- Pac Gas value adjustment for pension deficit (50%): \$342 million
- Residual value available to parent creditors: \$25.6 billion
- Debt claims at parents (deemed effectively unsecured) \$5.2 billion
- --Recovery expectations: Capped at 50%-70%; rounded estimate: 65%

Debt amounts include six months of accrued interest we assume will be owed at default, and are updated as of first quarter end 2022, pro forma for subsequent changes and the proposed transaction. We assume the cash flow revolvers at Pac Gas (\$4 billion) and PG&E (\$500 million) are 85% drawn at default and that the \$1 billion AR securitization is fully drawn. We assume debt maturing before our simulated default is refinanced on similar terms before maturity.

Ratings Score Snapshot**PG&E Corp.**

Issuer credit rating: BB-/Stable/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-1 notch)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bb-

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— Group credit profile: bb-

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Ratings Entity status within group: Core (no impact)

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ESG credit indicators: E-5, S-5, G-5

Pacific Gas & Electric

Issuer credit rating: BB-/Stable/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-1 notch)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile : bb-

- Group credit profile: bb-
- Entity status within group: Core (no impact)

ESG credit indicators: E-5, S-5, G-5

Related Criteria

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- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022

General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021

General Criteria: Group Rating Methodology, July 1, 2019

Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019

Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016

Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

General Criteria: Methodology: Industry Risk, Nov. 19, 2013

General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013

Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013

General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012

General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- Need a Rating?

Ratings List

Ratings Affirmed; Outlook Action		
	To	From
PG&E Corp.		
Pacific Gas & Electric Co.		
Issuer Credit Rating	BB-/Stable/--	BB-/Negative/--
Issue-Level Ratings Affirmed; Recovery Ratings Unchanged		
PG&E Corp.		
Senior Secured	BB-	
Recovery Rating	3(65%)	
Pacific Gas & Electric Co.		

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RRA Regulatory Focus

Major Energy Rate Case Decisions

July 29, 2024

Major energy rate case decisions in the US

January–June 2024

Quarterly update on decided rate cases

Lisa Fontanella, Research Director

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Majda Shabbir

For detailed data

Access the RRA's [electric and gas rate case decisions](#) as of June 30, 2024, data tables.

An overview of state-level electric and gas rate case decisions in the US through the first half of 2024 and select historical data.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

Table of Contents

Executive Summary	3
Introduction	3
About this report	3
The Take	5
Overview of electric and gas authorizations	5
Capital structure trends	7
A more granular look at ROE trends	8
Further Reading	12
About the Author(s)	12
About Regulatory Research Associates	12

Executive Summary

Introduction

The average electric and gas authorized returns on equity are trending modestly upward.

As per calculations from Regulatory Research Associates, the average return on equity (ROE) authorized electric utilities was 9.68% in rate cases decided in the first half of 2024, above the 9.60% average for full year 2023. There were 21 electric ROE authorizations in January–June 2024 versus 63 in full year 2023.

The average ROE authorized gas utilities was 9.83% in rate cases decided in the first half of 2024, above the 9.64% average for full year 2023. There were 10 gas ROE authorizations in January–June 2024 versus 43 in full year 2023.

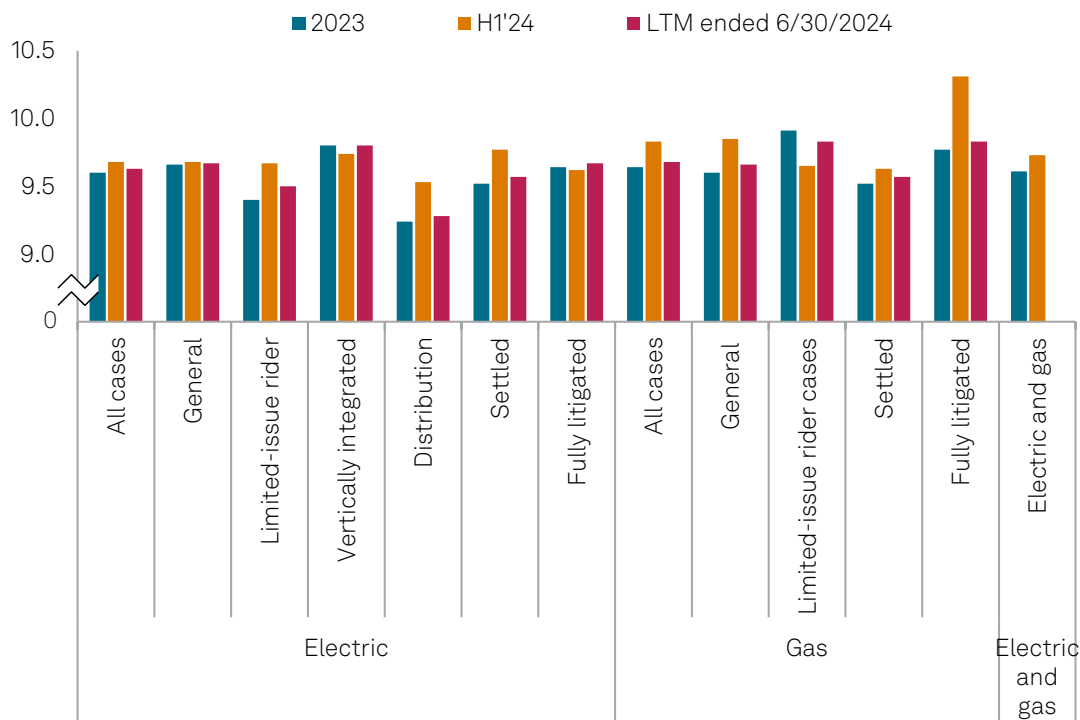
Rate case activity reached record-high levels in 2023, with nearly 165 decisions issued by state public utility commissions, including 106 electric or gas equity return determinations.

While the reasons for a rate case filing are numerous, the main driver continues to be the recovery of capital expenditures. Energy utilities are investing in infrastructure to modernize transmission and distribution systems; build new natural gas, solar and wind generation; and deploy new technologies to accommodate the expansion of electric vehicles, battery storage and advanced metering infrastructure that facilitate the transition toward decarbonization. Other reasons for rate filings include rising expenses, revised cost-of-capital parameters, the impact of broader economic and sectorwide forces on operations, recovery of storm and severe-weather-related costs, regulatory approval for alternative regulatory mechanisms, and the need to address rate treatment to be accorded generation facilities being retired prior to the end of their planned service lives due to the energy transition.

About this report

This quarterly report offers a detailed overview of electric and gas rate case decisions issued in the US during the first half of 2024 and select aggregated historical data. The information presented in this report utilizes the data compiled by Regulatory Research Associates for its rate case database, which is available on the S&P Capital IQ Pro platform. RRA endeavors to follow all “major” rate cases for investor-owned utilities nationwide, with “major” defined as a case in which the utility’s request would result in a rate change of at least \$5 million or in which the commission approves a rate change of at least \$3 million. In addition to base rate cases, the rate case history database includes details regarding certain limited-issue rider proceedings, primarily those involving significant rate base additions recognized outside of a general rate case. In some of these cases, the rate change coverage criteria may not apply. Historical data in this report may not match earlier data provided in previous reports due to differences in presentation, including the treatment of withdrawn or dismissed cases and the addition of cases not previously included in RRA’s coverage.

Average authorized ROE (%)



	2023	H1'24	LTM ended 6/30/2024
Electric averages			
All cases	9.60	9.68	9.63
General rate cases	9.66	9.68	9.67
Limited-issue rider cases	9.40	9.67	9.50
Vertically integrated cases	9.80	9.74	9.80
Distribution cases	9.24	9.53	9.28
Settled cases	9.52	9.77	9.57
Fully litigated cases	9.64	9.62	9.67
Gas averages			
All cases	9.64	9.83	9.68
General rate cases	9.60	9.85	9.66
Limited-issue rider cases	9.91	9.65	9.83
Settled cases	9.52	9.63	9.57
Fully litigated cases	9.77	10.31	9.83
Composite electric and gas averages			
Electric and gas	9.61	9.73	9.65
US Treasury			
30-year bond yield	4.09	4.46	4.44

Data compiled July 23, 2024.

ROE = return on equity; LTM = last 12 months.

Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights;

US Treasury Department.

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The Take

Averages calculated for the first half of 2024 show that electric and gas authorized ROEs are trending modestly higher, as the high-interest-rate environment begins to impact authorized ROEs. The effect of interest rate increases on authorized returns is not proportional, however, as regulators are slower to adjust ROEs upward than downward, and affordability concerns persist as regulators contend with customer rate increases stemming from significant but necessary capital investment in the energy transition during a period of high inflation.

In recent years, rate case activity for investor-owned electric and gas utilities in the US has been elevated, with state public utility commissions issuing almost 165 decisions in 2023. With higher interest rates, elevated inflation and accelerating capital spending to address public policy goals, particularly the energy transition, RRA anticipates that the flurry of rate case activity will continue.

Overview of electric and gas authorizations

Both the electric and gas average authorized ROEs in the first half of 2024 inched gently higher than the averages for full year 2023.

The average ROE authorized for electric utilities was 9.68% for rate cases decided in the first half of 2024, above the 9.60% average observed in full year 2023. There were 21 electric ROE determinations reflected in the calculations for January–June 2024 versus 63 in full year 2023.

The average ROE authorized for gas utilities was 9.83% for cases decided in the first half of 2024, above the 9.64% average observed in full year 2023. There were 10 ROE determinations reflected in the calculations for January–June 2024 versus 43 in full year 2023.

The electric data set includes several limited-issue rider cases. Historically, the ROEs authorized in limited-issue rider cases were meaningfully higher than those approved in general rate cases, driven primarily by incentives allowed in Virginia for certain types of generation investment. These premiums have largely expired. Excluding rider cases, the average authorized ROE for electric cases was 9.68% in the first half of 2024, versus 9.66% for full year 2023. There was only one limited-issue rider case with a gas authorized ROE in January–June 2024 and a 9.65% ROE was authorized. Excluding the one rider rate case in the first half of 2024 and six rider cases in full year 2023, the average authorized ROE for gas cases was 9.85% in January–June 2024 and 9.60% in full year 2023. For the most part, limited-issue riders have a limited impact on average ROEs in the gas sector, as most of the gas riders rely on ROEs approved in a previous base rate case.

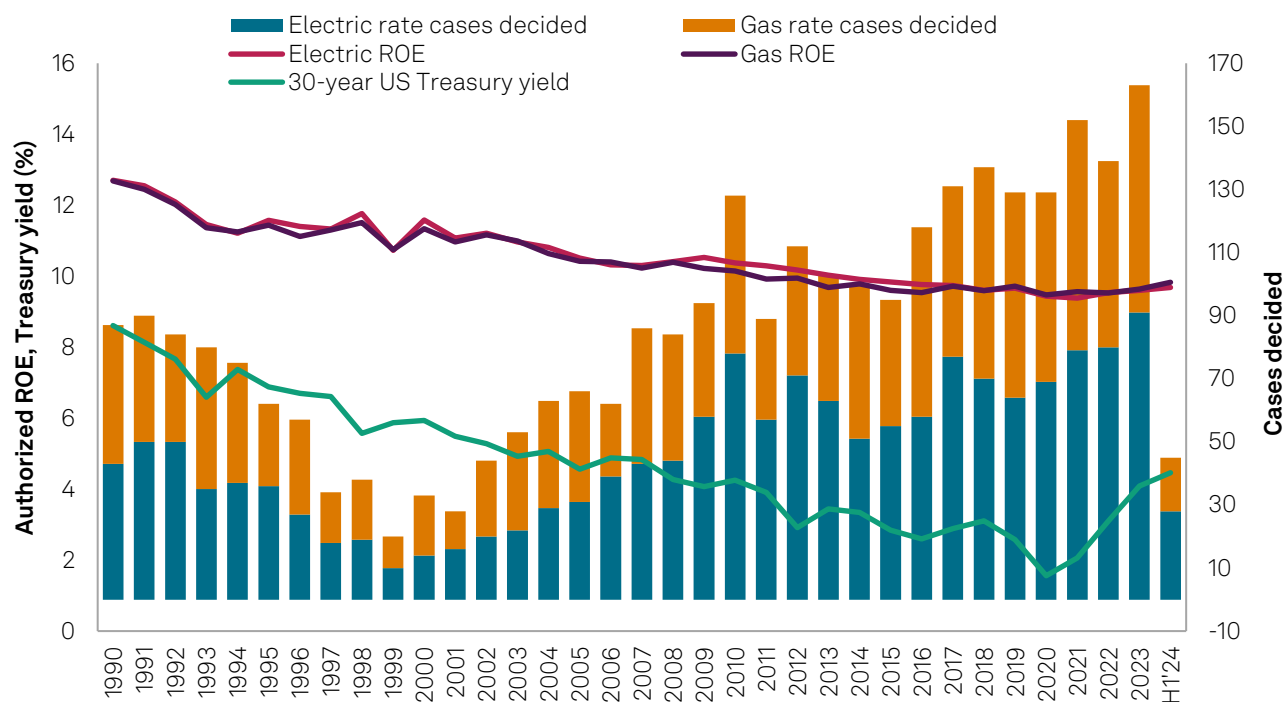
In the first half of 2024, the median ROE authorized in all electric utility rate cases was 9.70% versus 9.50% in full year 2023; for gas utilities, the metric was 9.68% in the first half of 2024 and 9.60% in full year 2023.

Looking at the last 12 months ended June 30, 2024, the average ROE authorized in all electric utility rate cases was 9.63% and the median was 9.60%. For gas utilities in the 12-month period ending June 30, 2024, the average was 9.68% and the median was 9.65%.

Historically, authorized returns have generally tracked the overall direction of interest rates, albeit with two important caveats to keep in mind — the magnitude of the change in authorized ROEs may not be as dramatic as that observed in interest rates, and changes in authorized ROEs may lag changes in interest rates, especially in the upward direction.

Interest rates — as measured by the 30-year US Treasury bond yield — fell almost steadily between 1990 and 2020, placing downward pressure on authorized ROEs. Between 1990 and 2020, Treasury yields fell more than 700 basis points, to 1.56% from 8.61%, while average authorized ROEs for electric and gas utilities combined fell less than 325 basis points, to 9.45% from 12.69%. The average authorized ROEs did not fall below 10% until 2011 for gas utilities and until 2014 for electric utilities. The calendar-year averages fell below 9.50% for the first time in 2020.

Average electric, gas authorized ROEs; number of rate cases decided



Data compiled July 23, 2024.

ROE = return on equity.

Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

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The decline in authorized ROEs has coincided with an upswing in rate case activity, with 100 or more cases adjudicated in 12 of the last 15 calendar years. This count includes electric and gas cases where no ROEs were specified but does not include withdrawn cases. At almost 165 cases decided, rate case activity in 2023 was the most robust observed in any year during the 1990–2023 period, with authorized increases totaling about \$12 billion.

With interest rates and authorized ROEs declining at different rates between 1990 and 2020, the spread between authorized ROEs and the average yield on 30-year US Treasurys somewhat widened over this period — going from a little over 400 basis points in 1990 to a peak of just under 800 basis points in 2020.

The widening spread is attributable primarily to the regulators' often-unstated understanding that the drop in interest rates caused by the US Federal Reserve intervention was unusual. Consequently, regulators did not fully reflect the interest rate drop in newly authorized ROEs in some instances; in others, regulators acknowledged that the changing dynamics of the industry and instability in the overall economy presented increased risks for investors, justifying a higher premium over interest rates.

However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023.

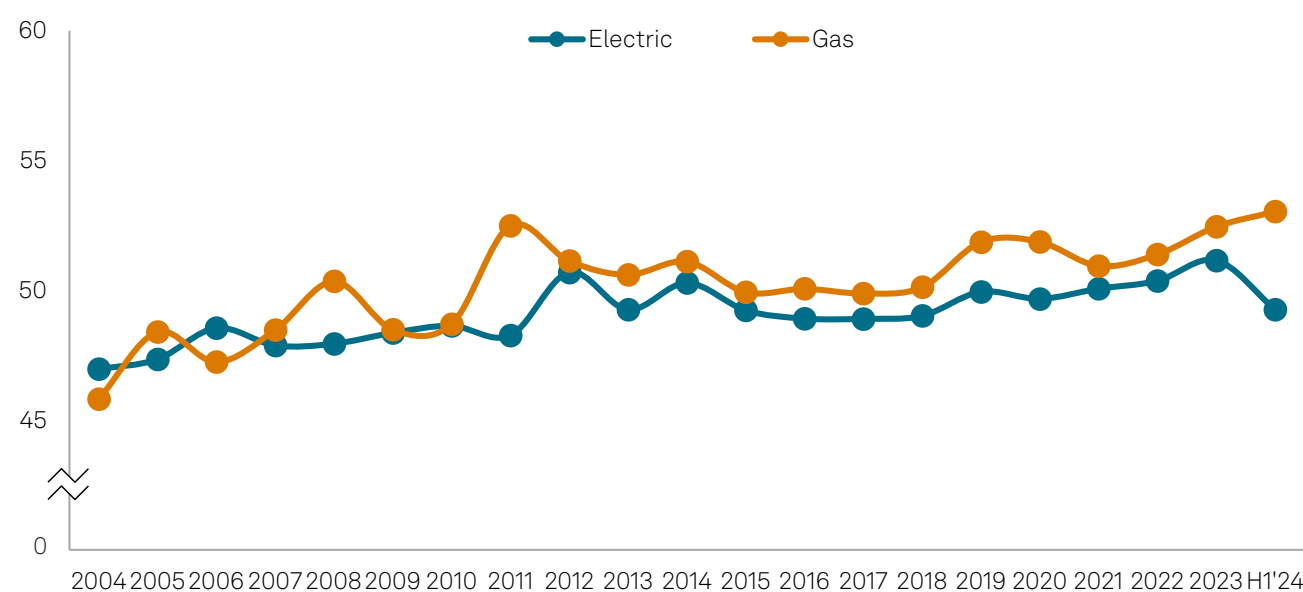
With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.

Capital structure trends

The negative cash flow impact of federal tax changes that took effect in 2018 raised concerns regarding utility liquidity and credit metrics. In response, many utilities sought higher common equity ratios, and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than those observed in 2018 and 2017.

For full years 2023, 2022, 2021, 2020 and 2019, the average equity ratios authorized in electric utility cases were 51.15%, 50.36%, 50.06%, 49.67% and 49.94%, respectively. The average equity ratios authorized gas utilities for these years were 52.45%, 51.38%, 50.94%, 51.87% and 51.86%, respectively.

Average authorized equity ratio (%)



Data compiled July 23, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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In the first half of 2024, the average authorized equity ratio for electric utility cases nationwide was 49.26%. For gas utilities, the average authorized equity ratio nationwide was 53.03%.

From a longer-term perspective, equity ratios have generally increased over the last several years — the average equity ratio approved in electric rate cases decided during 2004 was 46.96%, while the average for gas utilities was 45.81%. In the wake of the 2008 financial crisis, many commissions began approving capital structures that were more equity rich. Authorized equity ratios for gas utilities have been above those of electric utilities for the bulk of the period since 2004.

A more granular look at ROE trends

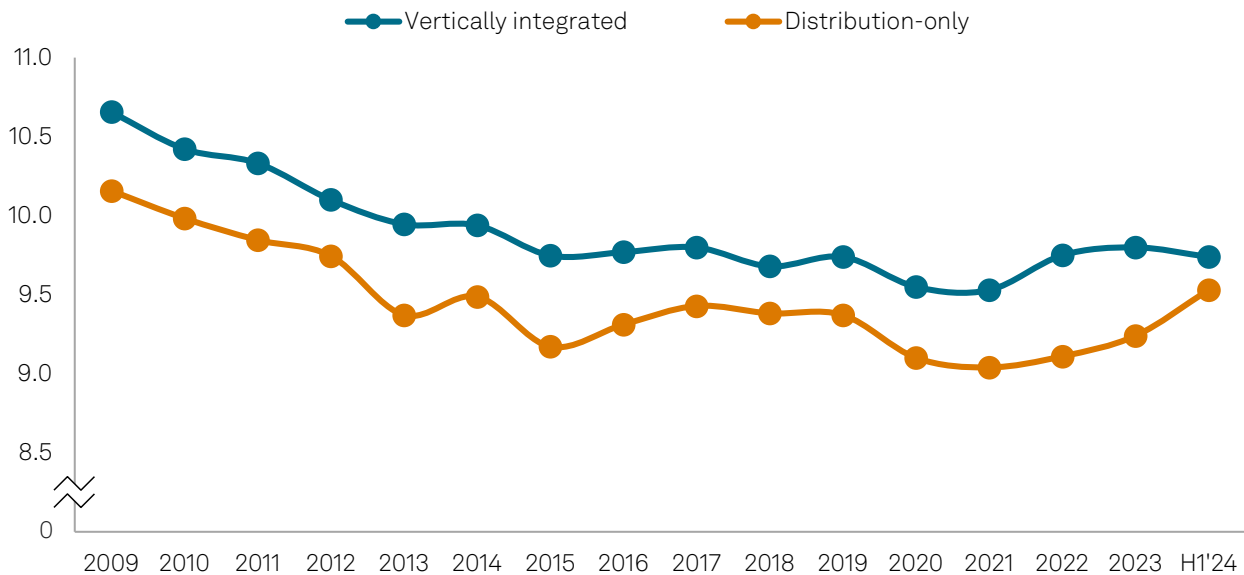
Thus far, the discussion has looked at broad trends in authorized ROEs; the following sections provide a more detailed view.

RRA has observed that there can be significant differences between average ROEs based on the types of proceedings/decisions in which these ROEs were established.

As a result of the electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for distribution operations.

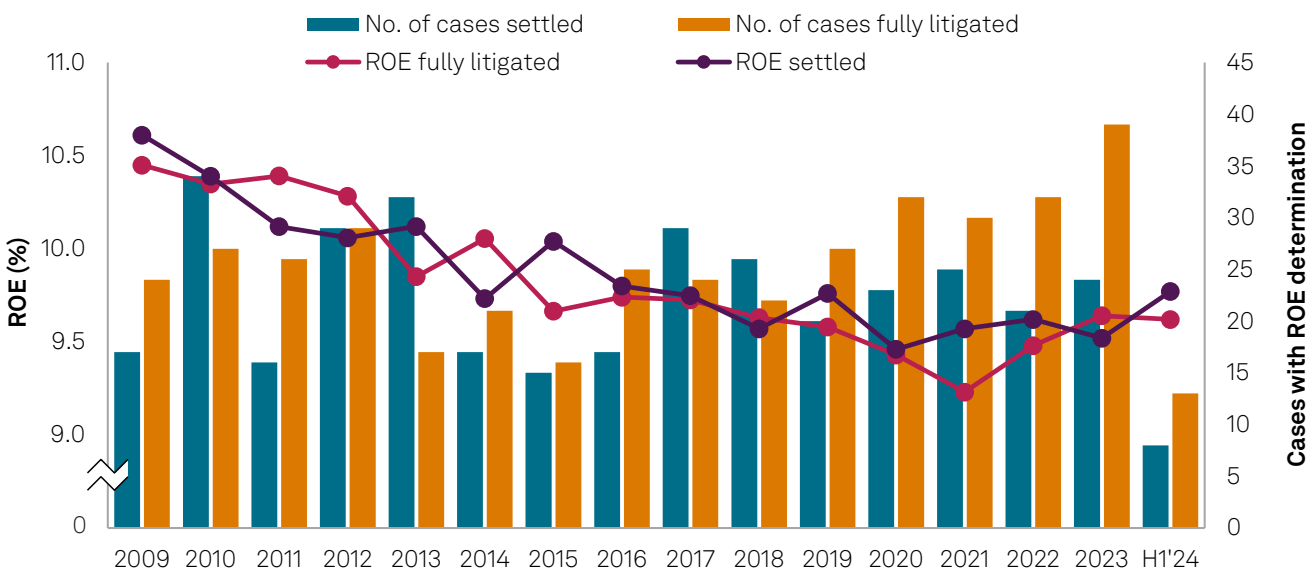
RRA finds that the annual average authorized ROEs in vertically integrated cases involving generation historically have been about 30-65 basis points higher than in distribution-only cases, arguably reflecting the increased risk associated with the ownership and operation of generation assets.

Average authorized electric ROEs (%)



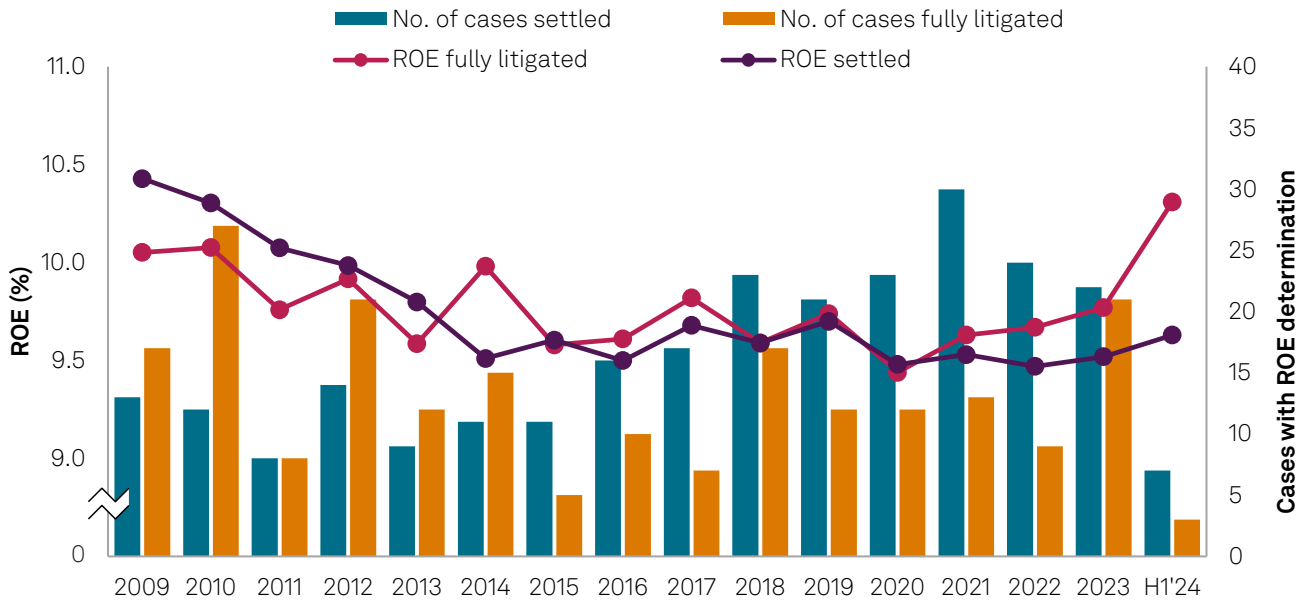
Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Average authorized electric ROEs: settled vs. fully litigated cases



Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Average authorized gas ROEs: settled vs. fully litigated cases



Data compiled July 23, 2024.
ROE = return on equity.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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The industry average ROE for vertically integrated electric utilities was 9.74% in cases decided in the first half of 2024 versus the 9.80% average in full year 2023. For electric distribution-only cases, the industry average ROE was 9.53% in January–June 2024 versus the 9.24% average in full year 2023.

Settlements have frequently been used to resolve rate cases over the last several years, and many are “black box” settlements that do not specify the ROE or other typical rate case parameters underlying the stipulated rate change. Some states, however, preclude this type of treatment, requiring settlements to specify these values, if not the specific adjustments from which these values were derived.

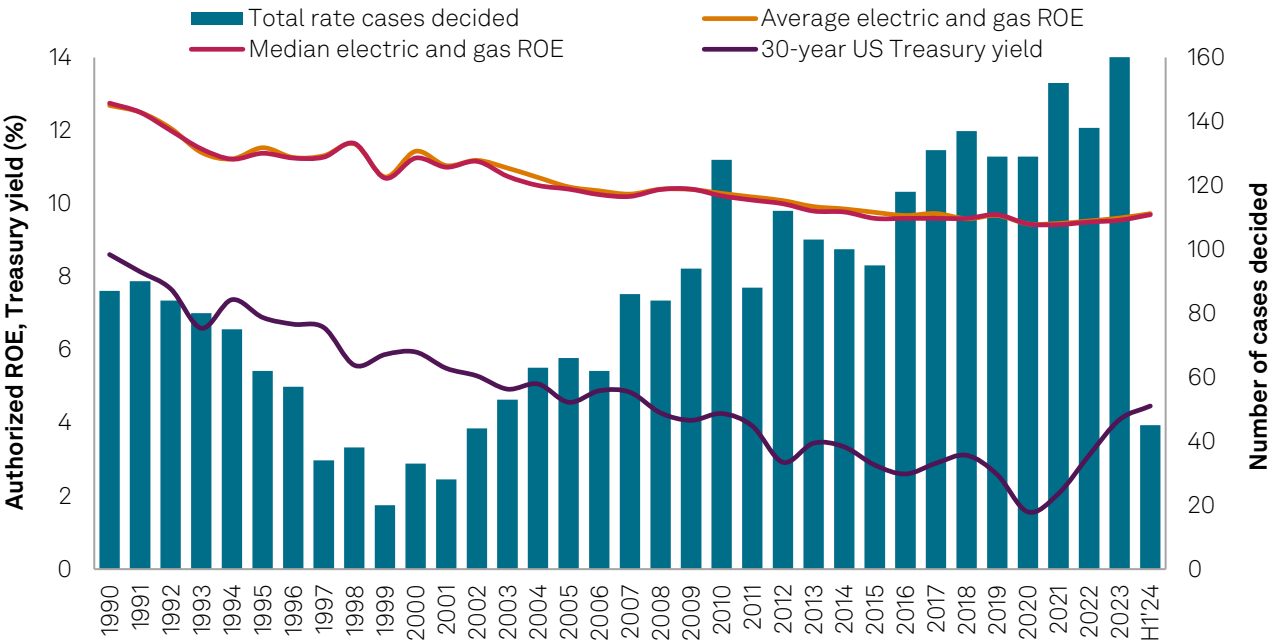
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, while in others, it was higher for settled cases.

The following discussion focuses on the corresponding tables available here.

Table 1 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and quarterly since 2019, followed by the number of observations in each period. **Table 2** indicates the composite electric and gas industry data for all major cases, summarized annually since 2004 and quarterly since 2021.

Tables 3 and 4 provide comparisons since 2009 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited-issue rider proceedings and vertically integrated cases versus delivery-only cases for electric and gas utilities, respectively.

Composite electric, gas average authorized ROEs; total number of rate cases



Data compiled July 23, 2024.

ROE = return on equity.

Sources: Regulatory Research Associates, a group within S&P Global Commodity Insights; US Treasury Department.

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The individual electric and gas cases decided in the first half of 2024 are listed in **Table 5**, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time the decisions were rendered. This study does not reflect fuel adjustment clause rate changes.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases decided during the specified time periods and are not necessarily representative of the average currently authorized ROEs for utilities industrywide or the returns earned by the utilities.

Table 6 and the graph above track the average and median equity return authorized for all electric and gas rate cases combined since 1990. As the table indicates, authorized ROEs have generally trended downward since 1990, reflecting the significant decline in interest rates and capital costs over this time frame.

Further Reading

[The rate case process: A conduit to enlightenment](#)

[Rate base: It's more complicated than it sounds](#)

[Frequently Asked Questions](#)

[Intro to Water Utilities — Current Trends and Growth Drivers](#)

[An Overview of FERC Regulation](#)

[FERC Regulatory Review](#)

[State Regulatory Evaluations — Energy](#)

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Contributors: Brian Collins, Jim Davis, Russell Ernst, Lillian Federico, Monica Hlinka, Jason Lehmann, Dan Lowrey

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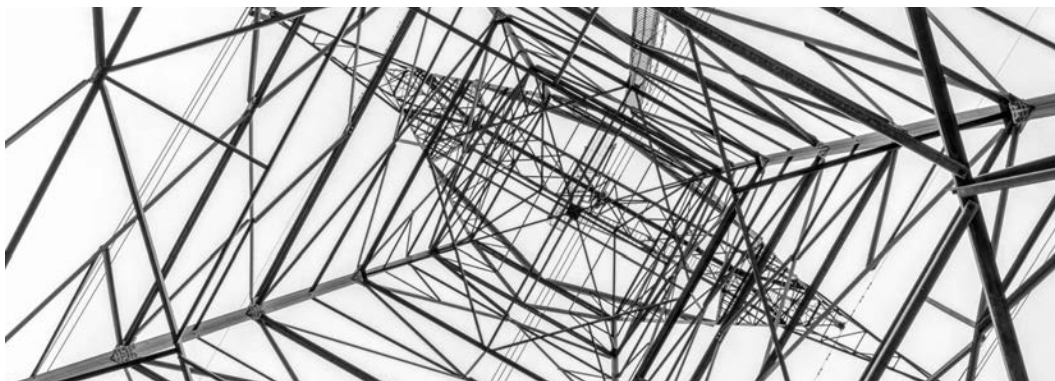
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North America Regulated Utilities

Capex and climate change pressures credit quality

January 14, 2025

This report does not constitute a rating action.



What's changed?

Lower ratings headroom. A high percentage of companies are operating with only minimal financial cushion from our downgrade threshold.

Rising capital spending, higher cash flow deficits, and increased wildfire risks led to downgrades outpacing upgrades for the fifth consecutive year.

Data centers spur electricity sales growth at about 1% annually, which will provide modest support to credit quality.

What are the key assumptions for 2025?

High cash flow deficits of about \$100 billion, which could harm financial performance if not funded in a credit-supportive manner.

Robust dividends of about \$50 billion for 2025 and at a dividend payout ratio of about 60%.

Record amount of hybrid securities. The industry issued \$26 billion of them in 2024, and we expect this trend will persist.

What are the key risks around the baseline?

Rising wildfire risks stemming from climate change.

Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability.

Common equity issuance is below our base-case expectations, and has been for the last several years, leading to weaker financial measures.

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Ratings Trends: North America Regulated Utilities

Chart 1
Ratings distribution

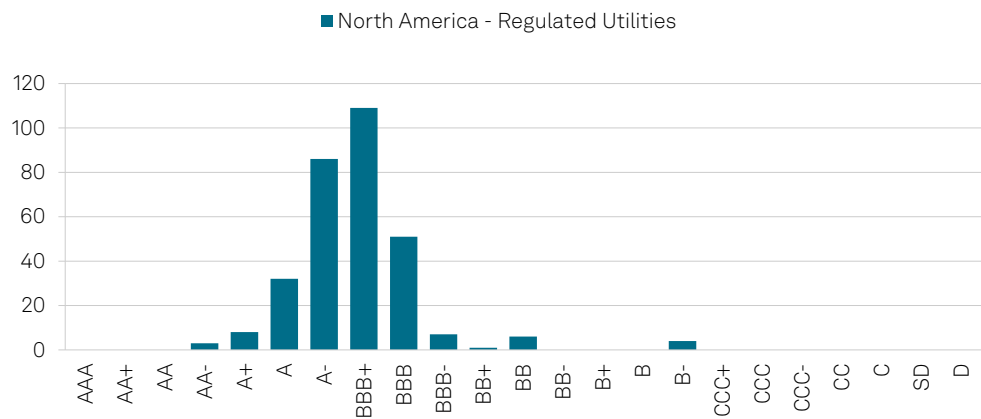


Chart 2
Ratings outlooks

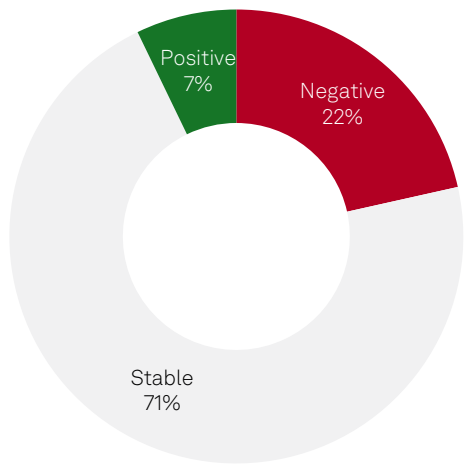
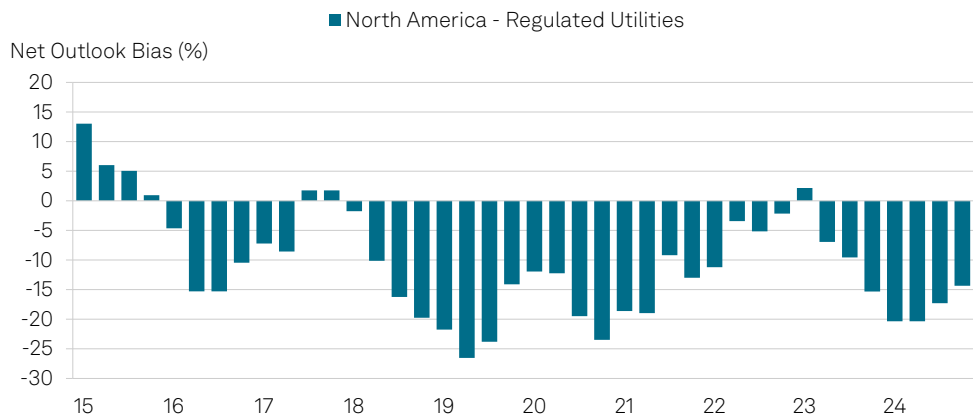


Chart 3
Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Credit Metrics:

North America Regulated Utilities

Chart 4
Debt / EBITDA (median, adjusted)

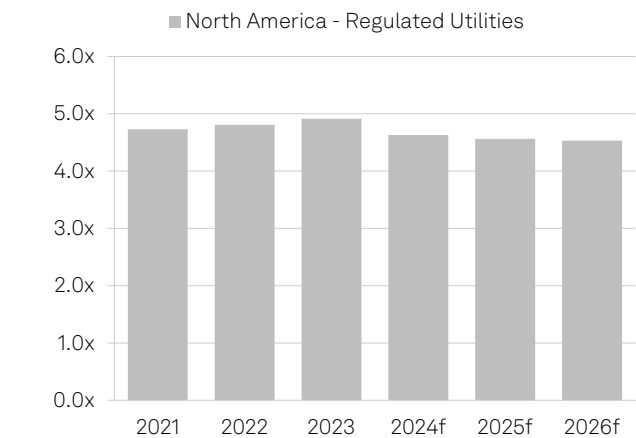


Chart 5
FFO / Debt (median, adjusted)

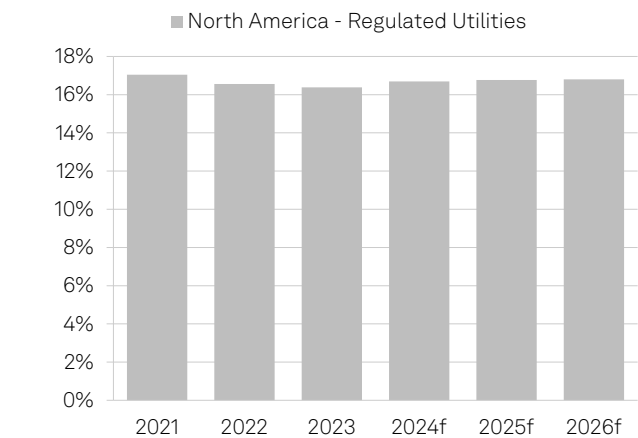


Chart 6
Cash flow and primary uses

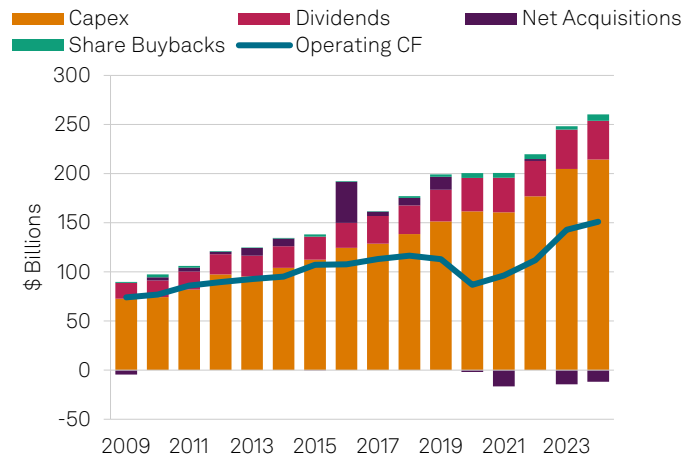
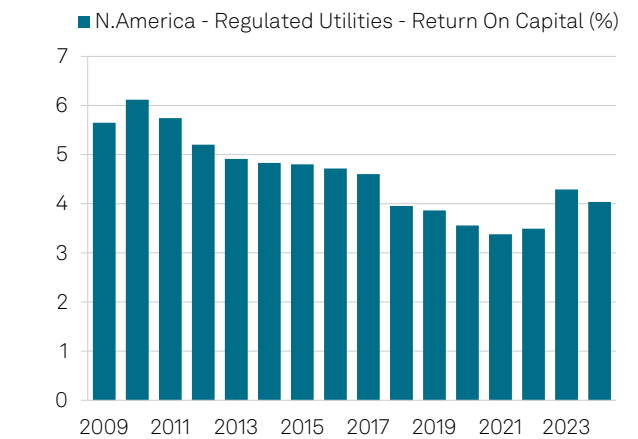


Chart 7
Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2024) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

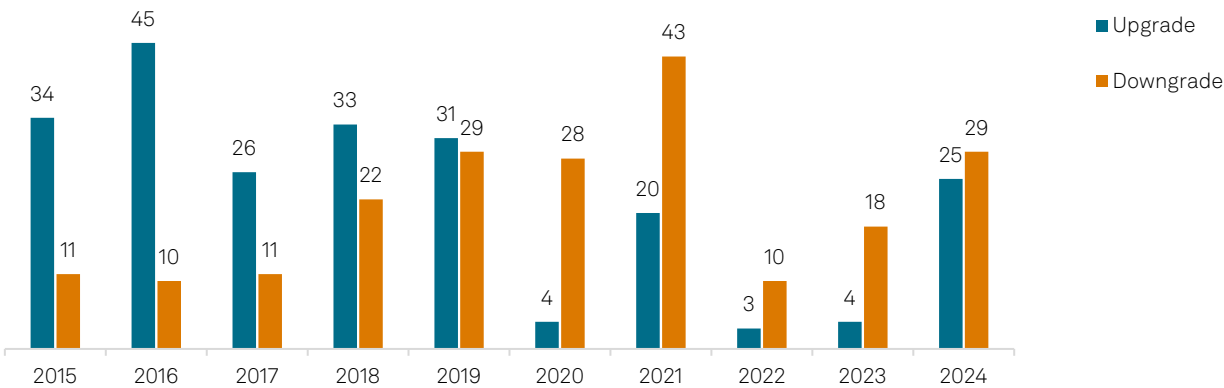
Industry Outlook

Ratings trends and outlook

In 2024, downgrades among North America’s investor-owned regulated utilities outpaced upgrades for the fifth consecutive year (see chart 8). Most were directly attributable to rising wildfire risks, robust capital spending, and challenging regulatory constructs. We expect these risks will persist for 2025, further pressuring the industry’s credit quality.

Chart 8

North America regulated utilities’ upgrades and downgrades



Source: S&P Global Ratings.

Main assumptions about 2025 and beyond

1. Record capital spending.

The industry is heavily investing in safety, reliability, energy transition, and data centers. We expect this spending will exceed \$300 billion before the end of the decade.

2. Management of regulatory risk.

This includes constructive rate case orders, minimizing regulatory lag, and earning the authorized return on equity (ROE).

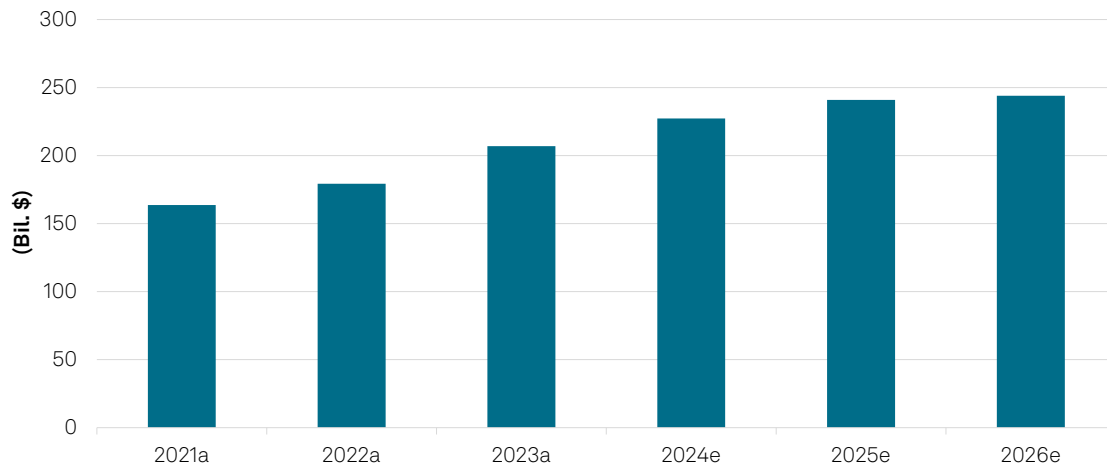
3. Climate change increases risks.

The growing frequency of devastating physical events, including hurricanes, storms, and wildfires, is elevating the industry’s credit risks.

Capital spending continues to break records. We expect capital spending for North America’s electric, gas, and water utilities will grow by a compound annual growth rate (CAGR) of about 10%. Accordingly, we expect 2025 capital spending to reflect about \$240 billion (see chart 9). To date, the industry’s capital spending has been primarily focused on safety, reliability, and energy transition.

Chart 9

North America regulated utilities' rising capital expenditures

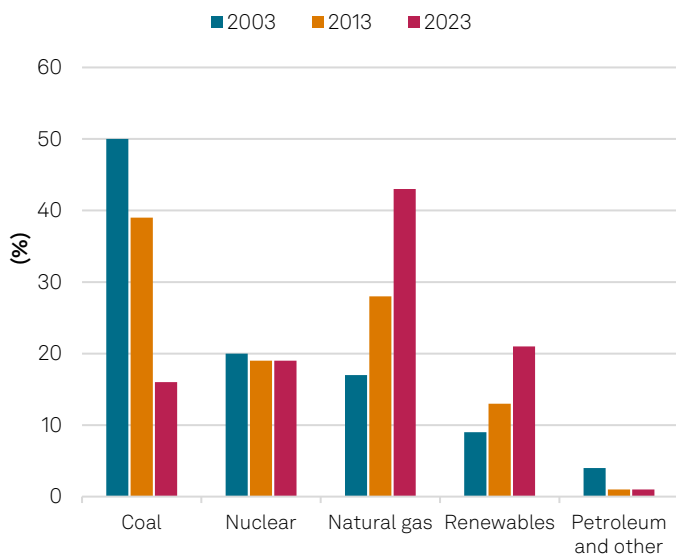


a—Actual. e—Estimate. Capital expenditures represent North American investor-owned electric gas, and water utilities.
Source: S&P Global Ratings.

Energy transition remains key. Over the past decade the industry has invested billions on reducing its reliance on coal-fired generation by about 50% (see chart 10), and today, coal represents only about 15% of total electric generation. Most of the coal was replaced with natural gas, which has about half the carbon emissions. We expect the industry will replace most of its remaining coal-fired generation by about 2030 with renewables and batteries, further reducing its carbon and greenhouse gas (GHG) emissions. The industry has reduced its GHG emissions by nearly 30% over the past decade (see chart 11), and we expect it will reduce them by another 30% by 2035.

Chart 10

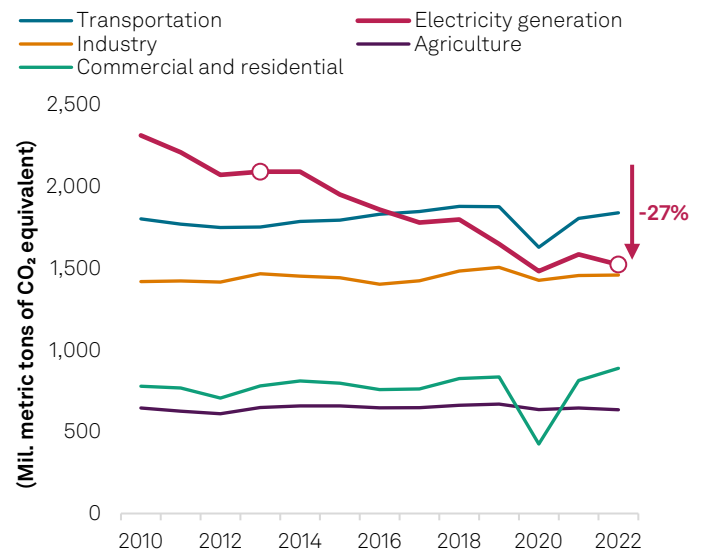
U.S. generation transformation



Source: U.S. Energy Information Administration.

Chart 11

GHG emissions by economic sector (2010-2022)

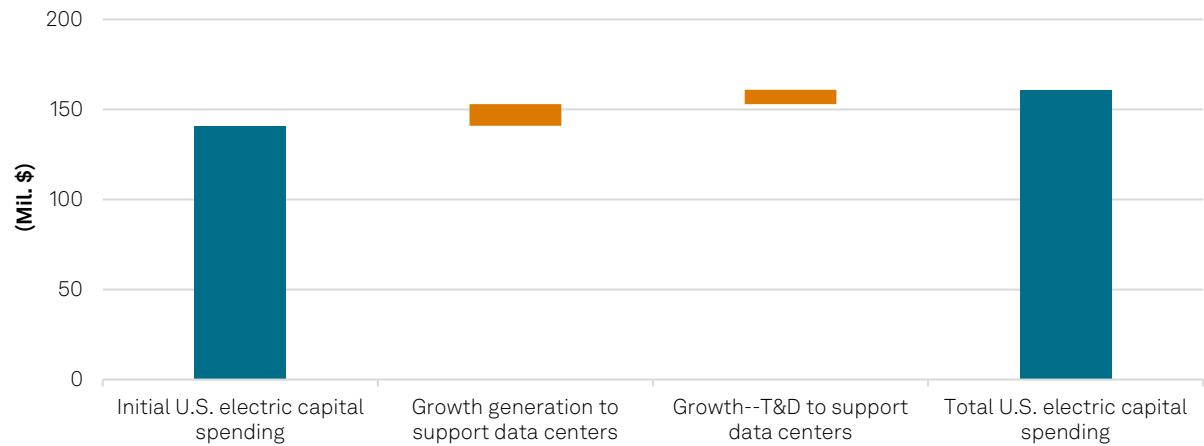


Source: U.S. Environmental Protection Agency.

Data center growth is relatively new, and our current base-case assumptions do not fully incorporate the incremental spending necessary for it. The higher spending for data centers is more likely to begin in 2026. Accordingly, 2026 capex could potentially increase by about another 15% above our current base case (see chart 12).

Chart 12

Data center growth will increase U.S. electric utility annual capital spending by about 15%

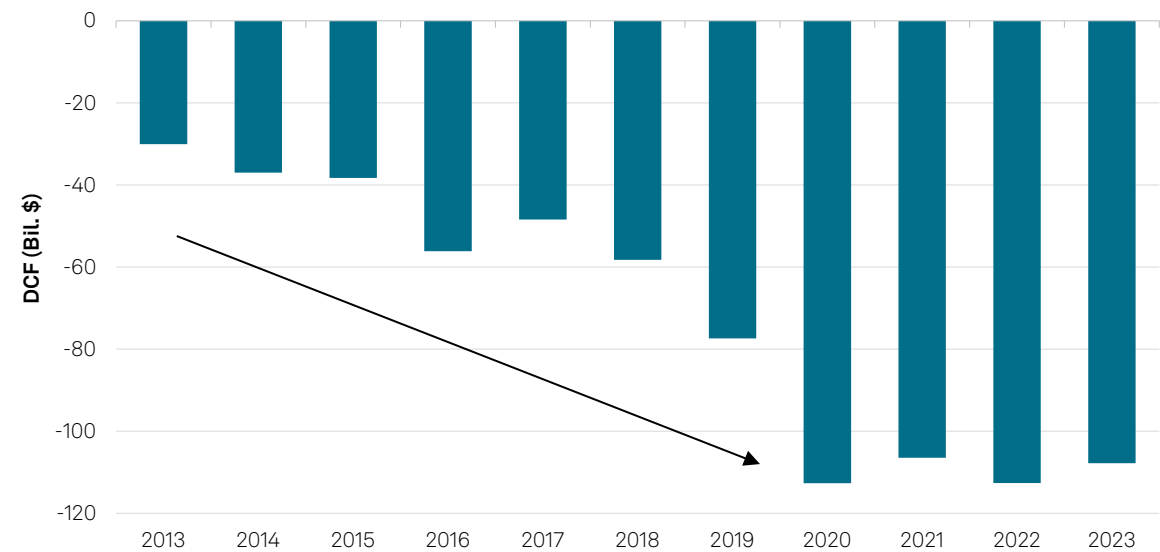


T&D—Transmission and distribution. Source: S&P Global Ratings.

Cash flow deficits will rise as a result, increasing the pressure on the industry’s credit quality. Over the past decade the industry’s cash flow deficits have grown from about \$50 billion to consistently over \$100 billion (see chart 13), and we expect this trend will continue.

Chart 13

North America regulated utilities’ cash flow deficits



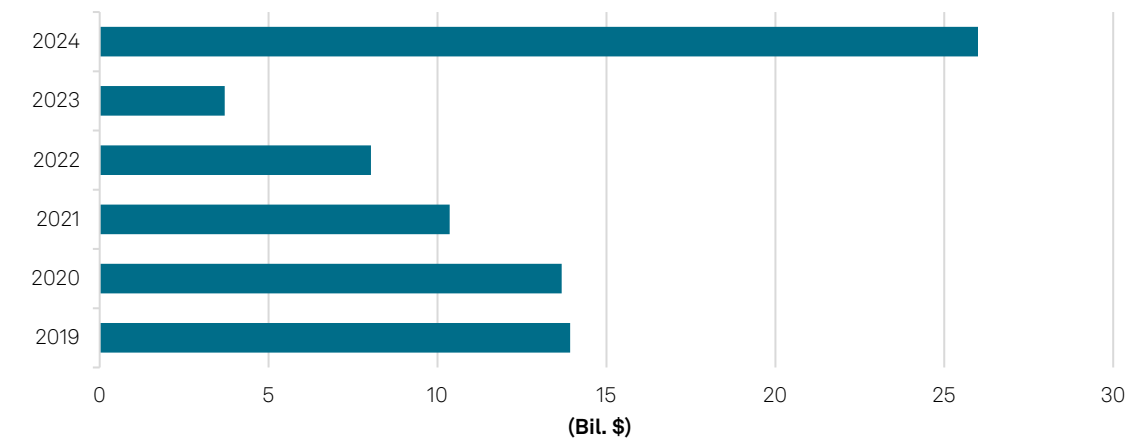
DCF—Discretionary cash flow. Sources: S&P Global Capital IQ, S&P Global Ratings.

Hybrid security issuance reached an all-time high of about \$26 billion in 2024, far exceeding the previous record of about \$14 billion in 2019 (see chart 14). We expect the industry will maintain this level of issuance in 2025 given its increased capital spending. This robust issuance supported the industry's 2024 financial measures because we typically assess hybrid securities as more

credit supportive than debt, with most of these securities having intermediate (50%) or high (100%) equity content.

Chart 14

North America regulated utilities’ annual hybrid securities issuance

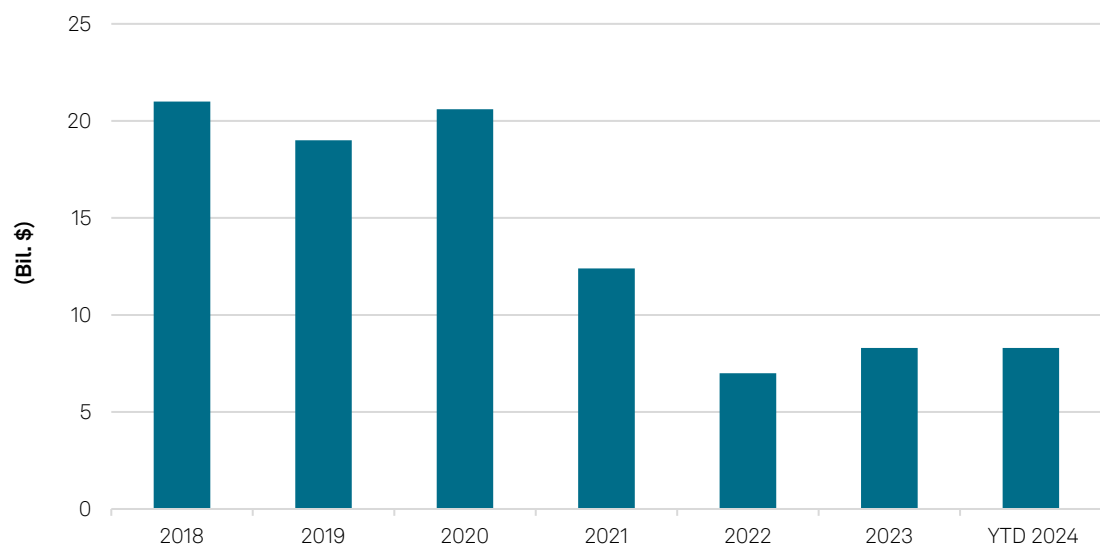


Sources: S&P Global Ratings, S&P Global Market Intelligence.

Common equity issuance has been weak and consistently below our expectations since 2021, pressuring the industry’s financial measures. It raised only about \$8 billion in 2024, and we estimate that the full year will reflect only about \$10 billion. This is well below the industry’s average run rate of about \$20 billion annually between 2018-2020 (see chart 15). We expect 2025 common equity issuance will again be relatively weak and more reflective of 2024 levels. Without significantly more common equity issuance, we expect the industry’s financial measures will continue to weaken, albeit gradually, supporting our negative outlook.

Chart 15

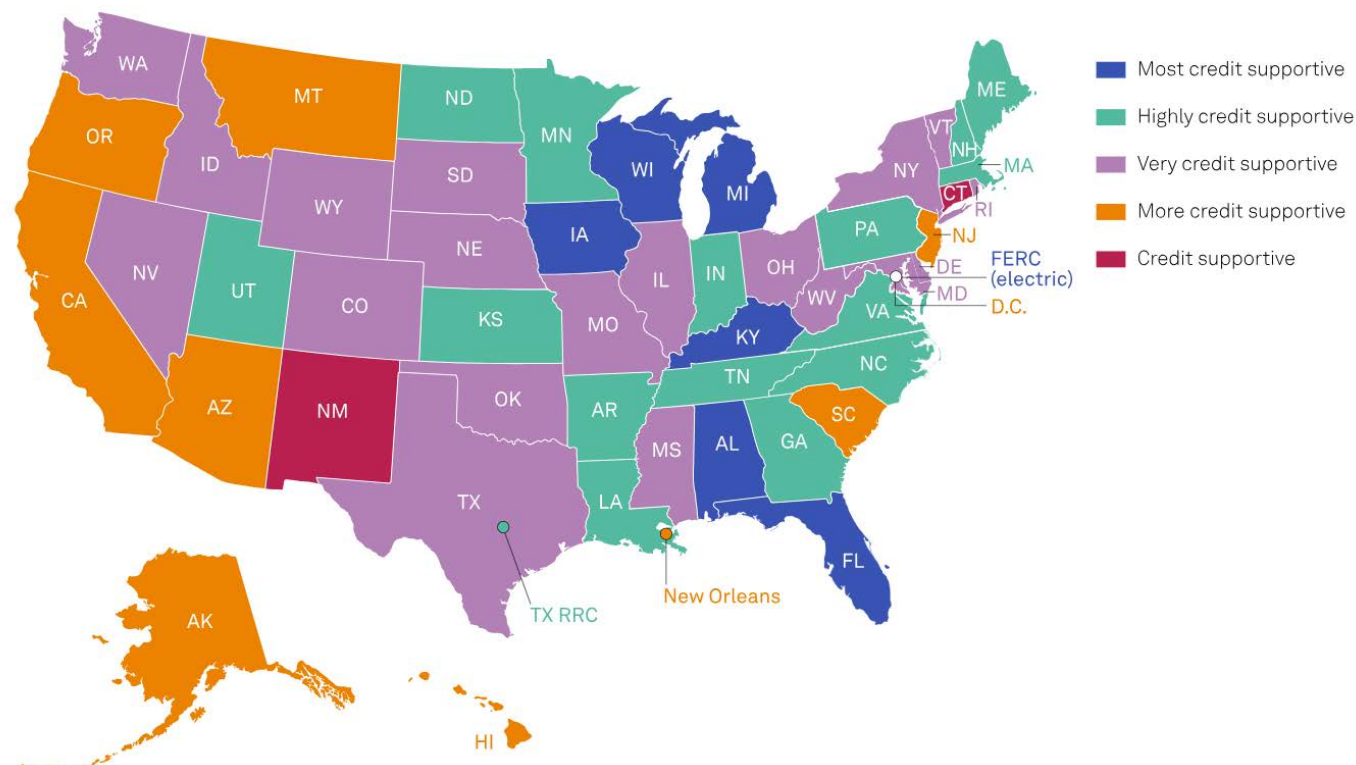
North America regulated utilities’ common equity issuance



YTD—Year-to-date as of Dec. 15, 2024. Sources: S&P Global Ratings, S&P Global Market Intelligence.

Effective management of regulatory risk will continue. We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates, capital trackers, formula rate plans, forward test years, multi-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag (that is, the timing difference between when a utility incurs costs and when it's recovered from ratepayers).

Regulatory assessment by state

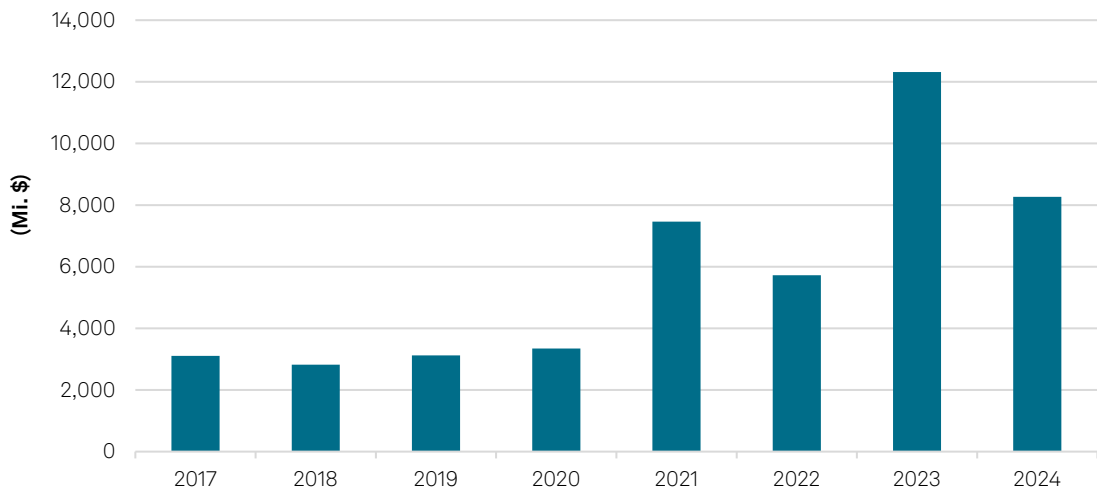


In general, we expect utilities will operate in a regulatory jurisdiction that is supportive of their credit quality by allowing for the full recovery of all their operating and capital costs in a timely manner. We also expect the regulatory jurisdiction will provide a consistent and predictable regulatory framework that results in cash flow stability. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

Regulatory rate case order increases have substantially risen over the past four years, reflecting the industry’s robust capital spending. Rate case increases for 2021-2024 have increased by more than 2.5x compared to 2017-2020 (see chart 17), and there are more than 100 U.S. rate cases pending, for which utilities are requesting over \$16 billion more in revenue. This is in line with our base case that this year’s rate case orders will again be robust and most likely in the top three years for rate case order increases.

Chart 17

U.S. rate case orders

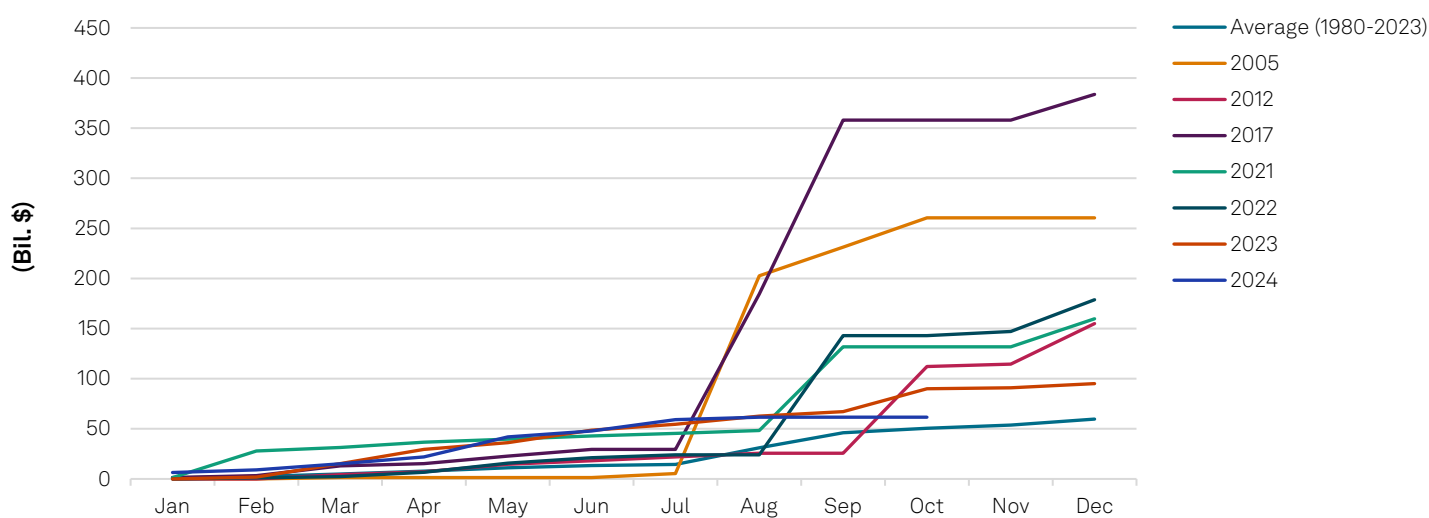


Source: S&P Global Commodity Insights.

Utilities' exposure to physical risks are increasing. According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the most destructive years for extreme weather events since 1980 (see chart 18). We assume these trends will persist, magnifying physical risks for the utility industry.

Chart 18

U.S. billion-dollar weather disaster year-to-date event cost (CPI-adjusted)



Source: National Ocean and Atmospheric Administration.

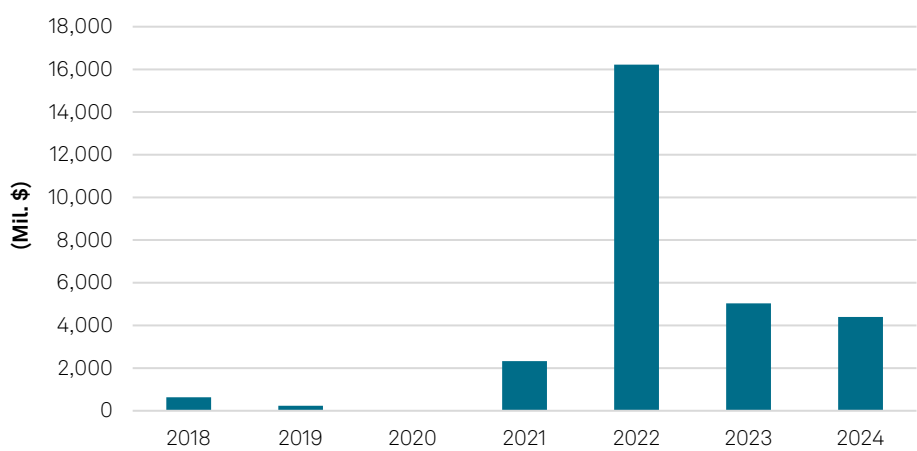
Drier, hotter weather has increased the acreage designated as high-fire-risk across the U.S. This is already taking a toll on credit ratings. For example, in 2024 we downgraded parent Xcel Energy Inc. and subsidiary Southwestern Public Service Co. (SPS) because of the scale and severity of the wildfires in the Texas panhandle, which highlights their increasing wildfire exposure. Overall, because of climate change, we expect the industry’s wildfire risk will increase.

Securitization increased, which we assess as supportive of credit quality (see chart 19).

Securitization allows for the issuance of debt secured by a non-bypassable charge to the customer's bill, allowing the utility to fully recover storm-related costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger credit measures.

Chart 19

S&P Global Ratings-rated utility-related securitization issuance (2018-2024)



Source: S&P Global Ratings.

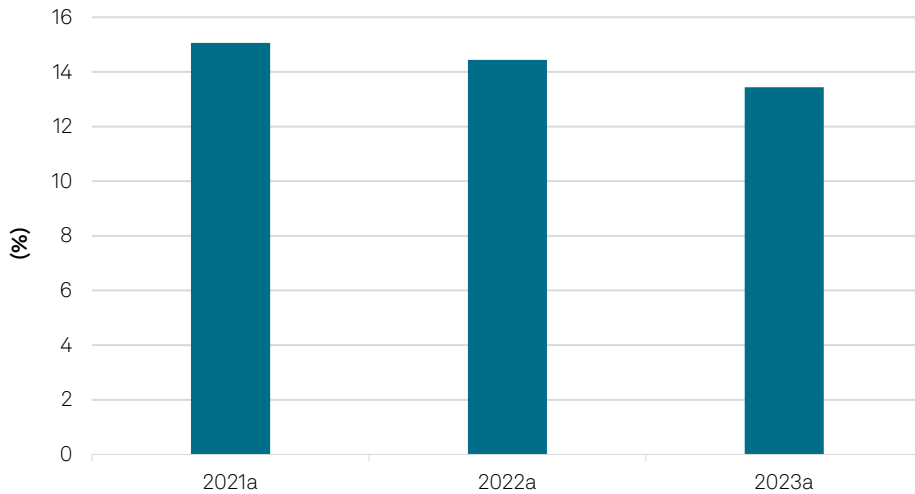
We expect securitization will remain an effective tool that the industry will continue to use. Our base case includes increasing severe natural disasters and weather events as well as continued efforts to decarbonize the energy sector, which sometimes requires securitization to fully recover under-depreciated retiring fossil-fuel generating plants.

Credit metrics and financial policy

We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured.

Chart 20

North American regulated utilities' average FFO to debt



a—Actual. Source: S&P Global Ratings.

Key risks or opportunities around the baseline

1. Wildfire mitigation efforts.

Wildfire risk mitigation, while clearly a credit positive, may not fully address the threats associated with extreme weather events.

2. Data centers and sales growth.

Data center electricity demand will likely boost revenues at North American investor-owned regulated utilities and provide modest support for the industry's credit quality.

3. Managing the customer bill.

The average electric customer bill is about 2% of U.S. median household income, which represents good value for customers relative to other typical household bills. Preserving this value is critical for the industry to maintain credit quality.

Wildfire risk has expanded. Recent events in the Northeast U.S. lead us to believe wildfire risk has spread and now potentially affects nearly every utility across North America. (About 15 years ago, it was primarily limited to just Southern California.)

Wildfire risk is highly negative for credit quality. The scale of potential liabilities, unpredictable nature of exposures, and frequency of events have materially increased wildfire risk for many utility stakeholders. From a credit standpoint, litigation risk is more problematic than risk of damage to infrastructure because it is difficult to predict or quantify and is so far without sufficient mitigation or containment. Also, wildfire-related litigation payments are typically not recoverable in rates or through other regulatory mechanisms, making them more problematic than physical risk.

Additional wildfire risks to credit quality include:

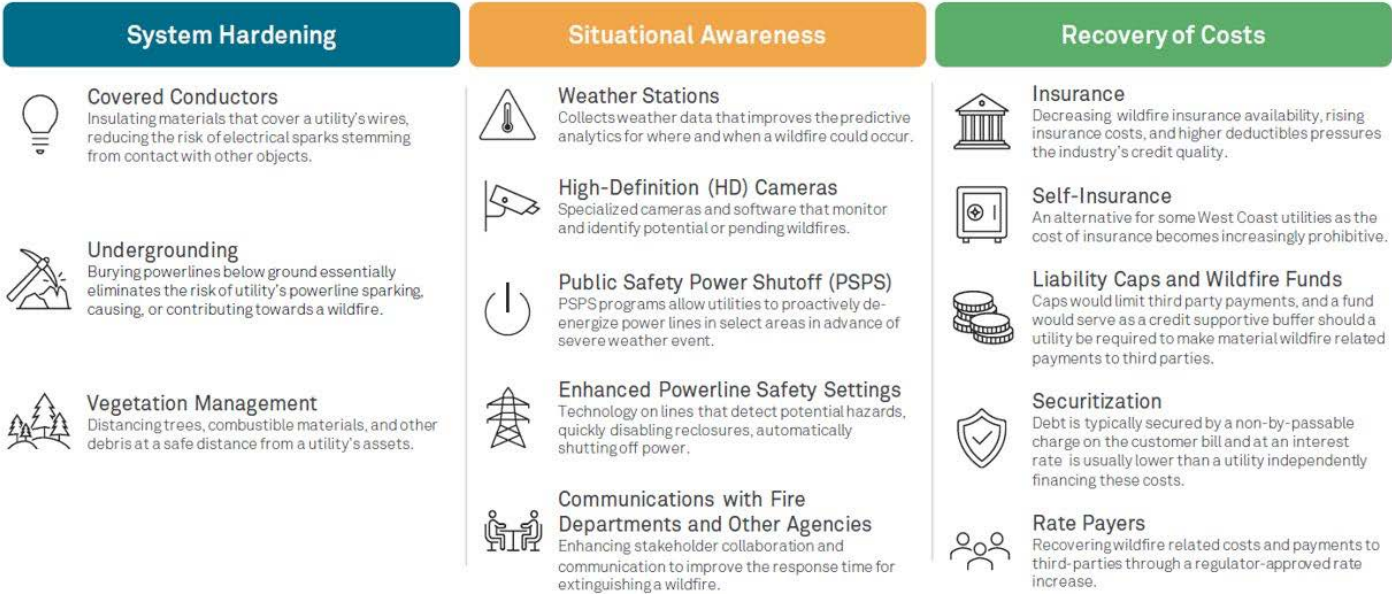
- Insurance is becoming more expensive and less available.
- It only requires a relatively small percentage of damaged or destroyed structures from a wildfire to have a material negative effect on a utility's credit quality.

- The utility industry’s relatively high leveraged balance sheets and modest authorized ROEs are not a backstop for wildfire risk.
- Utilities that are impacted by a catastrophic wildfire and material third-party claims typically cannot implement other strategic initiatives.

Mitigation strategies. We expect the industry will develop plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery from wildfires. We believe the industry will be able to implement much of these strategies over the nearer term because most are not predicated on the development of new technologies or products. That said, because the industry operates in many different service territories and topographies, we expect each utility’s mitigation plan will be customized to its unique exposure. Chart 21 represents an array of wildfire mitigation strategies that either have or are being implemented by many utilities across North America.

Chart 21

North American regulated utilities’ wildfire mitigation efforts



Source: S&P Global Ratings.

Data centers will likely deliver a return to electricity sales growth. We expect electricity sales will increase at a CAGR of about 1.1%. This reflects our view that systematic and careful planning across the investor-owned utility sector will likely limit its realistic capability to grow at a substantially faster pace. In general, the expansion of utility infrastructure assets is a long-term planning process that requires permitting, siting, and regulatory approvals.

However, even a 1% CAGR for electricity sales will likely prove transformative for the utility industry, which has experienced flat sales growth over the past two decades. In particular, the growing number of data centers will allow the industry to spread its fixed costs over a wider base. We anticipate this will provide some cushion for the industry to effectively manage regulatory risk and maintain credit quality without necessarily requiring that every rate case order is highly supportive of credit quality.

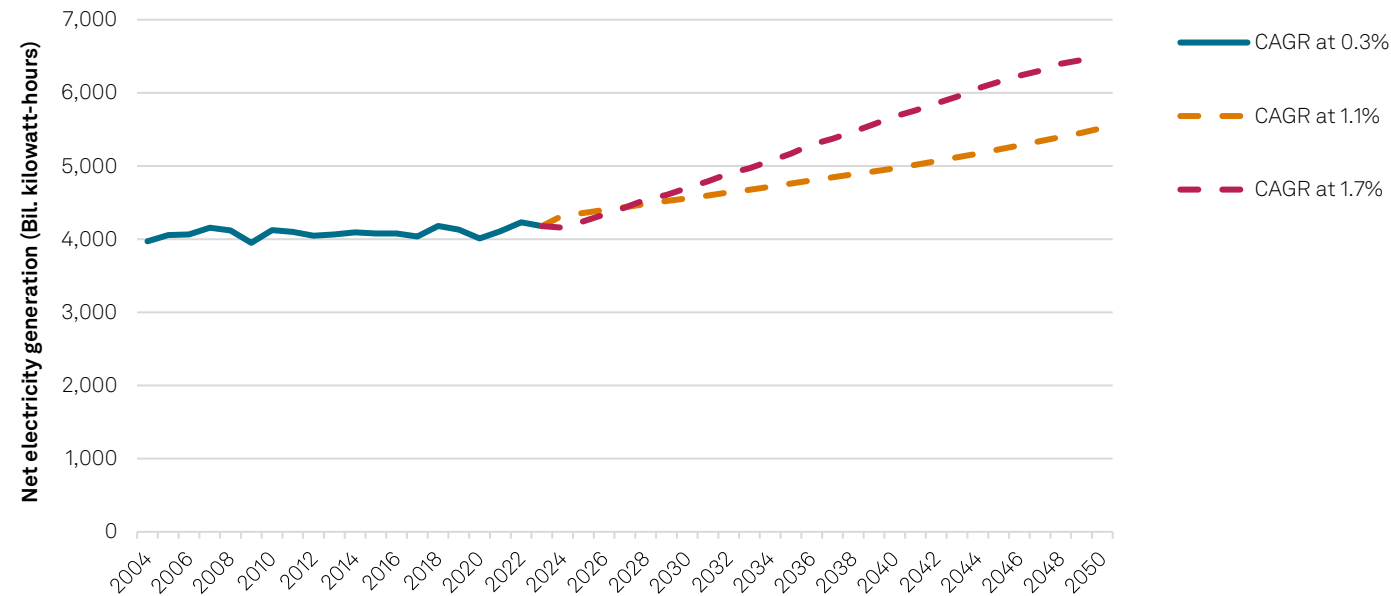
We also expect electric utilities' sales CAGR will be maintained over the longer term (see chart 22), which will support the industry's long-term credit quality. We expect growth in data center numbers will support most of the industry's growth through 2030. In the following decade,

increased onshoring of manufacturing and wider spread adoption of electric vehicles will also support growth.

Chart 22

Growth will be transformative for utilities used to stagnation

Electricity demand: U.S. regulated electric utilities



Data as of June 2024. CAGR—Compound annual growth rate. Sources: U.S. Energy Information Administration (historical and 1.1% CAGR) and S&P Global Commodity Insights (1.7% CAGR).

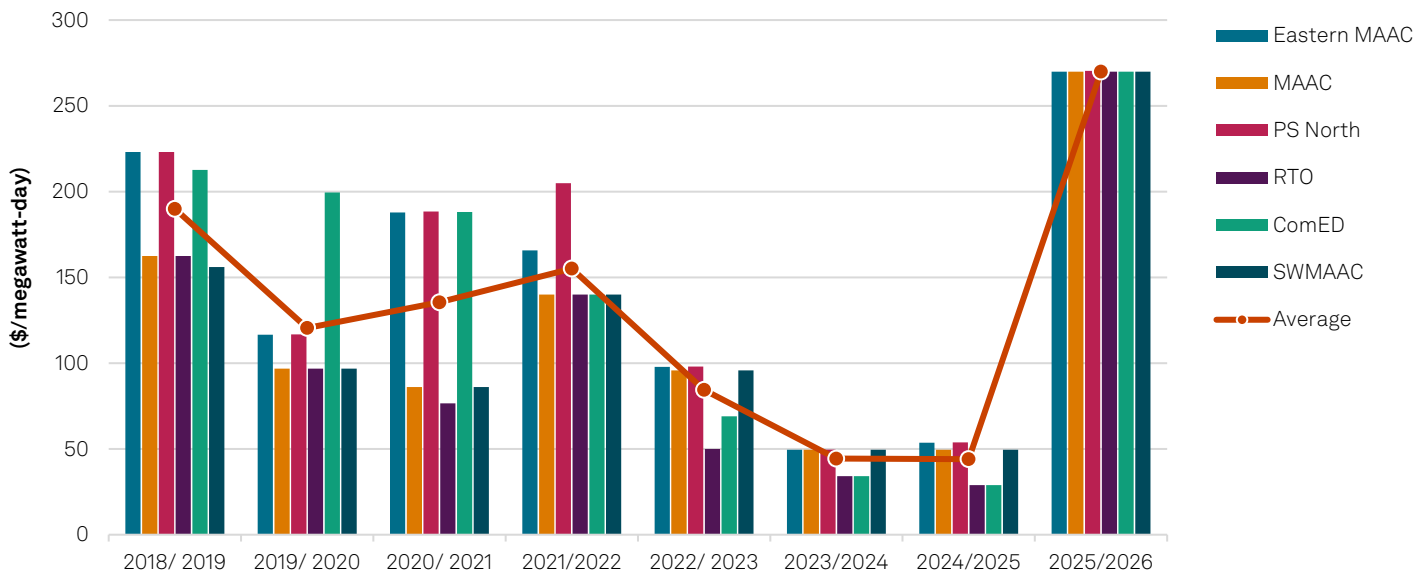
Data center credit risks. The industry must structure rates and contracts to ensure that the new data center customers are paying their share of electricity costs. Meeting the demands of relatively few, but very large, data center customers will require significant capital spending and infrastructure investments. If utilities assign a significant portion of data center-related infrastructure costs to existing residential customers, customer bills would increase. This, in turn, pressures regulators to limit rate case increases, which can negatively affect the industry's ability to effectively manage regulatory risk.

Therefore, we expect the increased capital spending needed to accommodate data center growth will be primarily recovered from data center customers over decades. Such a plan comes with risks. For example, a technological breakthrough that reduces or eliminates the need for data centers could shift the recovery of these long-term infrastructure investments onto residential customers.

Capacity prices. Pennsylvania-New Jersey-Maryland (PJM) Interconnection capacity prices materially increased during its latest capacity auction (see chart 23). These higher prices are directly passed onto customers, significantly increasing the electric utility bill. If these higher prices persist, it will likely result in higher customer complaints, pressuring regulators to limit increases to other areas of the customer bill that could potentially pressure a utility's ability to effectively manage regulatory risk.

Chart 23

PJM capacity auction results



Source: PJM website.

U.S. Environmental Protection Agency (EPA). In 2024 the EPA released final rules aimed at reducing pollution from fossil fuel-fired power plants, which included carbon pollution standards and effluent limitation guidelines and standards for coal-fired power plants. These rules would have increased costs for utilities, specifically regarding the requirement to install carbon capture and sequestration or storage technology on coal-fired power plants intending to operate beyond 2039.

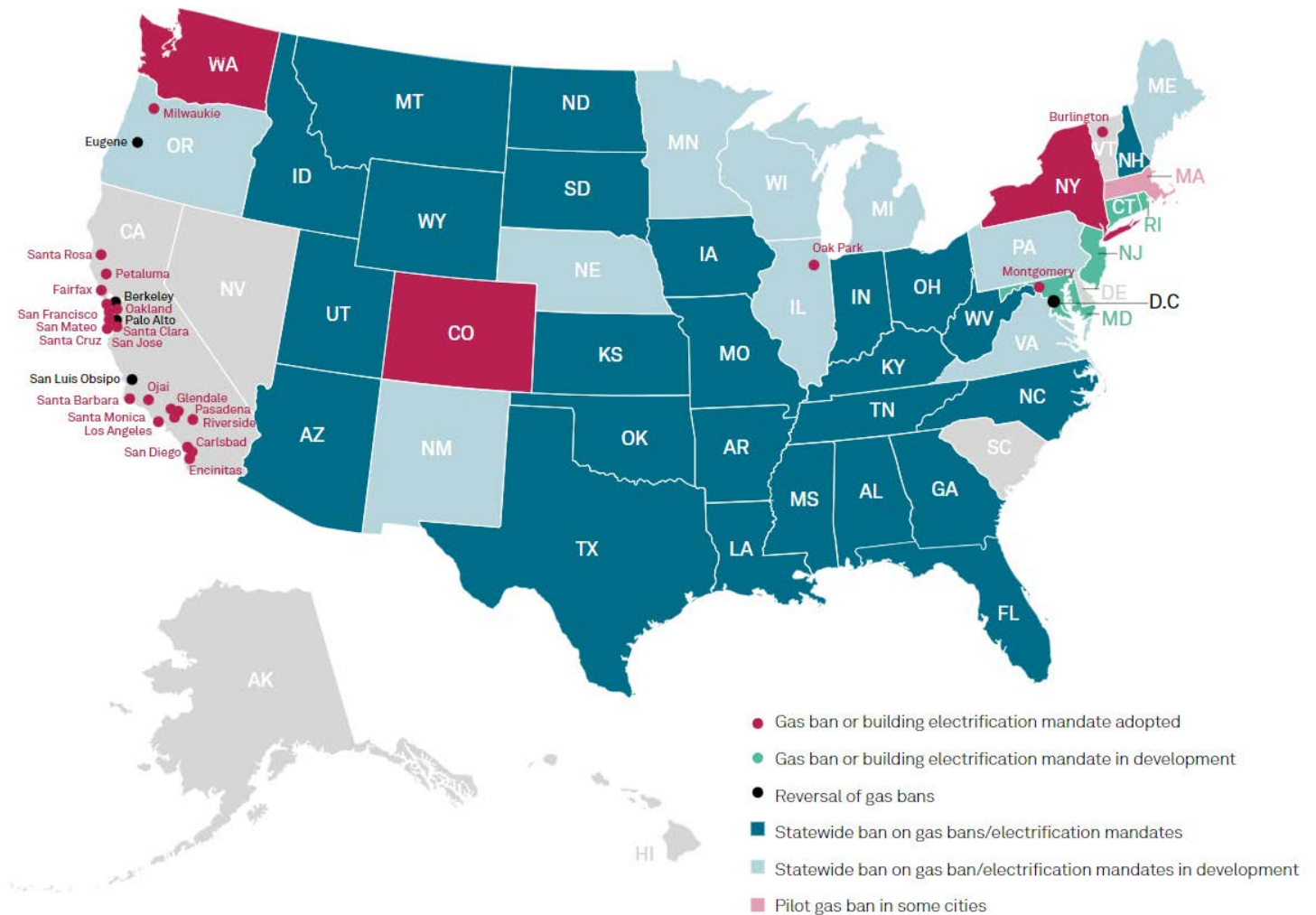
However, we note that the incoming U.S. presidential administration and Republican majority in congress could modify or eliminate these rules. We will monitor executive, legislative, or legal actions that could impact the industry’s credit quality.

Full electrification. We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that operate in warmer climates or whose cities or states have banned new gas connections, severely limiting the growth of natural gas LDCs (see chart 24). We expect this trend will also gradually persist through the passage of local city and town building codes that limit carbon and other emissions.

Offsetting some of this risk is that a majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 24

Gas bans and electrification mandates



Data as of April 26, 2024. *Municipalities shown on map are a subset of municipalities in the U.S. that have gas ban policies or electric reach codes in place. §Colorado and Burlington mandates target emissions requirements set out in respective laws or regulations. Source: S&P Global Commodity Insights.

Cybersecurity. While cybersecurity breaches against infrastructure assets have been relatively low, we believe the threat of cyberattacks remains high. The 2024 cybersecurity breach against American Water Works Co. Inc. underscores the risks. But the sector has heavily invested to limit this risk. We believe the sector's ongoing vigilance in this area is critical to maintaining credit quality.

Related Research

- [Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions](#), Nov. 6, 2024
- [Data Centers: Rapid Growth Creates Opportunities And Issues](#), Oct. 30, 2024
- [Evolving Risks In North American Corporate Ratings: Climate Change](#), Oct. 29, 2024
- [Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand](#), Oct. 22, 2024
- [Energy Transition: U.S. Investor-Owned Regulated Electric Utilities Face Hurdles With The EPA's Finalized Rules For Fossil-Fueled Power Plants](#), Oct. 17, 2024
- [North American Utility Regulatory Jurisdictions Update: Some Notable Developments](#), Sept. 24, 2024

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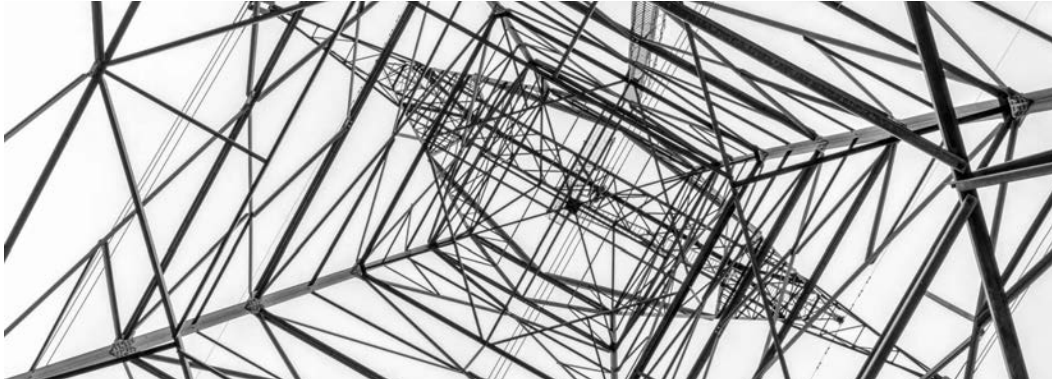
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North America Regulated Utilities

Credit quality remains pressured

January 9, 2024

This report does not constitute a rating action.



What's changed?

Expansion of wildfire risks across Western North America.

Common equity issuance was significantly below our base case expectations.

Credit quality erosion. For the fourth consecutive year, downgrades outpaced upgrades. It is conceivable that 2024 may be the fifth.

What are the key assumptions for 2024?

High capital spending for North America's investor-owned regulated electric, gas, and water utilities.

Robust dividends at about \$45 billion, reflecting a dividend payout ratio of about 60%.

Consistent access to the capital markets is necessary for the industry to fund its debt maturities and cash flow deficits.

What are the key risks around the baseline?

Timely recovery of prudently spent capital and operation and maintenance (O&M) costs is necessary for the industry to maintain credit quality.

Minimal financial cushion. About 35% of the industry is operating with limited ability to absorb unexpected events beyond their base case.

Inflation. S&P Global's economists expect the consumer price index (CPI) to decrease to below 3% by year-end 2024.

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Ratings Trends: North America Regulated Utilities

Chart 1
Ratings distribution

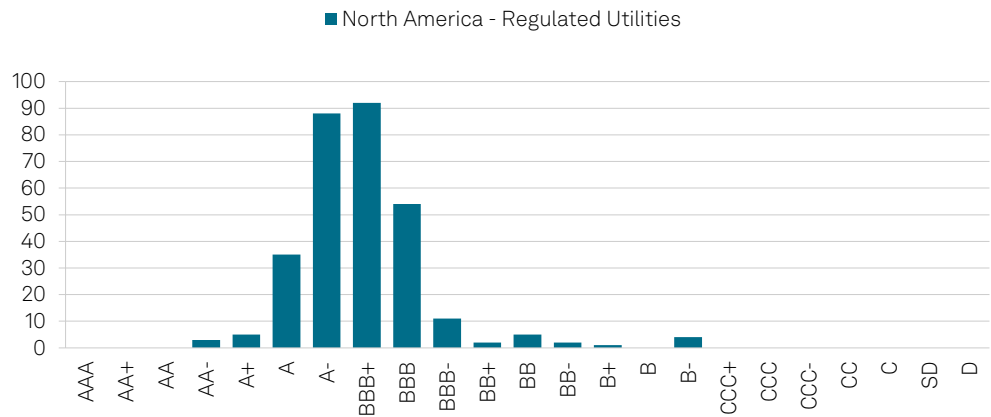


Chart 2
Ratings outlooks

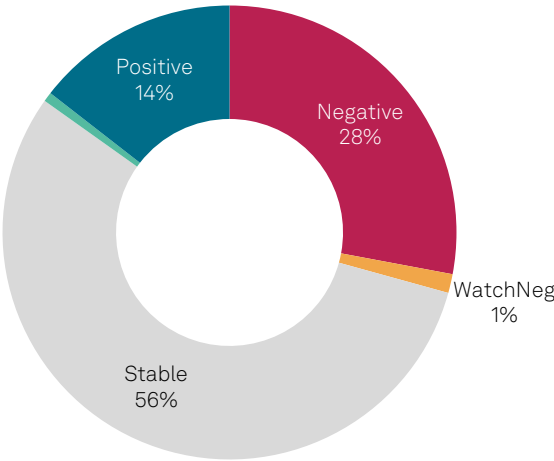
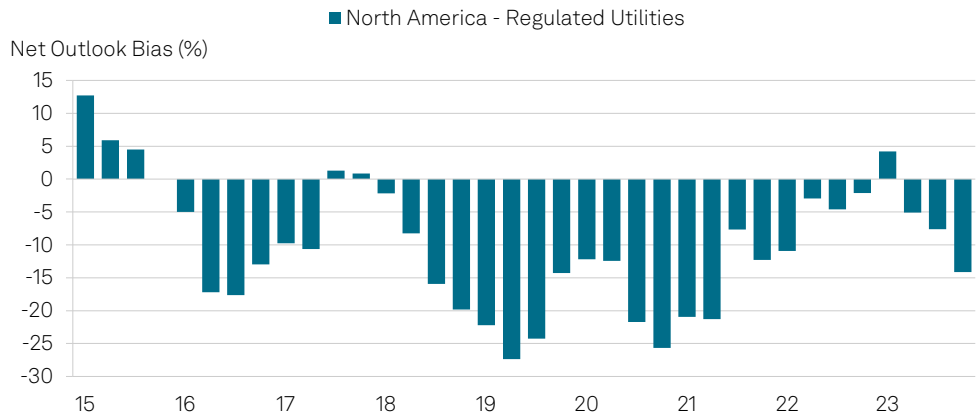


Chart 3
Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Credit Metrics: North America Regulated Utilities

Chart 4
Debt / EBITDA (median, adjusted)

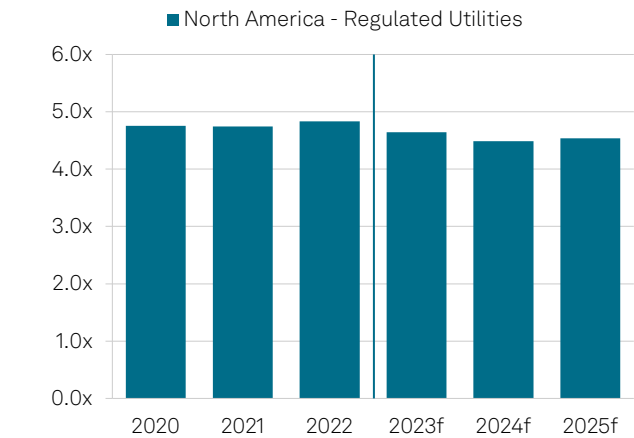


Chart 5
FFO / Debt (median, adjusted)

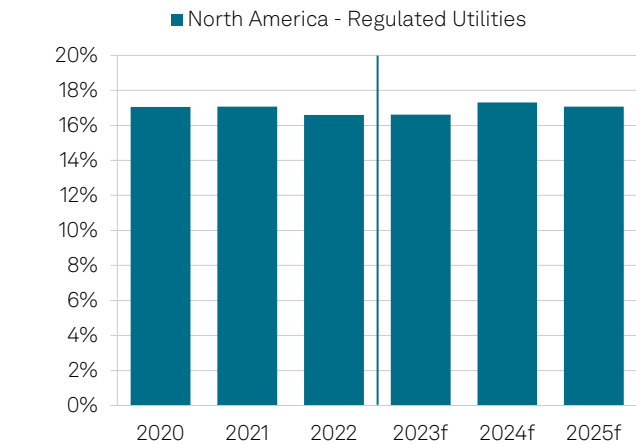


Chart 6
Cash flow and primary uses

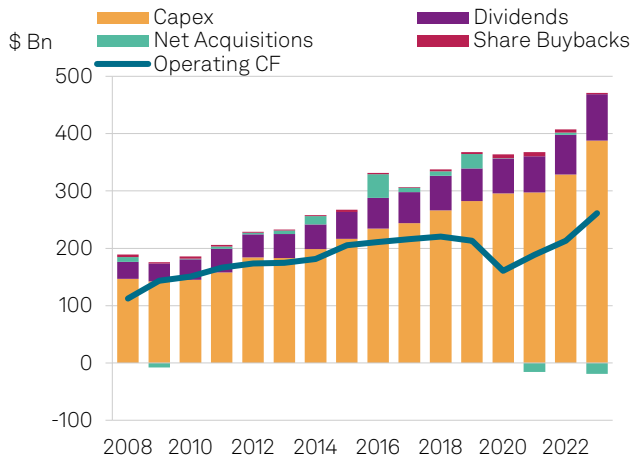
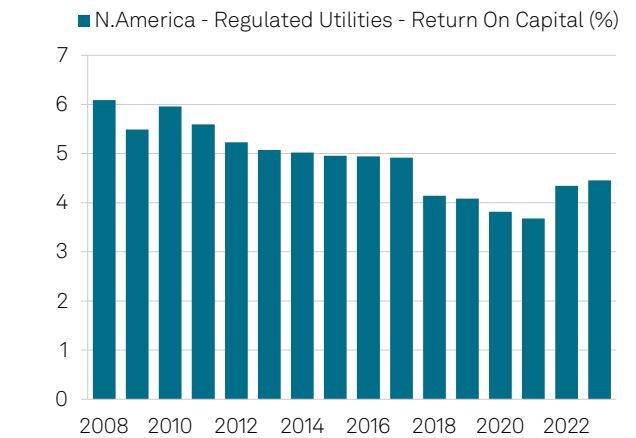


Chart 7
Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2023) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

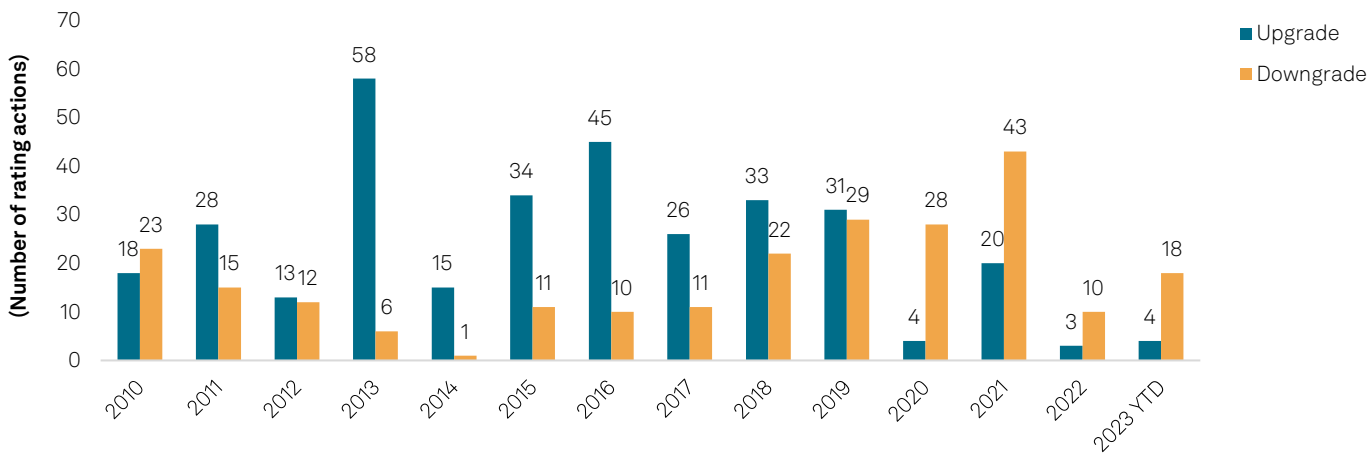
Industry Outlook

Ratings trends and outlook

For the fourth consecutive year downgrades significantly outpaced upgrades by more than 3:1 (see chart 8). Most of the 2023 downgrades were directly attributable to rising physical risks and rising leverage because of robust capital spending. We expect 2024 will remain challenging for the industry's credit quality, given the relatively high percentage of negative outlooks.

Chart 8

North America regulated utilities upgrades and downgrades



YTD—Year to date. Data as of Dec. 12, 2023. Source: S&P Global Ratings.

Main assumptions about 2024 and beyond

1. Climate change

Climate change is increasing the frequency of extreme and devastating hurricanes, storms, and wildfires, which is heightening credit risks for North America's investor-owned utilities (IOUs).

2. Record capital spending

While the industry's robust capital spending is necessary for prudent investments in safety, reliability, and energy transition, it is directly leading to high cash flow deficits. If these deficits are not funded with debt and equity in a balanced manner, credit quality will likely weaken.

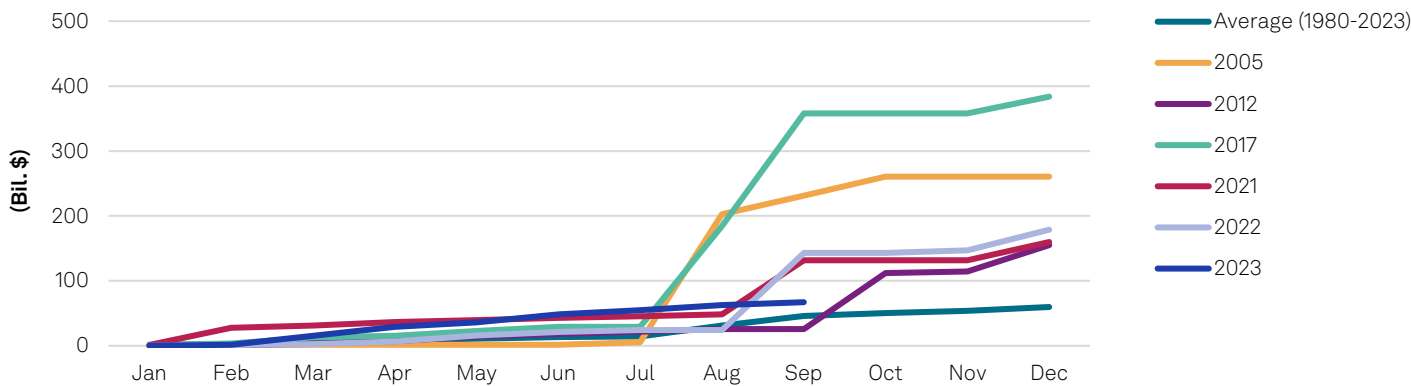
3. Management of regulatory risk

Given the significant capital spending, effective management of regulatory risk is important for the industry's credit quality. This includes constructive rate case orders, minimizing regulatory lag, earning its authorized return on equity, and managing the customer bill impact.

Utilities' exposure to physical risks is increasing. According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the top five most destructive years for extreme weather events since 1980 (see chart 9). Our base case assumes these trends will persist, magnifying physical risks for the utility industry.

Chart 9

U.S. billion dollar weather disaster year-to-date event cost (CPI-adjusted)



Source: National Ocean and Atmospheric Administration.

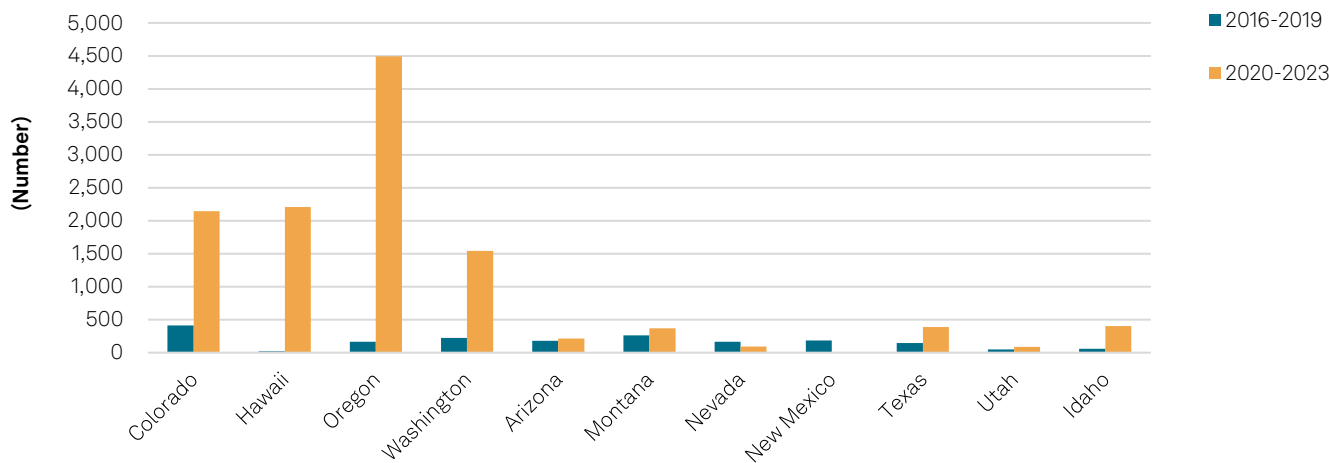
Warmer temperatures increase the humidity, leading to stronger winds and more-devastating tropical storms and hurricanes. Also, drier and hotter weather is a primary cause for more-severe wildfires--as temperatures rise, the vegetation dries up and the landscape becomes more combustible. When high winds are added, the probability of a catastrophic wildfire significantly escalates. As such, areas designated as high-fire-risk have grown across the U.S. This is already taking a toll on credit ratings.

For example, during 2023 we lowered the ratings on Hawaiian Electric Industries Inc. by multiple notches after the most destructive wildfire in Hawaii's history, with nearly 100 fatalities and about 2,200 structures damaged or destroyed. Also during 2023, an Oregon jury awarded 17 plaintiffs in a 2020 wildfire-related class action lawsuit against PacifiCorp about \$5.3 million per plaintiff, which was materially above our base case of about \$1 million per structure. The jury also found that a broader absent class affected by the fires could bring claims against the company. Accordingly, we downgraded PacifiCorp by two notches and revised the outlook to negative.

Furthermore, since 2020 the number of structures destroyed by wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas increased by more than 100% compared to the 2016-2019 period (see chart 10). Meanwhile, Arizona, Montana, and Utah have each experienced increases of at least 20% over the same timeframe.

Chart 10

Structures destroyed by wildfires



Source: Headwaters Economics and National Fire and Aviation Management FAMWEB.

Wildfire mitigation plans. In light of these trends, we expect IOUs--especially those in the western U.S.--will develop detailed wildfire mitigation plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery. While it may take considerable time and investments for the industry to fully implement these strategies, the solutions are largely predicated on already-developed and in-use technologies.

System hardening is one investment that improves resiliency, reducing damages and risk. Because our modern economy is so dependent on electricity, system hardening also allows for the faster restoration of operations, decreasing total economic impacts. While system hardening is often expensive and can take many years to fully implement, its long-term benefits typically outweigh its shorter-term costs. Examples include undergrounding powerlines, adding cover conductors--which is the insulation of bare electrical wires with durable long-lived materials that reduce the probability of an electrical fault or spark--and replacing wood poles with steel and concrete.

To reduce the likelihood of a catastrophic wildfire, many utilities have incorporated weather stations that collect data to forecast weather conditions, including high-wind events. Some have incorporated artificial intelligence (AI) and machine learning into their data analysis, high-definition (HD) cameras, satellite and aerial imaging, remote sensing, and drones to enhance their forecasting capabilities. Utilities have also improved communication with state agencies and fire departments, coordinating specific locations that have either encountered or could be highly susceptible to a wildfire.

Critical to reducing wildfire risks is the implementation of a public safety power shutoffs (PSPS) program. PSPS is the proactive de-energizing of power lines in extreme weather conditions, especially in high-wind events. The decision to de-energize is extraordinarily challenging because it could have serious health and safety ramifications for some customers. Accordingly, an effective PSPS program establishes a consistent protocol when drastic measures are required that is approved by regulators and adequately communicated well in advance of the event. We view a PSPS program that establishes such a formal process as credit-supportive for IOUs.

Another crucial component of wildfire prevention is vegetation management, which is the removing or modifying of live and dead vegetation to reduce the potential ignition and spread of wildfire. This ongoing maintenance is essential for reducing the likelihood of debris coming in contact with powerlines, causing a spark that could lead to a wildfire. To further reduce wildfire risks, utilities have implemented enhanced power safety setting systems (EPSS) that automatically shut off power within a tenth of a second if they detect a potential ignition source. Such systems include downed conductor detection, early fault detection, open phase detection, and partial voltage force-out.

Because of the different service territories and topographies, we don't expect the strategies implemented by utilities will be uniform. As such, we expect utility wildfire mitigation plans will be customized but with the consistent goal of reducing risk.

Litigation risk. Because utilities operate under potentially hazardous conditions that include safety as well as environmental risks, they have always been susceptible to litigation. However, in recent years, as the climate changes and wildfires increase, litigation and class action civil lawsuits against utilities have intensified. Currently, plaintiffs have filed civil lawsuits against nine utilities because of wildfires. Additionally, an increasing number of class action lawsuits have been filed against water utilities regarding PFAS (per-and poly-fluoroalkyl) contamination. Should the industry's litigation risk continue to increase, credit quality would likely suffer.

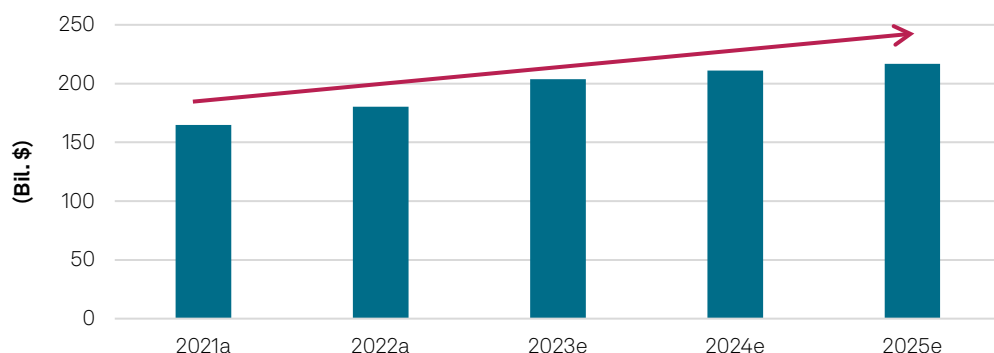
Securitization. More recently, utilities have increased their use of securitization, which we assess as supportive of credit quality. Securitization allows for the issuance of debt secured by a

non-bypassable charge to the customer's bill, allowing the utility to fully recover its costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger IOU credit measures.

Record capital spending. The industry's capital spending on safety, reliability, and energy transition continues to grow at record levels. We expect the 2023 capital spending for North America's electric, gas, and water utilities to approximate \$205 billion and rise to about \$210 billion and \$215 billion in 2024 and 2025, respectively (see chart 11). Under our base case, we expect that the industry's capital spending will continue to grow for at least the next decade.

Chart 11

North America regulated utilities' rising capital expenditures



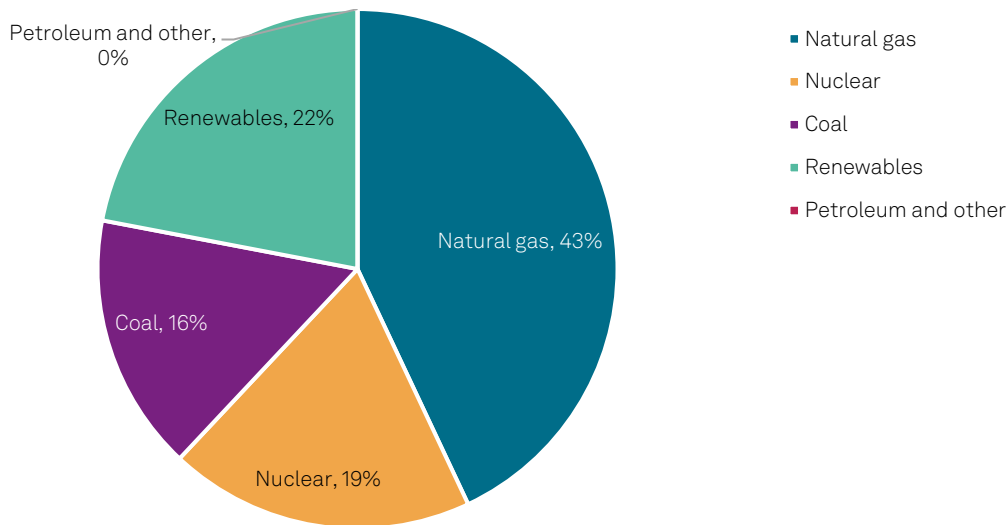
a—Actual. e—Estimate. Data as of Nov. 8, 2023. Capital expenditures represent North American investor-owned electric gas, and water utilities. Source: S&P Global Ratings.

Energy transition. The industry's reliance on coal generation has decreased by about 60% over the past decade, and we expect the vast majority of North America's IOUs will close their remaining coal generation by 2035. This transition will reduce the industry's environmental risks but also requires a thoughtful multi-decade strategy to expand renewable energy and battery storage, while simultaneously aligning depreciation and the retirement of coal generation to avoid stranded assets.

Renewable energy will eventually account for more than 50% of the industry's generation portfolio. While renewable energy only accounts for about 25% of the industry's electric generation portfolio, over the next decade renewable energy will likely double (see chart 12). The industry's funding of renewable energy will benefit from the Inflation Reduction Act (IRA), which includes significant tax incentives for renewable energy and permits for the transferability of such credits. Transferability allows tax credits that cannot be used on a company's own consolidated tax return because it has insufficient income to be transferred to a third-party. We expect the IOUs will be among the primary beneficiaries of these tax credits. Ultimately, we expect utility regulators will mandate that transferred tax credits are refunded back to customers, and as such we expect the growth of renewable energy will likely be less impactful on the customer bill.

Chart 12

2023 U.S. generation (through August)



Data as of Dec. 12, 2023. Source: U.S. Energy Information Administration.

Inflation. Although the rate of inflation has slowed from 2022 levels, it remains elevated relative to historical levels. We anticipate this will result in higher O&M costs that could weaken financial performance. While some utilities have interim mechanisms that reduce the regulatory lag, most will have to file rate cases on a more frequent basis should inflation remain high over the longer term.

Because of rising costs and higher capital spending, rate case filings have significantly increased. In 2019 and 2020, U.S. annual rate case filings averaged about \$6 billion but have since increased by 2.5x to an annual average of about \$16 billion. This elevates the industry's reliance on managing regulatory risks. Additionally, because about 35% of the industry is managing with only minimal financial cushion--reflecting funds from operations (FFO) to debt that is less than 100 basis points above the downgrade threshold--the ability to absorb unexpected events beyond their base case is limited. Accordingly, should rate case filings be delayed or rate case orders be less than constructive, financial performance and credit quality could weaken.

Effective management of regulatory risk. We assess all of North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 13). Over the past decade, most of the industry has implemented some combination of decoupling, formula rate plans, forward test years, multiyear rate cases, interim rates, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag, which is the timing difference between when a utility incurs costs and when it's recovered from ratepayers. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

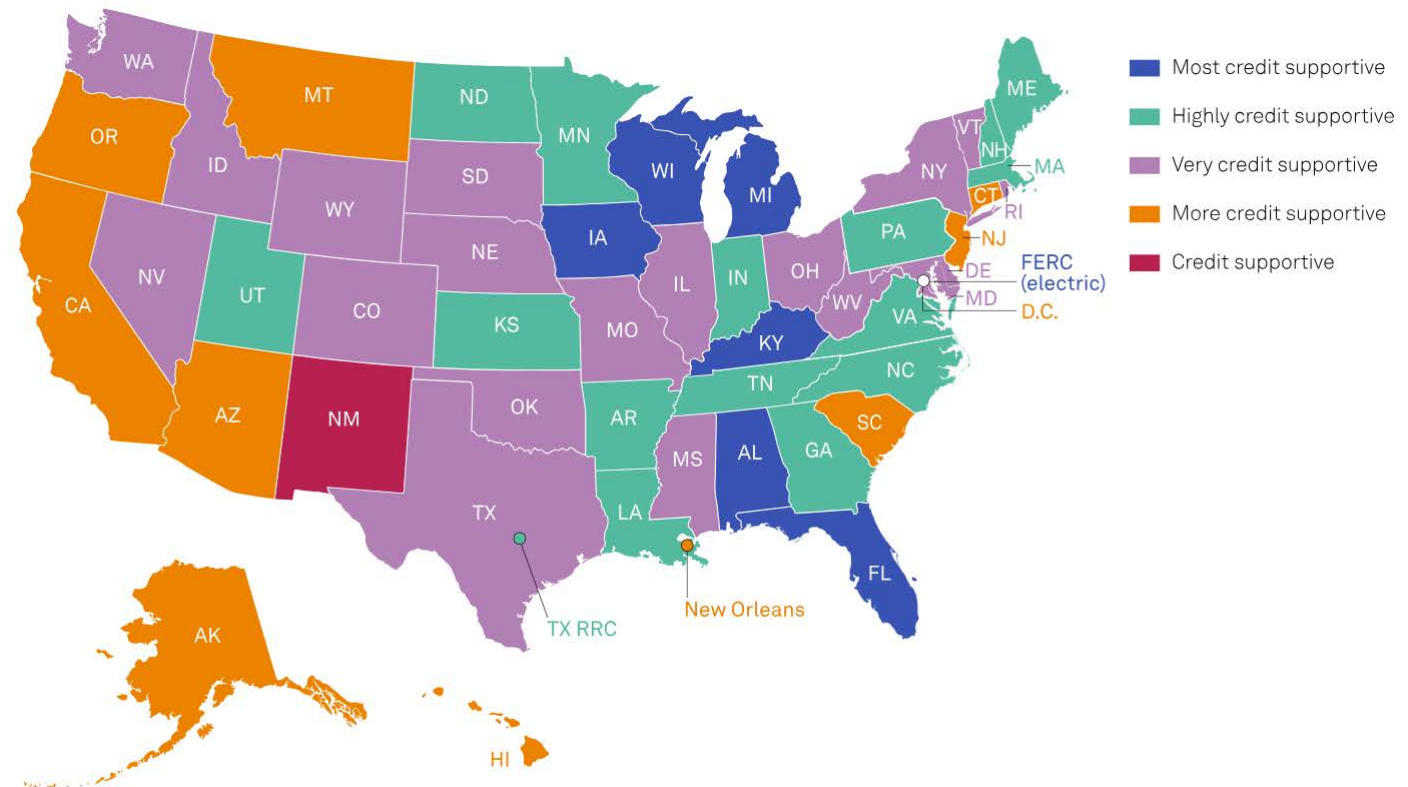
To manage regulatory risk, the industry must maintain the affordability of the customer bill. While the average U.S. electric bill accounts for less than 2.5% of the median U.S. household income, the 2022 average electric bill increased by about 13% primarily because of rising commodity prices. In 2022, the average monthly price for natural gas was \$6.40/MMBtu, or nearly double the average price for the prior 13 years. Subsequently, prices have retreated to about \$2-\$4/MMBtu. Had commodity prices remained high, we believe it would have weakened the industry's ability to manage regulatory risk, pressuring credit quality.

In 2023, several utilities experienced negative regulatory developments that could be indicative of longer-term risks. For example, earlier in 2023 we revised the outlooks on most of Ontario's local distribution companies (LDC) regulated by the Ontario Energy Board to negative, primarily reflecting the increasing regulatory lag associated with transmission costs and wholesale market rates. The lag affected the LDC's earned return on equity and financial performance.

Chart 13

Regulatory assessment by state

As of November 2023



Source: S&P Global Ratings.
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More recently, we revised the outlooks on most of Connecticut's utilities to negative, reflecting the possibility of less cash flow predictability. In June 2023, Senate Bill 7 was signed into law, which gave Connecticut's Public Utilities Regulatory Authority (PURA) greater latitude in determining whether companies over-earn, prohibits PURA from reauthorizing the electric system improvements charge, and allows PURA's discretion over the use of decoupling. We believe this law decreases utilities' cash flow predictability and increases regulatory lag. Additionally, recent 2023 PURA rate orders for Aquarion Co. and The United Illuminating Co. (UI) significantly deviated from our base case expectations, increasing regulatory lag for these utilities. These rate orders did not approve the multiyear rate plans filed, and included material disallowances, penalties for UI, and below-average returns on equity. Should these risks persist, it could result in an increase of regulatory lag and a weakening of utility cash flow predictability for all of Connecticut's regulated utilities, which would be negative for credit quality.

Credit metrics and financial policy

Despite our expectations that the industry's 2024 capital spending will increase to about \$210 billion, we expect generally consistent financial measures, reflecting FFO to debt of about 15%. Our base case is predicated on the industry funding its approximate \$85 billion of cash flow deficits with about \$40 billion in asset sales and equity issuance. For 2023 the industry's actual equity issuance was considerably below our expectations, resulting in weakening of financial performance. Should this trend persist in 2024, it would likely pressure credit quality.

Key risks or opportunities around the baseline

1. Interest rates stabilize.

Since 2022, rising interest rates have increased costs for North America's IOUs, weakening financial performance and credit quality. Our economists expect federal funds rate will peak in 2023 and then modestly decrease in 2024. Accordingly, we generally expect that as interest rates stabilize it will put less pressure on IOU's financial performance and credit metrics.

2. Sales growth will return.

Electricity sales growth stagnation has challenged the North America investor-owned electric regulated utility industry's ability to manage regulatory risk and credit quality. Over the next three years we expect sales growth trends to improve.

3. Complex projects increase risk.

During 2023, several offshore wind projects were delayed or canceled because of rising costs for these more challenging projects. To maintain credit quality, we generally expect the industry will focus on lower-risk and smaller projects.

Interest rates. IOUs have considerable near-term debt maturities that must be refinanced, and rising discretionary cash flow deficits that are mostly fund with debt. Because of regulatory lag, rising interest rates weakens financial performance. S&P Global economists expect the federal funds rate will peak in 2023 at about 5.5% and then modestly decrease to about 5.3% in 2024. Accordingly, as interest rates stabilize it will put less pressure on the industry's financial performance.

Spreads narrowing. Despite the 10-year treasury increasing by about 300 basis points over the last three years to about 4.5% from about 1.5% at year-end 2020, the average authorized return on equity has essentially remained flat at about 9.5% over this same timeframe. The narrowing of this spread directly affects the industry's financial performance. Most IOUs employ double leverage, issuing significant debt at both the holding company level and at the operating utility. The industry is reliant on cash flows from its operating utilities to service its debts at the holding company. As these spreads narrow, financial performance weakens, pressuring credit quality.

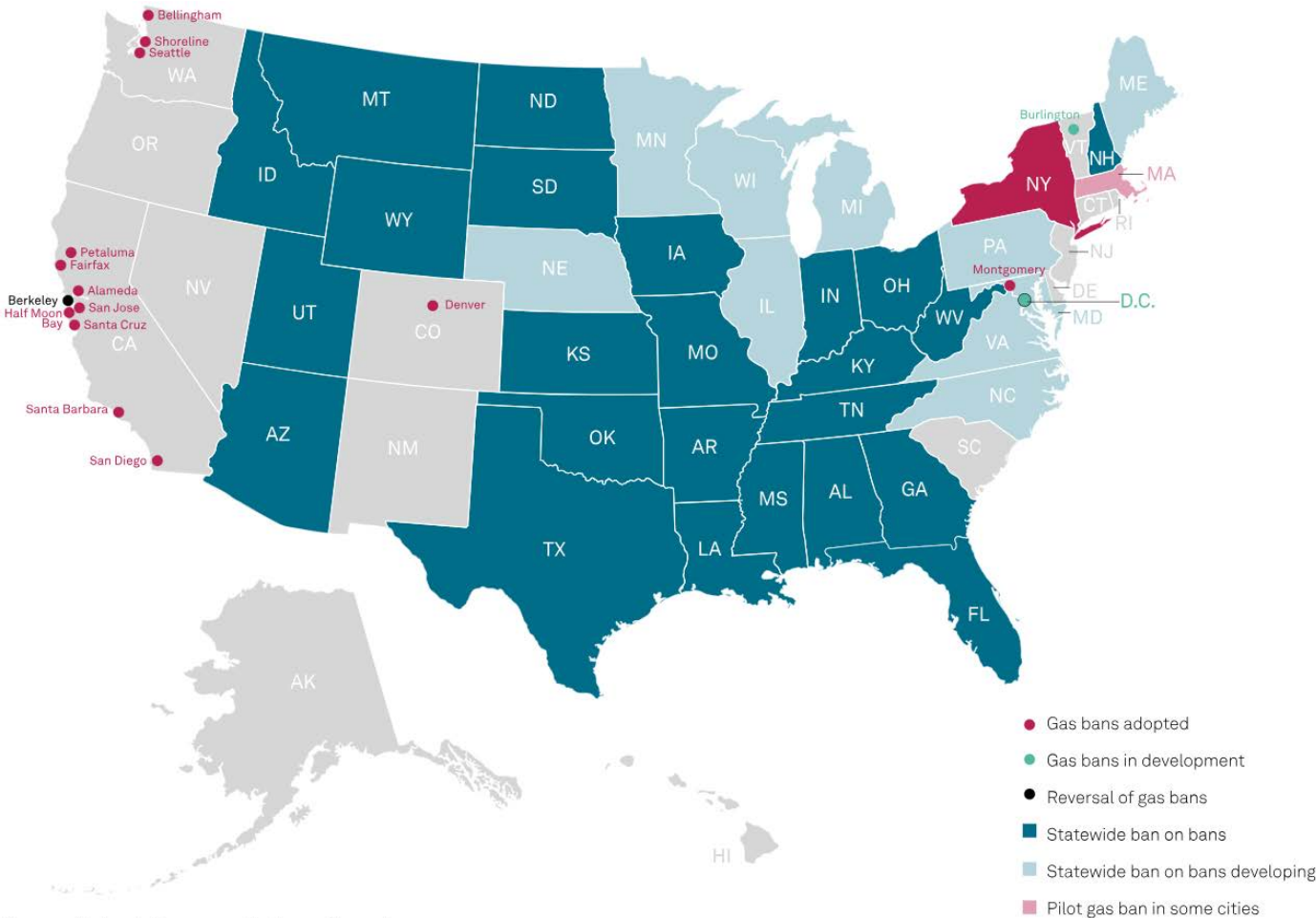
Sales growth. Electricity sales growth has been flat to negative over the past decade because of conservation, challenging North America's IOU's credit quality. Sales growth increases revenues, EBITDA, and FFO without necessitating a rate increase. This enhances the industry's capacity to maintain its financial measures without depending on a regulator's consistently constructive rate case order. We expect sales to grow in the short term, driven by the onshoring of manufacturing and data centers, and over the medium-term because of increased electrification and electric vehicles. Overall, we view this development as supportive of the industry's credit quality.

Full electrification. We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that

operate in warmer climates or whose cities/states have banned new gas connections, severely limiting the growth of the natural gas LDCs. While most of the city bans have occurred in the Western U.S. states, in 2023 New York State banned natural gas and other fossil fuels in most new buildings (see chart 14). Offsetting some of this risk is that a near-majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 14

Ban on new gas connections



Source: Natural Resources Defense Council.
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Technology. The industry generally embraces technology to reduce its O&M costs by leveraging in-use technologies, a practice we view as generally prudent. Examples include the industry's wide use of drone technology that reduces the cost of pole and wire inspections; battery technology, which reduces fuel costs; and advanced metering infrastructure, which reduces labor costs.

Currently, many gas LDCs and electric generation utilities are testing the blending of hydrogen with natural gas to further reduce carbon emissions. Many of these pilot programs are looking to reduce the cost of hydrogen and are testing the maximum allowable hydrogen that would be compatible with downstream appliances. We expect the industry will benefit from hydrogen tax

credits or other government grants allowed under the IRA, likely incorporating about 5%-10% of hydrogen by 2035.

However, periodically the industry invests in higher-risk larger projects that rely on newer technologies, often resulting in a weakening of credit quality. For example, while Southern Co.'s recent commercial operations of nuclear power plant, Vogtle Unit 3, was a significant achievement, we already downgraded the company by two notches since it began pre-construction activities in 2009, reflecting the higher construction risks associated with this complex project. Also, we expect Ørsted--which partnered with many U.S. utilities to build offshore wind in the U.S.--to write-off as much as \$6 billion associated with these higher risk projects. Additionally, we downgraded Eversource Energy by two notches since it announced its offshore wind power generation joint venture, reflecting the higher risks associated with this newer technology and longer-term project. Overall, we expect the industry will reduce its technological risks by generally maintaining its focus on smaller and lower risk projects.

Alternative minimum tax. The IRA of 2022 includes a 15% corporate alternative minimum tax (AMT) that we expect will weaken the financial measures of about 10% of the utility industry. The AMT is only applicable to corporations with at least \$1 billion of income. Most fully integrated large utilities with a growing or significant renewable generation portfolio will generally be able to use the renewable tax credits to minimize or eliminate the AMT. However, the financial measures of large electric transmission and distribution utilities, gas LDCs, and large water utilities could all be weakened by the AMT.

Cybersecurity. The recent 2023 suspected cyberattacks against water and wastewater treatment facilities in Texas and Pennsylvania underscores the industry's ongoing cybersecurity risks. Because critical infrastructure assets tend to have higher exposure, the industry's ongoing vigilance in this area is critical to maintaining credit quality.

Municipalization. Municipalization is the transferring of a privately owned utility to a public ownership. While such occurrences are infrequent and rare, in 2023 two ballot proposals explored these options. In both instances, the city of El Paso, Texas, and the state of Maine soundly rejected such proposals. Other cities, including San Diego, continue to explore these alternatives and we will continue to monitor these developments, including their impact on credit quality.

Related Research

- [North American Utility Regulatory Jurisdictions: Some Notable Developments](#), Nov. 10, 2023
- [A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality](#), Nov. 9, 2023
- [Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities](#), Nov. 6, 2023
- [Plugged In: How EVs Supercharge Growth For North America's Investor-Owned Electric Regulated Utilities](#), Oct. 31, 2023
- [A Closer Look At The Three Major California Investor-Owned Electric Utilities Amid The 2023 Wildfire Season](#), Oct. 24, 2023
- [Credit FAQ: What's Behind Our Recent Actions On Investor-Owned Utilities In Connecticut?](#), Sept. 28, 2023
- [Record Capex Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities](#), Sept. 12, 2023
- [Although Commodity Costs Are A Pass Through For Utilities, They Still Affect Credit Quality](#), Sept. 6, 2023

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09-Jan-2025 | 12:09 EST

Sempra Outlook Revised To Negative, Ratings Affirmed; Southern California Gas Downgraded, Outlook Stable

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- The California Public Service Commission (CPUC) recently issued rate case orders for the 2024-2027 rate years for Sempra's subsidiaries, Southern California Gas Co. (SoCalGas) and San Diego Gas & Electric Co.'s (SDG&E), authorizing revenue requirement increases of approximately \$750 million and \$576 million, respectively, over the four year period.
- We expect Sempra's financial measures will remain weak for the current rating, reflecting consolidated funds from operations (FFO) to debt that will not consistently be greater than our downgrade threshold of 15%, absent sufficient countermeasures.
- Similarly, we expect that subsidiary SoCalGas' stand-alone FFO to debt will remain below our downgrade threshold of FFO to debt of 20%.
- As such, we revised our rating outlook on Sempra to negative from stable and affirmed our ratings on the company.
- At the same time, we downgraded Southern California Gas Co. to 'A-' from 'A'. The outlook is stable. We also lowered our issue-level ratings on its senior unsecured debt to 'A-' from 'A' and its senior secured debt to 'A' from 'A+' and our short-term and commercial paper ratings on the company to 'A-2' from 'A-1'.
- We also affirmed our ratings on San Diego Gas & Electric. The outlook remains stable.
- The negative outlook on Sempra reflects its weak financial measures for the current rating. Specifically, we expect Sempra's consolidated FFO to debt to remain below our downgrade threshold of 15%.

NEW YORK (S&P Global Ratings) Jan. 9, 2025--S&P Global Ratings today took the rating actions listed above.

The outlook revision to negative for Sempra reflects the company's weak consolidated financial measures for the current rating.

Sempra has historically operated with minimal financial cushion. In 2023, Sempra's FFO to debt was only about 14%, which was below our downgrade threshold, and has weakened to 11.9% for the 12 months ended September 2024. The weak financial measures were largely due to higher capital spending, higher regulatory balancing account receivables, higher operating expenses, and higher cash interest paid. After incorporating the rate case increases for SoCalGas and SDG&E, we still do not expect that Sempra's consolidated financial measures will consistently be greater than our downgrade threshold.

Under our base case, we expect Sempra's consolidated FFO to debt to be 14%-15% through 2026, absent sufficient countermeasures. Our base case consolidates cash flows and leverage (which includes approximately \$3 billion of proportionally consolidated debt from the Cameron and Port Arthur Phase I [PALNG1] liquefied natural gas projects) subsidiary Sempra Infrastructure as part of Sempra's consolidated financial measures. In addition, capital spending average of about \$9.3 billion annually for 2025-2026, dividends averaging about \$1.7 billion annually, and approximately \$4.5 billion-\$5 billion of average annual negative discretionary cash flow through 2026.

The downgrade of SoCalGas reflects our expectation that the company's financial measures will remain consistently below our downgrade threshold of FFO to debt of 20%.

After incorporating SoCalGas' rate case order, we expect its stand-alone FFO to debt to be 17%-19% through 2027. Under our base case, we assume capital spending of about \$2 billion annually; continued use of the existing regulatory mechanisms, such as cash balancing accounts to recover costs not specifically addressed in the rate case; and dividend payments to the parents in line with maintaining the company's authorized capital structure. Furthermore, we expect the company to operate with negative discretionary cash flow throughout our forecast period, indicative of external funding needs. To account for this weakening of financial performance, we revised downward our comparable ratings analysis modifier to neutral from positive, which lowers SoCalGas' stand-alone credit profile and ratings.

The ratings affirmation of SDG&E reflects our expectation that the company will continue to maintain stand-alone financial measures within the range for its financial risk profile category and maintain its business risk in line with our expectations.

Specifically, we expect SDG&E to maintain FFO to debt of 18%-20%, incorporating the effects of the rate case outcome for SDG&E. In addition, we expect SDG&E to remain a global leader in wildfire prevention and mitigation given the high threat of wildfires in its service territory relative to utility peers across North America.

The rating outlook on both SDG&E and SoCalGas is stable.

The stable outlook incorporates the cumulative value of the insulating and regulatory measures in place that we assess as sufficient to potentially rate the utilities up to two notches above Sempra's (bbb+) group credit profile.

We assess Sempra's business risk profile as being at the upper end of the range for a strong business risk profile assessment.

This reflects its mostly lower-risk regulated utility operations in California and Texas, offset by higher-risk midstream activities. We expect the midstream business mix to reflect about 25% of consolidated adjusted EBITDA, with regulated utility operations (SDG&E, SoCalGas, and Oncor) accounting for about 75% of adjusted EBITDA.

Our assessment of Sempra's business risk incorporates the credit-supportive measures under Assembly Bill (AB) 1054 (which provides Sempra access to a \$21 billion wildfire fund) as well as the company's proactive operational enhancements that we believe reduce the probability of the company causing a significant wildfire, despite the company operating in a service territory that has high exposure to wildfire risk because of climate change.

On the regulated gas utility side, we expect subsidiary SoCalGas to continue to effectively manage regulatory risk but to likely face a gradual increase in business risk given California's ongoing energy transition away from natural gas-fueled technologies.

On the midstream side, while PALNG1 remains under construction, we believe the combination of Sempra's reduced ownership interest in the project and the executed engineering procurement and construction (EPC) contract with Bechtel protects the company's credit quality. Bechtel has a strong track record of successfully completing U.S. Gulf Coast LNG projects on time and on budget, and its parent (Bechtel Global Energy Inc.) guarantees Bechtel's performance under the EPC contract.

Sempra

The negative outlook on Sempra reflects minimal financial cushion for the company's consolidated financial measures that could weaken beginning in 2025 absent sufficient countermeasures.

We could lower our rating on Sempra over the next 12-18 months if:

- FFO to debt weakened consistently below 15%;
- SDG&E caused a significant wildfire;
- PALNG1 experienced significantly higher costs than Sempra took on; or
- Sempra expanded its LNG business beyond our base case such that either business risk increased or consolidated financial measures weakened.

We could revise our outlook on Sempra to stable over the next 12-18 months if FFO to debt remained consistently above 15%, without an increase to business risk.

Southern California Gas

The stable outlook on SoCalGas reflects our expectation that the company will continue to manage regulatory and energy transition risk effectively while maintaining stand-alone FFO to debt of 18%-19% over the next two years.

We could lower our ratings on SoCalGas in the next 12-18 months if:

- The company's stand-alone FFO to debt consistently weakened below 16%;
- Its business risk increased, either due to adverse regulatory developments or elevated risk related to its gas utility business; or
- Although unlikely, we lowered our ratings on its parent, Sempra by two notches.

We could raise our rating on SoCalGas over the next 12-18 months if the company maintained stand-alone FFO to debt of consistently above 20% and continued to effectively manage regulatory risk and we did not downgrade parent Sempra.

San Diego Gas & Electric

Our stable outlook on SDG&E reflects its track record of not causing a significant wildfire and that SDG&E can continue to sustain such performance while maintaining stand-alone financial measures that remain sufficient for the ratings. Specifically, we expect the company's stand-alone financial measures to reflect FFO to debt of 18%-20% over the next two years.

We could lower our ratings on SDG&E if it caused a significant wildfire, its stand-alone FFO to debt materially weakened to below 13%, or although unlikely, we lowered our rating on its parent Sempra by three notches.

S&P Global We could raise our rating on SDG&E if its stand-alone FFO to debt remained consistently at 21% or above and the company did not cause a significant wildfire.

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Related Criteria

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- [Criteria | Corporates | General: Sector-Specific Corporate Methodology](#), April 4, 2024
- [Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities](#), Jan. 7, 2024
- [Criteria | Corporates | General: Corporate Methodology](#), Jan. 7, 2024
- [General Criteria: Hybrid Capital: Methodology And Assumptions](#), March 2, 2022
- [General Criteria: Environmental, Social, And Governance Principles In Credit Ratings](#), Oct. 10, 2021
- [General Criteria: Group Rating Methodology](#), July 1, 2019
- [Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments](#), April 1, 2019
- [Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings](#), March 28, 2018
- [General Criteria: Methodology For Linking Long-Term And Short-Term Ratings](#), April 7, 2017
- [Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers](#), Dec. 7, 2016
- [Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers](#), Dec. 16, 2014
- [General Criteria: Country Risk Assessment Methodology And Assumptions](#), Nov. 19, 2013
- [General Criteria: Methodology: Industry Risk](#), Nov. 19, 2013
- [General Criteria: Principles Of Credit Ratings](#), Feb. 16, 2011

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30-May-2025 | 13:52 EDT

SLIDES PUBLISHED: North American Regulated Utilities Industry Highlights

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NEW YORK (S&P Global Ratings) May 30, 2025—S&P Global Ratings today published slides covering industry highlights for the investor-owned North American regulated utilities industry. A copy of the slide presentation is available here: "[**SLIDES: North American Regulated Utilities AGA Conference May 2025**](#)". The presentation was originally given to investors attending the annual American Gas Association Financial Conference in Marco Island, Fla., and covered the following topics:

- S&P Global Ratings' negative outlook on the industry
- Financials measures were generally maintained in 2024
- Tax credits and their implication for credit quality
- Increasing capital spending and cash flow deficits
- Transformative industry growth predicated on data centers
- Hybrid securities and common equity issuance were robust during the first quarter of 2025
- Newly enacted state laws result in a modest reduction in wildfire risks and regulatory lag for some utilities
- Rising wildfire and other physical risks

About 20% of the industry continues to have a negative outlook

While downgrades have significantly outpaced upgrades for each of the past five years (2020-2024) by more than 2 to 1, 2025 upgrades have slightly outpaced downgrades. Despite this development, our negative outlook on the industry reflects the relatively high percentage of the industry with a negative outlook, incorporating uncertainties regarding the future of tax credits, the high percentage of companies that effectively operate with only minimal financial cushion from their downgrade threshold, rising wildfire credit risks, and rising cash flow deficits that may not be sufficiently funded in a credit-supportive manner.

Financial performance was generally maintained in 2024

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The industry's 2024 funds from operations (FFO) to debt was maintained at about 13.5% after weakening in both 2022 and 2023 by about 150 basis points. The industry's 2024 financial performance was primarily maintained by the use of the transferability of tax credits, record hybrid issuance, and generally supportive rate case decisions. Need a Rating?

Since 2021, annual rate case increases have more than doubled. Prior to 2021, the industry's annual rate case increase averaged about \$3 billion and since 2021, this has climbed to about \$9 billion, annually. The rise of the industry's annual rate increases coincides with the industry's rising capital spending for safety, reliability, energy transition, and more recently for data center growth.

Tax credit phase outs

Recently, the U.S. House of Representatives passed its budget reconciliation bill that ends clean electricity production credits and clean electricity investment credits that do not begin construction within 60 days after the bill is enacted and are not fully in service by year-end 2028. The bill also ends nuclear power production credits by 2031. While we assess the end of these tax credits as negative for credit quality and will likely ultimately result in weaker financial measures, we view the phase-out period as sufficient to allow the industry ample time to adjust to the new rules. We expect that the phase out of these tax credit will very gradually weaken the industry's financial performance over the longer term. Because about 50% of industry is operating with minimal financial cushion from their downgrade threshold, which we define as having less than 100 basis points of financial cushion from a utility's FFO to debt downgrade threshold, a significant weakening in financial performance could pressure the industry's credit quality.

Rising capital spending and the growth of data centers

The industry's 2024 capital spending was again at a record level and represents the fourth consecutive year of record capital spending. This is indicative of a longer-term trend of ever-rising capital spending. The industry's 2024 capital spending was about \$208 billion, and we expect that the industry's capital spending will continue to rise in 2025 and 2026 to more than \$250 billion. Over the past decade, capital spending has been increasing to meet safety, reliability, and energy transition. We expect that future capital spending will even further increase to meet the growth of data centers. Over the past two decades the industry's electricity sales have essentially been flat as growth has been offset by conservation. However, looking forward, primarily because of data centers we expect that electricity sales growth will grow at 1%-2%, which is transformative for such a mature industry.

Record level of hybrid security issuance

Because the industry continues to experience record levels of capital spending it is also faces consistently high cash flow deficits that must be funded in a credit-supportive manner to maintain credit quality. Since 2020, cash flow deficits have approximated about \$100 billion annually. During 2024, the industry issued about \$26 billion of hybrid securities, which was a record level of issuance. We typically assess hybrid securities as 50% equity and 50% debt. This high level of hybrid issuance supported the industry's financial performance, maintaining FFO to debt at about 13.5%. Furthermore, during the first quarter of 2025, the industry issued robust levels of common equity and hybrid securities at about \$5 billion and \$6 billion, respectively. While the common equity issuance and hybrid security issuance has temporarily paused primarily because of market volatility from the threat of tariffs, further issuance of credit supportive instruments are necessary for the industry to maintain financial performance and credit quality.

Early 2025 state laws enacted modestly reduces wildfire risks and addresses regulatory lag for some utilities

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Many credit-supportive bills have been enacted across several states. Below is a brief synopsis of some recently enacted state laws:

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- Arizona: Utilities will develop a wildfire mitigation plan every two years and if approved, a utilities' wildfire liability may be limited.
- Hawaii: Establishes a liability cap on economic damages arising from future wildfires and authorizes the use of securitization to finance wildfire safety and grid resilience investments.
- Idaho: Mandates electric utilities to submit a wildfire mitigation plan for approval.
- Kansas: Enacted caps on punitive damages from wildfires caused by electric utilities at \$5 million per claim.
- Missouri: Allows natural gas, water, and sewer utilities to use of a future test period as part of their general rate-case filings. Furthermore, the law also allows electric utilities to request to include construction work in progress for gas-fired generation.
- Ohio: Will allow electric distribution utilities to file multi-year rate cases every three years based on a forward-looking test year.
- South Carolina: Will allow the electric utilities to request annual adjustments to rates, which we expect will reduce the regulatory lag.
- Washington: Utilities can securitize costs related to wildfires.
- Wyoming: Utilities will prepare a wildfire mitigation plan and utility losses associated with a wildfire may be limited.
- We view these developments as modestly supportive of credit quality and we will continue to actively monitor other pending legislative initiatives across North America.

Wildfire risks are increasing because of climate change

In January 2025, California again experienced severe wildfires that may test the longer-term viability of the state's wildfire fund. Currently, the fund does not have an automatic replenishing mechanism, and the credit quality of the state's investor-own utilities could materially weaken should the wildfire fund fully deplete.

However, wildfire risks are not limited to California's investor-owned utilities and we continue to actively monitor wildfire related developments in other U.S. western states including Oregon, Texas, and Colorado. Because of climate change, we expect that wildfire risks will be a rising risk for the industry for the foreseeable future.

Related Research

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- Tear Sheet: [Avista Corp.'s Credit Quality Supported By Washington And Idaho Bills](#), May 20, 2025
- [North American Utilities Regulatory Jurisdictions Update: Missouri And Arizona Assessments Revised Developments](#), May 16, 2025 Need a Rating?
- [The Pace Of North American Regulated Utilities' Common Equity And Hybrids Issuance Stalls, Raising Concerns For Credit Quality](#), May 15, 2025
- [For A Resilient Global Infrastructure Sector, The Immediate Impact From Tariffs Will Be Limited](#), May 14, 2025
- [Credit FAQ: After The Firestorms: Credit Risks Related To U.S. Wildfires](#), May 5, 2025
- [Tear Sheet: Passage Of Missouri Senate Bill 4 Is Supportive Of Union Electric Co.'s Regulatory Framework](#), April 17, 2025
- Tear Sheet: [New Kansas Law Addressing Electric Utilities' Wildfire Risks Modestly Supports Evergy Inc. And Subsidiaries' Credit Quality](#), April 17, 2025

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