The Role of Liabilities *(continued)*

materially affect the rate of currency growth. Since the start of the Global Financial Crisis, notes in circulation have more than doubled and, as of the end of 2018, stood at about $1 67 trillion, equivalent to about 8 percent of U.S. GDP, implying that accommodating demand for currency alone requires a larger balance sheet than before the crisis.

Reserve balances are currently the second-largest liability in the Federal Reserve's balance sheet, totaling $1.66 trillion at the end of 2018, or nearly 8 percent of nominal GDP. This liability item consists of deposits held at Federal Reserve Banks by depository institutions, including commercial banks, savings banks, credit unions, thrift institutions, and most U.S. branches and agencies of foreign banks. These balances include reserves held to fulfill reserve requirements as well as reserves held in excess of these requirements. Reserve balances allow banks to facilitate daily payment flows, both in ordinary times and in stress scenarios, without borrowing funds or selling assets. Reserve balances have been declining for several years, in part as a result of the ongoing balance sheet normalization program initiated in October 2017, and now stand about $1.2 trillion below their peak in 2014 At its January 2019 meeting, the Federal Open Market Committee decided that it would continue to implement monetary policy in a regime with an ample supply of reserves, which is often called a "floor system" or an "abundant reserves system."[1] Going forward, the banking system's overall demand for reserve balances and the Committee's judgment about the quantity that is appropriate for the efficient and effective implementation of monetary policy will determine the longer-run level of reserve balances. Although the level of reserve balances that banks will eventually demand is not yet known with certainty, it is likely to be appreciably higher than before the crisis. Banks' higher demand for reserves appears to reflect in part an increased focus on liquidity risk management in the context of regulatory changes.

Liabilities other than currency and reserves include the Treasury General Account (TGA), reverse repurchase agreements conducted with foreign official account holders, and deposits held by designated financial market utilities (DFMUs). By statute, the Federal Reserve serves a special role as fiscal agent or banker for the federal government. Consequently, the U.S. Treasury holds cash balances at the Federal Reserve in the TGA, using this account to receive taxes and proceeds of securities sales and to pay the government's bills, including interest and principal on maturing securities. Before 2008, the Treasury targeted a steady, low balance of $5 billion in the TGA on most days, and it used private accounts at commercial banks to manage the variability in its cash flows. Since 2008, the Treasury has used the TGA as the primary account for managing cash flows In May 2015, the Treasury announced its intention to hold in the TGA a level of cash generally sufficient to cover one week of outflows, subject to a minimum balance objective of roughly $150 billion. Since this policy change, the TGA balance has generally been well above this minimum; at the end of 2018, it was about $370 billion, or nearly 2 percent of GDP The current policy helps protect against the risk that extreme weather or other technical or operational events might cause an interruption in access to debt markets and leave the Treasury unable to fund U.S. government operations—a scenario that could have serious consequences for financial stability.

Reverse repurchase agreements with foreign official accounts, also known as the foreign repo pool, also rose during recent years. The Federal Reserve has long offered this service as part of a suite of banking and custody services to foreign central banks, foreign governments, and international official institutions

(continued)

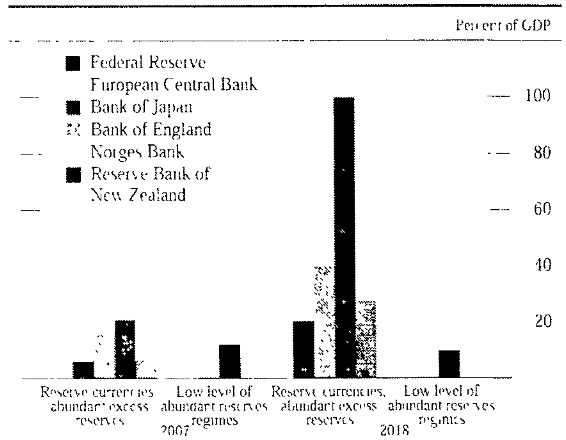
1. See footnote 18 in the main text.

Accounts at the Federal Reserve provide foreign official institutions with access to immediate dollar liquidity to support operational needs, to clear and settle securities in their accounts, and to address unexpected dollar shortages or exchange rate volatility. The foreign repo pool has grown from an average level of around $30 billion before the crisis to a current average of about $250 billion, equivalent to a little more than 1 percent of GDP. The rise in foreign repo pool balances has reflected in part central banks' preference to maintain robust dollar liquidity buffers.

Finally, "other deposits" with the Federal Reserve Banks have also risen steadily over recent years, from less than $1 billion before the crisis to about $80 billion at the end of 2018 Although "other deposits" include balances held by international and multilateral organizations, government-sponsored enterprises, and other miscellaneous items, the increase has largely been driven by the establishments of accounts for DFMUs. DFMUs provide the infrastructure for transferring, clearing, and settling payments, securities, and other transactions among financial institutions. The Dodd-Frank Wall Street Reform and Consumer Protection Act provides that DFMUs—those financial market utilities designated as systemically important by the Financial Stability Oversight Council can maintain accounts at the Federal Reserve and earn interest on balances maintained in those accounts

Putting together all of these elements- that is, projected trend growth for currency in circulation, the Committee's decision to continue operating with ample reserves, and the higher levels for the TGA, the foreign repo pool, and DFMU balances—explains why the longer-run size of the Federal Reserve's balance sheet will be considerably larger than before the crisis At the end of 2018, the Federal Reserve's balance sheet totaled $4 1 trillion, or about 20 percent of GDP. Figure B considers the size of the balance sheet in an international context. In response to the Global Financial Crisis, central bank balance sheets increased in many jurisdictions. Relative to GDP, the Federal Reserve's balance sheet remains smaller than those of other reserve-currency central banks in major advanced foreign economies that currently operate with abundant reserves— such as the European Central Bank, the Bank of Japan, and the Bank of England—although this difference is partly due to the Federal Reserve being much further along in the policy normalization process after the crisis. In addition, the Federal Reserve's balance sheet relative to GDP is only modestly larger than those of central banks, such as the Norges Bank and the Reserve Bank of New Zealand, that aim to operate at a relatively low level of abundant reserves. Of course, differences in central bank balance sheets also reflect differences in financial systems across countries

B. Central bank balance sheets relative to gross domestic product



NOTE Data for 2018 pertain to Q3, except for the Bank of England, whose data pertain to 2017 Q3 Norges Bank data exclude assets of Norway's Government Pension Fund Global

SOURCE Haver Analytics

judges it is an opportune time for the Federal Reserve to conduct a review of its strategic framework for monetary policy—including the policy strategy, tools, and communication practices. The goal of this assessment is to identify possible ways to improve the Committee's current policy framework in order to ensure that the Federal Reserve is best positioned going forward to achieve its statutory mandate of maximum employment and price stability.

Specific to the communications practices, the Federal Reserve judges that transparency is essential to accountability and the effectiveness of policy, and therefore the Federal Reserve seeks to explain its policymaking approach and decisions to the Congress and the public as clearly as possible. The box "Federal Reserve Transparency: Rationale and New Initiatives" discusses the steps and new initiatives the Federal Reserve has taken to improve transparency.

Federal Reserve Transparency: Rationale and New Initiatives

Over the past 25 years, the Federal Reserve and other major central banks have taken steps to improve transparency, which provides three important benefits First, transparency helps ensure that central banks are held accountable to the public and its elected representatives. Accountability is essential to democratic legitimacy and is particularly important for central banks that have been granted extensive operational independence, as is the case for the Federal Reserve. Second, transparency enhances the effectiveness of monetary policy. If the public understands the central bank's views on the economy and monetary policy, then households and businesses will take those views into account in making their spending and investment plans. Third, transparency supports a central bank's efforts to promote the safety and soundness of financial institutions and the overall financial system, including by helping financial institutions know what is expected of them. Thus, for each of these reasons, the Federal Reserve seeks to explain its policymaking approach and decisions to the Congress and the public as clearly as possible.

To foster transparency and accountability, the Federal Reserve uses a wide variety of communications, including semiannual testimony by the Chairman in conjunction with this report, the *Monetary Policy Report* In addition, the Federal Open Market Committee (FOMC) has released a statement after every regularly scheduled meeting for almost 20 years, and detailed minutes of FOMC meetings have been released since 1993.[1] In 2007, the Federal Reserve expanded the economic projections that have accompanied the *Monetary Policy Report* since 1979 into the Summary of Economic Projections, which FOMC participants submit every quarter. And in 2012, the FOMC first released its Statement on Longer-Run Goals and Monetary Policy Strategy, which it reaffirms annually.[2]

The Federal Reserve continues to make improvements to its communications. In January, the Chairman began holding a press conference after each FOMC meeting, doubling the frequency of the press conferences that were introduced in 2011. These press conferences are held 30 minutes after the release of the postmeeting statement and provide additional information about the economic outlook, the Committee's policy decision, and policy tools. Press conferences also allow the Chairman to answer questions on monetary policy and other issues in a timely fashion.

In November 2018, the Federal Reserve announced that it would conduct a broad review of its monetary policy framework—specifically, of the policy strategy, tools, and communication practices that the FOMC uses in the pursuit of its dual-mandate goals of maximum employment and price stability. The Federal Reserve's existing policy framework is the result of decades of learning and refinements and has allowed the FOMC to pursue effectively its dual-mandate goals. Central banks in a number of other advanced economies have also found it useful, at times, to conduct reviews of their monetary policy frameworks Such a review seems particularly appropriate when the economy appears to have changed in ways that matter for the conduct of monetary policy. For example, the neutral level of the policy interest rate appears to have fallen in the United States and abroad, increasing the risk that a central bank's policy rate will be constrained by its effective lower bound in future economic downturns. The review will consider ways to ensure that the Federal Reserve's monetary policy strategy, tools, and communications going forward provide the best means to achieve and maintain the dual-mandate objectives.

The review will include outreach to and consultation with a broad range of stakeholders in the U.S. economy through a series of "Fed Listens" events. The Reserve Banks will hold forums around the country, in a town hall format, allowing the Federal Reserve to gather perspectives from the public, including representatives of business and industry, labor leaders, community and economic development officials, academics, nonprofit organizations, community bankers, local government officials, and representatives of congressional offices in Reserve Bank Districts [3] In addition, the Federal Reserve

(continued on next page)

1 In December 2004, the FOMC decided to begin publishing the minutes three weeks after every meeting, expediting the publication schedule to provide the public with more timely information

2 The statement is reprinted at the beginning of this report on p ii The FOMC also publishes transcripts of its meetings after a five-year lag For a review of the main communication tools used by the Federal Reserve and other central banks, see the document "Monetary Policy Strategies of Major Central Banks," which is available on the webpage "Monetary Policy Principles and Practice" on the Board's website at https://www.federalreserve.gov/monetarypolicy/monetary-policy-principles-and-practice.htm

3 "Fed Listens" events will be held at the Federal Reserve Bank of Dallas this February and at the Federal Reserve Bank of Minneapolis this April Other "Fed Listens" events will be announced in coming weeks

Federal Reserve Transparency *(continued)*

System will sponsor a research conference this June at the Federal Reserve Bank of Chicago, with academic speakers and non-academic panelists from outside the Federal Reserve System.

Beginning around the middle of 2019, as part of their review of how to best pursue the Fed's statutory mandate, Federal Reserve policymakers will discuss relevant economic research as well as the perspectives offered during the outreach events. At the end of the process, policymakers will assess the information and perspectives gathered and will report their findings and conclusions to the public.

This review complements other recent changes to the Federal Reserve's communication practices. In November 2018, the Board inaugurated two reports, the *Supervision and Regulation Report* and the *Financial Stability Report*.[4] These reports provide information about the Board's responsibility, shared with other government agencies, to foster the safety and soundness of the U.S. banking system and to promote financial stability. Transparency is key to these efforts, as it enhances public confidence, allows for the consideration of outside ideas, and makes it easier for regulated entities to know what is expected of them and how best to comply.

The *Supervision and Regulation Report* provides an overview of banking conditions and the current areas of focus of the Federal Reserve's regulatory policy framework, including pending rules, and key themes, trends, and priorities regarding supervisory programs. The report distinguishes between large financial institutions and regional and community banking organizations because supervisory approaches and priorities for these institutions frequently differ. The report provides information to the public in conjunction with semiannual testimony before the Congress by the Vice Chairman for Supervision

The *Financial Stability Report* summarizes the Board's monitoring of vulnerabilities in the financial system. The Board monitors four broad categories of vulnerabilities, including elevated valuation pressures (as signaled by asset prices that are high relative to economic fundamentals or historical norms), excessive borrowing by businesses and households, excessive leverage within the financial sector, and funding risks (risks associated with a withdrawal of funds from a particular financial institution or sector, for example as part of a "financial panic"). Assessments of these vulnerabilities inform Federal Reserve actions to promote the resilience of the financial system, including through its supervision and regulation of financial institutions.

Through all of these efforts to improve its communications, the Federal Reserve seeks to enhance transparency and accountability regarding how it pursues its statutory responsibilities.

4 The *Supervision and Regulation Report* and the *Financial Stability Report* are available on the Board's website at, respectively, https://www.federalreserve.gov/publications/2018-november-supervision-and-regulation-report-preface.htm and https://www.federalreserve.gov/publications/2018-november-financial-stability-report-purpose.htm.

Part 3
Summary of Economic Projections

The following material appeared as an addendum to the minutes of the December 18–19, 2018, meeting of the Federal Open Market Committee.

In conjunction with the Federal Open Market Committee (FOMC) meeting held on December 18–19, 2018, meeting participants submitted their projections of the most likely outcomes for real gross domestic product (GDP) growth, the unemployment rate, and inflation for each year from 2018 to 2021 and over the longer run.[19] Each participant's projections were based on information available at the time of the meeting, together with his or her assessment of appropriate monetary policy—including a path for the federal funds rate and its longer-run value—and assumptions about other factors likely to affect economic outcomes. The longer-run projections represent each participant's assessment of the value to which each variable would be expected to converge, over time, under appropriate monetary policy and in the absence of further shocks to the economy.[20] "Appropriate monetary policy" is defined as the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her individual interpretation of the statutory mandate to promote maximum employment and price stability.

All participants who submitted longer-run projections expected that, under appropriate monetary policy, growth in real GDP in 2019 would run somewhat above their individual estimate of its longer-run rate. Most participants continued to expect real GDP growth to slow throughout the projection horizon, with a majority of participants projecting growth in 2021 to be a little below their estimate of its longer-run rate. Almost all participants who submitted longer-run projections continued to expect that the unemployment rate would run below their estimate of its longer-run level through 2021. Most participants projected that inflation, as measured by the four-quarter percentage change in the price index for personal consumption expenditures (PCE), would increase slightly over the next two years, and nearly all participants expected that it would be at or slightly above the Committee's 2 percent objective in 2020 and 2021. Compared with the Summary of Economic Projections (SEP) from September, many participants marked down slightly their projections for real GDP growth and inflation in 2019. Table 1 and figure 1 provide summary statistics for the projections.

As shown in figure 2, participants generally continued to expect that the evolution of the economy, relative to their objectives of maximum employment and 2 percent inflation, would likely warrant some further gradual increases in the federal funds rate. Compared with the September submissions, the median projections for the federal funds rate for the end of 2019 through 2021 and over the longer run were a little lower. Most participants expected that the federal funds rate at the end of 2020 and 2021 would be modestly higher than their estimate of its level over the longer run; however, many marked down the extent to which it would exceed their estimate of the longer-run level relative to their September projections.

19. Five members of the Board of Governors, one more than in September 2018, were in office at the time of the December 2018 meeting and submitted economic projections.

20. One participant did not submit longer-run projections for real GDP growth, the unemployment rate, or the federal funds rate.

Table 1. Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents, under their individual assessments of projected appropriate monetary policy, December 2018
Percent

Variable	Median[1]					Central tendency[2]					Range[3]				
	2018	2019	2020	2021	Longer run	2018	2019	2020	2021	Longer run	2018	2019	2020	2021	Longer run
Change in real GDP	3.0	2.3	2.0	1.8	1.9	3.0–3.1	2.3–2.5	1.8–2.0	1.5–2.0	1.8–2.0	3.0–3.1	2.0–2.7	1.5–2.2	1.4–2.1	1.7–2.2
September projection	3.1	2.5	2.0	1.8	1.8	3.0–3.2	2.4–2.7	1.8–2.1	1.6–2.0	1.8–2.0	2.9–3.2	2.1–2.8	1.7–2.4	1.5–2.1	1.7–2.1
Unemployment rate	3.7	3.5	3.6	3.8	4.4	3.7	3.5–3.7	3.5–3.8	3.6–3.9	4.2–4.5	3.7	3.4–4.0	3.4–4.3	3.4–4.2	4.0–4.6
September projection	3.7	3.5	3.5	3.7	4.5	3.7	3.4–3.6	3.4–3.8	3.5–4.0	4.3–4.6	3.7–3.8	3.4–3.8	3.3–4.0	3.4–4.2	4.0–4.6
PCE inflation	1.9	1.9	2.1	2.1	2.0	1.8–1.9	1.8–2.1	2.0–2.1	2.0–2.1	2.0	1.8–1.9	1.8–2.2	2.0–2.2	2.0–2.3	2.0
September projection	2.1	2.0	2.1	2.1	2.0	2.0–2.1	2.0–2.1	2.1–2.2	2.0–2.2	2.0	1.9–2.2	2.0–2.3	2.0–2.2	2.0–2.3	2.0
Core PCE inflation[4]	1.9	2.0	2.0	2.0		1.8–1.9	2.0–2.1	2.0–2.1	2.0–2.1		1.8–1.9	1.9–2.2	2.0–2.2	2.0–2.3	
September projection	2.0	2.1	2.1	2.1		1.9–2.0	2.0–2.1	2.1–2.2	2.0–2.2		1.9–2.0	2.0–2.3	2.0–2.2	2.0–2.3	
Memo: Projected appropriate policy path															
Federal funds rate	2.4	2.9	3.1	3.1	2.8	2.4	2.6–3.1	2.9–3.4	2.6–3.1	2.5–3.0	2.1–2.4	2.4–3.1	2.4–3.6	2.4–3.6	2.5–3.5
September projection	2.4	3.1	3.4	3.4	3.0	2.1–2.4	2.9–3.4	3.1–3.6	2.9–3.6	2.8–3.0	2.1–2.4	2.1–3.6	2.1–3.9	2.1–4.1	2.5–3.5

NOTE: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are percent changes from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The projections for the federal funds rate are the value of the midpoint of the projected appropriate target range for the federal funds rate or the projected appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. The September projections were made in conjunction with the meeting of the Federal Open Market Committee on September 25–26, 2018. One participant did not submit longer-run projections for the change in real GDP, the unemployment rate, or the federal funds rate in conjunction with the September 25–26, 2018, meeting, and one participant did not submit such projections in conjunction with the December 18–19, 2018, meeting.

1. For each period, the median is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.
2. The central tendency excludes the three highest and three lowest projections for each variable in each year.
3. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year.
4. Longer-run projections for core PCE inflation are not collected.

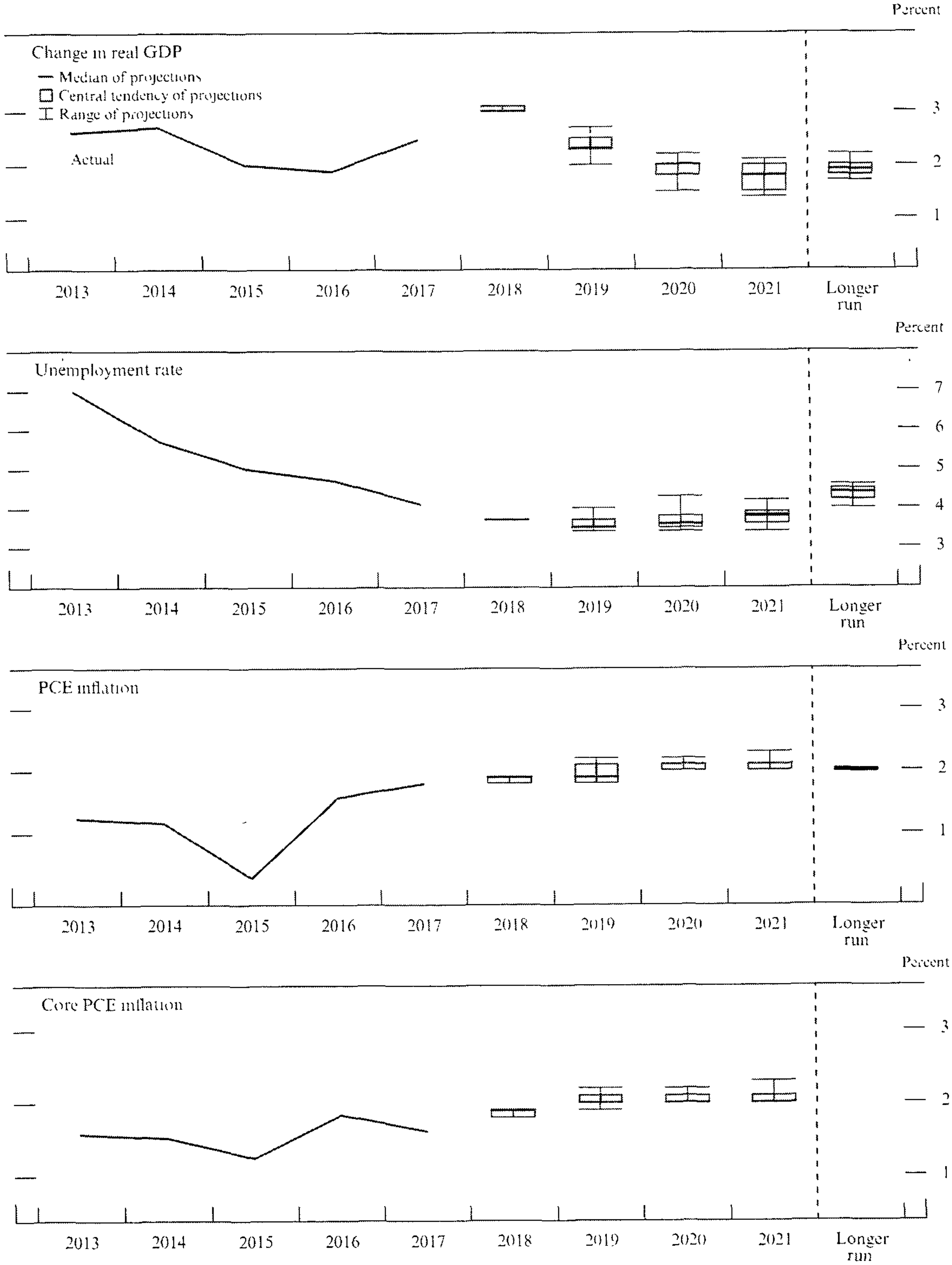
On balance, participants continued to view the uncertainty around their projections as broadly similar to the average of the past 20 years. While most participants viewed the risks to the outlook as balanced, a couple more participants than in September saw risks to real GDP growth as weighted to the downside, and one less participant viewed the risks to inflation as weighted to the upside.

The Outlook for Economic Activity

The median of participants' projections for the growth rate of real GDP for 2019, conditional on their individual assessment of appropriate monetary policy, was 2.3 percent, slower than the 3.0 percent pace expected for 2018. Most participants continued to expect GDP growth to slow throughout the projection horizon, with the median projection at 2.0 percent in 2020 and at 1.8 percent in 2021, a touch lower than the median estimate of its longer-run rate of 1.9 percent. Relative to the September SEP, the medians of the projections for real GDP growth for 2018 and 2019 were slightly lower, while the median for the longer-run rate of growth was a bit higher. Several participants mentioned tighter financial conditions or a softer global economic outlook as factors behind the downward revisions to their near-term growth estimates.

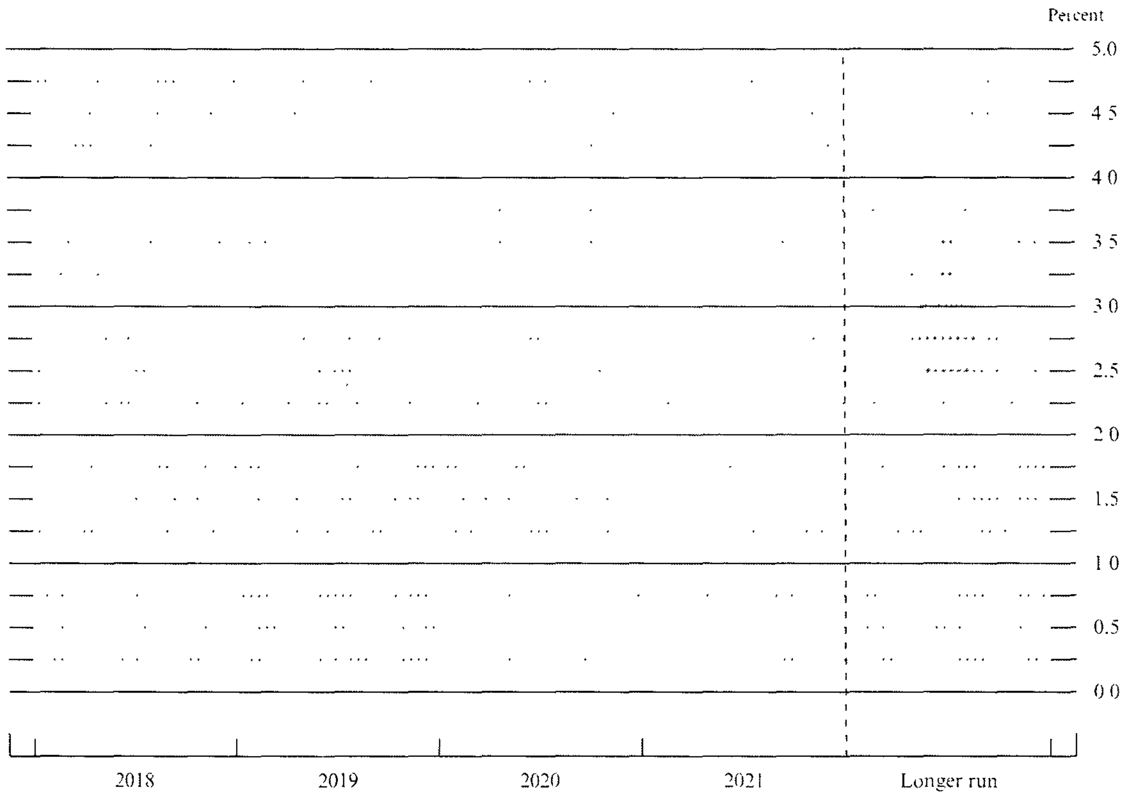
The median of projections for the unemployment rate in the fourth quarter of 2019 was 3.5 percent, unchanged from the September SEP and almost 1 percentage point below the median assessment of its longer-run normal level. With participants generally continuing to expect the unemployment rate to bottom out in 2019 or 2020, the median projections for 2020 and 2021 edged back up to 3.6 percent and 3.8 percent, respectively. Nevertheless, most participants continued to project that the unemployment rate in 2021 would still be well below their estimates of its longer-run level. The median estimate of the longer-run normal rate of unemployment was slightly lower than in September.

Figure 1. Medians, central tendencies, and ranges of economic projections, 2018–21 and over the longer run



NOTE. Definitions of variables and other explanations are in the notes to table 1 The data for the actual values of the variables are annual

Figure 2. FOMC participants' assessments of appropriate monetary policy: Midpoint of target range or target level for the federal funds rate



NOTE: Each shaded circle indicates the value (rounded to the nearest 1/8 percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. One participant did not submit longer-run projections for the federal funds rate.

Figures 3.A and 3.B show the distributions of participants' projections for real GDP growth and the unemployment rate from 2018 to 2021 and in the longer run. The distributions of individual projections for real GDP growth for 2019 and 2020 shifted down relative to those in the September SEP, while the distributions for 2021 and for the longer-run rate of GDP growth were little changed. The distribution of individual projections for the unemployment rate in 2019 was a touch more dispersed relative to the distribution of the September projections; the distribution moved slightly higher for 2020, while the distribution for the longer-run normal rate shifted toward the lower end of its range.

The Outlook for Inflation

The median of projections for total PCE price inflation was 1.9 percent in 2019, a bit lower than in the September SEP, while the medians for 2020 and 2021 were 2.1 percent, the same as in the previous projections. The medians of projections for core PCE price inflation over the 2019–21 period were 2.0 percent, a touch lower than in September. Some participants pointed to softer incoming data or recent declines in oil prices as reasons for shaving their projections for inflation.

Figures 3.C and 3.D provide information on the distributions of participants' views about the outlook for inflation. On the whole, the distributions of projections for total PCE price inflation and core PCE price inflation beyond this year either shifted slightly to the left or were unchanged relative to the September SEP. Most participants revised down slightly their projections of total PCE price inflation for 2019. All participants expected that total PCE price inflation would be in a range from 2.0 to 2.3 percent in 2020 and 2021. Most participants projected that core PCE inflation would run at 2.0 to 2.1 percent throughout the projection horizon.

Appropriate Monetary Policy

Figure 3.E shows distributions of participants' judgments regarding the appropriate target—or midpoint of the target range—for the federal funds rate at the end of each year from 2018 to 2021 and over the longer run. The distributions for 2019 through 2021 were less dispersed and shifted slightly toward lower values. Compared with the projections prepared for the September SEP, the median federal funds rate was 25 basis points lower over the 2019–21 period. For the end of 2019, the median of federal funds rate projections was 2.88 percent, consistent with two 25 basis point rate increases over the course of 2019. Thereafter, the medians of the projections were 3.13 percent at the end of 2020 and 2021. Most participants expected that the federal funds rate at the end of 2020 and 2021 would be modestly higher than their estimate of its level over the longer run; however, many marked down the extent to which it would exceed their estimate of the longer-run level relative to their September projections. The median of the longer-run projections of the federal funds rate was 2.75 percent, 25 basis points lower than in September.

In discussing their projections, many participants continued to express the view that any further increases in the federal funds rate over the next few years would likely be gradual. That anticipated pace reflected a few factors, such as a short-term neutral real interest rate that is currently low and an inflation rate that has been rising only gradually to the Committee's 2 percent objective. Some participants cited a weaker near-term trajectory for economic growth or a muted response of inflation to tight labor market conditions as factors contributing to the downward revisions in their assessments of the appropriate path for the policy rate.

Uncertainty and Risks

In assessing the appropriate path of the federal funds rate, FOMC participants take account of the range of possible economic outcomes, the likelihood of those outcomes, and the potential benefits and costs should they occur. As a reference, table 2 provides measures of forecast uncertainty—based on the forecast errors of various private and government forecasts over the past 20 years—for real GDP growth, the unemployment rate, and total PCE price inflation. Those measures are represented graphically in the "fan charts" shown in the top panels of figures 4.A, 4.B, and 4.C. The fan charts display the median SEP projections for the three variables surrounded by symmetric confidence intervals derived from the forecast errors reported in table 2. If the degree of uncertainty attending these projections is similar to the typical magnitude

Table 2. Average historical projection error ranges
Percentage points

Variable	2018	2019	2020	2021
Change in real GDP[1]	±0.8	±1.6	±2.1	±2.1
Unemployment rate	±0.1	±0.8	±1.5	±1.9
Total consumer prices[2]	±0.2	±1.0	±1.0	±1.0
Short-term interest rates[3]	±0.1	±1.4	±2.0	±2.4

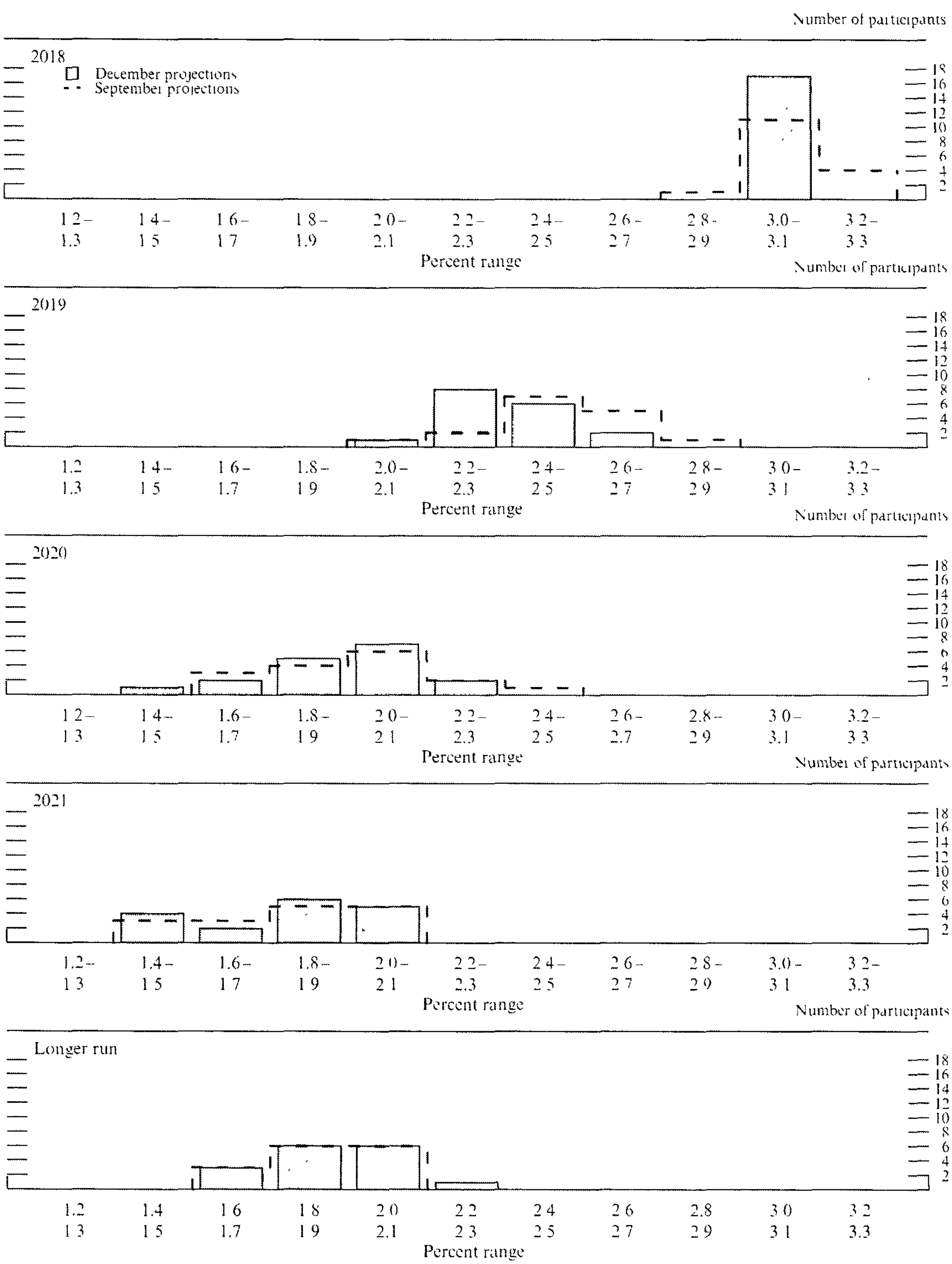
NOTE: Error ranges shown are measured as plus or minus the root mean squared error of projections for 1998 through 2017 that were released in the winter by various private and government forecasters. As described in the box "Forecast Uncertainty," under certain assumptions, there is about a 70 percent probability that actual outcomes for real GDP, unemployment, consumer prices, and the federal funds rate will be in ranges implied by the average size of projection errors made in the past. For more information, see David Reifschneider and Peter Tulip (2017), "Gauging the Uncertainty of the Economic Outlook Using Historical Forecasting Errors: The Federal Reserve's Approach," Finance and Economics Discussion Series 2017-020 (Washington: Board of Governors of the Federal Reserve System, February), [illegible].

1. Definitions of variables are in the general note to table 1.

2. Measure is the overall consumer price index, the price measure that has been most widely used in government and private economic forecasts. Projections are percent changes on a fourth quarter to fourth quarter basis.

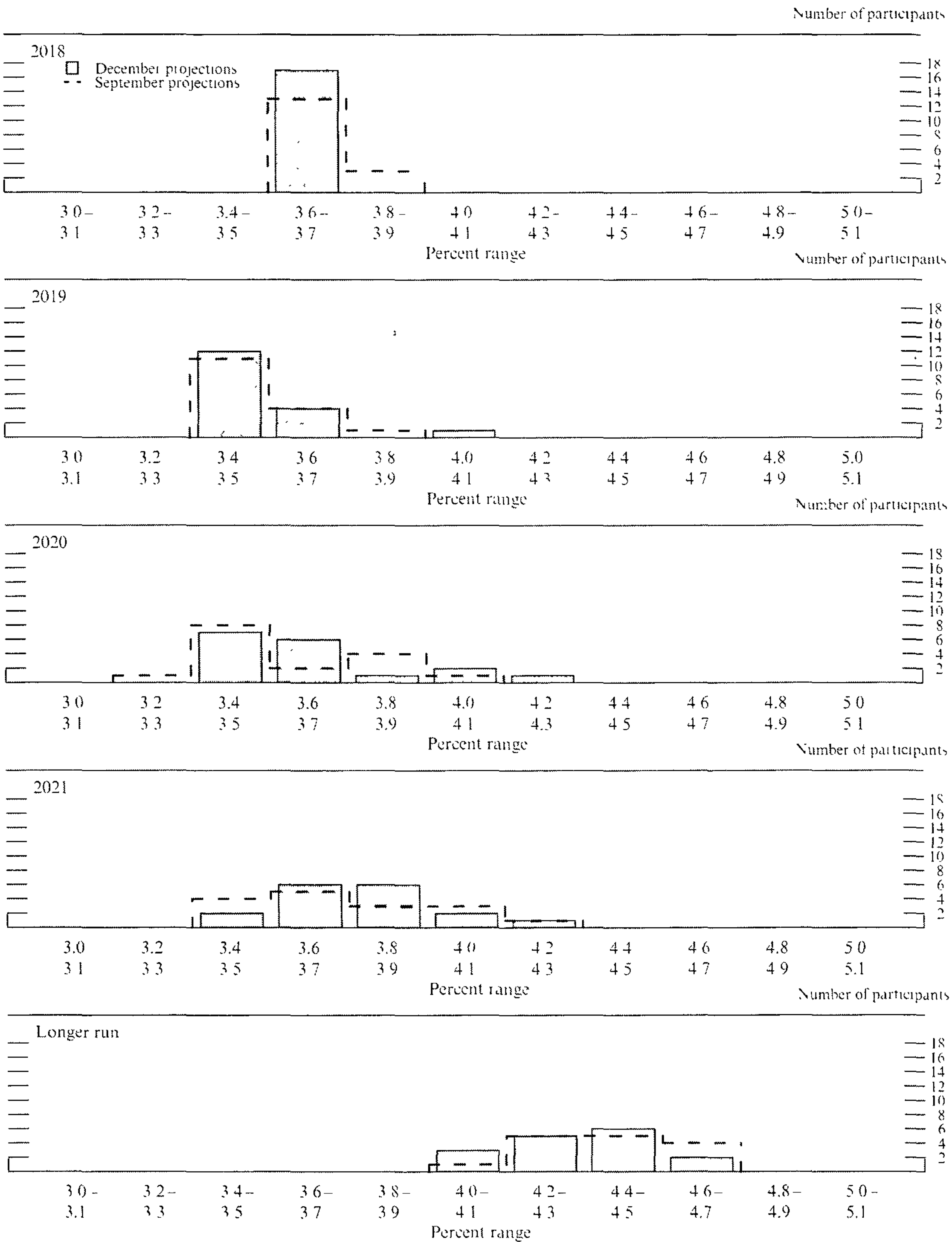
3. For Federal Reserve staff forecasts, measure is the federal funds rate. For other forecasts, measure is the rate on 3-month Treasury bills. Projection errors are calculated using average levels, in percent, in the fourth quarter.

Figure 3.A. Distribution of participants' projections for the change in real GDP, 2018–21 and over the longer run



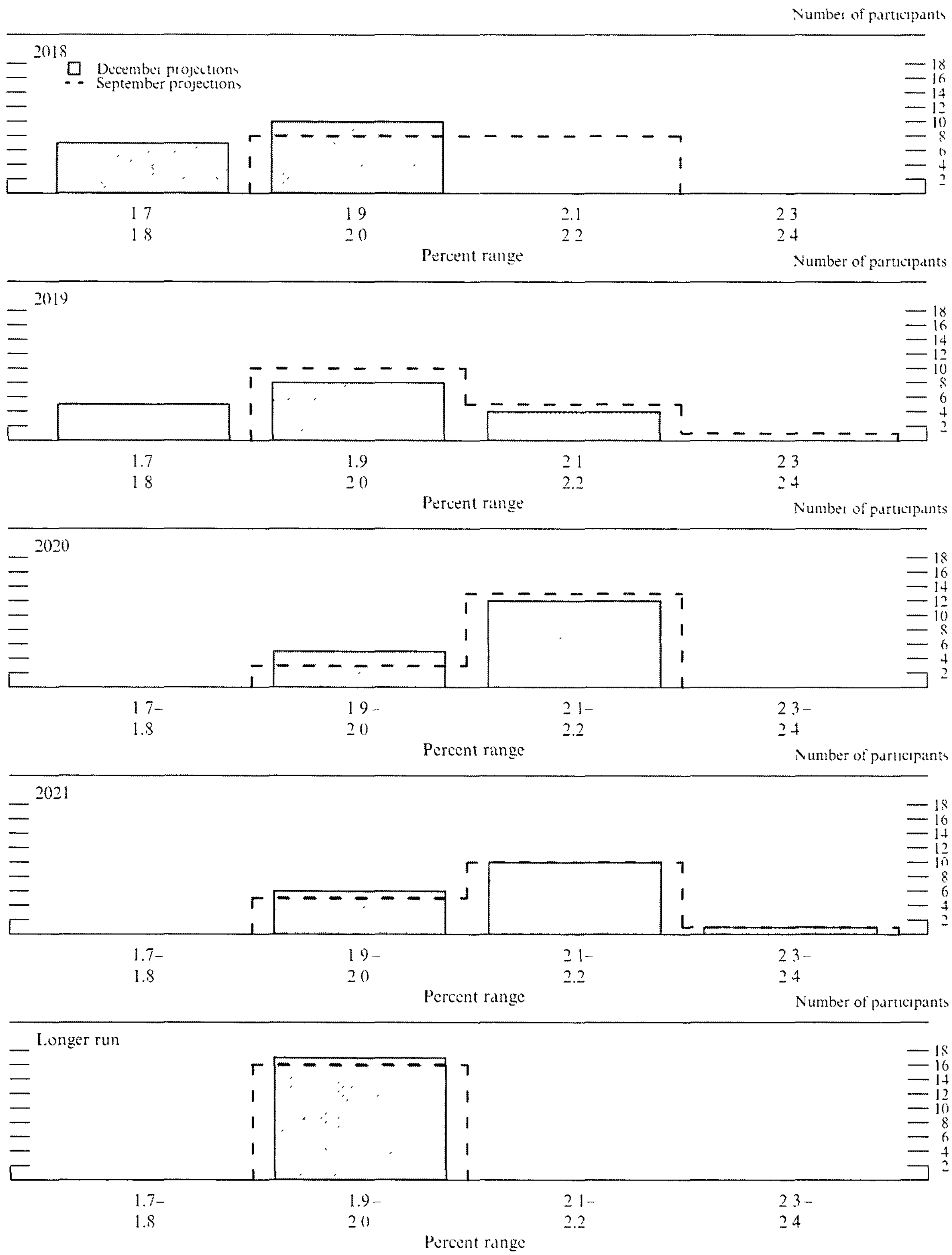
NOTE: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.B Distribution of participants' projections for the unemployment rate, 2018–21 and over the longer run



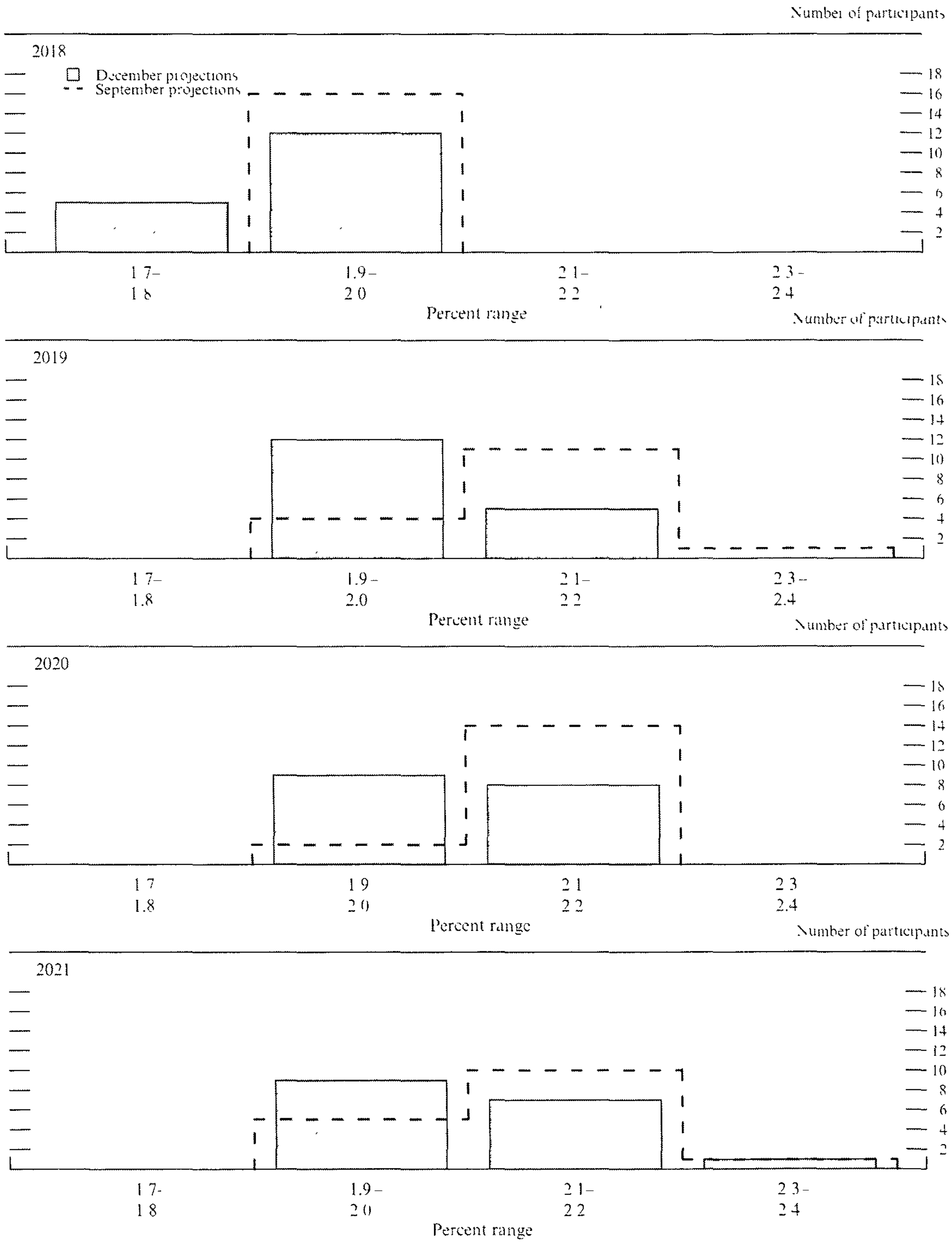
NOTE: Definitions of variables and other explanations are in the notes to table 1

Figure 3.C Distribution of participants' projections for PCE inflation, 2018–21 and over the longer run



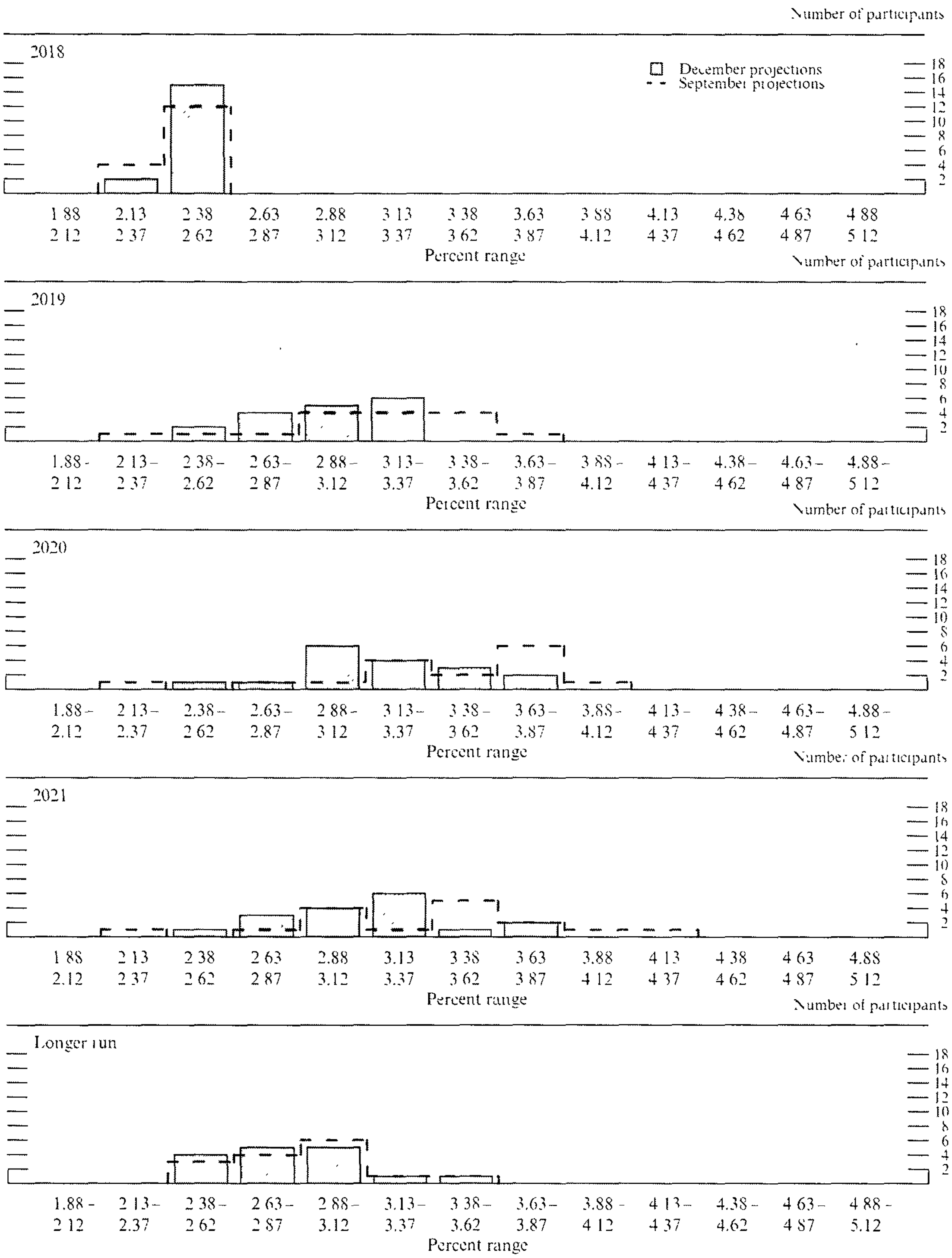
NOTE. Definitions of variables and other explanations are in the notes to table 1

Figure 3.D. Distribution of participants' projections for core PCE inflation, 2018–21



NOTE: Definitions of variables and other explanations are in the notes to table 1.

Figure 3.E Distribution of participants' judgments of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate, 2018–21 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1 of past forecast errors and the risks around the projections are broadly balanced, then future outcomes of these variables would have about a 70 percent probability of being within these confidence intervals. For all three variables, this measure of uncertainty is substantial and generally increases as the forecast horizon lengthens.

Participants' assessments of the level of uncertainty surrounding their individual economic projections are shown in the bottom-left panels of figures 4.A, 4.B, and 4.C. Participants generally continued to view the degree of uncertainty attached to their economic projections for real GDP growth and inflation as broadly similar to the average of the past 20 years.[21] A couple more participants than in September viewed the uncertainty around the unemployment rate as higher than average.

Because the fan charts are constructed to be symmetric around the median projections, they do not reflect any asymmetries in the balance of risks that participants may see in their economic projections. Participants' assessments of the balance of risks to their economic projections are shown in the bottom-right panels of figures 4.A, 4.B, and 4.C. Most participants generally judged the risks to the outlook for real GDP growth, the unemployment rate, headline inflation, and core inflation as broadly balanced—in other words, as broadly consistent with a symmetric fan chart. Two more participants than in September saw the risks to real GDP growth as weighted to the downside, and one less judged the risks as weighted to the upside. The balance of risks to the projection for the unemployment rate was unchanged, with three participants judging the risks to the unemployment rate as weighted to the downside and two participants viewing the risks as weighted to the upside. In addition, the balance of risks to the inflation projections shifted down slightly relative to September, as one less participant judged the risks to both total and core inflation as weighted to the upside and one more participant viewed the risks as weighted to the downside.

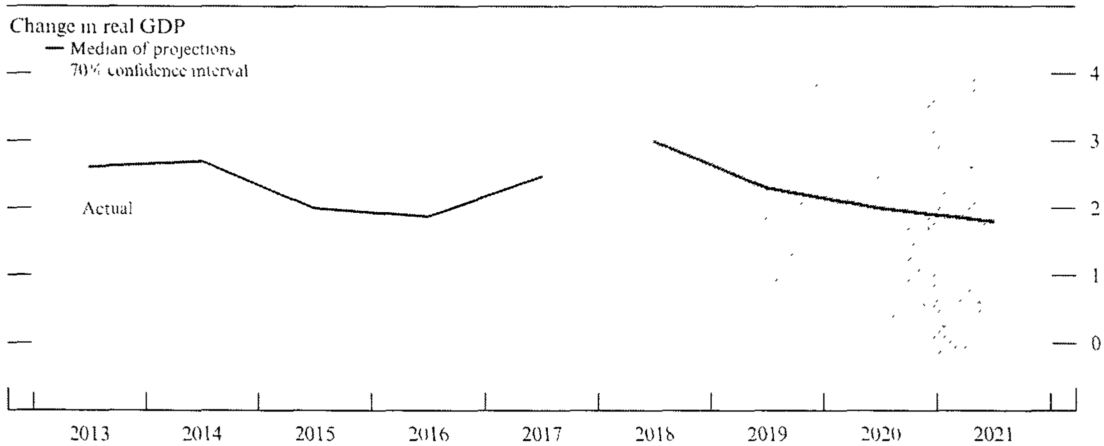
In discussing the uncertainty and risks surrounding their economic projections, participants mentioned trade tensions as well as financial and foreign economic developments as sources of uncertainty or downside risk to the growth outlook. For the inflation outlook, the effects of trade restrictions were cited as upside risks and lower energy prices and the stronger dollar as downside risks. Those who commented on U.S. fiscal policy viewed it as an additional source of uncertainty and noted that it might present two-sided risks to the outlook, as its effects could be waning faster than expected or turn out to be more stimulative than anticipated.

Participants' assessments of the appropriate future path of the federal funds rate were also subject to considerable uncertainty. Because the Committee adjusts the federal funds rate in response to actual and prospective developments over time in real GDP growth, the unemployment rate, and inflation, uncertainty surrounding the projected path for the federal funds rate importantly reflects the uncertainties about the paths for those key economic variables along with other factors. Figure 5 provides a graphical representation of this uncertainty, plotting the median SEP projection for the federal funds rate surrounded by confidence intervals derived from the results presented in table 2. As with the macroeconomic variables, the forecast uncertainty surrounding the appropriate path of the federal funds rate is substantial and increases for longer horizons.

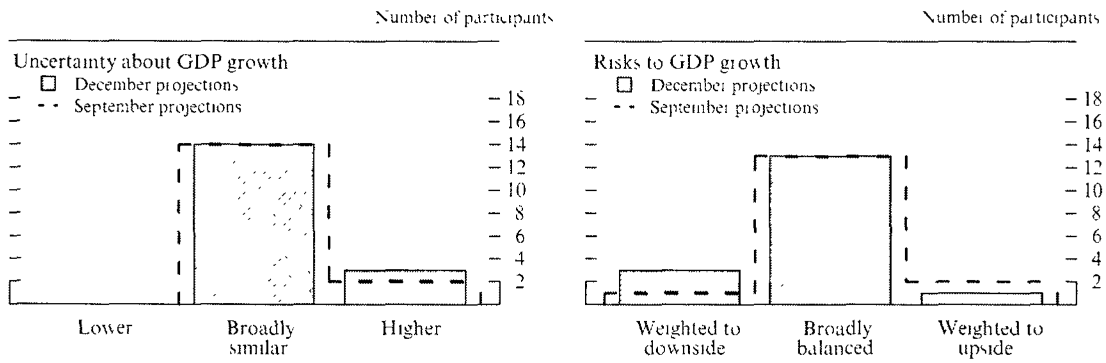
21. At the end of this summary, the box "Forecast Uncertainty" discusses the sources and interpretation of uncertainty surrounding the economic forecasts and explains the approach used to assess the uncertainty and risks attending the participants' projections

Figure 4 A. Uncertainty and risks in projections of GDP growth

Median projection and confidence interval based on historical forecast errors



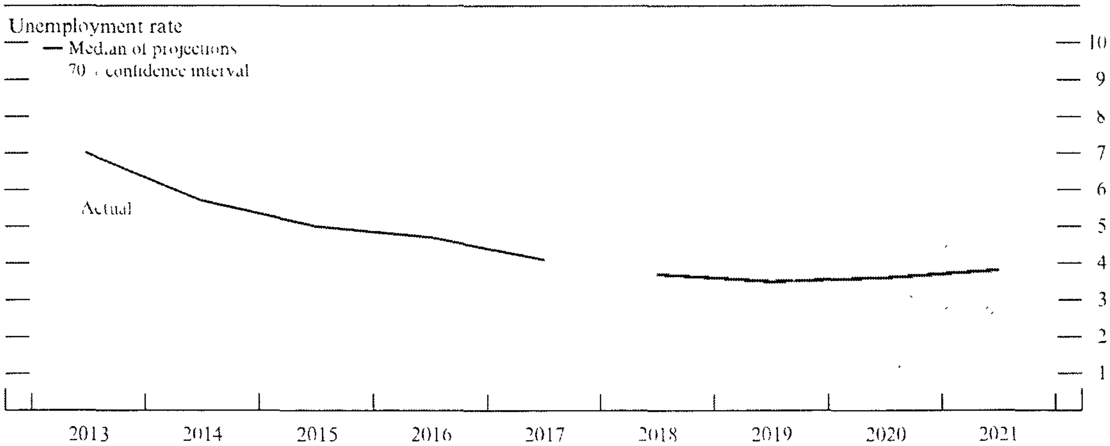
FOMC participants' assessments of uncertainty and risks around their economic projections



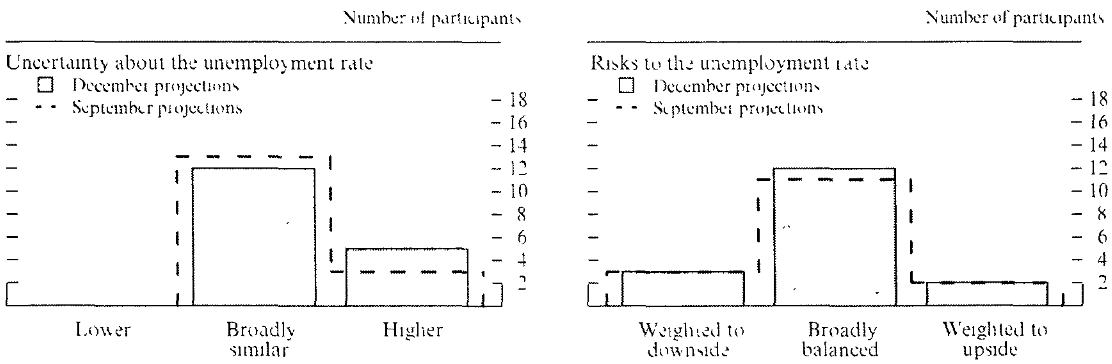
NOTE The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in real gross domestic product (GDP) from the fourth quarter of the previous year to the fourth quarter of the year indicated The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2 Because current conditions may differ from those that prevailed, on average over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty "

Figure 4.B Uncertainty and risks in projections of the unemployment rate

Median projection and confidence interval based on historical forecast errors

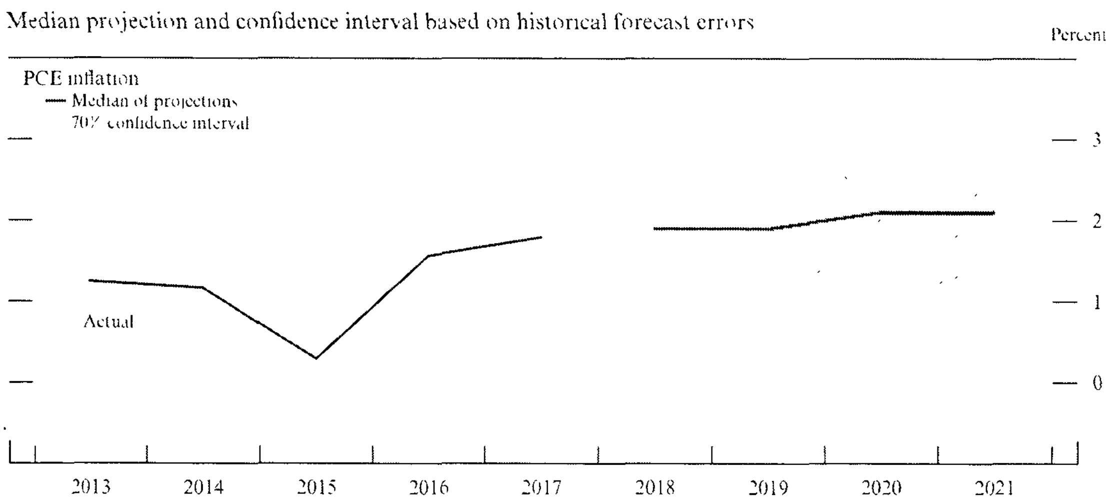


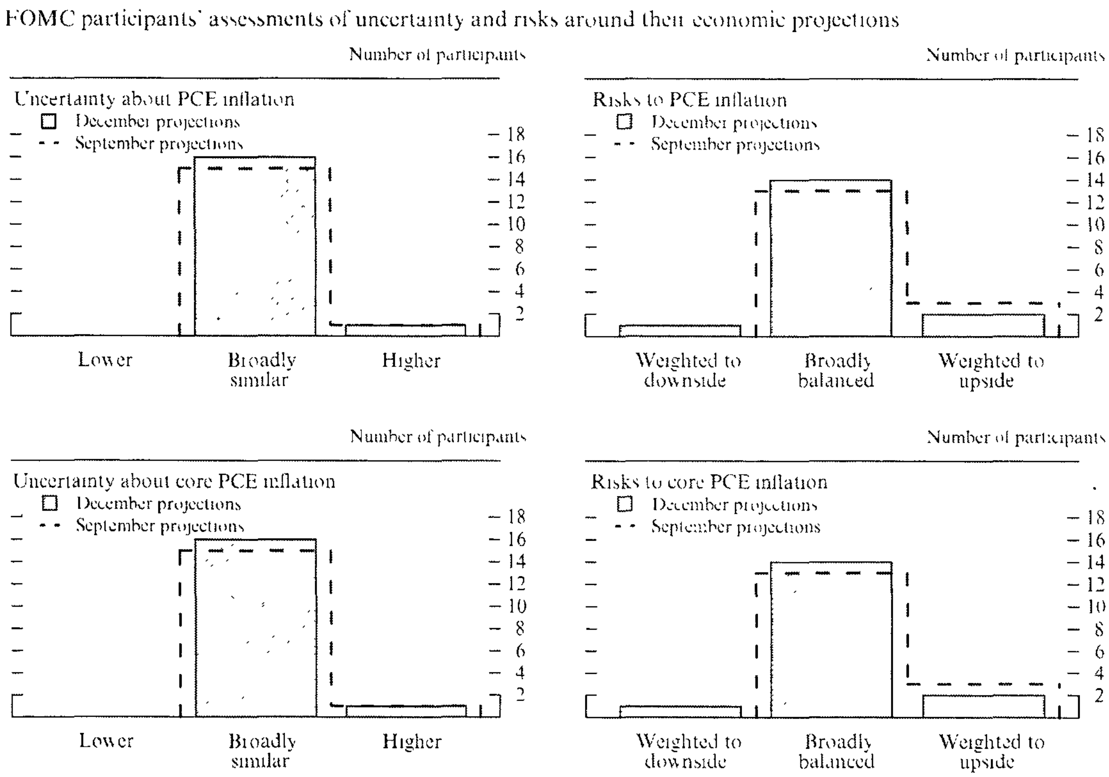
FOMC participants' assessments of uncertainty and risks around their economic projections



NOTE: The blue and red lines in the top panel show actual values and median projected values, respectively, of the average civilian unemployment rate in the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

Figure 4.C. Uncertainty and risks in projections of PCE inflation

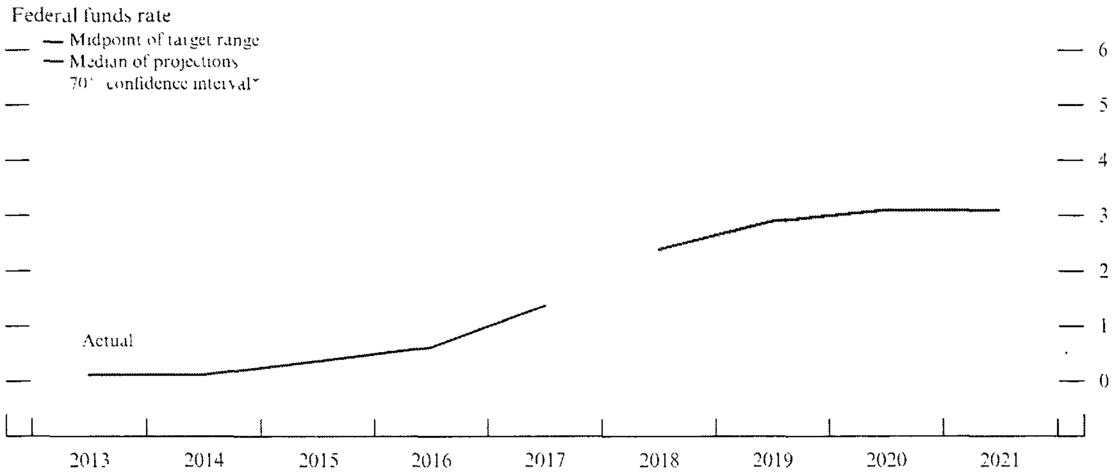




NOTE The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in the price index for personal consumption expenditures (PCE) from the fourth quarter of the previous year to the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2 Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

Figure 5. Uncertainty in projections of the federal funds rate

Median projection and confidence interval based on historical forecast errors



NOTE The blue and red lines are based on actual values and median projected values, respectively, of the Committee's target for the federal funds rate at the end of the year indicated The actual values are the midpoint of the target range, the median projected values are based on either the midpoint of the target range or the target level The confidence interval around the median projected values is based on root mean squared errors of various private and government forecasts made over the previous 20 years The confidence interval is not strictly consistent with the projections for the federal funds rate, primarily because these projections are not forecasts of the likeliest outcomes for the federal funds rate, but rather projections of participants' individual assessments of appropriate monetary policy Still, historical forecast errors provide a broad sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that may be appropriate to offset the effects of shocks to the economy

The confidence interval is assumed to be symmetric except when it is truncated at zero—the bottom of the lowest target range for the federal funds rate that has been adopted in the past by the Committee This truncation would not be intended to indicate the likelihood of the use of negative interest rates to provide additional monetary policy accommodation if doing so was judged appropriate In such situations, the Committee could also employ other tools, including forward guidance and large-scale asset purchases, to provide additional accommodation Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections

* The confidence interval is derived from forecasts of the average level of short-term interest rates in the fourth quarter of the year indicated, more information about these data is available in table 2 The shaded area encompasses less than a 70 percent confidence interval if the confidence interval has been truncated at zero

Forecast Uncertainty

The economic projections provided by the members of the Board of Governors and the presidents of the Federal Reserve Banks inform discussions of monetary policy among policymakers and can aid public understanding of the basis for policy actions. Considerable uncertainty attends these projections, however. The economic and statistical models and relationships used to help produce economic forecasts are necessarily imperfect descriptions of the real world, and the future path of the economy can be affected by myriad unforeseen developments and events. Thus, in setting the stance of monetary policy, participants consider not only what appears to be the most likely economic outcome as embodied in their projections, but also the range of alternative possibilities, the likelihood of their occurring, and the potential costs to the economy should they occur

Table 2 summarizes the average historical accuracy of a range of forecasts, including those reported in past *Monetary Policy Reports* and those prepared by the Federal Reserve Board's staff in advance of meetings of the Federal Open Market Committee (FOMC). The projection error ranges shown in the table illustrate the considerable uncertainty associated with economic forecasts. For example, suppose a participant projects that real gross domestic product (GDP) and total consumer prices will rise steadily at annual rates of, respectively, 3 percent and 2 percent. If the uncertainty attending those projections is similar to that experienced in the past and the risks around the projections are broadly balanced, the numbers reported in table 2 would imply a probability of about 70 percent that actual GDP would expand within a range of 2 2 to 3 8 percent in the current year, 1.4 to 4.6 percent in the second year, and 0.9 to 5 1 percent in the third and fourth years. The corresponding 70 percent confidence intervals for overall inflation would be 1 8 to 2.2 percent in the current year and 1 0 to 3 0 percent in the second, third, and fourth years Figures 4 A through 4 C illustrate these confidence bounds in "fan charts" that are symmetric and centered on the medians of FOMC participants' projections for GDP growth, the unemployment rate, and inflation. However, in some instances, the risks around the projections may not be symmetric. In particular, the unemployment rate cannot be negative; furthermore, the risks around a particular projection might be tilted to either the upside or the downside, in which case the corresponding fan chart would be asymmetrically positioned around the median projection.

Because current conditions may differ from those that prevailed, on average, over history, participants provide judgments as to whether the uncertainty attached to their projections of each economic variable is greater than, smaller than, or broadly similar to typical levels of forecast uncertainty seen in the past 20 years, as presented in table 2 and reflected in the widths of the confidence intervals shown in the top panels of figures 4.A through 4 C. Participants' current assessments of the uncertainty surrounding their projections are summarized in the bottom-left

(continued)

panels of those figures Participants also provide judgments as to whether the risks to their projections are weighted to the upside, are weighted to the downside, or are broadly balanced. That is, while the symmetric historical fan charts shown in the top panels of figures 4.A through 4.C imply that the risks to participants' projections are balanced, participants may judge that there is a greater risk that a given variable will be above rather than below their projections. These judgments are summarized in the lower-right panels of figures 4 A through 4.C.

As with real activity and inflation, the outlook for the future path of the federal funds rate is subject to considerable uncertainty. This uncertainty arises primarily because each participant's assessment of the appropriate stance of monetary policy depends importantly on the evolution of real activity and inflation over time If economic conditions evolve in an unexpected manner, then assessments of the appropriate setting of the federal funds rate would change from that point forward. The final line in table 2 shows the error ranges for forecasts of short-term interest rates. They suggest that the historical confidence intervals associated with projections of the federal funds rate are quite wide. It should be noted, however, that these confidence intervals are not strictly consistent with the projections for the federal funds rate, as these projections are not forecasts of the most likely quarterly outcomes but rather are projections of participants' individual assessments of appropriate monetary policy and are on an end-of-year basis However, the forecast errors should provide a sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that would be appropriate to offset the effects of shocks to the economy.

If at some point in the future the confidence interval around the federal funds rate were to extend below zero, it would be truncated at zero for purposes of the fan chart shown in figure 5; zero is the bottom of the lowest target range for the federal funds rate that has been adopted by the Committee in the past. This approach to the construction of the federal funds rate fan chart would be merely a convention; it would not have any implications for possible future policy decisions regarding the use of negative interest rates to provide additional monetary policy accommodation if doing so were appropriate. In such situations, the Committee could also employ other tools, including forward guidance and asset purchases, to provide additional accommodation.

While figures 4 A through 4.C provide information on the uncertainty around the economic projections, figure 1 provides information on the range of views across FOMC participants. A comparison of figure 1 with figures 4 A through 4.C shows that the dispersion of the projections across participants is much smaller than the average forecast errors over the past 20 years

Abbreviations

AFE	advanced foreign economy
BOE	Bank of England
C&I	commercial and industrial
CRE	commercial real estate
DFMU	designated financial market utility
EBITDA	earnings before interest, taxes, depreciation, and amortization
ECB	European Central Bank
EME	emerging market economy
EPOP	employment-to-population
EU	European Union
FOMC	Federal Open Market Committee; also, the Committee
GDP	gross domestic product
JOLTS	Job Openings and Labor Turnover Survey
LFPR	labor force participation rate
LSAP	large-scale asset purchase
MBS	mortgage-backed securities
Michigan survey	University of Michigan Surveys of Consumers
ON RRP	overnight reverse repurchase agreement
PCE	personal consumption expenditures
SEP	Summary of Economic Projections
SLOOS	Senior Loan Officer Opinion Survey on Bank Lending Practices
SSDI	Social Security Disability Insurance
TCJA	Tax Cuts and Jobs Act
TGA	Treasury General Account
TIPS	Treasury Inflation-Protected Securities
VIX	implied volatility for the S&P 500 index

U.S. DEPARTMENT OF THE TREASURY

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DATE	LT COMPOSITE (>10 Yrs)	TREASURY 20-Yr CMT	EXTRAPOLATION FACTOR
01/02/19	2.90	2.83	N/A
01/03/19	2.84	2.75	N/A
01/04/19	2.91	2.83	N/A
01/07/19	2.93	2.86	N/A
01/08/19	2.94	2.88	N/A
01/09/19	2.97	2.90	N/A
01/10/19	2.99	2.92	N/A
01/11/19	2.97	2.90	N/A
01/14/19	2.99	2.91	N/A
01/15/19	3.00	2.92	N/A
01/16/19	3.00	2.92	N/A
01/17/19	3.00	2.93	N/A
01/18/19	3.03	2.95	N/A
01/22/19	2.99	2.91	N/A
01/23/19	3.00	2.93	N/A
01/24/19	2.96	2.89	N/A
01/25/19	2.99	2.92	N/A
01/28/19	2.99	2.92	N/A
01/29/19	2.97	2.90	N/A
01/30/19	2.98	2.90	N/A
01/31/19	2.91	2.83	N/A
02/01/19	2.96	2.88	N/A
02/04/19	2.99	2.92	N/A
02/05/19	2.96	2.89	N/A
02/06/19	2.96	2.88	N/A
02/07/19	2.92	2.85	N/A
02/08/19	2.89	2.82	N/A
02/11/19	2.91	2.85	N/A
02/12/19	2.94	2.87	N/A
02/13/19	2.96	2.89	N/A
02/14/19	2.93	2.85	N/A
02/15/19	2.92	2.84	N/A

02/19/19	2 92	2.84	N/A
02/20/19	2 92	2 84	N/A
02/21/19	2 97	2 89	N/A
02/22/19	2.94	2 86	N/A
02/25/19	2.96	2 87	N/A
02/26/19	2 93	2.84	N/A
02/27/19	2 99	2 91	N/A
02/28/19	3.02	2 94	N/A
03/01/19	3 06	2 97	N/A
03/04/19	3 02	2 93	N/A
03/05/19	3 01	2 93	N/A
03/06/19	2.99	2 90	N/A
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04/03/19	2.84	2 75	N/A
04/04/19	2 83	2.74	N/A
04/05/19	2.81	2 72	N/A
04/08/19	2.83	2 74	N/A
04/09/19	2 82	2.73	N/A
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04/11/19	2 84	2 74	N/A
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04/16/19	2 90	2 81	N/A
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04/18/19	2 87	2 78	N/A
04/22/19	2 90	2 82	N/A
04/23/19	2 89	2 81	N/A
04/24/19	2 85	2 76	N/A
04/25/19	2.85	2 76	N/A
04/26/19	2 83	2 74	N/A

Treasury Long-Term Average Rate and Extrapolation Factors. Beginning February 18, 2002, Treasury ceased publication of the 30-year constant maturity series. Instead, from February 19, 2002 through May 28, 2004, Treasury published a Long-Term Average Rate, "LT>25," (not to be confused with the Long-Term Composite Rate, definitions below). In addition, Treasury published daily linear extrapolation factors that could be added to the Long-Term Average Rate to allow interested parties to compute an estimated 30-year rate. On June 1, 2004, Treasury discontinued the "LT>25" average due to a dearth of eligible bonds. In place of the "LT>25" average, Treasury published the Treasury 20-year Constant Maturity rate on this page along with an extrapolation factor that was added to the 20-year Constant Maturity to obtain an estimate for a theoretical 30-year rate. **On February 9, 2006, Treasury reintroduced the 30-year constant maturity and is no longer publishing the extrapolation factor.**

The Long-Term Average Rate, "LT>25," was the arithmetic average of the bid yields on all outstanding fixed-coupon securities (i.e , excluding Inflation-Indexed securities) with 25 years or more remaining to maturity This series first appeared on February 19, 2002, following discontinuation of the 30-year Treasury constant maturity series. Subsequently, the "LT>25" average was discontinued on June 1, 2004.

Linear Extrapolation Factors were determined by considering the slope of the yield curve at it's long end and extrapolating out to a theoretical 30-year point. To use the Extrapolation Factor to determine a 30-year proxy rate, add the factor to the 20-year Constant Maturity Rate. For example, if on a particular day the 20-year Constant Maturity was 5 40% and the Extrapolation Factor was 0.02%, then a 30-year theoretical rate would have been 5.40% + 0.02% = 5 42%. Publishing of the Linear Extrapolation Factors was discontinued on February 9, 2006 with the reintroduction of the 30-year Constant Maturity Rate.

The Long-Term Composite Rate is the unweighted average of bid yields on all outstanding fixed-coupon bonds neither due nor callable in less than 10 years.

For more information regarding these statistics contact the Office of Debt Management by email at debt.management@do treas gov.

Public Utility Commission of Texas

Memorandum

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PUBLIC UTILITY COMMISSION
FILING CLERK

To: Central Records

From: Darryl Tietjen, Rate Regulation

Re: Project No. 46046—**Report on Alternative Ratemaking Mechanisms**

Date: January 12, 2017

Please file in Project No. 46046 the attached ***Report on Alternative Ratemaking Mechanisms***.

This is the final version of the report that the Commission approved at its December 16, 2016 Open Meeting and that will be submitted to the Texas Legislature in compliance with Section 36.210 of the Public Utility Regulatory Act.

28

2017

Report to the 85th Texas Legislature

Alternative Ratemaking Mechanisms

Public Utility Commission of Texas
January 2017

ACKNOWLEDGEMENTS:

Public Utility Commission of Texas
Donna L. Nelson, Chairman
Kenneth W. Anderson, Jr., Commissioner
Brandy Marty Marquez, Commissioner

Brian H. Lloyd, Executive Director

Project Team
Darryl Tietjen

Bill Abbott
Anna Givens
Ruth Stark
Christina Switzer

Special thanks also to
Christensen Associates Energy Consulting, LLC

PUBLIC UTILITY COMMISSION OF TEXAS

January 15, 2017

Honorable Members of the 85th Texas Legislature:

We are pleased to submit to you the Commission's *Report and Recommendations on Alternative Ratemaking Mechanisms*, as required by Section 36.210 of the Public Utility Regulatory Act. This report includes an analysis of alternative ratemaking mechanisms adopted in other states and considers their possible use in Texas. The report also includes our recommendations regarding potential changes to the ratemaking process in Texas.

We look forward to continued collaboration with the Legislature as we work together to secure a bright energy future for Texas' residents, businesses, and industries. If you need additional information about the issues addressed in this report or any other PUC issues, please contact us.

Sincerely,

Donna L. Nelson
Chairman

Kenneth W. Anderson, Jr.
Commissioner

Brandy Marty Marquez
Commissioner

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Commission Recommendations 4

ATTACHMENT A: THE CHRISTENSEN REPORT

COMMISSION'S REPORT AND RECOMMENDATIONS ON ALTERNATIVE RATEMAKING MECHANISMS

Introduction

The Public Utility Commission of Texas (Commission) submits this report in response to Public Utility Regulatory Act (PURA) § 36.210, as amended by Senate Bill 774 of the 84th Legislature, Regular Session in 2015, which requires the Commission to "conduct a study and make a report analyzing alternative ratemaking mechanisms adopted by other states and... make recommendations regarding appropriate reforms to the ratemaking process in this state." This submission consists of two parts: the first part (this Commission Report) provides the Commission's assessment of the report prepared by Christensen Associates Energy Consulting, LLC[1] (the Christensen Report) and provides the Commission's final recommendations to the legislature; the second part (the Christensen Report, attached hereto as Attachment A) reviews and analyzes, as required by § 36.210, ratemaking mechanisms that have been adopted by other states and considers the applicability of these mechanisms to the rate-setting process in Texas.

Key Findings of the Christensen Report

The Christensen Report contains a comprehensive discussion and evaluation of various types of alternative ratemaking mechanisms that have been used by regulatory jurisdictions in other states. The report includes analyses of the following major categories of mechanisms, some of which allow for automatic rate adjustments that would entail significant revisions to Texas' ratemaking process:

- Formula rate plans;
- Revenue decoupling;
- Lost-revenue adjustment mechanisms;
- Multi-year rate plans;
- Price cap plans; and
- Straight fixed-variable rates.[2]

The Christensen Report also evaluates certain alternative ratemaking mechanisms that would make changes of a more incremental nature to the state's ratemaking process, including:[3]

[1] Commission Staff selected Christensen Associates Energy Consulting, LLC to prepare the report based on Staff's evaluation of submissions filed in response to the Commission's request for proposals in Project No. 45134, *RFP for a Contractor to Study and Make a Report Analyzing Alternative Ratemaking Mechanisms Adopted by Other States.*

[2] The use of straight fixed-variable rate design is currently within the Commission's authority and does not require legislative approval.

[3] The Christensen Report discussed and expressed support for the continued use in Texas of certain types of cost trackers already authorized, such as specific cost-recovery methods for transmission investment, distribution investment, advanced meters, and energy efficiency costs.

- Future test years;
- Earnings sharing mechanisms;
- Cost trackers;
- Infrastructure surcharges; and
- Performance incentive regulation.

In its discussion of each of the above types of ratemaking mechanisms, the Christensen Report identifies potential policy goals with respect to the setting of electricity rates and explains the ways in which the various mechanisms are designed to meet those goals. Additionally, the report evaluates the degree to which each ratemaking mechanism was deemed successful in the states in which it was used and considers its applicability to the Texas ratemaking environment.

In developing its recommendations regarding the use of alternative ratemaking mechanisms in Texas, the Christensen Report states that the choice among alternative ratemaking mechanisms and the design of those mechanisms depends upon the state's policy priorities. As the report states in its Executive Summary, a mechanism that meets one policy goal may fail to address—and may even conflict with—other policy goals. Ultimately, the Christensen Report recommends that the state consider a number of ratemaking policies for Texas, including the following:

- **Automatic updating of rates, which helps to reduce procedural costs.** The Christensen Report notes, however, that nearly all alternative ratemaking mechanisms require some degree of periodic review of revenue requirements and prudence of costs.
- **Establishing regular timeframes for adjusting rates and reconciling the adjustments with actual utility costs.** For example, major rates cases could be scheduled every three to five years, with automatic rate adjustments occurring annually.
- **Stabilizing utility recovery of fixed costs when energy usage significantly changes.** By decoupling cost recovery from usage variations, the use of a number of alternative ratemaking mechanisms—such as straight fixed-variable rates, revenue decoupling, and lost revenue adjustments—could serve to achieve this goal.
- **Assuring reasonable returns on equity (ROEs) with the use of earnings sharing mechanisms.** These mechanisms can be desirable as a means of maintaining ROEs within bands considered to be consistent with market-based returns.
- **Assuring rate stability by phasing in the use of alternative ratemaking mechanisms over a three- to five-year period.** To avoid or mitigate rate shock resulting from automatic rate adjustments, caps could be placed on the sizes of such adjustments, particularly rate increases. Rate adjustments that exceed the caps could be deferred for future recovery or refund.

Stakeholder Comments—Summary

After the filing of the Christensen Report, the Commission conducted a public hearing to receive stakeholder comments on the report. Additionally, parties filed follow-up written comments. Stakeholders provided a wide variety of viewpoints, which are briefly summarized below.

Stakeholders provided differing opinions on specific ratemaking mechanisms addressed in the Christensen Report. In general, utility companies expressed support for consideration and the possible use of alternative ratemaking mechanisms, while customer groups largely voiced opposition. Several parties expressed support for legislative clarification that would ensure that the Commission has the necessary statutory authority to adopt alternative ratemaking mechanisms, including those that would allow for automatic adjustment and pass-through of a utility's costs.

Some parties stated that the Christensen Report did not adequately address the question of whether alternative ratemaking mechanisms are appropriate for Texas. Although the report discussed several categories of alternative ratemaking mechanisms, these parties suggested that the report should have assessed whether current ratemaking practices properly address specific and much more narrow issues such as energy efficiency targets and performance bonuses, policies regarding renewable energy, the integration of new technologies such as distributed resources, and the appropriateness and affordability of rates paid by low-income customers, low-usage customers, and the elderly. Similarly, some parties filed comments regarding whether the Christensen Report should have provided a more detailed discussion of the impact of potential reforms on the Electric Reliability Council of Texas (ERCOT) energy-only market design and market participants, and other stakeholders filed comments on the differences between ERCOT and non-ERCOT areas with respect to the impact of alternative ratemaking mechanisms. Other parties, however, filed comments arguing that these types of issues are outside the scope of this report.

Parties also filed comments on potential requirements for the filing of periodic cost-of-service updates—in particular, transmission cost updates—and strengthening the Commission's earnings monitoring report. Opposing parties cited the potential for additional administrative burdens resulting from additional rate proceedings or the implementation of alternative ratemaking mechanisms, and these parties additionally commented that there are high transaction costs in every rate review and that requiring rate cases for the sake of having rate cases is not good public policy.

Commission Recommendations

At this time, the Commission does not believe that ratemaking mechanisms for transmission and distribution utilities that operate within ERCOT are in need of major revision. In fact, the Commission believes that existing streamlined methods of recovery are generally achieving their intended purposes.

- With respect to transmission rates, the Commission believes that adequate authority exists for the PUC to continue to refine these mechanisms to ensure timely recovery of investment while still ensuring rates are just and reasonable. To this end, for example, the Commission recently opened a new rulemaking proceeding in Project No. 46393 to evaluate certain revisions to the transmission rate mechanism.

- With regard to distribution rates, the Commission notes that the rate-adjustment provisions of PURA Section 36.210 (adopted in the 2011 session) appear to be working successfully to provide avenues for streamlined recovery of distribution investments, and that as the Commission, utility companies, and stakeholders have gained experience with this mechanism, rate adjustments have become less contentious.[4] The Commission notes that PURA Section 36.210 currently requires the Commission to provide a report prior to the 2019 legislative session analyzing this mechanism in advance of its scheduled expiration on September 1, 2019. The Commission recommends that the legislature consider whether, in light of this present report, it is now appropriate to permanently authorize this mechanism by eliminating the sunset date and the associated report.

The Commission believes that, at this time, the existing paradigm in which periodic rate proceedings are used in combination with already available streamlined recovery mechanisms is an efficient and effective way to balance the interests of all stakeholders and ensure that electric rates are just and reasonable. Additionally, reflecting the efficiencies of well-established practices in the rate-setting processes for the ERCOT utility companies, the Commission notes that a number of transmission-only companies have agreed to file administratively for rate reductions in light of Commission staff's analysis of their earnings reports.

With regard to the vertically integrated companies operating outside the ERCOT service area, the legislature may wish to consider authorizing certain mechanisms that could be used in conjunction with traditional ratemaking practices. The Commission notes that in recent years, certain key financial metrics of these companies have lagged in comparison to those of the ERCOT utility companies. For example, reported rates of return for the non-ERCOT companies

[4] The first application (filed in September 2014) for a change in distribution rates under PURA Section 36.210 required approximately four and a half months to process. In contrast, more recent applications (filed in April 2016) required approximately three and a half months.

have consistently been below Commission-authorized levels, sometimes materially. A key factor underlying this trend is that for a number of years the non-ERCOT companies have been placing into service significant amounts of additional capital investment, with recovery of the related costs delayed until appropriate Commission review. Consequently, reflecting efforts to obtain timely cost recovery for their increasing asset base, the non-ERCOT companies have in the past decade filed applications for comprehensive rate proceedings much more frequently than their ERCOT counterparts.[5] Nonetheless, "regulatory lag"—the time between the incurrence of a cost and recovery of that cost in rates—for the non-ERCOT companies may have been a contributing factor in these companies' comparatively lower levels of reported earnings.

The Commission believes that clarification of specific legislative intent with regard to the Commission's use of certain limited-scope ratemaking mechanisms expressly addressing the timing of cost recovery could, when warranted by company-specific circumstances and after proper consideration by the Commission, serve to ameliorate the potentially negative effects of regulatory lag. Such express authority for the Commission to use specific mechanisms for particular purposes could address the comparatively weaker financial conditions of the vertically integrated non-ERCOT utilities and, when or if circumstances warrant, be useful for ERCOT companies as well.

Specifically, based on the experiences of the Commission, the Commission believes that legislative clarification of Commission authority and discretion could be useful with respect to the Commission's use of at least three specific ratemaking mechanisms: 1) "tracker" mechanisms for cost items of unusual or special-case nature; 2) interim rates and discretion in implementing their effective dates;[6] and 3) "relate-back" provisions that allow for earlier effective dates of final approved rates.[7]

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[5] In contrast to the non-ERCOT utilities, the state's two largest transmission and distribution utility companies—Oncor Electric Delivery and CenterPoint Energy Houston Electric—have not filed an application for a comprehensive rate proceeding in approximately six years, while AEP Texas Central and AEP Texas North have not filed in over ten years. Currently, because of events related to the bankruptcy of Oncor's parent company, Oncor is expected to file a comprehensive rate proceeding in 2017, and the Commission expects the AEP utility companies, given the recent merger of AEP Texas Central and AEP Texas North, to soon begin considering filing for rate proceedings. Although at the present time it is not clear when CenterPoint may file its next comprehensive rate proceeding, the Commission staff continues to dedicate a substantial amount of focus on analysis of CenterPoint's earnings.

[6] PURA 36.109 permits the Commission to establish temporary rates during the pendency of a rate proceeding, although Commission procedural rules require either the agreement of all the parties or, after a contested hearing, if the utility can show good cause for the temporary rate. Practically speaking, because of the delay such a hearing will cause in establishing final rates for a utility, temporary rates have only been established where all parties agree.

[7] PURA Section 36.211 allows utilities to request that final rates be made effective 155 days after the rate-filing package is filed with the Commission. Because of the specificity of this section, the Commission does not believe that it has authority to adopt an earlier relate-back date absent legislative change.

The Commission believes that these recommended changes, in response to the legislative directive to the Commission to make "recommendations regarding appropriate reforms to the ratemaking process in this state," reflect the objective of identifying reasonable modifications to the existing ratemaking paradigm while doing so in an appropriately measured manner. The Commission believes that modifying the current system by implementing more substantial changes such as those outlined in the Christensen Report is premature at this time. Before any such changes are made, the Commission believes it would be wise to conduct further study and analysis.

The Commission believes that depending upon the fact-situations of a given utility, the use of certain ratemaking mechanisms (as discussed above and repeated in the listing below) may have merit and could provide the Commission explicitly with various means for more efficient regulation and allow for greater flexibility when addressing special circumstances in the process of setting electricity rates.

Accordingly, the Commission recommends the following specific legislative actions:

1. Provide the Commission with express authority to use the following ratemaking mechanisms and practices when deemed reasonable by the Commission:
   - "tracker" mechanisms for cost items of unusual or special-case nature;
   - authorization to adopt methods to streamline the ability of the Commission to set interim rates and implementation dates thereof;[8] and
   - increased flexibility in establishing "relate-back" provisions that allow for earlier effective dates of final approved rates.
2. With respect to distribution investment, eliminate the expiration date for PURA § 36.210, relating to *Periodic Rate Adjustments*, and the related provision in subsection (h) of that section requiring a study to inform the legislature of the need to continue the legislation.[9]
3. Affirm or acknowledge Commission authority to require periodic rate cases if appropriate based on a utility's individual circumstances or general industry policy.

[8] The Commission notes that as part of the transfer of the economic regulation of water utilities to the PUC, the legislature altered the rate-setting process to *reduce* the ability of water utilities to implement interim rates during the pendency of rate proceedings.

[9] Senate Bill 1693 of the 82nd Legislature, Regular Session in 2011, provided for the adjustment of a utility company's rates to allow for more timely recovery of costs related to investment in distribution plant. As noted previously in this report, this legislation is set to expire September 1, 2019.

ATTACHMENT A: THE CHRISTENSEN REPORT

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

ALTERNATIVE ELECTRICITY RATEMAKING MECHANISMS ADOPTED BY OTHER STATES

prepared for
Public Utility Commission of Texas

prepared by
Laurence D. Kirsch
Mathew J. Morey
Christensen Associates Energy Consulting LLC

May 25, 2016

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299

Voice 608.231.2266 Fax 608.231.2108

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ALTERNATIVE ELECTRICITY RATEMAKING MECHANISMS ADOPTED BY OTHER STATES

EXECUTIVE SUMMARY

Electricity rates have traditionally been set according to utilities' costs of service. To determine rates, the overall cost of service, called the "revenue requirement," is divided among functions (like generation, transmission, distribution, and customer service), then allocated among customer classes (like residential, commercial, industrial, and street lighting), and then assigned to billing determinants (like electrical energy consumed, peak power demand, and fixed monthly fees). Under traditional ratemaking, the price for each billing determinant for each class is basically the cost assigned to that billing determinant for that class divided by the quantity of that billing determinant for that class.

Over the past forty years, the electric power industry and its regulators have developed and experimented with a range of ratemaking mechanisms that depart from traditional embedded cost-based ratemaking. The development of these non-traditional ratemaking mechanisms has been spurred by the need to deal with uncertainties in input prices (like fuels) that are beyond utility control, by a desire to improve utilities' performance incentives, by the opportunities created by the restructuring of and competition in wholesale electricity markets, by public policy support for renewable energy, by technological progress in generation and information technologies, and by declining rates of electricity sales growth. In short, the evolution of the electric power industry is having and will continue to have substantial impacts on utility costs and on the considerations that influence how electricity should be priced.

This report responds to Senate Bill 774, through which the Texas Legislature has required the Public Utility Commission of Texas (PUCT) to analyze alternative ratemaking mechanisms adopted by other states and to provide a report thereon to the legislature by January 15, 2017. The bill reflects concerns that electric transmission and distribution (T&D) costs are increasing substantially over time. While PUCT rules allow T&D utilities (TDUs) to seek timely recovery of transmission infrastructure costs twice yearly, the rate adjustment mechanism that permits timely recovery of distribution infrastructure costs is scheduled to terminate on September 1, 2019. Prior to this expiration, the State of Texas would like to explore the types of ratemaking mechanisms that might be used to ensure timely cost recovery while preserving incentives to achieve the other goals that might be fostered by appropriate rate design.

Descriptions of Alternative Ratemaking Mechanisms

"Just and reasonable" retail electricity rates reflect a balancing of different objectives, including full recovery of utility costs, stable and predictable prices, fair prices, efficient consumption of electricity, reliable service, affordable electricity service, diverse and clean power resources, moderate regulatory burden, and public acceptability. Alternative ratemaking mechanisms should address these objectives.

The alternative ratemaking mechanisms that may be of interest to Texas are those that promise to streamline the regulatory process. Streamlining involves doing a better job of anticipating the future evolution of the utility's business, and thus may include specifying ways in which rates can automatically adjust over time in response to changes in the utility's business. Rate cases, or some other process for reviewing the utility's business conditions, will still be needed to confirm, at regular intervals, that the automatic adjustment mechanisms are yielding just and reasonable results and promoting prudent investments and operations; and regulatory proceedings that may include rate cases will also be needed to implement any changes in public policy that materially change the utility's business.

This report describes eleven alternative ratemaking mechanisms that are applicable to (and sometimes widely applied by) the U.S. electric power industry at the state level. These alternatives are all variants of traditional cost-of-service ratemaking, all of which rely on a determination of an initial revenue requirement through a cost-of-service study. But while traditional regulation generally allows rate changes relatively infrequently, the alternatives generally update the revenue requirement at regular intervals in response to changes in utility costs, sales, and profits. This updating mitigates the potential for rate shock and conflict among parties that sometimes accompany the relative infrequency of traditional rate cases.

The alternative ratemaking mechanisms that make broad revisions to traditional cost-of-service ratemaking are as follows:

- *Formula rate plans* use pre-specified formulas to calculate automatic rate adjustments to keep the utility's *actual* rate of return on equity (ROE) within or near a specified band around the *authorized* ROE. Formula rate plans can reduce the frequency and costs of rate cases, reduce utilities' financial risk and thereby reduce their costs of capital, allow customers to gain an early share of any cost efficiencies that the utility may develop between rate cases, allow rates to more closely track changes in electricity market conditions, and make rate changes more gradual over time. Only four states, mostly in the south, have formula rate plans for electric utilities.

- *Straight fixed-variable (SFV) rates* allow utilities to recover substantially all fixed costs through fixed monthly charges (per customer-month) or peak demand charges (per peak kW) that are independent of the volumes of electrical energy consumed. Volumetric charges (per kWh) are used to recover substantially all variable costs that depend primarily upon the energy consumed. By better aligning rates with costs, SFV rates improve utility recovery of fixed costs, provide customers with energy prices that are relatively efficient, mitigate or avoid the need to adjust rates in response to load changes, remove a disincentive to utility promotion of energy efficiency, encourage lower peak demands and higher load factors, and have more stable rates and lower administrative burdens than certain other ratemaking mechanisms. Only a few states have adopted SFV rates for electric utilities.

- *Revenue decoupling* adjusts energy prices to compensate for differences between actual sales and test-year sales per customer. Revenue decoupling encourages energy conservation by consumers, removes disincentives to utility promotion of energy efficiency, and protects utility recovery of fixed costs from fluctuations in sales per customer. Twenty states have adopted electric decoupling at one time or another, although five of these states have since let their decoupling mechanisms expire.
- *Lost revenue adjustment mechanisms (LRAMs)* adjust rates between rate cases to account for the impacts on utility sales of the conservation that was not considered in developing the general rate case forecasts. These mechanisms help make utilities indifferent to sales lost due to conservation, thus removing a disincentive to utility promotion of energy efficiency and reducing the need for frequent rate cases; and they appear to be associated with relatively high energy conservation. Twenty states have adopted LRAMs for electric utilities.
- *Multi-year rate plans* allow full true-ups to the utility's actual cost of service once every three to five years, with automatic rate adjustments occurring in the interim. These adjustments generally use external factors beyond the utility's control, thus reflecting changes in the utility's business environment rather than changes in the utility's actual revenues or costs. Multi-year rate plans give the utility temporary incentives to cut costs and improve performance, provide more predictable utility revenues and customer rates, spread investment-induced rate increases over relatively long periods, and require fewer general rate cases. Sixteen states have multi-year rate plans, though half of these are merely rate freezes.
- *Price cap plans* seek to encourage utilities to reduce costs by making retail electricity prices (or average unit revenues) exogenous to the utility. Prices (or average unit revenues) are allowed to increase no faster than some measure of inflation, minus some measure of productivity improvement for the electric power industry. The effect of this productivity adjustment is to mimic a competitive market by giving industry-wide productivity gains to customers and allowing utility shareholders to profit from efficiency gains that beat the industry average productivity improvement. Price caps provide strong incentives for production efficiency. We are not aware of any U.S. electric utilities that have adopted price or revenue caps in more than the narrow sense of indexing some costs to inflation.

The alternative ratemaking mechanisms that make incremental revisions to either traditional or broadly revised versions of cost-of-service ratemaking are as follows:

- *Future test years* can be used as the source of the projected data used in rate cases. The future test year approach has the advantage of using data that are appropriate for the period to which the data will apply. States are fairly evenly divided between those that use future test years and those that use historical test years.
- *Earnings sharing mechanisms* allow rate adjustments outside of general rate case proceedings when actual ROEs would otherwise fall outside of specified bands around authorized ROEs. No rate adjustment is made when actual ROEs fall within the band;

and rates are adjusted to share between customers and shareholders the excess or deficient earnings outside of the band. Earnings sharing mechanisms help hold down procedural costs of assuring that utilities' actual ROEs do not stray far from authorized ROEs due to the operation of automatic rate change mechanisms or to changing business conditions.

- *Cost trackers* allow utilities to use a formula or predefined rule to recover specific costs from customers outside of general rate cases. They provide timely recovery of significant costs that are beyond utility control, which reduces utilities' financial risk without compromising their performance and without, in the long run, increasing costs to consumers. Cost trackers are ubiquitous throughout the U.S.
- *Infrastructure surcharges* allow some capital cost recovery prior to the completion of a facility's construction. By spreading capital cost recovery over a longer period of time than is traditional, infrastructure charges mitigate rate shock, improve utilities' cash flow during construction, and avoid delays in capital cost recovery.
- *Performance incentive regulation* provides incentives for utilities to maintain or improve service quality. Performance incentives can help make regulatory goals and incentives explicit, improve performance, and focus regulatory attention on the achievement of desired outcomes rather than on the means of obtaining those outcomes. Many states have adopted performance incentives of one type or another.

Recommendations for Alternative Ratemaking Mechanisms

The choice among the alternative ratemaking mechanisms and the designs of those mechanisms depend upon Texas' policy priorities. A mechanism that meets one policy goal will fail to address other policy goals, and may even conflict with other policy goals.

To reduce procedural costs, rates should update automatically, with minimal need for review by the PUCT and intervenors. Nonetheless, nearly all of the alternative ratemaking mechanisms require at least periodic review of revenue requirements and the prudency of costs; and some, like price cap plans, require significant data that are not otherwise needed for reviewing the reasonableness of costs and rates.

To establish reasonable procedural timetables, there should be a regular timeframe for adjusting rates and reconciling them with utility costs. For example, major rate cases could be scheduled every three to five years, except under extraordinary circumstances; and automatic rate adjustments could occur annually, or perhaps semi-annually. The automatic rate adjustments would be accompanied by utility reports that would assure transparency, allow the PUCT and intervenors to review rate changes, and permit settlement negotiations if necessary.

To decouple cost recovery from load variations, three alternative ratemaking mechanisms are available: SFV rates, revenue decoupling, and LRAMs. They all stabilize utility recovery of fixed costs when loads significantly change, help reduce the importance of load forecasts in rate cases, and help mitigate utility disincentives for energy conservation. For Texas' TDUs, this need for decoupling is an issue only for residential and small non-residential customers, as large non-residential customers have no energy charges in their retail T&D rates.

Although only a few states have adopted SFV rates while many have adopted the two other alternatives, a competitive market would tend toward SFV rate structures, not revenue decoupling or LRAMs. Competitive markets have many examples of fixed-variable pricing structures in which customers pay a fixed fee that covers the provider's fixed costs and a variable fee that covers the provider's variable costs. By contrast, revenue decoupling and LRAMs are purely artifacts of regulation: in competitive markets, firms will go out of business if they raise the price one customer pays because some other customer decides to consume less.

Thus, to decouple cost recovery from load variations, Texas' basic choice is between a ratemaking alternative (SFV) that mimics competition but requires significant revision of present rates, and two ratemaking alternatives (revenue decoupling and LRAMs) that begin with existing rates but are artifacts of regulation that are relatively burdensome to maintain. Our preference is to gradually move rates from their uneconomic initial levels toward those implied by SFV, not merely based on the theory that SFV is the only one of the three alternatives that mimics competition but also based on the fact that competition is coming – and is already here – in the form of distributed generation. The cross-subsidies that are implicit in present rates will be unsustainable in the face of this competition. The key "virtue" of revenue decoupling and LRAMs that has induced many states to adopt these alternative ratemaking mechanisms is that they allow continuation of the present cross-subsidies.

To assure cost recovery, a limited set of cost trackers is warranted. In principle, Texas' present cost trackers appear to be reasonable and worthy of continuation in some form.

To assure prudency of costs, any streamlined ratemaking process should retain the ability of the PUCT and intervenors to review rate changes. To reduce potential conflicts during reviews, the data requirements and the methods for automatic rate adjustments need to be carefully defined at the outset of the design of the automatic adjustment programs.

To assure reasonable ROEs, earnings sharing mechanisms are desirable as a means of maintaining ROEs within bands consistent with market-based returns. At the inception of a TDU's automated rate change mechanisms, bands around the authorized ROE are defined within which no change would be made to the actual ROE. Actual ROEs would be ratcheted up or down when falling outside of the bands. The adjustment of any actual ROE falling outside the band could be limited to a pre-specified number of basis points in order to limit the volatility of rates over the plan period.

To assure service quality, performance incentives should accompany the operation of automatic rate adjustment mechanisms that might induce cost-cutting.

To promote energy conservation, SFV rates, revenue decoupling, and LRAMs can be used to remove a key disincentive to utility promotion of energy efficiency. Revenue decoupling, cost trackers, and performance incentives can be used to encourage energy conservation by consumers.

To assure rate stability, new alternative ratemaking mechanisms could be phased in over a three- to five-year period. To avoid or mitigate rate shock due to automatic rate adjustments, Texas could place caps on the sizes of such adjustments, particularly rate increases. Rate adjustments that exceed the caps could be deferred for future recovery or refund.

ALTERNATIVE ELECTRICITY RATEMAKING MECHANISMS ADOPTED BY OTHER STATES

INTRODUCTION

Since the energy crisis and widespread generation investment cost overruns of the 1970s, the electric power industry and its regulators have developed and experimented with a range of ratemaking mechanisms that depart from traditional embedded cost-based ratemaking. These include, but are not limited to, revenue decoupling, lost revenue adjustment mechanisms (LRAMs), cost-specific trackers and riders, formula-based ratemaking, and performance-based ratemaking. These mechanisms are all currently in use in one or more states, so they can be assessed on the basis of experience. Some of them may prove useful tools in Texas if they meet Texas' various policy goals, such as incorporating adequate incentives for cost control and price efficiency, enhancing the precision and timeliness of utilities' cost recovery, and reducing the costs of rate case proceedings.

Although the development of the non-traditional ratemaking mechanisms was initially spurred by gyrating fuel prices and reconsideration of the incentive effects of traditional ratemaking upon utility performance, their development can usefully be seen as a general response to the rapidly changing business conditions of the electric power industry. These changing conditions are the result of several factors, of which the following are preeminent:

- *Improving utilities' performance incentives* has been a goal of regulation for decades, as traditional ratemaking provides mixed incentives for cost control and technological innovation.
- *Restructuring of wholesale electricity markets* fostered a potential for retail competition by facilitating competing firms' ability to deliver power to customers, creating new trading possibilities, and providing vital new market information.
- *Public policy support for renewable energy* has resulted in substantial investments in wind power and in solar power, causing significant impacts on power system operations and costs, transmission and distribution (T&D) needs and costs, and distributed resource technologies available to retail electricity customers.
- *Technological progress* in generation and information technologies has improved power system operations and is facilitating development of distributed resources, thus affecting power system costs and competition for sales to retail customers.
- *Declining electricity sales growth* over the past two decades, and particularly since the financial crisis of 2008-2009, is pressuring utilities to cut costs and reform rate structures so that the fixed and variable components of retail rates better reflect the fixed and variable components of utility costs.

The foregoing factors will continue to induce future change in the power industry's business and operating conditions. They have had substantial impacts on utility costs and on the considerations that influence how electricity should be priced, and will continue to do so in the future.

This report responds to Senate Bill 774, through which the Texas Legislature has required the Public Utility Commission of Texas (PUCT) to analyze alternative ratemaking mechanisms adopted by other states and to provide a report thereon to the legislature by January 15, 2017. The bill specifically calls for "recommendations regarding appropriate reforms to the ratemaking process in this state" and "an analysis that demonstrates how the commission's recommended reforms would improve the efficiency and effectiveness of the oversight of electric utilities and ensure that rates are just and reasonable..." The bill reflects concerns that electric T&D costs are increasing substantially over time. While PUCT rules allow T&D utilities (TDUs) to seek timely recovery of transmission infrastructure costs twice yearly, the rate adjustment mechanism that permits timely recovery of distribution infrastructure costs is scheduled to terminate on September 1, 2019. Prior to this expiration, the State of Texas would like to explore the types of ratemaking mechanisms that might be used to ensure timely cost recovery while preserving incentives to achieve the other goals that might be fostered by appropriate rate design.

RETAIL ELECTRICITY RATEMAKING GOALS

"Just and reasonable" retail electricity rates reflect a balancing of different objectives. These objectives include the following.

- *Full Recovery of Utility Costs.* Rates should allow a reasonable opportunity for a prudent utility to receive sufficient revenues to attract new capital and avoid significant financial difficulties.
- *Stable and Predictable Prices.* Prices should change gradually over time. Rate shocks should be avoided.[10]
- *Fair Prices.* Rates should fairly allocate costs and risks among customer classes and between shareholders and customers. Rates should be non-discriminatory, reflect the relative costs of serving different customers, and minimize cross-subsidies.
- *Efficient Consumption of Electricity.* Rates should encourage customers to use efficient quantities of electricity. This generally means that prices should be based, to the extent possible, upon the utility's marginal costs of electricity production and delivery.
- *Reliable Service.* Rates should be consistent with promotion of power system reliability as measured by the frequency, duration, and magnitude of customer service outages. At a minimum, this means that rates should cover utilities' prudently incurred costs. It

[10] Throughout this report, the term "electricity prices" refers to a number of dollars per unit of electricity services consumed, while the term "electricity rates" encompasses electricity prices as well as other elements of tariff structures. For example, the electricity rate paid by an industrial customer might include prices for electrical energy consumed, peak power consumption, and a monthly customer charge.

may also mean that consumers should face high peak-period prices that encourage peak load reductions.

- *Affordable Electricity Service.* Rates should encourage prudent cost control on the part of the utility.
- *Diverse Power Resources.* Rates should be consistent with public policy goals regarding fuel diversity and access to less polluting energy resources. This generally means that rates should be sufficient to cover the costs of power plant operations that minimize pollution, land use impacts, and water use; and that customers may be offered options to purchase power from renewable resources.
- *Moderate Regulatory Burden.* Rates should be designed to minimize the need for regulatory proceedings to update rates.
- *Public Acceptability.* Rates should be widely acceptable to the public.

The foregoing objectives sometimes conflict with one another, which is why ratemaking inevitably involves policy trade-offs among objectives.

TRADITIONAL ELECTRICITY RATEMAKING PRACTICE

Rates are traditionally set according to utilities' costs of service. The overall cost is the "revenue requirement," which is calculated as follows:

$$\text{Revenue Requirement} = \text{Rate Base} \times \text{Rate of Return} + \text{Depreciation} + \text{Taxes} + \text{Operations and Maintenance Expenses}$$

where Rate Base is more or less the depreciated value of fixed assets, Rate of Return is a weighted average of the cost of debt and the return on equity capital, and Operations and Maintenance Expenses include labor and fuel costs.[11]

To determine rates, the revenue requirement is divided among functions (like generation, transmission, distribution, and customer service), then allocated among customer classes (like residential, commercial, industrial, and street lighting), and then assigned to billing determinants (like electrical energy consumed, peak power demand, and fixed monthly fees). The price for each billing determinant for each class is basically the cost assigned to that billing determinant for that class divided by the quantity of that billing determinant for that class. In principle, fixed monthly fees and demand charges are used to recover fixed costs, while energy charges are used to recover variable costs.

[11] The rate base component of the revenue requirement includes an amount determined to be a working capital allowance for fuel inventory. Certain fuel and purchased power costs are recovered through fuel factors and are not part of the base revenue requirement. TAC § 25.235 establishes the procedures for setting and revising fuel factors and for regularly reviewing the reasonableness of fuel expenses recovered through the fuel factors. TAC § 25.236 identifies the types of fuel expenses that are eligible for recovery through the fuel factor and reconciled through the fuel reconciliation process, the latter of which must occur at least every three years and may occur outside of a base rate proceeding. TAC § 25.237 provides the instructions for revising fuel factors. TAC § 25.231 describes the working capital allowance for fuel inventory to be included in the invested capital of the utility.

The data used to determine rates are for a Test Year, which may be a recent historical year or may be a future year to which the rates will apply.[12] Because of variations in circumstances such as weather, data may be normalized to reflect expectations for a "normal" year.

THE IMPETUS FOR RETAIL ELECTRICITY RATEMAKING REFORM

For decades, retail ratemaking reform has been driven by a desire to improve the incentive effects of traditional ratemaking on utility performance. In the wake of the wholesale restructuring of the 1990s and early 2000s, retail electricity ratemaking reform has also been driven by institutional changes at the wholesale level, public policy support for renewable energy sources, and advances in generation and information technologies. Since the financial crisis of 2008, the slowdown in the growth of electricity demand has been an additional consideration in ratemaking reform.

o **Improving Utilities' Performance Incentives**

Traditional electricity ratemaking provides mixed incentives for cost control and technological innovation. Utilities have strong incentives to cut costs during the regulatory lag between rate cases because they can generally keep any savings resulting from increased efficiency; but cost-of-service ratemaking passes these savings on to customers after a rate case is completed. The relatively poor incentives of traditional electricity ratemaking have contributed to utility performance that is often below that of comparable competitive industries with respect to asset utilization, innovation, and research and development.[13]

The electric power industry has been dominated by regulated monopolies because monopolies can be the most efficient providers of services with large economies of scale and scope. For electricity, a single firm can provide T&D services in a given area more cheaply than can multiple firms; and, until the 1980s, it was generally believed that a single firm could provide integrated generation and transmission services more cheaply than vertically disaggregated firms. On the other hand, competition can be a spur to technological innovation and cost cutting, which has in fact been a benefit of restructuring of wholesale electric markets.

For the purpose of improving performance, public policy has encouraged competition in generation and customer services. It has also led to retail ratemaking based upon various types of "incentive regulation," also known as "performance-based regulation."

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[12] Texas uses an historical test year that is adjusted for known and measureable changes. See TAC § 25.231.

[13] R. Lehr, "New Utility Business Models: Utility and Regulatory Models for the Modern Era," *The Electricity Journal*, 26(8): 35-53, 2013, http://www.americaspowerplan.com; and D. Malkin and P.A. Centolella, "Results-Based Regulation: A more dynamic approach to grid modernization," *Fortnightly Magazine*, March 2014, http://mag.fortnightly.com/article/Results-Based+Regulation/1652496/200086/article.html.

- **Restructuring of Wholesale Electricity Markets**

In the 1990s, federal law and regulatory action opened electric transmission networks to non-discriminatory access.[14] In the late 1990s and early 2000s, the creation of Independent System Operators and Regional Transmission Organizations provided new centralized markets for trading electric power services and greatly added to the transparency of wholesale electricity prices in most of the U.S. Both of these developments fostered a potential for retail competition, the first by facilitating competing firms' ability to deliver power to customers, the second by creating trading possibilities and providing vital market information that had not existed before. That potential became a reality as, again in the late 1990s and early 2000s, nearly half the states passed laws or reformed regulation so that retail customers could shop for their electricity suppliers, and nearly half the states mandated or strongly encouraged their utilities to divest generation so that wholesale and retail competition could complement each other.

- **Public Policy Support for Renewable Energy**

Public policy has provided substantial support for renewable energy, particularly wind and solar. Substantial federal tax credits encourage investment in renewable energy resources. States offer a plethora of loan and rebate programs in support of renewable energy, as well as the following major programs:[15]

- Corporate tax credits for investment in renewable energy resources (40 states);
- Personal tax credits for investment in renewable energy resources (42 states);
- Property tax incentives for investment in renewable energy resources (nearly all states);
- Renewable portfolio standards by which minimum percentages of electricity must be generated by specified renewable energy resources (30 states); and
- Net metering, which effectively pays the full retail rate for some self-generated electricity (42 states).

This public policy support has resulted in substantial investments in wind power and, to a lesser but growing extent, in solar power. These investments have had significant impacts on T&D needs and on how power systems must be operated. They have also had significant impacts on the power resource options available to retail customers, on the power system costs that must be recovered from retail electricity customers, and on the allocation of power system costs among customers.

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[14] In this regard, the seminal law was the Energy Policy Act of 1992 and the seminal regulatory reform, in 1996, was Order No. 888 of the Federal Energy Regulatory Commission.

[15] The listing and statistics are derived from information found at http://programs.dsireusa.org/. In the listing, "states" include the District of Columbia.

- **Technological Progress**

Technological progress has resulted in substantial improvements in the efficiency and performance of a wide range of generation resource types, including fossil fuel, nuclear, and renewable resources. Technology advances have increased the efficiency of customers' electricity-using equipment and devices, thus contributing to a reduction in electricity consumption relative to gross domestic product (GDP). Startling improvements in information technologies have facilitated significant efficiency gains in the coordination of power system resources, thereby also facilitating the incorporation into power systems of new resources like renewables, demand-side resources, and distributed resources in general. New information technologies have also helped implement competition among resources.

- **Declining Sales Growth**

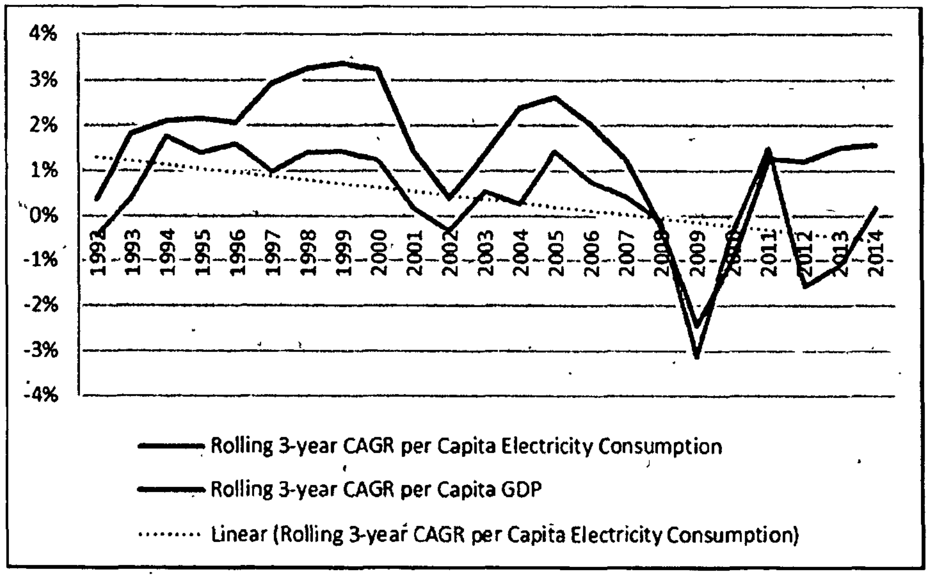
The electricity-intensity of the U.S. economy – that is, electricity consumption relative to GDP – has fallen in recent decades due to the technology advances just described as well as due to the shift of the U.S. economy from manufacturing toward service industries. The growth rate of electricity demand is today less than one half that of GDP, and is not expected to return to the higher levels experienced from 1975 to 1995, when electricity demand and GDP grew at about the same rate, or the two decades prior to that when electricity demand growth rates exceeded those of GDP.

Consistent with this falling electricity-intensity, **Figure 1** shows that, over the period 1992 to 2014, the rate of growth of per capita retail electricity sales slowed relative to the rate of growth of per capita real GDP, particularly since the financial meltdown of 2008-2009. To smooth out very short-term fluctuations, the figure shows three-year rolling compound annual growth rates (CAGRs) of sales and GDP. The trend line for retail sales growth signals a generally downward trend over the period, which is a departure from the relationship in previous decades during which electricity sales growth rates exceeded those of GDP. Since 1992, the growth rate of per capita electricity sales has generally lagged far behind that of GDP.

Under traditional ratemaking, a utility's ability to recover its authorized rate of return on equity (ROE) is compromised if its long-term investments are made in anticipation of forecast sales growth that turns out to be higher than actual sales growth. While utilities can substantially reduce variable costs in response to low sales, they cannot significantly reduce fixed costs. For competitive generation services, fixed cost recovery depends upon prices that are set by the market. For non-competitive services, including T&D, fixed costs are recovered through charges that are basically averaged over sales: when sales go down, the per-unit charge for recovery of these fixed costs goes up.

Because sales growth in recent years has been lower than the previous historical trend, and because distributed generation promises to limit future sales growth, utilities are concerned about their ability to recover fixed costs. Consequently, utilities are seeking ways by which rates for T&D services can be adjusted more or less automatically with changes in electricity sales.

Figure 1
Growth Rates of U.S. Per Capita Retail Electricity Sales and Real GDP, 1992-2014



REVIEW OF ALTERNATIVE RATEMAKING MECHANISMS

For all the reasons discussed in the preceding section, state legislatures, regulators, and utilities have sought alternatives to the traditional ratemaking mechanisms. Although this search is not a recent phenomenon, interest in and adoption of alternatives has increased significantly over the past decade. Many of the alternative mechanisms have been adopted to address the issue of regulatory lag associated with the traditional approach. "Regulatory lag" refers to the distance in time between a significant change in a utility's annual revenue requirement (or costs) and the effective date of implementation of rate changes that recognize the change in revenue requirement. During this time period, a utility's actual ROE may drift significantly above its authorized ROE, in which case customers arguably pay too much for utility service; or it may drift significantly below its authorized ROE, in which case the utility's ability to finance investment may be compromised.

Under traditional ratemaking, rates are changed only after a rate case in which the utility, interested stakeholders, and the regulator exchange information and debate outcomes. This process is costly in both time and money, which makes it desirable to have infrequent rate cases. On the other hand, rate cases that are too infrequent create a regulatory lag by which rates may fail to reflect significantly changed conditions that warrant revisiting cost allocations, the authorized ROE, and rate designs. Furthermore, infrequent rate cases can lead to utility earnings that are well above or below authorized ROEs.

The alternative ratemaking mechanisms that may be of interest to Texas are those that promise to streamline the regulatory process. Streamlining involves doing a better job of anticipating the future evolution of the utility's business, and thus may include specifying ways in which rates can automatically adjust over time in response to changes in the utility's business. Rate cases, or some other process for reviewing the utility's business conditions, will still be needed to confirm, at regular intervals, that the automatic adjustment mechanisms are yielding just and reasonable results and promoting prudent investments and operations; and regulatory proceedings that may include rate cases will also be needed to implement any changes in public policy that materially change the utility's business.

Other alternative ratemaking mechanisms of interest to Texas are those that promise to assure timely and efficient recovery of T&D costs. Senate Bill 774 is particularly motivated by the expiration of the periodic rate adjustment mechanism for recovery of distribution infrastructure costs, though the substantial transmission investment costs associated with connecting renewable resources to the Texas grid are also a motivating factor.

This section describes eleven alternative ratemaking mechanisms that are applicable to (and sometimes widely applied by) the U.S. electric power industry at the state level. These alternatives are all variants of traditional cost-of-service ratemaking, all of which rely on a determination of an initial revenue requirement through a cost-of-service study. But while traditional regulation allows rate changes on an infrequent basis that depends on when the utility determines that it needs to change rates to keep pace with changes in its costs and sales, the alternatives generally update the revenue requirement at regular intervals in response to changes in utility costs, sales, and profits. This updating mitigates the potential for rate shock and conflict among parties that sometimes accompany the relative infrequency of traditional rate cases. The alternatives can also differ from traditional regulation in how they allocate costs to energy, demand, and customer charges.

This section divides the alternative ratemaking mechanisms into two groups: those that make broad revisions to traditional cost-of-service ratemaking; and those that make incremental revisions to either traditional or broadly revised versions of cost-of-service ratemaking. These mechanisms are not entirely distinct, however, partly because they have overlapping elements and characteristics, and partly because different states use the same names to refer to programs that might be quite different. Consequently, the descriptions of these mechanisms reflect both the overlaps and the inconsistencies. For Texas, the substantive challenge is to identify the elements of these mechanisms that are most attractive and to combine them in coherent programs regardless of their names.

- **Broad Revisions to Cost-of-Service Ratemaking**

This section is concerned with six broad alternatives to cost-of-service ratemaking. Although costs of service serve as the foundation for all these alternatives, the six alternatives each make some fundamental changes in how rates are set.

Formula Rate Plans

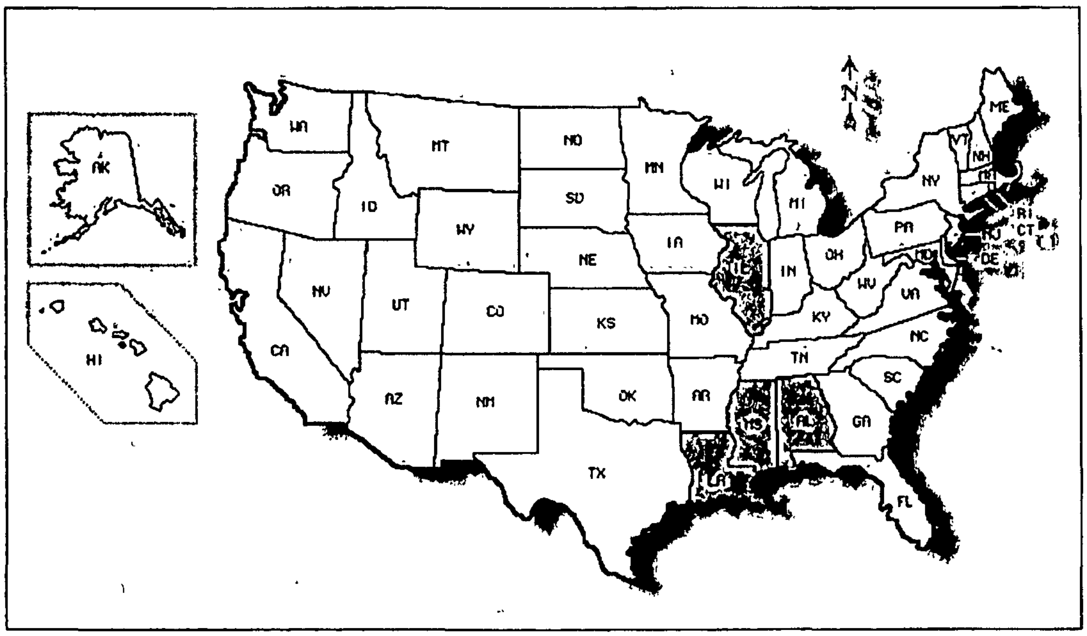
Formula rate plans (FRPs) use pre-specified formulas to calculate automatic rate adjustments to keep the utility's actual rate of ROE within or near a specified band around the authorized

ROE.[16] Such plans require specification of the initial base ROE, the band around the authorized ROE, the sharing between customers and shareholders of actual earnings that fall outside the band, any limits on the size of adjustments to the ROE, any performance standards that the utility must meet to qualify for adjustments to the ROE through performance adders, and monitoring and reporting requirements. Performance standards are important to assure that quality of service will not be impaired by any cost-cutting that is incented by the plan. The most recent general rate case provides the overall cost allocation and rate design methods, key parameters such as depreciation rates and the cash working capital allowance, and the formula for making rate adjustments.

At regular intervals, the cost basis for FRP rates is re-examined. Utilities are required to provide the cost and revenue information used in the formula. Regulatory review focuses on the prudence of utility costs and the utility's application of the formula.

Figure 2 shows that only four states, mostly in the south, have FRPs for electric utilities.[17]

Figure 2
Jurisdictions With Formula Rate Plans for Electric Utilities[18]



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[16] This definition is more or less that of K. Costello, "Formula Rate Plans: Do They Promote the Public Interest?," National Regulatory Research Institute, 10-11, August 2010, p. ii. M.N. Lowry, "PBR for the Electric 'Utility of the Future'," presentation, September 24, 2014, p. 20, offers a somewhat equivalent alternative definition under which FRPs annually adjust the revenue requirement to reflect certain cost changes.

[17] A fifth state, Missouri, has recently passed legislation promoting a version of an FRP that the legislation calls "performance-based" ratemaking.

[18] M.N. Lowry, M. Makos, and G. Waschbusch, *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, prepared for Edison Electric Institute, November 11, 2015.

- *Benefits and Shortcomings of Formula Rate Plans*

The benefits of FRPs include the following:

- They can reduce the frequency and costs of rate cases.
- They can reduce utilities' financial risk, thereby reducing their costs of capital.
- They can allow customers to gain an early share of any cost efficiencies that the utility may develop between rate cases.
- They allow rates to more closely track changes in electricity market conditions.
- They can make rate changes more gradual over time, meeting cost increases through rates that change by moderate amounts annually rather than by a single large amount in the aftermath of a general rate case.

On the other hand, formula rates have the following shortcomings:

- They tend to shift financial risks toward customers.
- Their automatic adjustment of rates can result in less thorough review of utility costs by regulators.
- Their reduced regulatory lag may reduce utility incentives to control costs between general rate cases.

These shortcomings can be mitigated by limiting the circumstances in which rate adjustments are made. For example, adjustments may be allowed only when particular circumstances cause ROE to fall outside the band. The shortcomings can also be mitigated by requiring utilities to demonstrate the prudence of any unexpected costs that imply the need for a rate increase.

- *State Experience with Formula Rate Plans*

<u>Alabama</u>

Alabama Power Company (APCO) has had an FRP, called the Rate Stabilization and Equalization plan, since 1982. The Alabama Public Service Commission (APSC) annually examines the reasonableness of APCO's costs and compares APCO's expected ROE to its authorized ROE range on its retail business. Public meetings throughout APCO's service territory accompany the annual reviews. If necessary, the APSC adjusts APCO's base revenues and rates to keep the expected ROE within the authorized range. To mitigate rate shock, annual rate increases may not exceed 5% and the average annual rate increase over any two-year period may not exceed 4%.

By December 1 of each year, APCO provides to the APSC its projected retail ROE for the next year, with an analysis of the main causes of the need for any rate adjustment. In December, relevant parties discuss whether and why a rate adjustment may be needed. Any necessary adjustment begins with January billings.

By March 1 of each year, APCO provides to the APSC a calculation of its actual retail ROE for the prior calendar year. If APCO's actual ROE exceeds the authorized range, APCO refunds the excess to customers. If its actual ROE was below the authorized range, no action is taken.

In addition to the annual reviews, the APSC regularly monitors and examines APCO's operations, expenses, and budgets.

The APSC supports the continuation of the Rate Stabilization and Equalization plan because it is less adversarial than the traditional cost-of-service regulation process. Nonetheless, APSC made some revisions to the plan in 2013. To reduce the ROE over time, the APSC changed the ROE range of reasonableness so as to increase APCO's equity ratio.[19] The APSC also increased its oversight of APCO by requiring that APCO make semi-annual rather than annual financial reports, by requiring APCO to produce five-year historical performance reports, and by including the Attorney General in the APSC's ongoing review process.

Illinois

Illinois' FRPs incent the state's two largest utilities to invest in T&D upgrades and advanced metering infrastructure. The two utilities have the option of adopting FRPs for their distribution rates if their investments in such infrastructure over a ten-year period meet certain targets: $360 million to $720 million for Ameren Illinois; and $1.5 billion to $3.0 billion for Commonwealth Edison. During the investment program's peak year, Ameren Illinois and Commonwealth Edison must respectively create at least 450 and 2,000 full-time equivalent jobs or make payments to a state job training program. A utility's failure to meet these requirements or certain other performance targets can result in discontinuation of the formula rate, at which time the utility's rates remain unchanged until reset in the next general rate case.

Authorized ROEs are set at current yields of 30-year U.S. Treasury bonds for the applicable year plus 6%. Rates are adjusted to keep actual ROEs within 0.5% of the authorized levels; but residential rates may not rise by more than 2.5% per year. Rates also depend upon various performance measures, such as budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance.

The 2011 legislation that authorized the FRPs (Public Act 097-0616) mostly sunsets at the end of 2017. By that time, the Illinois Commerce Commission must report to the legislature on the infrastructure program and the FRPs.

Louisiana

Entergy's three Louisiana affiliates have FRPs that were initiated in the years 1992 through 2008. The 2008 FRP initiated for Entergy New Orleans led to five years of rate reductions, a

[19] Alabama Public Service Commission, *Public Proceeding Established to Consider Any Necessary Modification to Rate Stabilization and Equalization Mechanism Applicable to Alabama Power Company*, Dockets 18117 and 18416, Report and Order, August 21, 2013, obtained at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx%3FId%3D13e2bb0b-6bfd-46d7-b5cf-78966693820a+&cd=4&hl=en&ct=clnk&gl=us

happy result that may have been less attributable to the FRP than to the happenstance of natural gas price decreases in the years following 2008.

All three FRPs adjust rates annually to bring actual ROEs within bands. ROE deviations greater than 0.05% trigger adjustments to base revenue requirements. Special consideration may be given to extraordinary events that have costs that significantly affect ROEs. The annual evaluation process requires several months and extensive communications among parties.

The FRPs are accompanied by trackers for the costs of environmental compliance, energy efficiency program implementation, renewable generation capacity, and other specific endeavors.

Mississippi

The FRP for Mississippi Power Company was initiated in 1986 and that for Entergy Mississippi was initiated in 1992. These two very similar FRPs use pre-determined formulas to adjust base rates between rate cases in response to changes in economy-wide inflation rates, overall economic activity, and utility costs. Near the end of each year, the utilities file updates to their FRPs for the forthcoming year, which determines whether rates need to be changed to be within 0.50% of the ROE targets. Hearings are scheduled for "major" changes as defined by Mississippi statute.

Early in each year, the utilities submit calculations of their actual ROEs for the preceding year. If the actual ROEs deviate by more than 0.50% from the ROE targets, the utilities refund to current customers or charge current customers amounts of money sufficient to bring actual ROEs within 0.50% of the targets. In no event, however, may the revenue adjustment for the prior year plus any other revenue adjustment for the same prior year exceed 4% of the utility's annual aggregate retail revenues for that prior year.

The ROE targets are adjusted for each utility's performance rating. The performance rating is based upon an aggregate of three performance metrics:

- The utility's average retail price per kWh relative to those of peer utilities, which are other vertically integrated investor-owned utilities in the Southeastern U.S.
- Customer satisfaction with the utility as measured by a semi-annual Commission-administered customer opinion survey conducted by independent professional survey firms. The current performance rating is based upon the average results of the two most recent surveys.
- Customer service reliability as measured by the percentage of time that electric service was available to customers during a recent thirty-six month period.

Straight Fixed-Variable Rates

Utilities have variable costs that depend primarily upon the volumes of electrical energy consumed, and they have fixed costs that depend primarily upon numbers of customers or peak loads. Under traditional ratemaking, large shares of fixed costs are recovered through volumetric charges (dollars per kWh) rather than through fixed monthly charges (dollars per customer-month) or peak demand charges (dollars per peak kW). This traditional approach leads to systematic mismatches between utility revenues and costs: growing sales cause utility revenues to rise faster than costs, while shrinking sales cause utility revenues to fall faster than costs.

To foster a better match between utility revenues and costs, straight fixed-variable (SFV) rates allow utilities to recover substantially all fixed costs through fixed monthly charges or peak demand charges that are independent of the volumes of electrical energy consumed. Volumetric charges are used to recover substantially all variable costs that depend primarily upon the energy consumed.

Most SFV applications have eliminated volumetric charges as a means of recovering the costs of base rate inputs. The lost volumetric revenues are recovered through fixed customer charges or reservation charges that vary with expected peak demand. Fixed charges tend to be used for residential and small non-residential customers, while reservation or other peak demand charges are used for larger customers with interval or other advanced meters.

SFV can be applied with fixed charges or demand charges that are differentiated across time or customer groups. Fixed charges can be constant all year or vary by season, though seasonal variation would not likely improve customer welfare or consumption efficiency. On the other hand, well-designed seasonal or on peak demand charges could improve customer welfare and consumption efficiency while reducing the impact of demand charges upon customers that operate at off-peak times. SFV charges can apply the same fixed charge to all customers in a service class, or can have a "sliding scale" mechanism that assigns lower fixed charges to customers who have historically had relatively low consumption and higher fixed charges to customers who have historically had relatively high consumption.[20] Nonetheless, most SFV rate designs implemented to date use the same charge for all customers within each class.

Table 1 lists four states that have adopted SFV rates over the past decade for five of their electric utilities.[21] The scarce application of this ratemaking alternative is probably due to the disinclination of regulators to raise bills for low-volume customers who are often perceived to have low incomes, and to the widespread adoption of revenue decoupling and LRAMs.[22]

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[20] Such a sliding scale would be cost-justified if the utility generally needs less standby capacity for low-volume customers than for high-volume customers.

[21] Another state is Mississippi, for which there has been a form of SFV in place for Mississippi Power Company that has been overshadowed by the FRPs of that utility. In Oklahoma, Public Service of Oklahoma has a variation on an SFV design that has fixed-cost based charges that vary with expected long-term consumption patterns. In Wyoming, Rocky Mountain Power has moved gradually toward an SFV rate design over the past decade through a series of rate cases that increased the fixed charge component of its retail rates.

[22] The effect that an SFV tariff would have on low-income customers is far from conclusive. The literature is not consistent regarding whether low-income customers use more or less electricity than the average customer. Consumption often depends on demographics other than income, such as family size; quality of housing stock; owners versus renters; whether renters pay electric bills directly; end uses such water heating, cooking, and space heating; appliance efficiency; and age of householders. There are many other ways of addressing low-income

Table 1
Timing of State Adoption of Straight-Fixed Variable Rate Design for Electric Utilities

State	Utility Name	Year
• CT	• United Illuminating	• 2006
• CT	• Connecticut Light & Power	• 2008
• NY	• New State Electric & Gas	• 2010
• OK	• Oklahoma Public Service Company	• 2010
• WY	• PacifiCorp (dba Rocky Mountain Power)	• 2009

The average length of time the SFV rate designs have been in place in these four states is about 6.5 years.

SFV rates have the following benefits relative to traditional rates:

- They better assure utility recovery of fixed costs, such as those of distribution system facilities.
- They provide customers with energy prices that are relatively efficient in the sense that they reflect variable costs that are related to marginal costs. Ignoring the costs of externalities such as the pollution associated with electricity generation, this may encourage more efficient use of electricity.
- Because of the better match between variable costs and volumetric revenues, they mitigate or avoid the need to adjust rates in response to changes in load growth.
- They reduce the importance of load forecasts in rate cases, potentially reducing the contentiousness of rate cases.
- They remove a disincentive to utility promotion of energy efficiency, since any revenue declines due to energy efficiency are roughly matched by reductions in variable costs.
- Because of their higher demand charges and lower energy charges, they encourage lower peak demands and higher load factors, thus increasing the use of existing electric power system facilities and potentially slowing the growth of capacity-related costs.
- Higher demand charges may facilitate investment in and use of market-based distributed resources such as load management and energy storage technologies.
- SFV rates tend to be stable relative to revenue decoupling rates.
- Compared to revenue decoupling and LRAMs, the SFV rate design imposes low administrative burdens on regulators and intervenors.

customers' energy affordability issues besides allocating fixed costs to variable charges that may or may not be beneficial to low-income customers.

On the other hand, SFV rates have the following actual or perceived shortcomings relative to traditional rates:

- They adversely affect low-volume customers within each customer class, who must pay fixed charges that cover the fixed costs of their service, like those of their own line drops. To the extent that there is a correlation (between customer size and customer income, SFV rates could adversely affect low-income customers.
- They reduce incentives for energy efficiency because of lower electrical energy prices..
- They reduce energy charges to short-term variable cost, which may be lower than the economically efficient level of long-term marginal cost. Such low energy charges could therefore lead to inefficiently high consumption.
- SFV pricing does not avoid the need for occasional price revisions due to inflation.

- *State Experience With SFV Rate Design*

Connecticut

In 2007, Connecticut law was amended to require the state utility commission to decouple the distribution revenues of Connecticut Light & Power (CL&P) from the volume of its electricity sales.[23] This decoupling was to be achieved either through a mechanism that adjusts actual distribution revenues so that they equal allowed distribution revenues or through a mechanism that increases the amount of distribution cost recovery that is achieved through fixed distribution charges.

In response to this legislation, CL&P developed an SFV mechanism that has gradually shifted distribution fixed cost recovery from energy charges toward customer and demand charges. This mechanism is weather-normalized: customers are credited with or charged amounts based upon differences between weather-adjusted revenue per customer and the revenue requirement per customer determined in the most recent rate case.

In its 2008 order approving CL&P's SFV mechanism, the state commission said the following:

> While the concept of fixed revenue recovery is straightforward, implementing this rate design is not and must be implemented gradually. As noted by CL&P, there are identifiable differentials in the cost to serve residential customers. Therefore, it is appropriate to consider a tiered or sliding structure of residential distribution charges. The Department [of Public Utility Control] considered using monthly consumption to establish sliding customer charges. However, using this standard could subject the Company to frequent changes to the applicable customer charge as customers' monthly usage changes. This in turn could result in revenue instability, a situation that this [sic] contrary to the goal of this policy. Further, basing a customer charge on consumption (i.e., increased consumption

[23] Public Act No. 07-242, *An Act Concerning Electricity And Energy Efficiency*, effective July 1, 2007.

warrants the assessment of a higher charge) would continue to link sales and earnings.[24]

New York

In 2007, the New York Public Service Commission required that the state's utilities adopt revenue decoupling mechanisms, among which it included SFV rate designs.[25] The Commission's explicit goal was to remove disincentives for utility support of energy efficiency, renewable generation, and distributed generation.

In compliance with this requirement, New York State Electric & Gas Company (NYSEG), in 2009, proposed an SFV rate design for both electric and natural gas customers, in which context that rate design has been consistently called a revenue decoupling mechanism. NYSEG's Commission–approved plan, which was the product of negotiations between NYSEG and various consumer representatives, includes the following features:

- It sets revenue targets by customer class.
- It recovers most fixed costs through demand and customer charges.
- It has an earnings sharing scheme that has two sets of deadbands. The utility retains all earnings variations within the first deadband, 50% of earnings variations between the first and second deadbands, and 15% of earnings variations beyond the second deadband. The deadbands depend upon the utility's reliability performance as measured by a Customer Average Interruption Duration Index and a System Average Interruption Frequency Index: poor utility performance lowers the deadbands and thus shifts earnings toward customers.

Wyoming

In the wake of a stipulation with consumer representatives reached in 2009, Rocky Mountain Power has gradually shifted toward an SFV rate design that recovers most fixed costs through customer and demand charges. For example, by raising the residential customer monthly base charge from $10.18 to $20.00, the utility shifted to the monthly customer charge a significant share of fixed cost recovery from the residential class. The SFV rate design also includes inverted energy rates that have lower energy prices on low levels of consumption than on higher levels of consumption.

The Wyoming commission accepted the stipulation for several reasons.

> The Commission... finds the proposed monthly basic charge of $20.00 is supported by the Company's cost of service study which identified a cost of service monthly charge of approximately $26.00 per month... The Commission

[24] Department Of Public Utility Control, *Draft Decision*, Application of The Connecticut Light and Power to Amend Rate Schedules, Docket No. 07-07-01, January 16, 2008, p. 117.

[25] New York Public Service Commission, *Order Requiring Proposals for Revenue Decoupling Mechanisms*, Cases 03-E-0640 and 06-G-0746, April 20, 2007.

> finds that implementation of the inverted block rate design, which provides reduced energy charges for lower energy usage, sends appropriate pricing signals to customers, and encourages energy conservation. Further, the increase in the basic monthly charge is consistent with the Commission's desire for continued -- but measured-- movement toward cost-based rates.[26]

Revenue Decoupling

The revenue decoupling concept was developed in the 1980s for the explicit purposes of encouraging energy efficiency and of removing utility incentives to increase sales. While SFV rates address the latter purpose, they do so by reducing the energy component of retail electricity rates, thereby reducing conservation incentives. Revenue decoupling, by contrast, assures utility recovery of fixed costs without significantly reducing retail energy prices. Revenue decoupling accomplishes this by adjusting energy prices to compensate for differences between actual sales and test-year sales per customer.

Many states have also used revenue decoupling as a means of reducing rate case frequency and streamlining electricity regulation.

- *State Adoption of Revenue Decoupling*

Twenty-two states have adopted gas decoupling and twenty states have adopted electric decoupling at one time or another, although five of these states have since let their decoupling mechanisms expire.[27] This encompasses 52 local gas distribution utilities and 25 electric utilities.

Figure 3 depicts the states in which at least one electric utility (but not necessarily all electric utilities) has a revenue decoupling mechanism. Over half of the states adopting decoupling mechanisms are states that also opened their retail markets to competitive retail providers and reside in territories served by Regional Transmission Organizations operating restructured wholesale electricity spot markets. The three states with pending electric decoupling proposals are Arkansas, Colorado, and New Mexico.

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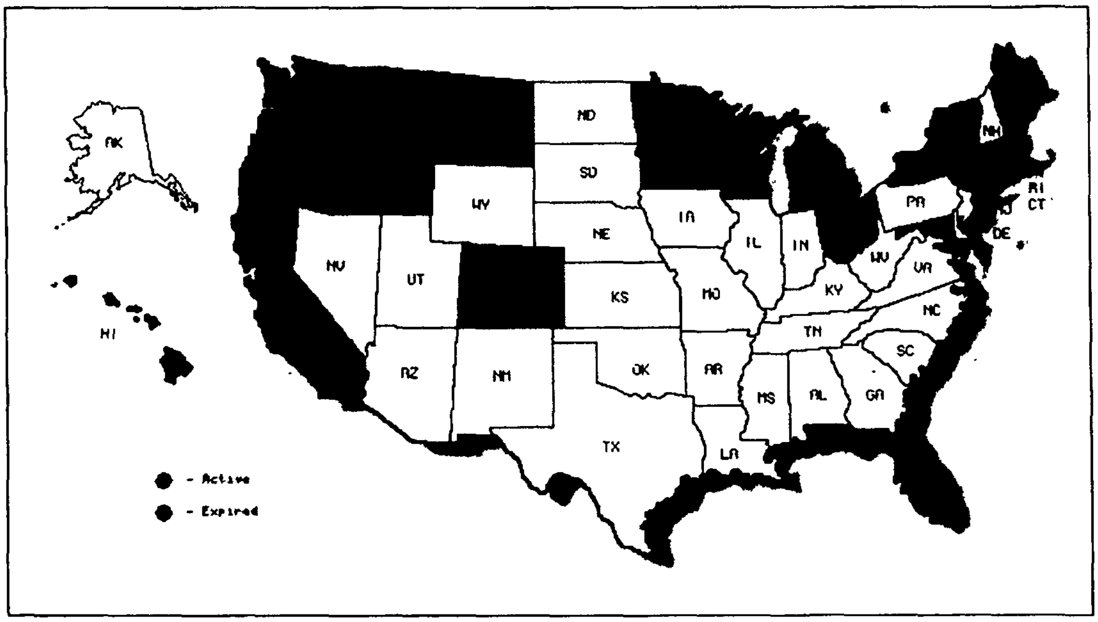
[26] Wyoming Public Service Commission, *Memorandum Opinion, Findings And Order Approving Stipulation*, In The Matter Of The Amended Application of Rocky Mountain Power for Approval of a General Rate Increase of Approximately $28.8 Million Per Year (6.1 Percent Overall Average Increase), Docket No. 20000-333-ER-08 (Record No. 11824), May 20, 2009, p. 21.

[27] The twenty-two states that have adopted gas decoupling mechanisms are Arizona, Arkansas, California, Georgia, Illinois, Indiana, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New Jersey, New York, North Carolina, Oregon, Rhode Island, Tennessee, Utah, Virginia, Washington, Wisconsin, and Wyoming. The three states with pending gas decoupling proposals are Connecticut, Delaware, and Nebraska. The Arizona commission considered an electric revenue decoupling mechanism but has instead adopted an LRAM for Arizona Public Service Company. The five states that have let revenue decoupling mechanisms expire are Colorado, Florida, Michigan, Montana, and Wisconsin.

Figure 3
Jurisdictions With Revenue Decoupling for Electric Utilities[28]



For each of the states shown in **Figure 3** with active programs, **Table 2** shows the years in which each state adopted their electric utility revenue decoupling mechanisms. These mechanisms were adopted, on average, in 2009, which gives the average state six years' experience.

Table 2
Timing of States' Adoption of Electric Utility Revenue Decoupling

State	Year	State	Year	State	Year
CA	2002	MA	2011	OH	2012
CT	2009	MD	2007	OR	2009
DC	2009	ME	2009	RI	2011
HI	2010	MN	2015	VT	2006
ID	2007	NY	2007	WA	2013

- *Revenue Decoupling Design Issues*

Decoupling mechanisms are generally based upon revenues per customer. Authorized revenue per customer is calculated by dividing the last approved revenue requirement by the number of customer accounts assumed in that rate proceeding. Total authorized revenues are calculated by multiplying the authorized revenue per customer times the number of customers in the

[28] Lowry, Makos, and Waschbusch, *op cit.*

current decoupling period. If a utility's actual sales per customer are lower than the level assumed in setting existing rates, retail energy rates would be increased so that actual revenue per customer better approximates authorized revenue per customer. Similarly if sales are higher than assumed, retail energy rates would be reduced.

In designing and implementing a revenue decoupling program, several questions must be addressed, including the following:[29]

- How often should decoupling adjustments be made? Nineteen electric utilities have annual adjustments, while four have monthly adjustments.
- Should decoupling adjustments be based on the entire difference between actual and authorized revenues, or upon some fraction of that difference? Fifteen electric utilities base their adjustments on fractions of the difference.
- Should actual revenues be adjusted for deviations of actual weather from the normal weather assumed at the time base rates are set? Two electric utilities have such weather adjustments, while twenty-one do not.
- Should authorized revenues change annually by means other than a general rate case? Eleven electric utilities have such "attrition adjustments" for changes in fixed costs.
- Should comparisons of actual revenues to authorized revenues be at the utility level or at a customer class or rate schedule level? Class-level treatment is common, particularly for the purpose of avoiding changes in customer class cost allocations between general rate cases. This can result, however, in rate increases for some classes at the same time as rates are being reduced for other classes.
- Should there be limits on the size of decoupling adjustments? If so, should any excesses be ignored, carried forward to future periods, or handled in some other manner? New York handles this problem by requiring utilities to file for a decoupling adjustment when the accumulated balance reaches a pre-specified limit.
- Does revenue decoupling reduce business risk? If so, should authorized ROEs be reduced for utilities with revenue decoupling programs?

There are a variety of unique or uncommon features in revenue decoupling mechanisms. Four utilities' decoupling schemes provide only for surcharges, not refunds. One utility anticipates the impacts of rate changes on energy demand by making a price elasticity adjustment in its decoupling true-up. Utilities vary in the extent to which the components of the fixed cost revenue requirement are subject to revenue decoupling adjustments.

Almost every state regulatory commission order approving a utility revenue decoupling mechanism has addressed the question of whether adoption of revenue decoupling reduces the utility's business risk and should therefore require a reduction in the authorized ROE. As shown in **Table 3**, a large majority of state commission decisions and stipulated agreements for the adoption of decoupling included no ROE reductions. Of the reductions that occurred, 10

[29] Most of these questions also must be addressed in considering SFV rate designs.

basis points was the most common amount. Almost half of the cases including a 10-basis point reduction were approvals of settlement agreements. One of the three decisions making a 25 basis point reduction concerned adoption of a settlement agreement. The largest reductions – 50 basis points – are limited to Maryland and the District of Columbia; but Maryland, with three of these decisions, did not impose an ROE reduction in two other cases.

Table 3
State PUC Decisions Regarding Return on Equity Reduction

ROE Reduction	Number of Decisions	Result of Stipulated Agreement
None	60	29
10 basis points	9	4
25 basis points	3	1
50 basis points	4	
Total	76	34

- *Benefits and Shortcomings of Revenue Decoupling*

Revenue decoupling has the following ostensible benefits:

- It encourages energy conservation by consumers by retaining electrical energy prices that significantly exceed variable costs.
- It removes disincentives to utility promotion of energy efficiency.
- If protects utility recovery of fixed costs from fluctuations in sales per customer.
- It reduces the need for accurate sales forecasts in general rate cases.

On the other hand, revenue decoupling has the following shortcomings:

- Ignoring the costs of externalities, it can encourage inefficiently low consumption of electricity.
- It shifts some risks, like that of weather variability, from the utility to its customers.
- It discourages utilities from trying to make electricity sales for uses that might be beneficial to both consumers and society.
- It is more administratively complex than SFV ratemaking.

Gilleo *et al* found that, when states with LRAM were compared to states with at least one electric utility operating under revenue decoupling, states with decoupling appear to be spending more on energy efficiency relative to revenue, and a similar pattern appears for electricity savings.[30] Median incremental electricity savings in 2013 was 1.4% for states with decoupling, compared with median savings of 0.5% for states with LRAM. However, it is important to note that all but one of the decoupling states also had an energy efficiency resource standard policy in place, which is the dominant policy associated with greater energy efficiency spending and savings.

- *State Implementation Experience*

Based on recent research on decoupling mechanisms applied in the U.S., several broad conclusions can be reached:

- *Electric decoupling rate adjustments are generally no more than 2% of retail rates.* Morgan reports that 65% of monthly electric decoupling rate adjustments and 85% of annual electric decoupling rate adjustments are less than 2%.[31]
- *Decoupling rate adjustments yield both refunds and surcharges.* For all electric and gas utility adjustments reported in Morgan, 63% were surcharges and 37% were refunds. Actual revenues deviate from forecast values because of weather, changing economic conditions, energy efficiency programs, customer response to price, and other factors.
- *Decoupling rate mechanisms generally fail to normalize revenues for the effects of weather.* Because weather is the primary cause of sales volume variations, this lack of normalization adds to the instability of rate adjustments, particularly when such adjustments are made on a monthly basis or are for customer classes (e.g., residential) with particularly weather-sensitive loads.

Figure 4 summarizes the distribution of percentage rate increases (surcharges) and decreases (refunds) for electric utility revenue decoupling mechanisms across 195 monthly rate adjustments each for the residential and commercial classes. For both classes, the monthly adjustments tend to be increases, averaging +0.5% for residential customers and +0.7% for commercial customers. About 90% of residential adjustments are between -2% and +3%, while about 90% of commercial adjustments fall in the wider range of -4% to 3%.

Figure 5 summarizes the distribution of 86 residential and 53 commercial rate adjustments for electric utilities that adjust rates annually. Again, surcharges outnumber refunds, averaging +0.5% for residential customers and +0.2% for commercial customers; and commercial rate adjustments have a slightly wider dispersion.

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[30] A. Gilleo, M. Kushler, M. Molina, and D. York, *Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms*, for the American Council for an Energy-Efficient Economy, Report U1503, June 2015.

[31] P.A. Morgan, *Decade of Decoupling for US Energy Utilities· Rate Impacts Designs, and Observations*, Graceful Systems LLC, February 2013.

Figure 4
Distribution of Monthly Electric Decoupling Rate Changes[32]

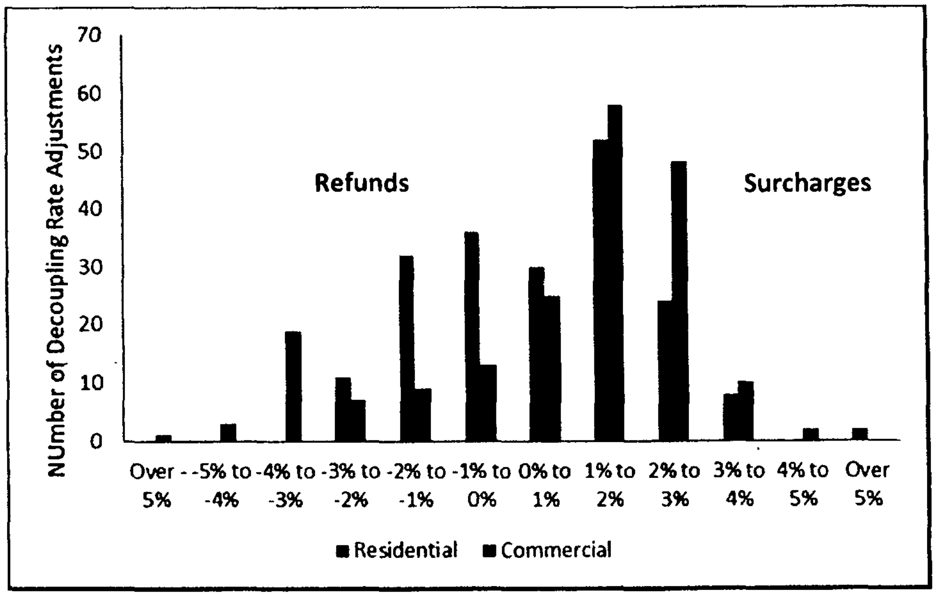
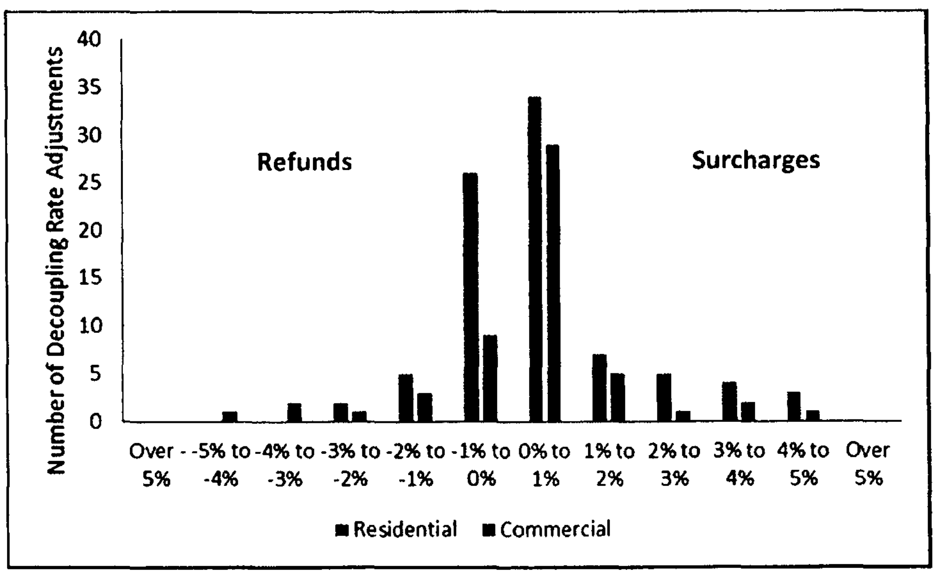


Figure 5
Distribution of Annual Electric Decoupling Rate Changes[33]



[32] *Id.*, p. 10.

[33] *Id.*, p. 11.

Some of the experiences of individual states are as follows.

California

The California Public Utilities Commission (CPUC) established Electric Revenue Adjustment Mechanisms for its three major electric investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) by 1982. These mechanisms reconciled billed revenues to authorized revenues to "eliminate any disincentives… [the utility] may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that… [the utility] receives no more or no less than the level of revenues intended to be earned."[34] These mechanisms were suspended by the CPUC in 1996 with the implementation of California's electric restructuring.

In the wake of the western power crisis of 2001, Assembly Bill 29 sought to reduce energy usage in part by mandating reintroduction of revenue regulation.[35] Beginning in 2004, the CPUC has implemented this requirement through a process that determines a separate authorized revenue requirement for each functional operating area through a General Rate Case every three years. The determination excludes electric transmission revenue requirements regulated by the Federal Energy Regulatory Commission (FERC), uses a future test year, and has not involved any explicit reduction of ROE. Revenue adjustments are made first through a stair-step method that makes revenue requirement adjustments that are predetermined during a general rate case, and second through additional adjustments for "exogenous" changes in revenue requirements.

Maryland

Baltimore Gas and Electric and Potomac Electric Power have revenue regulation mechanisms that are intended eliminate utility disincentives for conservation and demand response. These mechanisms compare actual and authorized distribution revenues, adjusted for numbers of customers, for each applicable rate schedule. Reconciliations occur monthly. Differences between actual and authorized revenues are divided by the forecasted sales for the following period to calculate the monthly rate adjustment. Balancing accounts carry adjustments between the times that they are calculated and the times they are billed or refunded. Monthly rate adjustments are limited to 10%, and any excesses are carried forward to future periods. ROEs have been reduced by 50 basis points to reflect the supposed risk reduction due to revenue regulation.

Maine

Central Maine Power Company's Alternative Rate Plan (ARP) has been approved for four multi-year cycles since 1996. In 2013, the utility asked to revise ARP so that it includes a revenue

[34] California Public Utilities Commission, Decision 93887, December 30, 1981.
[35] Assembly Bill 29, Ch. 8, 2001 Cal. Stat. http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_29_bill_20010412_chaptered.pdf. This became Public Utilities Code section 739.10.

decoupling mechanism. The Maine Public Utilities Commission staff recommended rejection of the ARP proposal and the revenue decoupling mechanism, and further recommended returning the utility to traditional cost-of-service regulation due to the alleged failure of previous ARPs to meet the key objectives of rate predictability and stability, reduced administrative burden, and adequate incentives for system reliability investments. Aside from Commission staff, all intervenors endorsed the revenue decoupling mechanism with modifications. Separate revenue targets apply to two classes – residential and commercial/industrial – with annual reconciliations for under-recovery limited to 2% revenue increases for each class, with amounts exceeding the cap deferred for recovery in subsequent years, and with unlimited annual reconciliations for over-recovery.

Lost Revenue Adjustment Mechanisms

LRAMs are similar to revenue decoupling in their intention of making utilities indifferent to sales lost due to conservation and, in some instances, distributed generation. To the extent that a utility's fixed costs are recovered through rates dependent upon usage, conservation impinges upon the utility's ability to recover its fixed costs. LRAMs enable utilities to recover the fixed costs that would otherwise be lost due to conservation, thus removing some important incentives for the utility to oppose alternatives to utility generation.

Each general rate case includes utility sales forecasts that account for conservation to the extent that it has already occurred, but not necessarily for additional conservation that might occur in the future. LRAMs adjust rates between rate cases to account for the impacts on utility sales of the conservation that was not considered in developing the general rate case forecasts.

The need for lost revenue adjustments arises from the infrequency of rate cases. On the one hand, frequent rate cases mitigate the need for such adjustments. On the other hand, the use of an LRAM reduces the need for frequent rate cases.

- *Quantifying Lost Revenues*

LRAMs' lost revenues are calculated by multiplying the sales lost due to conservation (in kWh) by base rates (in dollars per kWh). Base rates are used because of the need to exclude from the adjustment a variety of non-base rate revenues, such as fuel cost adjustments. LRAM dollars are not additional costs of efficiency programs, but are instead a means of collecting already authorized utility system fixed costs and of thus bringing the utility back in line with its revenue requirement.

Quantifying the sales lost due to conservation is problematic and controversial. Sales are affected by a multiplicity of factors, including weather and economic conditions. Thus, at the outset of an LRAM program, there needs to be agreement among stakeholders upon the methods by which the sales lost due to conservation will be measured. Such methods rely upon a combination of sampling, statistical analysis, and estimation of customer loads, and sometimes upon engineering estimates of the energy savings associated with particular energy efficiency investments.[36] In addition, LRAMs may need to incorporate true-up mechanisms that allow for delays in the measurement of lost sales. These methods for measuring lost sales should be transparent and verifiable. Although such measurement could, in principle, be identical to whatever methods the states already use to evaluate the benefits and costs of conservation programs, existing evaluation methods generally face greater scrutiny when they are applied to the new purpose of determining lost revenue adjustments.[37]

Gilleo *et al* found that some states exercise little regulatory oversight of evaluation methods or results. Although this speeds the regulatory process, it may reduce the accuracy of the estimated savings. An appropriate evaluation process would include stakeholders in discussions of evaluation methods, set clear evaluation and reporting guidelines for utilities, and include independent evaluators. Smart meters and faster computing technologies may facilitate the evaluation process through better gathering and analysis of data.

Lost revenue calculations can be designed in a number of different ways. Some states make separate LRAM calculations for each rate class. While all states consider revenue losses due to reduced electrical energy consumption, only some states also consider revenue losses due to peak demand reductions.

- *Extent of State Adoption of LRAM*

Figure 6 shows that twenty states have adopted some form of LRAMs for electric utilities. **Table 4** summarizes the years in which these states adopted these LRAMs. On average, states adopted LRAMs in 2010, and so have an average of just over five years' experience.

[36] Engineering estimates have dubious reliability. For example, M. Fowlie, M. Greenstone, and C. Wolfram, *Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program*, June 2015 reports the results of an experimental evaluation of the nation's largest residential energy efficiency program conducted in Michigan on a sample of 30,000 households. It finds that "upfront investment costs are about twice the actual [value of] energy savings," that "model-projected savings are roughly 2.5 times the actual savings," and that even "when accounting for the broader societal benefits of energy efficiency investments, the costs still substantially outweigh the benefits; the average rate of return is approximately -9.5% annually." In a widely cited study, J.A. Dubin, A.K. Miedema, and R.V. Chandran, "Price e□ects of energy-e□cient technologies: A study of residential demand for heating and cooling," *The RAND Journal of Economics*, 17(3), pp. 310–325, 1986 exploit a small field experiment conducted by a Florida utility in which efficiency improvements were randomly assigned. They find that consumers with improved insulation and more efficient heating equipment conserve 8-13% less energy than would be predicted from engineering models. More recently, L.W. Davis, A. Fuchs, and P. Gertler, "Cash for Coolers: Evaluating a Large-Scale Appliance Replacement Program in Mexico," *American Economic Journal: Economic Policy*, Vol. 4, No. 4, November 2014, pp. 207-38 use quasi-experimental variation to measure *ex post* realized energy savings for an appliance replacement program in Mexico. They find upgrading the efficiency of air conditioners actually increased energy consumption, which they interpret as a large rebound effect.

[37] Gilleo *et al*, *op. cit.*, surveyed key participants in the regulatory process of setting electric utilities' LRAMs, and found that some consumer advocates are wary of savings estimates, saying that it was impossible to judge whether savings were actually achieved. They also found regulatory staff who were concerned about the lengthy back-and-forth exchanges between utilities and regulatory staff that are required to change evaluation methodologies.

Figure 6
Jurisdictions with Lost Revenue Adjustment Mechanisms for Electric Utilities[38]

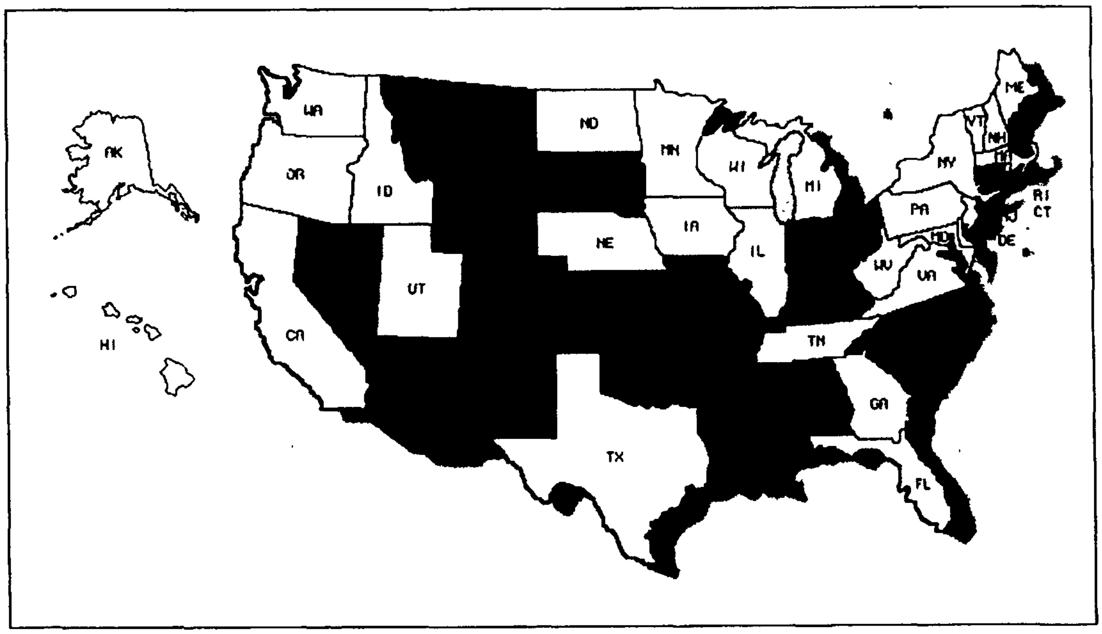


Table 4
Timing of State Adoption of LRAMs[39]

State	Year	State	Year	State	Year	State	Year
AL	2010	IN	2013	MS	2013	OH	2007
AZ	2012	KS	2011	MT	2005	OK	2009
AR	2010	KY	2006	NC	2009	SC	2009
CO	2014	LA	2013	NM	2010	SD	2010
CT	2013	MO	2012	NV	2010	WY	2007

Some states that had adopted LRAMs have since replaced them with revenue decoupling mechanisms. For example, Hawaii terminated its LRAM in 2010 in favor of revenue decoupling; and Minnesota, having adopted LRAMs for its electric utilities in the 1990s, recently approved a revenue decoupling mechanism for Xcel.

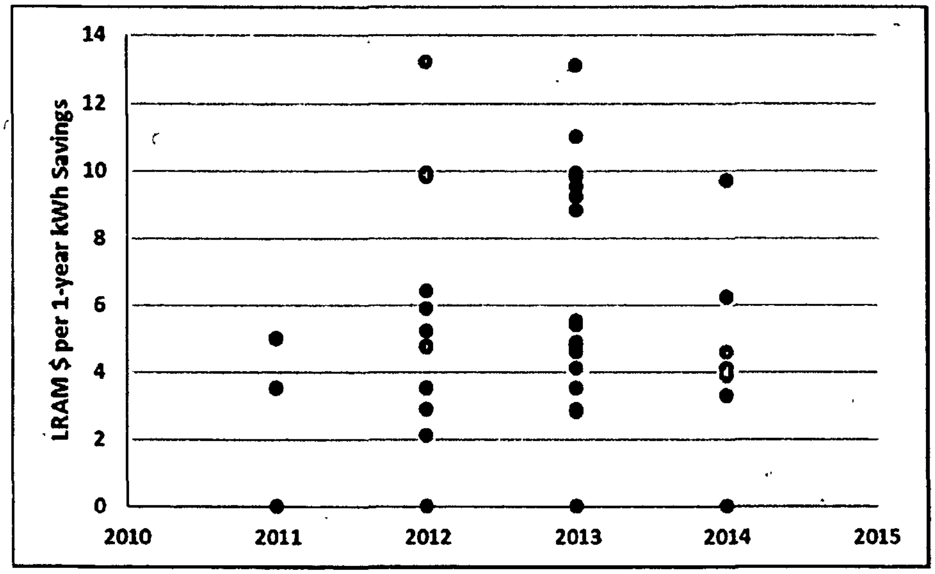
38 Gilleo *et al, op. cit.*

39 *Id.*

- *Costs and Effectiveness of LRAM Programs*

A recent study of LRAMs by Gilleo *et al* gathered data for 32 utilities in 17 states covering program expenditures, annual savings, and eligible LRAM dollars in years 2012 and 2013, with a few results from 2011 and 2014. **Figure 7** summarizes utilities' LRAM cost recovery per kWh of annual energy saved through electricity efficiency programs. Cost recoveries ranged from $0.02 to $0.13 per kWh, with a median value of $0.05 per kWh.

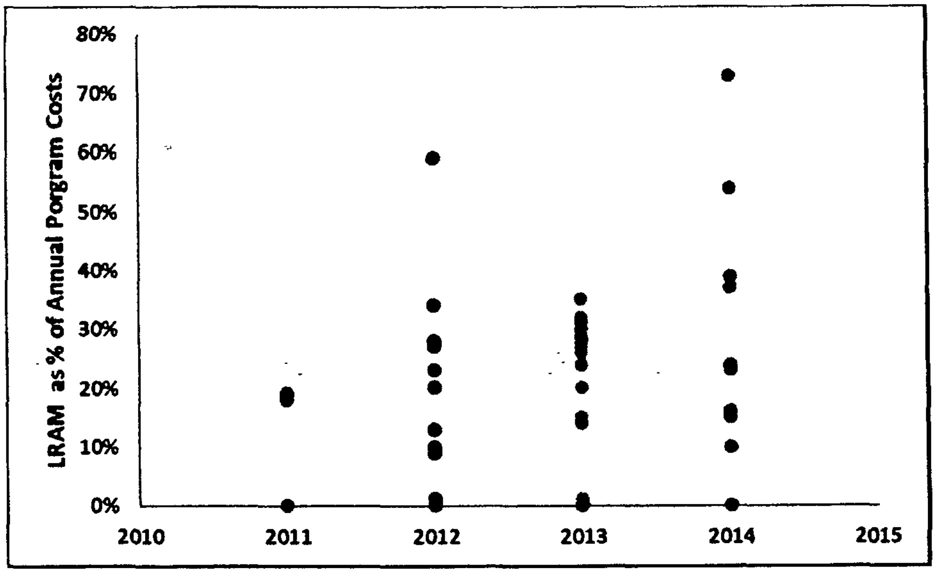
Figure 7
LRAM Dollars Recovered per kWh of Electricity Energy Efficiency Savings[40]



Gilleo *et al* also calculated lost revenue recovery as a percentage of energy efficiency program expenditures. As **Figure 8** shows, there is wide range of outcomes. While the median recovery was 25% of annual program costs, the entire range was from 1% (for a very small energy efficiency program) up to 70%.

[40] *Id.*, Figure 4, p. 9.

Figure 8
Lost Revenue Dollars as Percentage of Electricity Efficiency Program Expenditures[41]



The wide range of recovered values arises from the significant variety in the details of the LRAM designs that have been adopted over the past decade.

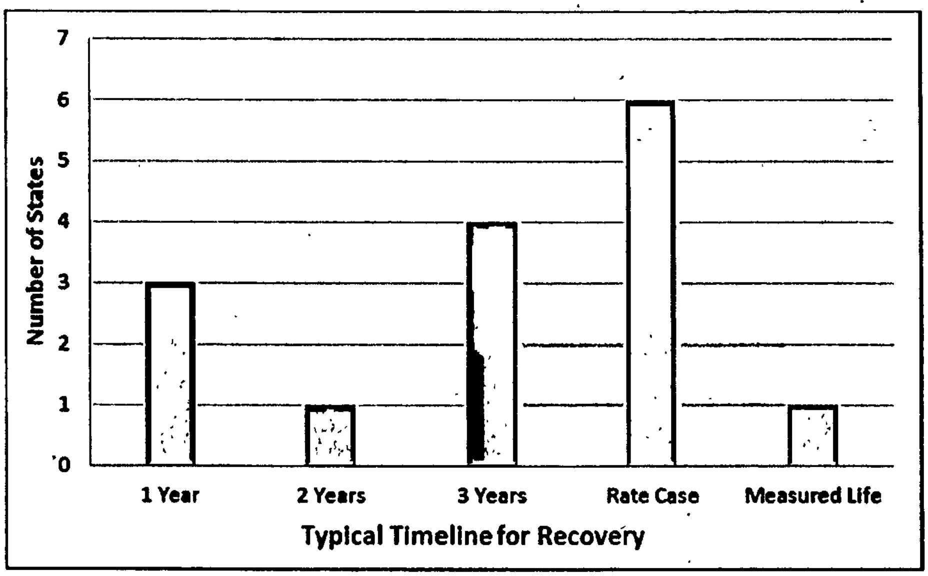
- The more that a utility relies upon volumetric charges for its cost recovery, the higher its LRAM rate will be.
- The higher that a utility's fixed costs are relative to its variable costs, the higher its LRAM rate will be.
- The wider the range of services provided by a utility, the higher its LRAM rate will be. For example, the LRAM of a vertically integrated utility will recover fixed costs for both generation and distribution service, while the LRAM of a distribution-only utility will recover the fixed costs of distribution service only.
- The shorter the cost recovery period relative to the period in which conservation reduced sales, the higher the LRAM will be. For example, if two years' of conservation-related revenue losses are to be recovered in a single year, the LRAM will be higher than if one year's worth of revenue losses were to be recovered in a single year.

LRAMs are subject to a pancaking effect if general rate cases are infrequent. With infrequent rate cases, LRAM account balances can build up as LRAM needs to recover not only the revenues lost due to this year's efficiency measures but also those lost due to energy efficiency measures put in place since the last general rate case. Frequent rate cases can help minimize this pancake effect. Consequently, states often set requirements stipulating the frequency with which utilities must come in for rate cases and reset lost revenues. **Figure 9** shows the lengths

[41] *Id.*, Figure 6, p. 11.

of time that utilities typically collect lost revenues associated with a particular program year before they must reset lost revenues in a general rate case. Most states limit recovery to between one and three years, while six states allow lost revenue recovery for indefinite periods of time until the next general rate case. One state apparently allows its utilities to recover lost revenue over the full life of an efficiency measure, regardless of rate cases.

Figure 9
LRAM Recovery Time for a Single Program Year Before Reset[42]

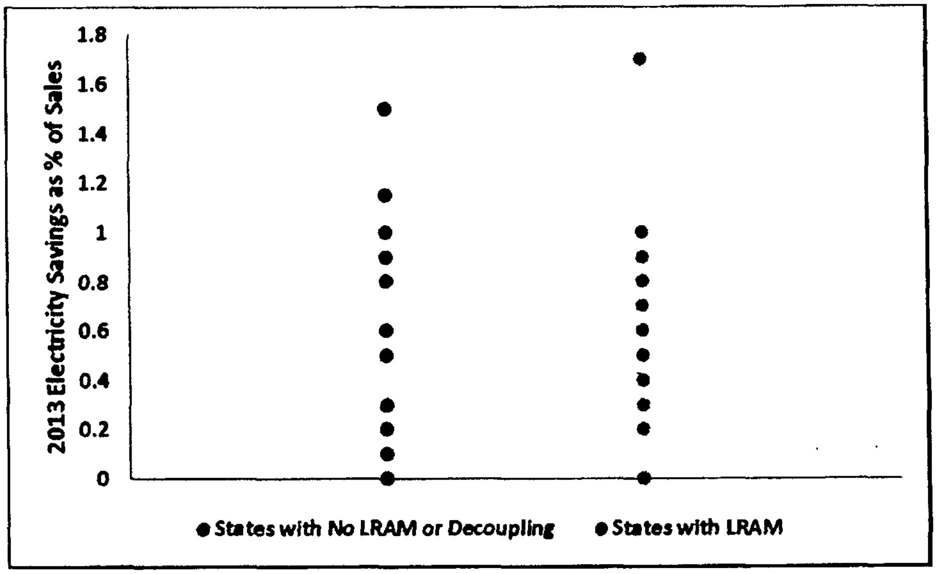


Even in the absence of regulatory limits, however, utilities tend to seek relief in general rate cases every two to three years. Apparently, the rejection of LRAM policy in Minnesota was partly due to its utilities not seeking such rate relief.

Gilleo *et al* attempted to determine whether electric utility LRAMs are associated with greater energy efficiency savings. They found no clear pattern when comparing efficiency budgets between states with and without LRAM policies. Although states with LRAMs have a larger dispersion of budgets, the median budgets in states with and without LRAM, at 0.95% and 0.85% of revenues, respectively, were about the same in 2013. Gilleo *et al* did find, however, that states with LRAM have higher median electricity savings than those without LRAM, with the savings being 0.55% and 0.30% of loads, respectively, in 2013. It therefore appears that LRAMs induce greater energy efficiency savings for similar relative budget levels. **Figure 10** summarizes this comparison.

[42] *Id.*, Figure 8, p. 13.

Figure 10
2013 Electricity Savings as a Percentage of Sales[43]



In summary, LRAMs do not seem to be associated with higher levels of energy efficiency effort as measured by program spending, but they do appear to be associated with greater achievement as measured by energy savings than is found in states without an LRAM policy.

- *Benefits and Shortcomings of LRAMs*

LRAMs have the following benefit:

- They help make utilities indifferent to sales lost due to conservation, thus removing a disincentive to utility promotion of energy efficiency and reducing the need for frequent rate cases.
- They appear to be associated with higher energy savings.

On the other hand, LRAMs also have the following shortcomings:

- They require controversial estimates of sales lost due to conservation.
- There is a significant risk of over-estimating efficiency gains, thus over-compensating utilities and over-charging customers.
- They can make utilities indifferent to sales lost due to poor service.
- They do little to actually encourage conservation. Indeed, a utility may be able to profitably increase some electricity sales while providing energy efficiency programs subject to LRAM.

[43] *Id.*, Figure 10, p. 15.

- They do not appear to be associated with higher levels of energy efficiency program spending.
- The regulatory burden can be significant.

To mitigate these problems, it is advisable for regulators to closely monitor the outcomes of the LRAMs, and particularly to reset rates frequently to reflect updated electricity sales and cost forecasts. Furthermore, some states continue to seek simpler and fairer ways to implement their LRAMs. Alternatively, states can pursue energy efficiency through performance incentives tied to specific energy saving levels, and can use revenue decoupling to offset energy efficiency's adverse impacts on utility revenues.

- *State Experience*[44]

Nevada

Stakeholders have identified a variety of problems with Nevada's LRAM.

- Demand-side program evaluation, measurement, and verification procedures are controversial in terms of both inputs and methodology, and sometimes yield controversial estimates of energy savings.
- Utilities and commission staff have substantially increased their staffing and expenditures on program EV&M.
- The timing of rate cases and demand-side management cases needs improvement. In particular, there are inconsistencies between rate years and demand-side program years.
- True-up procedures are complex as they are based upon two proceedings, one on demand-side management portfolios and the other on lost sales and rates. Furthermore, true-ups for one year are spread over three or more years.
- As utilities' demand-side programs evolve, there are questions about the types of demand-side programs that should be eligible for lost revenue recovery.

In 2014, the commission began an investigation into the state's LRAM, and received a universal complaint that the current LRAM is overly complex. In 2015, the commission issued a notice of its intent[45] to develop a new mechanism that provides utilities with a return on their demand-side program costs, though there is controversy over the commission's authority to proceed without new legislation.

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[44] This section generally relies upon Gilleo *et al*, *op. cit.*

[45] Docket 14-10018.

Oklahoma

Oklahoma's LRAM programs have had problems with the calculations of the energy savings from demand-side programs.

- Some utilities have measured energy savings according to gross savings, while others used net savings.[46] In 2014, the commission resolved this inconsistency by requiring all utilities to use net energy savings as the basis for calculating lost revenues.
- Initially, utilities verified their own energy savings estimates, a process with an inherent conflict of interest. The commission now requires utilities to have energy savings verified by independent contractors, which some stakeholders believe still has a conflict of interest problem because the contractors are hired by the utilities.
- There are questions about the extent to which energy savings estimates include conservation that would have occurred without utilities' demand-side programs.
- There are questions about the extent to which energy savings are double-credited to multiple demand-side programs.

Dealing with these issues has required additional commission staff.

In addition, utilities' reports on energy savings and lost revenues have sometimes been inconsistent with one another and have sometimes not been publicly available. Even when utilities' energy savings estimates have been available, stakeholders have sometimes been surprised by higher-than-expected lost revenue requests. The commission has addressed these problems by requiring utilities' evaluation, measurement, and verification filings to include the data underlying the lost revenue and performance incentive calculations.

Indiana

Indiana has had LRAM since 1995, though energy efficiency programs have grown substantially only since 2009. Energy savings are defined as being net of savings that would have occurred without the programs. The programs are evaluated by independent third parties who are sometimes chosen by each utility and sometimes chosen by committees with utility, consumer, and other stakeholder representatives. The evaluations are used to determine lost revenues and performance incentives.

LRAMs are contentious because the recent growth in Indiana's energy efficiency programs has caused a large increase in lost revenues being recovered by utilities. Because Indiana has no dollar limit or time limit on lost revenue recovery, pancaking of lost revenues adds to amount of money subject to recovery, with the total lost revenue recovery for some programs threatening to exceed program costs. Indiana has experienced contention over the measurement of energy savings and lost revenues, inconsistencies among utilities' measurement methods, the

[46] Gross savings are the changes in energy consumption and/or demand that result from an energy efficiency program, regardless of why consumers participated or changed consumption. Net savings include only the changes in energy consumption and/or demand that are specifically attributable to an energy efficiency program.

timeliness of utilities' data submissions, and the difficulties of tracking lost revenues that are recovered over multiple years.

Because of the foregoing problems, major changes have been proposed for Indiana's energy efficiency programs and LRAMs. Some parties, including Vectren in 2011, have sought to replace LRAM with decoupling; but thus far, the commission has rejected this alternative.[47] In 2014, Senate Bill 340 limited and in some cases prohibited the commission's energy efficiency savings targets, so that future projected savings are projected to be roughly half of what they had been in recent years.

Multi-Year Rate Plans

Multi-year rate plans allow full true-ups to the utility's actual cost of service once every three to five years, with automatic rate adjustments occurring in the interim. These adjustments generally use external factors beyond the utility's control, like fuel prices, to reflect changing business conditions. The adjustments thus reflect changes in the utility's business environment rather than changes in the utility's actual revenues or costs. This use of external factors gives the utility incentives to cut costs and improve performance during the multi-year period, after which the benefits of better performance are shared with customers.[48]

Multi-year rate plans are established during general rate case proceedings, and establish future rate changes according to future conditions that are forecast during these proceedings. With the occasional exception of indexation to external cost factors as described below, multi-year rate plans do not adjust rates in response to the future conditions that actually occur. General rate case filings are generally prohibited during the term of the multi-year plan.

Multi-year rate plans can be accompanied by elements of other alternative ratemaking mechanisms. For example, they can include earnings-sharing components that limit the extent to which the utility's actual ROE can deviate from its authorized ROE, which would reduce the incentives for cost-cutting and performance improvement. In addition, there can be trackers for some specific cost categories, as well as performance-based awards or penalties that provide incentives for certain behavior or outcomes, like highly reliable power service.

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[47] Indiana Utility Regulatory Commission, *Final Order in Petition of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc ("Petitioner") for Approval of and Authority for (1) An Increase in its Rates and Charges for Electric Utility Service Including a Second Step That Will Include the Revenue Requirement for Its Dense Pack Projects; (2) New Schedules of Rates and Charges Applicable Thereto; (3) The Sharing of Wholesale Power Margins Between Petitioner and Its Electric Customers; (4) A Sales Reconciliation To Decouple Fixed Cost Recovery From the Amount of Customer Usage for Certain Rate Classes; (5) A Demand Side Management Program Which Will Include a Mechanism for the Timely Recovery of Costs Relating Thereto and Performance Incentives Based On Achieved Savings; (6) An Alternative Regulatory Plan Allowing Petitioner To Retain Its Share of Wholesale Power Margins and Demand Side Management Performance Incentives; and (7) Approval of Various Changes To Its Tariff for Electric Service Including New Net Metering, Alternate Feed Service, Temporary Service, and Standby or Auxiliary Service Riders, Revisions To Its Existing MISO Cost and Revenue Adjustment (Including the Addition of a Component to Track Variable Production Costs) and Revisions To Its General Terms and Conditions for Service*, Cause No. 43839, April 27, 2011.

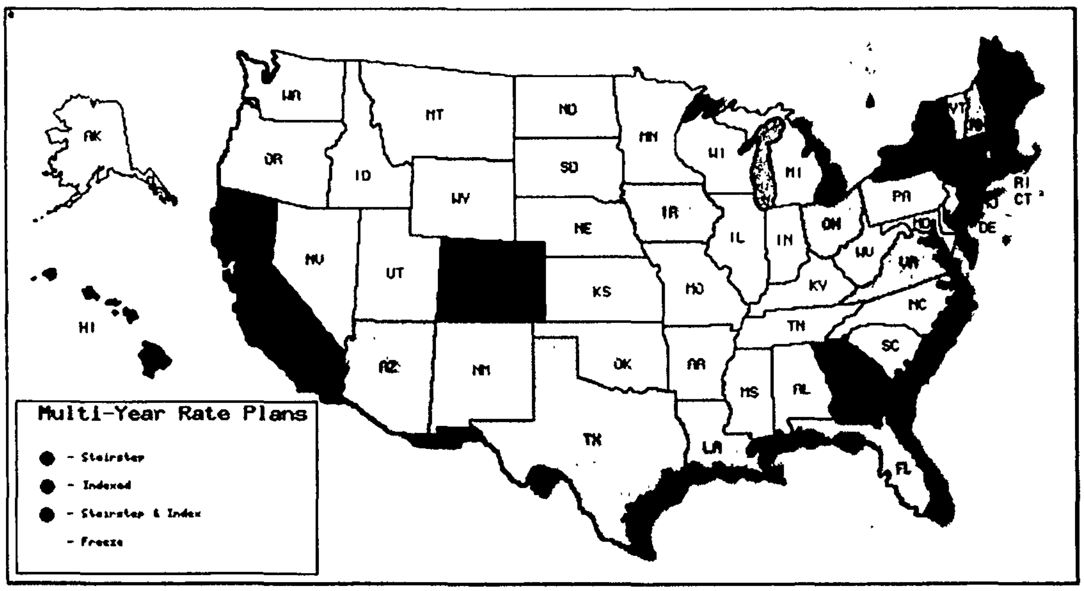
[48] Pacific Economics Group Research, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute, January 2013, p. 35.

Some multi-year rate plans specify the maximum dollar amounts of each year's allowable revenue changes, while others use formulas to determine maximum allowable changes. Multi-year rate plans may involve use of a "stairstep" approach to rate increases, allowing pre-specified percentage rate increases in each year of the plan; while other plans may involve some form of indexation of rate increases to forecast or actual values of external cost factors. Other plans freeze rates at an agreed-upon level between rate cases.

Multi-year rate plans differ from FRPs. While a multi-year rate plan escalates rates over time according to assumptions about the rates of escalation of specified utility costs, an FRP adjusts rates to meet banded ROE targets, perhaps adjusted according to measures of performance such as customer satisfaction and local distribution system reliability. Multi-year rate plans thus focus on the utility's costs, while FRPs focus on ROEs.

Figure 3 identifies the states where multi-year plans are applied using a variety of approaches including stairstep, indexation, combinations of stairstep and indexation, and rate freezes. Rate freezes are the most common form of multi-year plan, with the stairstep approach coming in second. Only two states use indexation, which means that only two states have multi-year rate plans that adjust rates to reflect actual business conditions. The scant use of indexation is due to the relative complexity of the indexation approach, which generally requires agreement on the external factors to which prices will be indexed, on the determination and quantification of a productivity offset factor, and on the other factors (e.g., major plant additions, storm recovery costs) that will automatically change rates during the plan period.

Figure 11
Jurisdictions With Multi-Year Rate Plans for Electric Utilities[49]



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[49] Lowry, Makos, and Waschbusch, *op cit.*

Ideally, multi-year rate plans have the benefits of providing more predictable revenues to utilities and more predictable rates for customers, of providing timely recovery of investment costs while spreading rate increases over longer periods than is otherwise possible, and of *requiring fewer general rate cases. Because of their automatic adjustments, multi-year rate* plans lessen the need for cost trackers and surcharges.[50] On the other hand, multi-year rate plans require longer forecasts of future conditions than are needed for traditional rates, and they require careful definition of the external factors to which automatic rate adjustments will apply.

- *State Experience*

<u>Colorado</u>

Public Service Company of Colorado Case (PSCo) has a stairstep plan that covers a three-year forward period. The plan includes a profit-sharing provision when PSCo's actual ROE exceeds 10.6% or is less than 9.9%, with a true-up mechanism to address over- or under-recovery. PSCo may not file a new rate case unless the revenue shortfall for a 12-month period exceeds 2% of the targeted revenue for the year. PSCo's revenue requirement calculations are based both on a future test year and a historical test year. In a 2013 rate case, all but one of the intervenors supported use of the historical test year, even though it implied need for a larger rate increase.

<u>Georgia</u>

Georgia Power Company operates under a three-year rate plan that uses a stair-step approach to adjust revenue requirements in second and third years. The ROE band for 2014 was 10.00% to 12.00%, with an initial 10.95% value. Revenue requirement adjustments are made for base rates, the Demand Side Management tariff, the Environmental Compliance Cost Recovery tariff, and the Municipal Franchise Fee tariff. Georgia Power will not file a general rate case unless its projected retail ROE is less than 10.00%. Two-thirds of any retail ROE above 12.00% is refunded to customers, with the remaining one-third being retained by Georgia Power.

Price Cap Plans

In competitive industries, price is determined by the market, and firms keep as profit any cost savings that they might develop through more efficient production. Under traditional electricity regulation, the retail electricity price is set according to the utility's costs; so if the utility finds ways to cut costs through greater efficiencies, the retail electricity price is reduced so that the benefit goes to customers, not to utility shareholders. This cost-plus pricing gives relatively weak incentives for utilities to increase production efficiencies.

Price cap plans seek to encourage utilities to reduce costs by making retail electricity prices (or average unit revenues) exogenous to the utility. Prices (or average unit revenues) are allowed

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[50] These are described in Section 5.2.

to increase no faster than some measure of inflation, such as the prices of specified inputs (like fuels) or economy-wide inflation. At the same time, prices (or average unit revenues) are reduced according to some measure of productivity improvement for the electric power industry. The effect of this productivity adjustment is to give industry-wide productivity gains to customers (which is about what would happen in a competitive market), and to allow utility shareholders to profit from efficiency gains to the extent that the utility beats the industry average productivity improvement (which is also what would happen in a competitive market). Prices and average revenues may also be adjusted for special cost-drivers like major storms or major regulatory changes.

There are many variations of price cap plans. For example, a plan may divide gains from productivity enhancements between customers and utilities in a manner that differs from the general approach of giving industry-wide productivity gains to customers.

The main benefit of price caps is that they provide stronger incentives for production efficiency than are provided by traditional ratemaking. On the other hand, price cap plans require a significant amount of information for setting price and revenue caps, the development of which can be time-consuming and controversial. In addition, price cap plans can incent utilities to cut costs in ways that harm service quality. It is therefore necessary for price cap plans to be accompanied by performance incentives to maintain or improve service quality and seeking to satisfy other public policy goals. These characteristics and design of such performance incentives are described in Section 0 below.

We are not aware of any U.S. electric utilities that have adopted price or revenue caps in more than the narrow sense of indexing some costs to inflation. The lack of electricity price or revenue cap plans may be due to the limited opportunities for "regulatory bargains" in the electricity sector and to the limited competition in the T&D components of the sector.[51]

o Incremental Revisions to Ratemaking Approaches

This section describes incremental revisions in ratemaking methods that could be applied either to traditional cost-of-service ratemaking or to the alternatives just described. These revisions address important details of either the procedures by which rates are set or the manner in which particular categories of costs are recovered from customers.

Future Test Years

The rates and rate designs established in general rate cases depend upon the utility's revenues and costs. The data used to determine these revenues and costs may come from the recent actual experience of an historical test year, or from forecasts applicable to the future test years to which updated rates will apply, or from some combination thereof.

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[51] D.E.M. Sappington and D. L. Weisman, "The Price Cap Regulation Paradox in the Electricity Sector," *The Electricity Journal*, April 2016, 29(3): 1-5.

An historical test year is usually a twelve-month period that ends a few months before the rate case filing. There is typically a two-year lag between the historical test year and the first rate year to which updated rates would apply.[52] Consequently, although the historical test year approach has the advantage of using relatively objective data, it has the disadvantage of using stale data that may poorly predict future conditions. To compensate for this disadvantage, historical test year data are often adjusted to make them more relevant to business conditions anticipated for the first rate year, with normalizations for weather or business conditions being common. For example, if the historical test year had an unusually hot summer, load data could be adjusted to reflect normal summer weather conditions. As another example, known changes in union labor rates could be used to adjust historical test year data.

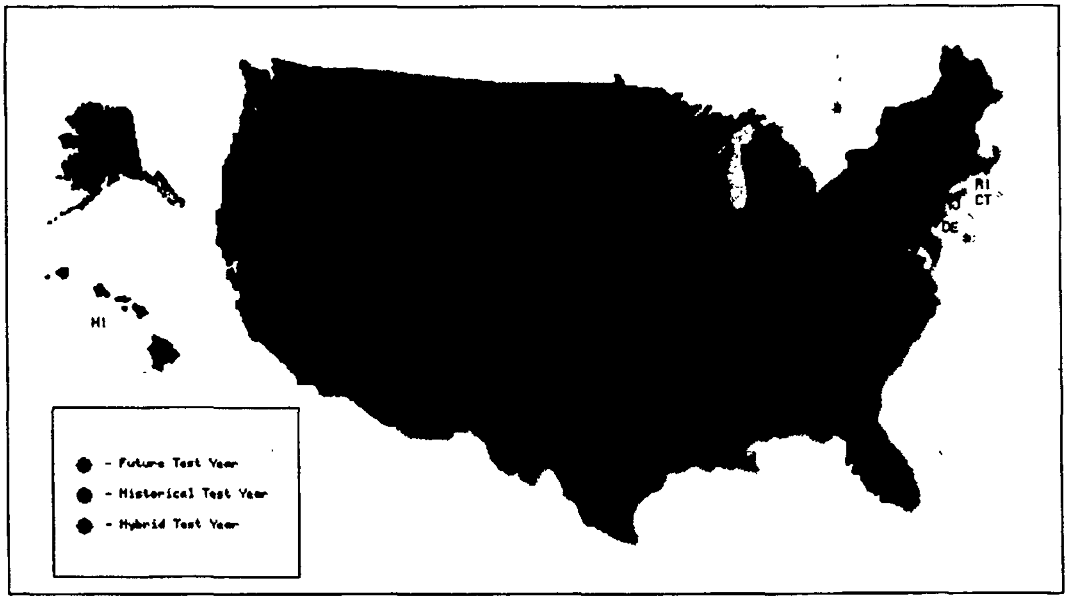
A future test year is usually the first twelve-month period to which new rates would apply, and usually begins after the general rate case is complete. The future test year approach has the advantage of using data that are appropriate for the period to which the data will apply, but has the disadvantage of being susceptible to bias and error. This disadvantage is compounded by information asymmetries: the utility usually has better information about the future than is available to regulators and other stakeholders, which gives the utility some extra ability to manipulate the ratemaking process.

Some utilities use hybrid test years that are based upon a combination of history and forecasts.

Figure 12 presents a map of the states by their test year approaches. Nineteen states use an historical year, fifteen states use a future year, and sixteen states plus the District of Columbia use some mixture of historical and future test years. There is thus plenty of precedent for both of the major test year approaches.

[52] For example, a utility filing for new rates applicable to calendar 2020 might request new rates in April 2019 using data from calendar 2018; so the rates applicable in 2020 would be based upon business conditions in 2018.

Figure 12
Jurisdictions by Test Year Approach for Electric Utilities[53]



The choice between historical and future test years should depend, in large part, upon the speed with which business conditions are changing. If conditions are changing slowly, historical data are strongly indicative of the future, so an historical test year approach has its inherent advantage of objectivity without the disadvantage of being a poor predictor of future conditions. If conditions are changing rapidly, however, a future test year approach is needed to provide a reasonable basis for future rates, particularly because "empirical research... shows that utilities operating under forward [future] test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years."[54] In other words, rapidly changing market conditions tend to undermine utility finances when the historical test year approach is used. On the other hand, the reduced regulatory lag inherent in the future test year approach may reduce utility incentives to control costs.

Earnings Sharing Mechanisms

Earnings sharing mechanisms allow rate adjustments outside of general rate case proceedings when actual ROEs would otherwise fall outside of specified bands around the authorized ROE. No rate adjustment is made when actual ROEs fall within the band; and rates are adjusted to share between customers and shareholders the excess or deficient earnings outside of the

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[53] Lowry, Makos, and Waschbusch, *op cit.*

[54] M.N. Lowry, D. Hovde, L. Getachew, and M. Makos, *Forward Test Years For US Electric Utilities*, prepared for Edison Electric Institute, August 2010, p. 1.

band. There is often a second set of outer bands beyond which customers get all excess earnings or pay for all earnings shortfalls. The bands allow utilities to enjoy for a period of time some of the efficiencies that they create, and eventually pass substantial shares of such efficiencies to customers.

Earnings sharing mechanisms help hold down procedural costs of assuring that utilities' actual ROEs do not stray far from targets due to the operation of automatic rate change mechanisms or to changing business conditions. They are a type of FRP that focuses on earnings rather than on specific costs or revenues. As such, it shares the aforementioned benefits and shortcomings of FRPs. Its focus on earnings has the benefit of avoiding the need to track specific costs and revenues, and the shortcoming of overlooking special cost and revenue developments that might arguably warrant special treatment.

Cost Trackers

Cost trackers allow utilities to recover specific costs from customers outside of general rate cases. The recoverable costs may be zero-based (so that the cost adjustment equals the whole amount of the cost) or may be relative to a baseline cost included in the general rate case (so that the cost adjustment equals the actual cost minus the baseline amount). Utilities recover these costs based upon some formula or predefined rule.

In principle, cost trackers should be used only for those items of cost that are substantial, unpredictable, volatile, recurring, or beyond utility control. Such items arguably include the following:[55]

- Fuel costs, due to significant fluctuations in fuel commodity prices;
- Capital costs;
- Transmission costs, for firms paying wholesale transmission charges;
- Distribution costs, to reflect changes in the costs of owning or maintaining distribution plant;
- Storm fund costs;
- Environmental compliance costs, which can change suddenly with changes in law or regulation;
- Tax costs, due to changes in tax rates or tax codes; and
- Bad debt, because the percentage of uncollectible receivables can suddenly rise during recessions.

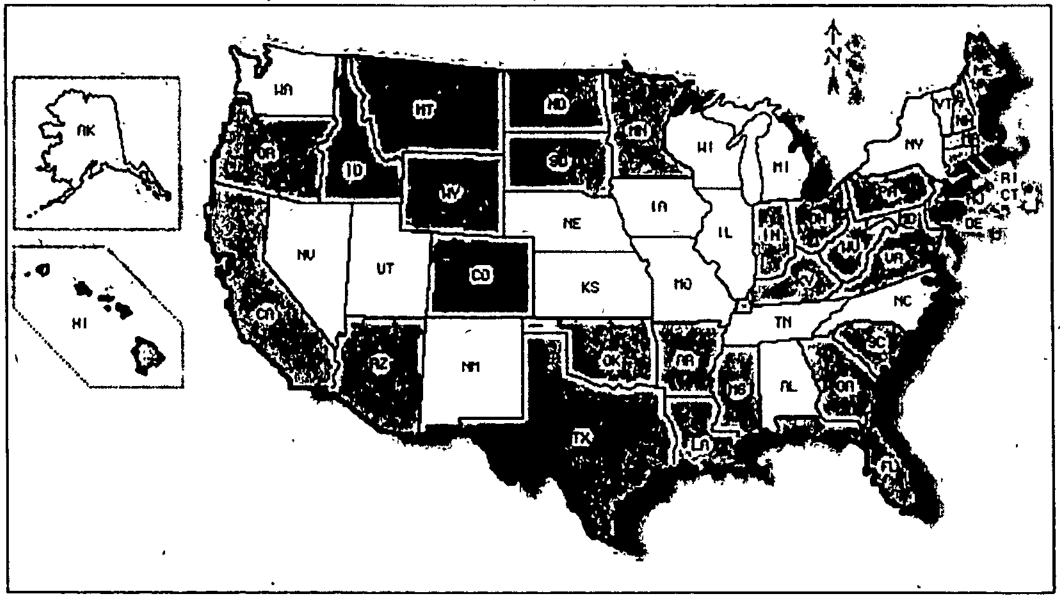
[55] The following lists are partly drawn from C. Harder, Alternatives to Traditional Rate Processes, presentation, CenterPoint Energy, Inc., 2013 and J.W. Rogers, *The Two Sides of Cost Trackers: Why Regulators Must Consider Both*, NRRI Teleseminar, October 27, 2009.

Nonetheless, the use of cost trackers has greatly expanded to include items that may fail the test of being substantial, unpredictable, volatile, recurring, or beyond utility control. These additional cost trackers include the following:

- Basic service administrative cost adjustment;
- Cumulative capital tracker;
- Forward capital tracker;
- Inflation adjustment;
- Pension and other post-retirement benefits;
- Attorney General rate case consultant cost;
- System inspection costs;
- Plant reclassification adjustment mechanism;
- Net metering charge, to recover net revenue losses due to net metering;
- Energy efficiency charge, to recover the costs of funding energy efficiency programs;
- Solar investment charge; and
- Smart grid charge, to recover costs of smart grid investments.

Figure 13 presents a map of jurisdictions with one type of cost tracker, namely that for capital costs. The figure shows that most states have this type of cost tracker. Similar maps would show that other types of cost trackers are widespread (as is the case for fuel adjustment clauses) while others are not.

Figure 13
Jurisdictions With Capital Cost Trackers for Electric Utilities[56]



Cost trackers have the benefit of providing timely recovery of significant costs that are beyond utility control, which reduces utilities' financial risk without compromising their performance and without, in the long run, increasing costs to consumers. The main shortcoming of cost trackers is that, by insulating utilities from fluctuations of costs that are within utility control, they weaken utilities' incentives to control costs. Another shortcoming is that, when applied to inappropriate cost categories, cost trackers add unnecessary complexity and administrative burdens to the ratemaking process.

Infrastructure Surcharges

Infrastructure surcharges have the purpose of avoiding the large one-time rate increases that are characteristic of the addition of large new facilities to rate base. To avoid such rate shock, infrastructure surcharges spread capital cost recovery over a longer period of time than is traditional. They accomplish this by allowing some cost recovery prior to the completion of a facility's construction, often dependent upon the utility achieving specified construction milestones.

Infrastructure surcharges offer the benefits of mitigating rate shock, helping utilities' cash flow during construction, and avoiding delays in capital cost recovery that might depend upon rate case completion. When implemented in the form of construction work in progress, this early recovery of capital costs may enable the utility to secure project financing at a lower cost than it would otherwise.

[56] Lowry, Makos, and Waschbusch, *op cit.*

On the other hand, infrastructure surcharges can erode utility incentives for capital cost management if they lead to less regulatory scrutiny of those costs, which may occur because capital costs are partially recovered from customers before regulators review these costs. Infrastructure surcharges also have the shortcoming of requiring customers to pay for facilities that are not yet used and useful, which violates the beneficiary pays principle because no benefits can flow from a facility before its construction is complete.

Infrastructure surcharges are band-aids that address the symptom of new facilities' rate shock without addressing the causes of such rate shock. There are two such causes. First, new facilities periodically turn out to be high-cost, sometimes due to capital cost overruns or poor management, sometimes due to the misfortune of the facilities entering service during a period of recession or low fuel prices. This first cause is addressed by regulatory proceedings on prudency. Second, one-time rate increases are perennially due to the ubiquitous financing convention of recovering capital costs through levelized *nominal* dollars rather than levelized *real* dollars. The effect of this convention is that the inflation-adjusted value of capital cost recovery is always higher in the early years of a facility's life than it is later in the facility's life, with the distortion being greatest during periods of high inflation. Because the convention of levelized nominal capital cost recovery is set by the financial industry, regulators lack the power to overturn it. Infrastructure surcharges are a very imperfect tool for addressing the levelization problem; but that is, at root, the problem that infrastructure charges address.

Performance Incentive Regulation[57,58]

Performance incentive regulation provides incentives for utilities to maintain or improve service quality. Although such incentives are particularly essential to the implementation of price cap plans, they can also be useful in the context of other broad rate design approaches.

For example, performance incentive regulation can provide rewards or penalties that depend upon:

- the level of actual customer service outages (such as measured by the frequency, extent, or duration of outages, or more specifically by the system average interruption duration index or the system average interruption frequency index);
- actual employee safety performance (such as measured by lost-time injuries);
- actual customer service performance (such as measured by complaints or telephone response time); and

[57] Some of the ideas in this section are from M. Whited, T. Woolf, and A. Napoleon, *Utility Performance Incentive Mechanisms*, prepared for the Western Interstate Energy Board, March 9, 2015.

[58] "Performance-based rate regulation" is the term generally used to refer to performance incentive regulation combined with price cap regulation or other alternative ratemaking mechanisms. In this report, we separate performance incentive regulation from other components of performance-based rate regulation because the former can be implemented on its own or in combination with several other alternative ratemaking mechanisms.

- other performance measures (such as measured by average days to interconnect distributed generation).

In each case, the reward or penalty would depend upon actual performance relative to an appropriate benchmark.

Ideally, performance targets should be realistic, flexible, long-term, bounded by deadbands, promising of net benefits, responsive to stakeholder input, and related to policy goals. Performance metrics should be clearly defined, readily quantifiable with reasonably available data, reasonably objective, largely within utility control, easily interpreted, easily verifiable, and related to policy goals. Rewards and penalties should be related to the customer benefits and costs attributable to utility action.

Potential benefits of utility performance incentives include the following:

- They may help make regulatory goals and incentives explicit.
- They may help identify incentives that are well aligned with the public interest and that may help improve performance.
- They may allow regulators to focus on whether desired outcomes are achieved rather than on the costs and means of obtaining those outcomes.
- They may be applied incrementally and flexibly.

On the other hand, utility performance incentives have significant shortcomings:

- They may provide rewards or penalties that are disproportionately large or small relative to customer benefits or associated utility costs.
- They may provide rewards or penalties that inappropriately depend upon factors that are beyond utility control.
- They may depend upon poorly defined metrics.
- They depend upon information that can be controversial and time-consuming to develop, and that are better available to utilities than to regulators and other stakeholders.
- They may focus utility management attention on some aspects of performance to the detriment of focusing on other important aspects of performance.
- They may be subject to gaming and manipulation by utilities.

As the examples provided in earlier sections of this report demonstrate, many states have adopted performance incentives of one type or another. For example, long-standing FRPs in place in Alabama, Mississippi, and Louisiana adjust utilities' authorized ROEs according to how well they meet certain performance targets; and Missouri may soon do so as well. When a utility exceeds its performance targets, its authorized ROE is adjusted upward by a specified number of basis points; and when it falls short of the targets, the ROE is adjusted downward. Performance metrics may be measured annually or may be computed as rolling averages over three- to five-year periods.

APPLICABILITY OF ALTERNATIVE RATEMAKING MECHANISMS TO TEXAS

We begin with a description of Texas' electric power industry and its present methods for setting electricity rates. We then assess the applicability of alternative ratemaking mechanisms to the Texas electric power industry and recommend a course for ratemaking reform.

o Texas' Electricity Industry and Market Structure

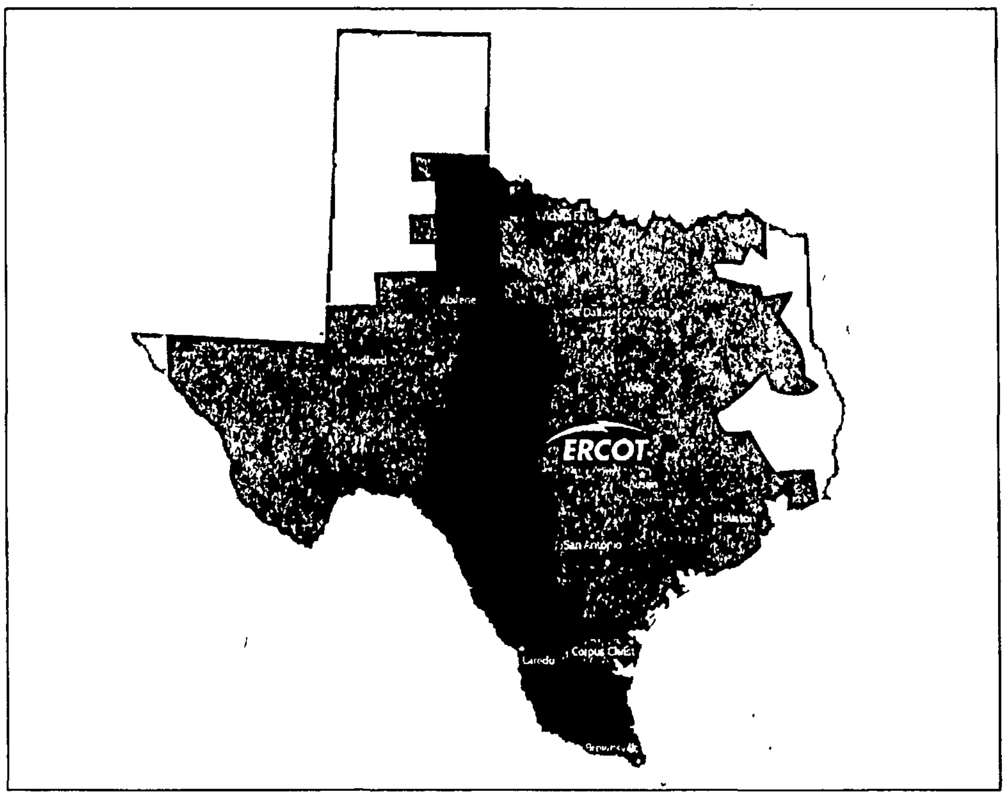
Electrical energy[59] is produced by generators and delivered to consumers through T&D systems. Since 2002, Texas legislation has required that the service territories of the investor owned T&D systems located in the Electric Reliability Council of Texas (ERCOT), shown in **Figure 14**, be open to retail competition in the provision of electrical energy, in the hope that such competition would reduce consumers' electricity prices and foster greater customer choice.[60,61] Although municipal and electric cooperative utilities located in the ERCOT region are allowed to open their systems to retail competition in electrical energy services, only one electric cooperative has chosen to do so.

[59] For simplicity, the text implies that "electrical energy" is the only service provided by generators, though generators also provide frequency regulation, operating reserve, voltage control, and black start services, the first two of which are potentially competitive.

[60] ERCOT covers about 75% of Texas' land area and serves about 85% of Texas' electricity use. The rest of Texas is in reliability regions overseen by the Midcontinent Independent System Operator (Entergy's service territory in east Texas), the Southwest Power Pool (Texas' panhandle and northeast corner), and the Western Electricity Coordinating Council (the western-most part of Texas).

[61] The Texas legislation creating retail competition was Senate Bill 7, passed in 1999. Its Section 39.001 defines the purpose of the legislation in generalities about the benefits of competition: "The legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition. As a result, this chapter is enacted to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry." In signing this law, however, Governor George Bush said "Competition in the electric industry will benefit Texans by reducing rates and offering consumers more choices."

Figure 14
ERCOT Region Map[62]



Texas has its own unique jargon for the different types of players in its electricity markets. "Retail electric providers" buy wholesale electricity and T&D services, seek retail customers, and set their own retail electricity prices. "Transmission and distribution service providers" are TDUs that own and operate T&D systems, though there are also "transmission service providers" that own and operate only transmission systems and "distribution service providers" that own and operate only distribution systems.

Within ERCOT, the supply and pricing of electrical energy are determined by competitive processes, though competition and prices are affected by Texas' policies regarding renewable energy. Meanwhile, the supply and pricing of wholesale transmission services within Texas as well as investor-owned TDU services are determined through traditional regulatory processes that are under the jurisdiction of the PUCT, with transmission investment decisions somewhat influenced (again) by Texas' renewable energy policies.[63] Interstate wholesale transmission services are under the jurisdiction of FERC.

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[62] http://www.ercot.com/content/news/mediakit/maps/ercotRegionMap.jpg.

[63] Texas is building transmission to serve its Competitive Renewable Energy Zones (CREZ), in which there is substantial wind power that would be difficult to deliver to consumers without such transmission investment. See

Table 5 shows that, in 2014, 61% of the Texas electricity market was served by investor-owned TDUs within ERCOT. Another 22% of the Texas electricity market was served by municipal utilities and cooperative utilities within ERCOT. The remaining 15% of Texas load was served by utilities outside of ERCOT.

Table 5
Relative Shares of Texas Electrical Energy Deliveries, by Utility, 2014[64]

	MWh		Shares	
ERCOT:				
Oncor	114,905,829		29%	
CenterPoint	82,025,715		21%	
AEP Central	24,813,888		6%	
TNMP	9,877,771		3%	
AEP North	5,476,300		1%	
Sharyland	2,517,299		1%	
municipal utilities	46,132,830		12%	
cooperative utilities	39,339,642		10%	
Total ERCOT		325,089,274		83%
Non-ERCOT:				
investor-owned utilities	45,557,593		12%	
municipal utilities	2,855,119		1%	
cooperative utilities	9,154,941		2%	
Total non-ERCOT		57,567,653		15%
Discrepancy		7,012,893		2%
Total Texas		389,669,820		100%

Figure 15 shows the patterns of growth of non-affiliate sales in the ERCOT region and displays the percentage shares of MWh sales for each of the three major customer types. As shown by the solid green line, competing suppliers made half of sales to the large commercial and industrial customers within a few months of the opening of competition, a share that has thereafter grown to nearly 90%. As shown by the dashed red line, it took competing suppliers a couple of years to take half of the small commercial market, a share that has since grown to over 80%. As shown by the dotted blue line, competition has more slowly taken hold of the

http://www.puc.texas.gov/industry/maps/maps/transmission_scenario2dev_crez.pdf for one example of a transmission planning response to CREZ power delivery needs.

[64] From https://www.puc.texas.gov/industry/electric/reports/RptCard/Default.aspx, Market Share Data.xls; and U.S. Energy Information Administration, Electricity Data Browser, http://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=g407vvvvv3vvo&endsec=vg&freq=A&start=2001&end=2015&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin= , and EIA 2014 Form No. 861. The 2% discrepancy arises from inconsistencies between the PUCT and EIA datasets.