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Foreword

July 2018

To our clients, colleagues, and other friends:

We are pleased to present the most current version of our Accounting, Financial Reporting, and Tax Research Guide for the power and utilities (P&U) industry. We have revised this publication to serve principally as a reference guide for readers rather than just as an annual update. Our industry continues to face changing markets, new and revised legislation, environmental initiatives or changes, regulatory pressures, cyber and physical threats, and new technologies, in addition to new accounting standards.

This publication discusses accounting, tax, and regulatory matters that P&U entities will need to consider as a result of these changes, including updates to SEC, FASB, and tax guidance, and focuses on specialized industry accounting topics that frequently affect P&U companies, including rate-regulated entities. We have expanded several sections in this year’s publication that concentrate on accounting and reporting considerations related to the new accounting standards, including the discussion of those specific industry matters that remain outstanding with the AICPA’s Power and Utility Entities Revenue Recognition Task Force.

Certain sections of this publication are designed to help you understand and address potential challenges in accounting and reporting related to topics on which the FASB has recently issued (1) proposed guidance or (2) final standards that are not yet effective or available for adoption. Our publication discusses such proposed and codified standards and highlights nuances that could affect our industry.

We hope you find this update a useful resource, and we welcome your feedback. As always, we encourage you to contact your Deloitte team or any of our Deloitte specialists for additional information and assistance.

Sincerely,

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Section 1 — Industry Developments
Role of M&A in the P&U Sector

M&A activity in the energy sector continued to be active in 2017, with many micro- and macroeconomic factors coming together to create an opportunistic environment. The micro- and macroeconomic factors are being driven by market volatility throughout the sector, which is attributable to low natural gas and wholesale power prices and a low interest rate environment. Compounding the market volatility is the movement away from traditional fossil fuel-fired generation toward cleaner sources, coupled with changing energy market dynamics. Many regulated utilities have significant capital expenditure plans related to infrastructure needs that constitute growth potential for acquirers. All of these factors have led to shifting opportunities for energy investments by both public and private entities, including several deals between U.S. and Canadian utilities that were completed or announced in 2017.

The acquisitions of public companies completed and announced in 2017 and the first quarter of 2018 had a wide range of premiums. Some examples of the premiums on transactions include the following:

- **Completed:**
  - September 2017 *(announced February 2017)* — Peoples Natural Gas and Delta Natural Gas Company Inc. (17 percent premium).
  - April 2018 *(announced October 2017)* — Vistra Energy Corporation and Dynegy Inc. (43.8 percent premium).

- **Announced:**
  - January 2017 — AltaGas and Washington Gas and Electric (12 percent premium).
  - July 2017 — Hydro One Limited and Avista Corporation (24 percent premium).
  - January 2018 — Dominion Energy Inc. and SCANA Corporation (42 percent premium).
  - April 2018 — CenterPoint Energy Inc. and Vectren Corporation (17 percent premium).
  - May 2018 — Southern Company (select subsidiaries and assets) and NextEra Energy (27 percent premium).

M&A Activity

M&A continued to play an active role in the P&U sector in 2017 and early 2018. Acquiring companies have sought to increase their financial security, reduce their risk profiles and costs, strengthen their balance sheets, diversify their state regulatory risk, and enhance their abilities to employ large capital investment programs. Some companies with regulated operations have sought to expand their rate bases and provide more stable, predictable earnings. During 2017, as in 2016, there were a significant number of
cross-border deals with Canadian entities as they sought to diversify their Canadian portfolios with U.S.-based utilities and assets.

A number of significant M&A activities have been completed in the P&U sector over the past year, including the following:

• **Liberty Utilities and the Empire District Electric Co.** — On January 1, 2017, Liberty Utilities, a subsidiary of Algonquin Power & Utilities Corp., completed its acquisition of the Empire District Electric Co. for approximately $2.3 billion, representing a 21 percent premium to the closing share price on February 8, 2016, before the initial announcement. As a result of the acquisition, Algonquin Power & Utilities Corp. now serves more than 782,000 electric, gas, and water customers.

• **Enbridge Inc. and Spectra Energy Corp.** — On February 27, 2017, Enbridge Inc. completed the acquisition of Spectra Energy Corp. The acquisition created one of the largest energy infrastructure companies in North America. After the acquisition, the company has more than 34,000 miles of natural gas pipeline, 415 billion cubic feet (Bcf) of natural gas storage, 18,500 miles of liquids pipeline, and 11.4 billion cubic feet per day (Bcf/d) in natural gas processing capacity.

• **AES Corporation, Alberta Investment Management Corporation, and other investors and Sustainable Power Group (sPower)** — On July 31, 2017, Fir Tree Partners announced that it completed the sale of sPower to a joint venture controlled by AES Corporation and Alberta Investment Management Corporation for $1.6 billion in cash and assumed nonrecourse debt. sPower operates nearly 1.3 GW of utility-scale solar investments in 11 states.

• **Peoples Natural Gas and Delta Natural Gas** — On September 20, 2017, Peoples Natural Gas (a subsidiary of PNG Companies LLC) announced that it had completed the acquisition of Delta Natural Gas for $270 million, at $30.50 per share. Delta Natural Gas serves nearly 39,000 customers in Kentucky.

• **Brookfield Renewable Partners L.P. and TerraForm Power** — On October 16, 2017, Brookfield Renewable Partners L.P. and its institutional partners completed the acquisition of 51 percent interest in TerraForm Power for $656 million. This acquisition adds 2,600 MW of solar and wind energy to Brookfield Renewable's portfolio with a postacquisition capacity of more than 13,000 MW. Shortly after this deal closed, Brookfield and its institutional partners announced on December 28, 2017, the close of their acquisition of TerraForm Global for $750 million, adding 952 MW of solar and wind energy to Brookfield's portfolio.

• **Eversource and Aquarion Water Company** — On December 4, 2017, Eversource announced the completion of its acquisition of Aquarion Water Company for $1.68 billion ($880 million in cash and $795 million in assumed debt), adding 230,000 water customers to its existing portfolio of electricity and natural gas customers.

• **Energy Capital Partners and Calpine Corporation** — On March 8, 2018, Energy Capital Partners and a consortium of investors, including Access Industries and Canada Pension Plan Investment Board, announced the close of their acquisition of Calpine Corporation for $5.6 billion cash, representing $15.25 per share. Calpine owns and operates 80 power plants that serve customers in 25 states, Canada, and Mexico.

• **Sempra Energy and Energy Future Holdings Corp.** — On March 9, 2018, Sempra completed its acquisition of Energy Future Holdings Corp., which owns approximately 80 percent of Oncor Electric Delivery Company LLC, for $9.45 billion in cash, after the previous $9 billion deal with Berkshire Hathaway Energy was abandoned by Energy Future Holdings.
• **Vistra Energy Corporation and Dynegy Inc.** — Vistra Energy Corporation announced on April 9, 2018, the close of its acquisition of Dynegy Inc., a power generator and distributor, in an all-stock transaction worth more than $1.7 billion. The new company now has approximately 40 GW of generation capacity and serves 2.7 million residential customers and 240,000 commercial and industrial customers.

• **AltaGas Ltd. and WGL Holdings** — AltaGas Ltd. announced on January 25, 2017, its plans to acquire WGL Holdings Inc. for $6.4 billion in cash. The agreement is for $88.25 per share, which represents a 12 percent premium on WGL's stock, which was at $78.78 at the close of the business day of the announcement, but a 27.9 percent premium from the closing price before rumors began of a potential offer. The deal received FERC approval in July 2017. WGL and AltaGas have signed settlement agreements with several intervening parties, including the Maryland Energy Administration and the key stakeholders in the Washington, D.C., regulatory proceedings. The agreements featured, among other things: credits to the customers; a commitment to the development of renewable energy, energy efficiency, and energy conservation initiatives; and the relocation of the headquarters of AltaGas’s U.S. power business to Maryland. The deal closed on July 6, 2018.

• **Westar Energy Inc. and Great Plains Energy Inc.** — Westar Energy Inc. announced on July 10, 2017, that its board of directors and the board of Great Plains Energy Inc. had approved a revised transaction that is a stock-for-stock merger, creating a new holding company. Under the agreement, Westar shareholders will receive a share in the new holding company for each share in Westar, and Great Plains shareholders will receive $.5981 shares of common stock in the new holding company for each share of Great Plains. In addition, the agreement removes any premium paid or received with respect to either company, any transaction debt, and any cash exchanged from its original deal, which was announced on May 31, 2016. The revised agreement, which will create a company worth approximately $14 billion, was in response to regulators’ concerns about the initial deal. The new deal was approved by the shareholders of each company in November 2017, by FERC in February 2018, and by the Kansas Corporation Commission and the Missouri Public Service Commission (PSC) in May 2018. The deal closed on June 4, 2018.

Other significant M&A activity announced in 2017 and early 2018 included the following:

• **On July 19, 2017, Hydro One announced its plans to acquire Avista Corporation in a $5.3 billion all-cash offer.** The acquisition will add 379,000 electric service customers and 343,000 natural gas customers in the northwestern United States, including Alaska, to Hydro One’s existing Ontario electric service territory. On November 21, 2017, Avista shareholders approved the proposed acquisition, and FERC approved the deal in January 2018. On March 27, 2018, the companies filed a settlement agreement with the Washington Utilities and Transportation Commission that includes rate credits to customers in Washington, Oregon, Idaho, and Alaska as well as a commitment to not seek recovery of transaction costs. The settlement agreement is now pending approval from the utility commissions of Washington, Idaho, Oregon, Montana, and Alaska. The deal is expected to close in the second half of 2018.

• **Dominion Energy Inc. announced on January 3, 2018, its plans to acquire SCANA Corporation for a total of $7.9 billion (approximately $14.6 billion including the assumption of debt) in an all-stock offering equivalent to $55.35 per share for SCANA shareholders.** This represents a 42 percent premium on SCANA’s closing stock price on January 2, 2018. The deal was approved by the Federal Trade Commission in February 2018 and the Georgia PSC in March 2018 and is subject to approval from SCANA shareholders, FERC, and the NRC. In addition, Dominion has offered, among other things, a $1.3 billion cash payment to electricity customers of SCANA's
South Carolina Electric & Gas Company (SCE&G) subsidiary after the deal’s closing, as well as an estimated 5 percent reduction in rates, which is subject to approval by the South Carolina PSC.

- CenterPoint Energy Inc. announced on April 23, 2018, its plans to merge with Vectren Corporation through acquisition of Vectren stock at $72 in cash per share (about $8.5 billion in cash plus assumed debt of Vectren). The combined company will serve more than 7 million customers with total assets of $29 billion and will operate regulated gas and electric utility businesses in eight states. The acquisition’s closing is pending the approval of Vectren’s shareholders, FERC, and the FCC as well as the expiration or termination of the applicable Hart-Scott-Rodino Act waiting period. It is expected to close by the first quarter of 2019.

- In May 2018, Southern Company announced that it had reached an agreement to sell Gulf Power Company, Florida City Gas, and the entities holding Southern Power’s interests in Plant Oleander and Plant Stanton to NextEra Energy. The total purchase price is approximately $6.5 billion, which represents a 27 percent premium on the equity value (net of debt) of $5.1 billion. Each transaction is conditioned upon the appropriate regulatory approvals and is expected to close from the third quarter of 2018 to the second quarter of 2019.

During 2017, as in the past three years, there was significant activity involving acquisitions of power plants, with a focus on clean energy plants, including natural-gas-fired plants and wind and solar assets. The following table lists some of the transactions that occurred in 2017 (dollar amounts in millions):

<table>
<thead>
<tr>
<th>Date</th>
<th>Buyer</th>
<th>Seller</th>
<th>Value</th>
<th>Assets</th>
</tr>
</thead>
<tbody>
<tr>
<td>10/31/2017</td>
<td>Blackstone Energy Partners</td>
<td>Energy Transfer Partners L.P.</td>
<td>1,570</td>
<td>32.44 percent interest in natural gas pipeline with capacity to transport 3.25 Bcf/d</td>
</tr>
<tr>
<td>8/14/2017</td>
<td>Pattern Energy Group Inc.</td>
<td>Pattern Energy Group LP</td>
<td>68</td>
<td>51 percent interest in 179-MW wind facility</td>
</tr>
<tr>
<td>8/1/2017</td>
<td>La Frontera Holdings LLC</td>
<td>Odessa-Ector Power Partners L.P.</td>
<td>355</td>
<td>1,054-MW combined-cycle natural-gas-fired power plant</td>
</tr>
<tr>
<td>3/27/2017</td>
<td>NRG Yield Inc.</td>
<td>NRG</td>
<td>594</td>
<td>Partial ownership of approximately 300-MW utility-scale solar projects</td>
</tr>
<tr>
<td>1/25/2017</td>
<td>Fiera Infra LP</td>
<td>Suncor Energy</td>
<td>Undisclosed</td>
<td>50 percent interest in 100-MW wind farm</td>
</tr>
</tbody>
</table>
Ratemaking

Rate-Case Activity

The number of retail rate cases in the United States has been increasing in recent years, with 133 electric and gas rate cases resolved in 2017. There were 119 electric and gas rate cases resolved in 2016, 98 in 2015, and 99 in both 2014 and 2013. Approximately 120 electric and gas rate cases were decided in the first nine months of 2017, and roughly 35 electric and gas rate cases were decided in the 12 months ending March 31, 2018; this volume is consistent with that of the 12 months ending March 31, 2017, and continues a marked increase above the activity seen in the early 2000s. The elevated level of activity since the early 2000s is attributable to increased costs driven by environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and employee benefits, combined with slower growth in sales volumes.

For the 12 months ending March 31, 2018, the average authorized return-on-equity (ROE) percentages for electric and gas utilities were relatively the same as they were for the 12 months ending March 31, 2017. For electric utilities, the average ROE percentage was approximately 9.68 percent for the 12 months ending March 31, 2018 (based on 68 cases) and approximately 9.69 percent for the 12 months ending March 31, 2017 (based on 73 cases). For gas utilities, the average ROE percentage set by regulators was approximately 9.66 percent for the 12 months ending March 31, 2017 (based on 22 cases) and approximately 9.66 percent in 2016 (based on 58 cases). Despite the justified need for rate increases, regulators are cognizant of the impact of such increases on customers given the current economic conditions, which could affect rate-case outcomes.

Further, as noted in Section 7, regulators are also seeking prompt rate decreases to pass the benefits of the Tax Cuts and Jobs Act to customers.

Separately, some states have decided to look into nontraditional rate-case models and have begun working on implementing these new regulatory frameworks. Two such frameworks are highlighted below.

Minnesota's e21 Initiative

Minnesota's e21 initiative was launched in 2014. As described on the Minnesota Center for Energy and Environment Web site, the initiative is intended to “provide regulators and other decision makers with recommendations on how Minnesota's regulatory framework, and the existing utility business model, might evolve to continue to protect and promote the public interest.” In Phase I of the initiative, which was completed in December 2014, “e21 released consensus recommendations for Minnesota to evolve toward a more consumer-centric, performance-based regulatory approach and utility business model.” Phase II was completed in December 2016 with the publication of white papers addressing the following matters:

- **Utilities’ shift to a performance-based compensation framework would incentivize performance on outcomes that would be valued by customers and supportive of state energy policies. This framework would continue to allow utilities to recover prudently incurred costs but also would provide several alternatives for returns on capital. These alternatives would range from one that would maintain current returns and allow for performance-based compensation incentives to one that would provide equity returns proportionate to the achievement of performance targets within established tiers.**

- **To ensure that state energy policies are carried out, utilities would have to focus on five-year plans to create actionable incentives for integrated resource planning. In addition, when**
calculating the length of time to process those plans through regulatory systems, utilities should consider the plans’ costs and effects on customers.

- Grid modernization should ensure the two-way flow of energy and information as well as the efficient coordination of many more participants within the system.

The participants in the e21 Initiative are currently focusing on e21’s third phase, which is devoted to improving the implementation of the recommendations in e21’s Phase I and Phase II.

Some industry observers believe that by focusing on “the utility of the future,” Minnesota (through the e21 Initiative) and other states could define new options for how the electric system is modernized and how the utility business model is structured.

New York’s REV Initiative

In early 2015, the New York PSC issued an order attempting to revamp the state’s utility business model, known as the Reforming the Energy Vision (REV) initiative. For more information about the REV initiative, refer to Electricity Storage in Section 1.

Future of Coal-Fired Generating Units

The future use of coal-fired generating units in the United States continues to evolve. Coal as an energy source faces a number of regulatory and market-imposed headwinds since coal-fired power plants remain viewed as environmentally unfriendly, as they are major CO$_2$ emitters. Market dynamics, including low prices of natural gas and the reduced demand for electricity, continue to affect the power plant generating mix across the country. In addition, regulators keep pressuring power plant owners, especially owners of plants that use fossil fuel to generate electricity, to further reduce emissions, all while state regulatory commissions mandate the increased usage of renewable power generation.

In the meantime, economic concerns are also mounting. Lower natural gas prices and subsidized renewables, along with higher operating and maintenance costs for coal plants versus those for natural gas or renewable energy facilities, have contributed to the lack of new coal plant construction. A less significant factor is the Mercury and Air Toxics Standards Act (MATS), which has affected the economics of some coal-fired power plants through limits it places on the emissions of toxic air pollutants such as mercury, arsenic, and metals; it is discussed in greater detail below.

As a result of these factors, there remains a concerted effort to reduce the use of coal-fired generating units in the United States, as demonstrated by the fact that certain plants are set to be retired or converted to other fossil fuel sources such as natural gas or biomass over the next several years. More than 250 coal plants, primarily older and smaller, have been retired since 2010. Plant retirement announcements in 2017, however, trended earlier and larger than ever. For example, in March 2017, in Page, Arizona, the operators of the Navajo Generating Station, the largest coal-fired power plant in the West, announced plans to close it by 2019. In April 2017, Duke Energy outlined a goal to reduce coal’s supply of its generation mix by a third by 2030. The electric utility Dayton Power & Light announced plans to shut two coal plants in southern Ohio by the end of 2018. WEC Energy Group (WEC) retired the 1,190-MW Pleasant Prairie coal plant in April 2018 and plans to retire the 200-MW Pulliam power plant in late 2018 or early 2019 and the Presque Isle plant by 2020. All those facilities are fired by coal; WEC expects to retire approximately 1,800 MW of coal generation by 2020 in a bid to reduce carbon dioxide emissions by approximately 40 percent below 2005 levels by 2030. On March 31, 2018, FirstEnergy

2 Source: https://platform.mi.spglobal.com/web/client?auth=inherit#news/article?id=44141871&KeyProductLinkType=2.
Solutions (FES), its subsidiaries, and FirstEnergy Nuclear Operating Company filed for Chapter 11 bankruptcy protection in the U.S. Bankruptcy Court in the Northern District of Ohio. FES obtained about 6.7 million tons of coal in 2017 from Murray Energy Corp. S&P Global Market Intelligence reports that FES will “commence a sale and investor solicitation process” for the fossil assets owned by FirstEnergy Generation LLC. This fleet of primarily coal-fired generation assets includes the 2,510-MW Bruce Mansfield plant in Pennsylvania and the 2,210-MW W.H. Sammis plant in Ohio. S&P Global Market Intelligence also reports that U.S. power producers plan to take at least 11.4 GW of coal-fired power plant capacity off-line in 2018, more than has been retired in a single year since 14.7 GW of coal capacity was retired in 2015. The U.S. Energy Information Administration’s Annual Energy Outlook 2017 reports nearly 90 GW of coal capacity could be retired from 2017 to 2030.

Retirements and the retrofitting of existing coal-fired units, as well as market dynamics and the current regulatory environment, may affect decisions about the construction of new power plants. For example, President Trump ordered the U.S. Department of Energy (DOE) to prepare steps to stop the loss of coal and nuclear plants, and the agency has examined the use of two federal laws to do so. While the administration’s previous attempts to subsidize older coal and nuclear plants have failed, market observers say Trump’s increased engagement in the issue, coupled with indications that the DOE is willing to go around entities that traditionally manage electricity markets, may indicate that support is coming soon.

Similarly, no new coal gasification facilities are anticipated in the United States in the foreseeable future, and some projects under construction have been reconsidered. For example, Southern Company had built a plant in Kemper County in central Mississippi to take advantage of a strip coal mine nearby. The plant’s equipment was meant to turn the coal into gas and remove at least two-thirds of the CO₂ emitted. But the company determined that because of increasing cost overruns and delays and the fact that the gasifying equipment was not working as designed, the plant would burn only natural gas instead.

Although coal prices in the United States have rebounded and remained steady throughout 2017, evidenced by the fact that coal futures on the New York Mercantile Exchange for Western Rail PRB and Eastern Rail CSX remained within a relatively tight range through the third quarter of 2017, they have slowly declined in recent years and are still generally lower than in past years. Lower natural gas prices, combined with the increasing regulatory constraints that are causing power producers to gradually turn their attention from coal to natural-gas-fired generation capacity, have led to decreases in demand and reductions in price.

The EPA’s Coal Combustion Residuals (CCRs) rule, which regulates how coal ash should be safely disposed of by coal-fired power plants, has also had an effect on the economics of coal-fired generation. However, the EPA in September 2017 stated that the agency is granting two petitions from the utility industry to review the portions of the 2015 rule governing CCRs, and that it will delay for two years the Obama-era rule on handling toxic wastewater from coal plants. The EPA said the decision was based partly on new authority granted to it under the Water Infrastructure for Improvements to the Nation Act, which was passed last year and gives the EPA new enforcement authority over how states set up their programs to handle coal ash.

3 Source: https://platform.m.i.spglobal.com/web/client?auth=inherit#news/article?id=44109345&KeyProductLinkType=2
4 Source: https://platform.m.i.spglobal.com/web/client?auth=inherit#news/article?id=43987127&KeyProductLinkType=6
7 Source: https://www.eia.gov/coal/markets/#tabs-prices-2
Clean Air Interstate Rule

In April 2005, the EPA issued the CAIR to regulate emissions of SO$_2$ and NO$_x$ from power plants, seeking to limit particles that drift from one state to another. The CAIR’s cap-and-trade system, which covers 27 eastern states and the District of Columbia, allows the states to meet their individual emissions budgets by employing either of two compliance options: (1) requiring power plants to participate in an EPA-administered interstate cap-and-trade system that caps emissions in two stages or (2) undertaking measures of their own choosing. The CAIR has been replaced by the Cross-State Air Pollution Rule (CSAPR) as of January 1, 2015.

Cross-State Air Pollution Rule

The EPA continued its efforts to curtail power plant emissions by issuing the CSAPR in July 2011. This rule set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. The intent of the rule is to improve air quality by reducing power plant emissions that may affect pollution in other states.

Although a federal appeals court vacated certain aspects of the CSAPR in August 2012, the U.S. Supreme Court ultimately ruled to uphold the CSAPR in April 2014. The Supreme Court’s decision did not automatically reinstate the CSAPR; it simply remanded the case to the appeals court. On October 23, 2014, the appeals court approved the EPA’s request to lift the stay of the CSAPR and delay the compliance deadlines by three years since the original compliance dates have passed.

The Supreme Court’s decision to vacate the federal appeals court ruling in April 2014 did not mark the end of the ongoing legal battles since there were several other legal challenges to be considered by the appeals court. On January 15, 2015, the EPA formally filed a brief with the appeals court, refuting the merits of the remaining challenges. On July 28, 2015, while offering its opinion on the remaining issues, the appeals court upheld the rule. Consequently, the CSAPR remains in place.

On February 26, 2016, the EPA issued a ministerial action to align the dates in the final rule’s text with the final implementation schedule. On September 7, 2016, the EPA issued a final update to the CSAPR to address the interstate air quality effects with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS).

The effective dates of the CSAPR requirements are staggered. As a result of the revised implementation timeline, the Phase 1 emissions budgets apply to 2015 and 2016, and the Phase 2 emissions budgets and assurance provisions apply to 2017 and beyond. Starting in May 2017, power plant NO$_x$ emissions were reduced during the summer months (i.e., May to September), reducing the effects on air quality of ozone pollution that travels across state lines. This helps enable states that are downwind from power plants to maintain the level of air quality required by the NAAQS.

The September 2016 EPA update to the CSAPR aimed to reduce NO$_x$ emissions from power plants in 22 states and was projected by the EPA to cut ozone season NO$_x$ emissions by 80,000 tons, a 20 percent reduction from 2015 levels. Officials in Wisconsin, Alabama, Arkansas, Ohio, and Wyoming filed suit against the EPA in November 2016, suggesting that the update improperly relied on generation shifting and failed to properly account for changes in ozone pollution that may drift over from other countries. In August 2017, the EPA asked a federal appeals court to dismiss an attempt by several states to bring under court purview an as-yet nonexistent administrative action related to the update. Further, the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit”) suspended the briefing schedule in the case that month, and the EPA said it generally did not oppose the move. However, the agency has pushed back against the petitioners’ request for regular updates on its progress in reviewing

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petitions for reconsideration of the rule, noting that those petitions were filed outside of the court challenge.

Mercury and Air Toxics Standards

On December 16, 2011, the EPA issued the MATS rule to set a national standard for mercury emissions and to regulate power plant emissions of mercury, acid gases, and nonmercury metallic toxic pollutants. The MATS rule is intended to (1) prevent emission into the air of about 90 percent of the mercury in coal burned in power plants, (2) reduce acid gas emissions from power plants by 88 percent, and (3) reduce $SO_2$ emissions from power plants by 41 percent. Unlike the CSAPR or CAIR, the MATS rule is not a cap-and-trade program; no emissions allowances are involved. If a specific plant emits more mercury or other toxics than permitted, that plant is not allowed to operate. Under the MATS rule, reductions were to be achieved starting in the first quarter of 2015.

On June 29, 2015, however, the U.S. Supreme Court blocked the rule from taking effect, holding that the EPA had not properly considered cost estimate implications when drafting the rule. The case was remanded to the D.C. Circuit. On December 15, 2015, the D.C. Circuit issued a ruling allowing the EPA to move forward with enforcing the MATS requirements as the EPA considers the flaws identified by the Supreme Court ruling (i.e., potential cost burden). The MATS rule was effective as of April 6, 2016. Its requirements finalize standards to reduce air pollution from coal- and oil-fired power plants under Sections 111 (new source performance standards) and 112 (toxics program) of the 1990 Clean Air Act amendments.

Although the MATS rule is in effect, the EPA and other stakeholders continue to consider the rule’s relevance and implications. The EPA completed a supplemental analysis evaluating the rule’s costs, issuing a final report on April 14, 2016, that reaffirmed that the significant benefits of reducing mercury and other toxic pollutant emissions outweigh the related additional costs. Further, the EPA continues to receive challenges to the rule, most recently evaluating two petitions and then denying them on August 8, 2016. In April 2017, the Trump administration asked the D.C. Circuit to delay litigation over the MATS rule when it filed a motion requesting that the D.C. Circuit postpone oral argument on pending legal challenges to the April 2016 final report.

Clean Power Plan

The EPA’s most recent legislation intended to reduce the toxic emissions from coal-fired power plants is the Clean Power Plan (CPP), which the agency initially proposed on June 2, 2014, and formally issued as a final rule on August 13, 2015. The CPP is a comprehensive plan that is designed to reduce existing emissions by fossil-fuel electric-generating-unit plants. Under the CPP, by 2030, carbon emissions within the power sector would be reduced by about 32 percent compared with 2005 levels (this marks an increased reduction compared with the 30 percent specified in the proposed rule). The CPP is also expected to reduce other particle pollution, as well as $NO_x$ and $SO_2$ levels, by about 25 percent.

The CPP is not a new set of rules or regulations but an initiative that would allow states to develop their own implementation plan to meet certain $CO_2$ emissions requirements. Under the CPP, states would still need to comply with existing federal and state emissions regulations such as the CAIR, the MATS, the NAAQS, and regional haze rules. However, these regulations would be supplemented by individualized state-developed strategies that would further reduce power plant emissions to meet a state’s CPP-defined goal.

President Trump and his administration, including EPA Administrator Scott Pruitt, have been critical of the CPP, and President Trump signed an executive order in March 2017 to nullify President Obama’s climate-change-mitigation efforts and revive the coal industry by directing the EPA to start the complex
and lengthy process of withdrawing and rewriting the CPP. Throughout the presidential campaign, Mr. Trump vowed to roll back President Obama’s major climate change policies, a set of ambitious EPA regulations to curb greenhouse gas pollution from coal-fired power plants. On October 9, 2017, the EPA announced that Mr. Pruitt had signed a proposed measure to repeal the CPP. The proposal argues that the EPA overstepped its legal authority in seeking to force utilities to reduce carbon emissions outside their actual facilities to meet federal emissions targets. The proposal contends that the CPP does not offer a replacement plan for the regulation of emissions of CO₂, which the Supreme Court has ruled that the EPA is obligated to do. Rather, the agency said it intends to seek public input on how best to cut emissions from natural-gas and coal-fired power plants.¹⁰

In addition, in late September 2017, the DOE proposed that FERC consider, on an expedited timetable, a rule to compensate coal-fired plants and nuclear power stations for the reliability they bring to the nation’s electric supply. The proposal asks FERC to craft a rule to ensure that certain power plants serving wholesale markets can fully recover their costs. To qualify for full cost recovery, plants must have at least 90 days of fuel supply on-site. The DOE gave FERC 60 days from its September 28, 2017, request to take action, but in December 2017, the DOE extended the deadline to January 10, 2018.

On January 8, 2018, FERC terminated the rulemaking initiated by the DOE, and the commission said the rulemaking was not supported by the record and that it lacked the evidentiary support needed to satisfy legal requirements. While some commenters on the proposed rule maintained that grid resilience and reliability are suffering because of the premature retirement of certain resources, FERC said it found no proof that past or planned generator retirements may be a threat to grid resilience.¹¹

Also on January 8, 2018, recognizing the importance of infrastructure resilience, FERC issued Docket No. AD18-7-000, which initiated a proceeding to holistically evaluate bulk-power system (BPS) reliance in the United States. According to this FERC order, each RTO and ISO was required to address specific questions about potential resilience issues. The FERC order had an original compliance deadline of 60 days that was extended to May 9, 2018, because of numerous other FERC commitments. FERC is evaluating the comments that were submitted by the various industry stakeholders.

**Carbon Pollution Standards for New, Modified, and Reconstructed Power Plants**

On August 3, 2015, the EPA issued its final rule establishing CO₂ emissions standards for new, modified, and reconstructed power plants. The guidelines would limit emissions in the following manner:

- **Newly constructed fossil-fuel-fired steam-generating units** — Emissions would be limited to 1,400 pounds of CO₂ per MWh.
- **Reconstructed and modified fossil-fuel-fired steam-generating units** — Emissions would be limited to:
  - 1,800 pounds of CO₂ per MWh for sources with heat input greater than 2,000 MMBtu/h.
  - 2,000 pounds of CO₂ per MWh for sources with heat input less than or equal to 2,000 MMBtu/h.
- **Newly constructed and reconstructed fossil-fuel-fired stationary combustion turbines** — Emissions would be limited to 1,000 pounds of CO₂ per MWh (or 1,030 pounds of CO₂ per MWh for base-load natural-gas-fired units).

¹¹ Source: https://platform.mi.spglobal.com/web/client/auth=inherit#news/article?KeyProductLinkType=2&id=42890829.
¹² Source: https://platform.mi.spglobal.com/web/client/auth=inherit#news/article?KeyProductLinkType=2&id=43135854.
The only fossil-fuel-fired power plants placed in service over the past few years that are capable of meeting these requirements are combined-cycle gas turbine generators. For existing coal-fired generating units to meet the new requirements, they would need to use technology such as carbon capture and storage to reduce emissions. The final rule became effective on October 23, 2015. Since the EPA’s issuance of its carbon pollution standards for new, modified, and reconstructed power plants, the agency has received five petitions challenging certain aspects of the standards. On April 29, 2016, after considering the merits, the EPA denied the submitted petitions.

Liquefied Natural Gas

Natural gas accounts for roughly a quarter of global energy demand. Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state to facilitate storage and allow the fuel to be economically stored or transported over long distances. The natural gas is condensed into a liquid at close to atmospheric pressure by cooling the gas to approximately –260°F. LNG is principally used for transporting natural gas to markets, where it is “regasified” and distributed as pipeline natural gas for storage or consumption. Approximately 10 percent of the natural gas used globally is supplied as LNG. The cost of transforming LNG back to natural gas remains substantial, and there are few LNG facilities in the United States. In recent years, the growth in demand for LNG has been directly correlated with the increasing popularity of natural gas across global markets.

While the supply of LNG had grown faster than that of any other energy source in recent years, LNG’s global market share growth had stalled since 2010. However, global LNG exports are expected to increase given the numerous export terminals that are under development around the world. Specifically, LNG exports to the Asia-Pacific region are expected to increase because geographic and geologic restrictions make LNG the only viable source of gas in that area. Japan, South Korea, and Taiwan rely on LNG to meet nearly 100 percent of their natural gas demand.

The United States has historically been a net importer of LNG through regasification facilities located on the East and Gulf Coasts given that the price of natural gas for many years was higher in the domestic markets than in many of the international markets. The development of these facilities was supported by the $12 per MMBtu natural gas price in 2008. However, given the prices of $2 to $5 per MMBtu for 2014 through 2017, owing in part to the increased supply of shale gas, regasification facilities have begun to convert from regasification to liquefaction in anticipation of LNG export.

According to the U.S. Energy Information Administration, the United States became a net exporter of natural gas in 2017 for the first time since 1957. LNG exports are expected to grow to 3 trillion cubic feet (Tcf) per year by 2020 and to 5.36 Tcf per year by 2040. Whether those projections will be met depends on domestic and global energy prices. The incentive to pursue the development of LNG export terminals will persist as long as the prices in international markets exceed domestic gas prices, plus LNG conversion and transportation costs.

The first export shipment of LNG from the continental United States occurred on February 24, 2016, from Cheniere Energy’s Sabine Pass terminal in Louisiana. The terminal has a permitted LNG export capacity of 4.16 Bcf/d. Sabine Pass is permitted to construct LNG production plants, referred to as trains, four of which are operational; a fifth train is expected to be commissioned in 2019. Dominion Energy’s Cove Point LNG facility, in Lusby, Maryland, exported its first LNG cargo in March 2018. The Cove Point facility has one train with a capacity of 0.75 Bcf/d.
Several other notable LNG export terminals that are under development include the following:

- **Corpus Christi LNG**, in Texas, another Cheniere project. The terminal is under construction and is scheduled to begin service in 2018. The facility will have two trains, each with a capacity of 0.6 Bcf/d.

- **Sempra Energy's Cameron LNG terminal**, in Hackberry, Louisiana. It is under construction and is scheduled to begin service in 2018. The facility will have two trains, each with a capacity of 0.6 Bcf/d.

- **Freeport LNG's terminal**, in Texas. It has three trains under construction, each with a capacity of 0.7 Bcf/d. The first two trains are scheduled to begin service in 2019, and the third is expected to come online in 2020.

- **Elba Island LNG**, in Georgia, a Kinder Morgan project. The facility will have 10 modular liquefaction trains, each with a capacity of 0.03 Bcf/d.

On the basis of current construction plans, the U.S. Energy Information Administration “expects that by 2020 the United States will have the third-largest LNG export capacity in the world after Australia and Qatar.”

The U.S. LNG export licensing process is administered by the DOE under the Natural Gas Act. To speed up the licensing process, the DOE has begun to prioritize projects on the basis of their merits. Further, the DOE has proposed a rule that would expedite the review and approval of applications to export small amounts of natural gas. Several LNG producers are competing on cost, and some are considering entering into tolling arrangements to deliver LNG to international markets. FERC has approved or is evaluating the approval of the export of LNG from several other terminals, primarily along the Gulf Coast. However, many industry observers consider the completion of all such facilities to be unlikely given the uncertainty inherent in obtaining regulatory approvals and competing developments in other emerging markets, such as those in East Africa. Construction will also depend on successful financing of construction costs, which may exceed $10 billion for certain projects, and the successful execution of long-term capacity arrangements.

Despite these trends in activity, the market for bilateral LNG forwards has remained very small. Broker-dealer markets for LNG have been slow to develop, and there are still no exchange-traded LNG contracts.

A company with a contract to buy or sell LNG needs to evaluate whether LNG is readily convertible to cash (RCC) in connection with the accounting assessment of the contract. Given the current trends in market activity, most companies would conclude that LNG is not RCC.

Companies with LNG transactions are encouraged to keep up to date with their RCC conclusions as the market continues to evolve. Further, with development of the LNG markets, companies will likely enter into new types of contracts. Since LNG can be shipped globally, companies are likely to structure long-term LNG shipping and natural gas supply contracts and may also need additional access to natural gas transportation and storage.

**Cybersecurity**

**Grid Modernization**

Over the past decade, the P&U industry has been subjected to disruptive technological advancements with numerous benefits, including improved quality of service, efficiency, and reliability. The latest
A wave of these advancements has been given the umbrella term “grid modernization.” This phrase is used to describe a variety of emerging technologies that leverage IT to change the way we manage the distribution and flow of power, producing the following significant benefits for utilities and their customers:

- Reduced outage times and improved reporting.
- Streamlined integration of distributed energy resource management systems.
- Better operational analytics.
- Optimized power quality.
- Improved system reliability and efficiency.
- Improved maintenance planning and forecasting.

However, the prospect of numerous benefits is tempered by daunting realities. Limited architecture standards, burgeoning regulatory environments, and unforeseen cyber threats are all challenges utilities will need to address. Fortunately, the P&U industry has faced a similar challenge recently and can capitalize on the lessons learned.

Throughout the past decade, advanced metering infrastructure (AMI) has been adopted by a vast segment of utilities around the world, enabling functions such as meter to cash, remote disconnect, customer Web presentment, and demand response. The early adopters of these programs overcame unanswered engineering and organizational challenges similar to those that many of the same utilities face today regarding grid modernization.

The early adopters of AMI routinely had to deal with emerging technology and risks. Fundamental architecture questions (e.g., Do we use an enterprise service bus or point-to-point interfaces for back-office systems?), unforeseen product vulnerabilities (e.g., shared cryptographic keys embedded in meters), and the chartering of new operational capabilities (e.g., How do we manage and support this massive distributed network?) were the issues of the day.

As the AMI product market has matured, vendors have improved their platforms’ interoperability, reliability, and security. Utilities deploying AMI solutions today face significantly fewer challenges than the early adopters did nearly a decade ago for the following reasons:

- Vendors’ products have matured and support better integration.
- Early security vulnerabilities have been remediated in newer product versions.
- Industry groups and veteran integration partners can help navigate organizational change and operational impacts with confidence.
- Standards bodies have matured, allowing for consistency and scalability.

What lessons can be learned from the AMI adoption life cycle that would support the adoption of grid modernization technologies? Through analysis and discussion with industry experts, a few specific lessons can be extrapolated:

- **Like AMI, grid modernization is a program, not a project** — Forecasting the ongoing impacts to distribution operations, IT, cybersecurity, and net new capabilities related to grid technology management is needed to successfully sustain the program past the delivery stage.
- **Security is critical and will need to evolve with the technology** — During the early days of AMI adoption, utilities had to address new challenges: How do we secure such a large number of distributed devices? How do we protect the integrity of the networks that support these devices?
Similar security challenges are faced today by utilities embarking on the grid modernization transformation. Cybersecurity will be critical to addressing these challenges, including cryptographic trust, access control, device hardening, incident response, vulnerability management, and many other domains that will be significantly affected.

- *New opportunities also introduce new risks* — Microgrid management, distributed energy resource management, power flow optimization, self-healing, grid forecasting, and all the other benefits associated with a grid modernization program will present new opportunities for utilities and customers. However, there are also new risks, as more than ever in history our power grid becomes interconnected with IP-based technology controlling the granular function.

Addressing this challenge will require utilities to break traditional norms of walls and isolation-based approaches to ICS security, and move toward extensibility and rapidly growing third-party integration. These are the new trends of the digital utility.

### Regulation

The most significant development in cyber regulation for the power grid in 2017 was North American Electric Reliability Corporation's (NERC's) approval of Critical Infrastructure Protection (CIP)-013-1, the new standard for supply-chain cybersecurity risk management. This standard was ordered by FERC in July 2016; FERC mandated that the standard be developed and approved by the end of September 2017. Despite requiring three ballots of the NERC membership, the standard was developed and approved and sent to FERC on time. Given that CIP-013-1’s implementation period is 18 months, if FERC takes six months to one year to approve it, this means that CIP-013-1 is likely to come into effect in late 2019 or early 2020.

The impact of CIP-013-1 is likely to be far-reaching. For large utilities, coming into compliance — and maintaining it afterward — will involve a significant effort from the utilities’ supply-chain, legal, IT, cybersecurity, and NERC compliance departments. It will in most cases require significant changes in OT procurement. Even more important, CIP-013-1 is very different from previous CIP standards in that it doesn't prescribe particular actions but simply requires the utility to develop and implement a supply-chain cybersecurity risk management plan. It will be for the utility and the auditor to decide whether the plan is a good one and if it has been properly implemented. It remains to be seen how well utilities and NERC auditors will adapt to this very different approach to cybersecurity regulation.

### Physical Security

**North American Electric Reliability Corporation**

In June 2017, NERC issued a media release about its *State of Reliability 2017* report:

The North American Electric Reliability Corporation's State of Reliability 2017 report reviews past performance of the bulk power system, examines the state of system design, planning and operations, and the ongoing efforts by NERC and industry to continually improve system reliability and resiliency [. . . ] NERC's *State of Reliability 2017* also highlights key recommendations, including enhancing measurement of frequency response and voltage to quantify effects of changing resource mix, including vendors and manufacturer in analyses where possible, and redefining reportable cyber and physical security incidents to be more granular.

This independent review of bulk power system is based on analysis of data and metrics, which enables NERC to examine trends, identify potential risks to reliability, establish priorities and develop effective mitigation strategies. . . .

In 2016, protection system misoperations continued a four-year decline, decreasing to 8.7 percent [calculated as the ratio of incorrect protection system operations to total system protection system operations] — down from 9.5 percent in 2015 and 10.4 in 2014. However, the three largest causes of misoperations remains the
same — incorrect settings/logic/design errors, relay failure/malfunctions, and communication failures. This shows that continued focus on regional education, outreach and training efforts with stakeholders is needed.

While there were no reported cyber or physical security incidents that resulted in a loss of load in 2016, cyber and physical security threats are increasing and becoming more serious over time.

**Electricity Information Sharing and Analysis Center**

The following material is adapted from the *State of Reliability 2017* report, with footnotes omitted:

The Electricity Information Sharing and Analysis Center (E-ISAC) gathers security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity industry across interdependent sectors and with government partners.

Most of the E-ISAC’s communications with electricity industry members are via a secure Internet portal that was significantly upgraded at the end of 2015. In 2016, the E-ISAC added 1,512 new users to the portal, a growth of 19.5 percent over 2015. As the E-ISAC continues to collect portal activity data, the information will assist the E-ISAC in recruiting new members to the portal and determining how the E-ISAC can best serve members’ interests and needs.

Increased physical security and cybersecurity information sharing will enable the E-ISAC to conduct a more complete analysis. Robust data collection over time helps identify important trends and patterns. By providing unique insight and analysis on physical and cybersecurity risks, the E-ISAC aims to add value for its members and assist with overall risk reduction across the electric reliability organization enterprise.

NERC and the electricity industry have taken actions to address cyber and physical security risks to the reliable operation of the BPS as a result of potential and real threats, vulnerabilities, and events. The E-ISAC has started hosting unclassified threat workshops biannually. These workshops bring together security experts from government and industry to discuss threats facing the electricity industry. The discussions include a focus on past threats, incidents and lessons learned, current threats that may affect industry, and views on emerging threats. The E-ISAC held its first threat workshop on December 6, 2016, in Washington, D.C., and has future workshops planned.

**E-ISAC Monthly Briefing Series Update**

The E-ISAC continues to host its monthly briefing series for asset owners and operators (AOOs) covering timely CIP topics for participants. The briefings involve federal and technical partners, including staff from the Department of Homeland Security's Industrial Control Systems Cyber Emergency Response Team, the Office of Intelligence and Analysis, and the National Cybersecurity and Communications Integration Center (NCCIC), as well as FireEye and iSIGHT Partners. The monthly briefing series also includes special guest presentations.

The monthly briefings during 2016 drew from 180 to more than 400 attendees. That was the first full year that the series included a physical security section (added April 2015), and full replays were made available for member download (added December 2015). On the basis of polling feedback, 70 percent to 96 percent of attendees consider the meetings to be of “Considerable Value” or “Great Value.” The E-ISAC will continue to encourage industry to share security best practices and lessons learned on topics relevant to the industry by inviting more industry AOOs to be guest presenters.
Grid Security Exercise (GridEx)

NERC conducted its third biennial grid security and emergency response exercise, GridEx III, on November 18 and 19, 2015. The first GridEx took place in November 2011. NERC’s mission is to assure the reliability of the BPS, and GridEx III provided an opportunity for industry and other stakeholders to respond to simulated cyberattacks and physical attacks affecting the reliable operation of the grid. Led by the E-ISAC, GridEx III was the largest geographically distributed GridEx to date and consisted of a two-day distributed play exercise and a separate executive tabletop on the second day. More than 4,400 individuals from 364 organizations across North America participated in GridEx III, including industry, law enforcement, and government agencies.

In March 2016, the E-ISAC released three reports (one available to the public and two restricted to industry and government stakeholders) regarding the lessons learned from GridEx III. The reports summarize the exercise and provide recommendations that the E-ISAC has integrated into its internal crisis action plan and standard operating procedures. In addition, the Electricity Subsector Coordinating Council (ESCC) has adopted many of the recommendations into its playbook and used the GridEx III exercise to spur action on cyber mutual assistance, increase spares of critical equipment, and provide cross-sector support during crisis situations. Finally, all participating organizations were able to (1) improve internal and external communications and relationships with important stakeholders and (2) exercise crisis response procedures against an advanced attack scenario that identified potential gaps and improvements to security, resilience, and reliability.

GridEx IV, the fourth such exercise, was held November 15 and 16, 2017, and involved more than 6,500 participants from 450 organizations in the United States, Canada, and Mexico. The GridEx IV public public report was made available in March 2018. The GridEx IV distributed play exercise resulted in recommendations that entities in the electricity industry do the following: increase the roles of lead planners, boost participation from law enforcement, improve the functionality of the E-ISAC portal, use their public affairs and corporate communications functions to develop guidelines on how to respond to a crisis, enhance communications among reliability coordinators, strengthen the resiliency of communications in emergency situations, encourage participation in the Cyber Mutual Assistance program, and continue to develop the Move 0 event, which focuses on activities that prepare entities for encounters with adversaries as well as for cyberattacks coordinated with physical attacks during the two-day exercise.

In addition, the GridEx IV executive tabletop “involved multiple sophisticated cyber and physical attacks that targeted the electricity industry’s critical grid control systems, key generation and transmission facilities, and other critical infrastructure facilities that caused widespread and prolonged power outages.” Recommendations were for P&U entities and government to do the following: increase utilities’ sharing of information with state and local governments; strengthen the ability of the ESCC and Energy Government Coordinating Council (EGCC) to share information nationwide; augment utilities’ coordination with the federal government; use the ESCC and EGCC to ensure the consistency of messages delivered to the public; boost the capabilities of grid operators to respond to emergencies; increase the timeliness of information provided by NERC and E-ISAC; strengthen coordination with other critical infrastructure sectors; develop a process by which the ESCC, the DOE, and the ESCC can consult to ensure that any orders issued in an emergency are appropriate; make sure that utilities have access to sensitive information; ensure that utilities’ financial needs are met during disaster recovery periods; identify state and national priorities; and continue to promote the EGCC’s large power transformer transportation program and the Cyber Mutual Assistance program.
Cross-Sector Activities

The E-ISAC engages with the government at all levels, including international, federal, state, local, territorial, tribal, and provincial governments. It also includes close international allies with CIP sector partners and other ISACs.

During 2016, the E-ISAC's federal partners were active in response to Presidential Policy Directive 41: United States Cyber Incident Coordination and created projects covering cyber mutual assistance, high-profile exercises, cyber incident response plans, learning opportunities for the E-ISAC staff, and power outage technical reference products. The E-ISAC worked closely with our federal partners in support of their activities and provided feedback where appropriate, such as with the recently updated National Cyber Incident Response Plan. The E-ISAC has also maintained participation with the NCCIC, the National Integration Center, and the National Operations Center.

Through the National Council of ISACs (NCI), the E-ISAC is able to collaborate with all critical infrastructure-specific ISACs. The E-ISAC assisted the NCI in establishing new information sharing procedures and collaborative analytical approaches. This partnership helped lead to additional threat briefing opportunities and increased information sharing.

Market Activity

Natural Gas

U.S. natural gas prices have remained depressed despite a shift from coal to natural gas. Henry Hub spot prices decreased from $3.59 per MMBtu on December 31, 2016, to $2.82 per MMBtu as of December 31, 2017, and forward prices for the forward 36-month period decreased during this time by about 6 percent on average. This is the result of substantial increases in supply without a corresponding increase in demand. Supply increases are coming from improved drilling efficiency and new wells coming online as natural gas producers, particularly in the Marcellus Shale region, have been able to extract massively greater amounts of gas than had been expected. This further supports the expectation that supply is unlikely to be challenged even if a harsh winter drives increases in seasonal demand.

Current environmental regulatory trends, combined with the proliferation of shale gas, have created a situation in which power producers are increasingly retrofitting generators to adapt to natural-gas-fired technology. Natural gas storage surplus and midstream capacity constraints will continue to play an important role in the pricing of natural gas in the medium term. Gas continues to behave like a local commodity because of these constraints. Short-term volatilities, infrastructure constraints, and evolving market locations all continue to contribute to the complexity of fair value accounting. Historical relationships and location basis assumptions require updated analysis and can make it challenging to ensure that current market conditions have been appropriately reflected.

For more on industry developments regarding coal and LNG, see Future of Coal-Fired Generating Units and Liquefied Natural Gas above.

Electricity

U.S. electricity prices also slightly decreased from December 2016 to December 2017, as reflected in an analysis of prices charged by various regional transmission organizations (RTOs) across the country, including Midwest Indiana, PJM Western Hub, ISO New England Inc. (ISO-NE) Internal Hub, and ERCOT-North Zone. Forward prices for the forward 36-month period decreased by 2 percent on average from December 2016 to December 2017. The decrease in the price of power has been largely driven by
the decrease in the price of natural gas and coal used to fuel generation facilities. One exception is California Independent System Operator (CAISO), whose power prices actually increased by 1 percent for the forward 36-month period. The state of California has passed legislation that requires significant amounts of renewable power generation to be sourced entirely within the state. This requirement has driven up prices in California but not for the other major RTOs. In the ERCOT market, while overall three-year forward prices are relatively flat compared with those of a year ago, there has been a seasonal spike because of significant plant retirements announced in 2017, resulting in an average 30 percent increase in forward prices for the summer months. Some power generation companies are seeing lower profits because of the decrease in electricity prices. Further, as cash flows from certain power plants decline, entities are being required to consider long-term asset impairments.

Natural Gas Liquids

Natural gas liquids continue to be treated as local commodities because of limitations in pipeline capacity. Per a Kinder Morgan white paper published in June 2017, “[i]n 2016, approximately 50 percent of all U.S. NGLs were fractionated in Texas and Louisiana. Yet that same year, Texas and Louisiana combined accounted for only about one-third of U.S. natural gas production.” This is a result of the high cost of transporting natural gas liquids. Industry in the United States produces more natural gas liquids than it is able to transport to customers. Transportation costs tend to make up a material portion of the prices realized for the delivered gas, thereby preventing most companies from concluding that delivered products are RCC. However, as midstream infrastructure improves in the medium term and commercially viable markets develop, RCC conclusions will need to be revisited.

The Future of Nuclear

Construction within the global nuclear industry has largely been stagnant in recent years, except in Asia. In Europe, leaders in France and Germany have announced that they plan to reduce nuclear’s share of their country’s electric generation by 2022 and 2025, respectively. Siemens has exited the reactor-building business. Westinghouse filed for Chapter 11 bankruptcy, and its parent, Toshiba, has admitted to having substantial doubt about its ability to continue as a going-concern. France’s EDF continues to face financial difficulties. Westinghouse, Toshiba, and EDF account for more than half of nuclear generation worldwide. Rising construction and maintenance costs, safety concerns, historically low natural gas prices, and continued growth in renewables are all factors that are putting pressure on the nuclear industry. In the United States, during the 1980s, 1990s, and 2000s, no new reactors were placed in service, but the industry was able to add capacity through uprates and boosting output. But the aforementioned factors are threatening the aging nuclear fleet, even those plants with extended operating licenses. As of September 2017, there were 99 operating commercial nuclear reactors at 61 nuclear power plants in the United States with an average age of 36 years, of which 83 have received license extensions and 9 have pending applications. This is down from the 112 units operating in 1990. Four units have provided notice to the NRC of their plan for future submittal of license renewal applications. Exelon Corp. plans to apply for a second license extension for Peach Bottom Atomic Power Station, Units 2 and 3, in the third quarter of 2018, and Virginia Electric and Power Company plans to apply for a second license extension for Surry Power Station Units 1 and 2 in the first quarter of 2019.

Five plants have been retired in the past several years for various reasons:

- Duke Energy Corp.’s Crystal River Unit 3 in Florida.
- Edison International’s San Onofre Nuclear Generation Station in California.

Source: https://www.kindermorgan.com/content/docs/White_Natural_Gas_Liquids.pdf.
• Dominion Resources Inc.'s Kewaunee plant in Wisconsin.
• Entergy Corp.'s Vermont Yankee in Vermont.
• Omaha Public Power District's Fort Calhoun Nuclear Generating Station in Nebraska.

Several plants will be retired before their operating licenses expire:
• Exelon Corp.'s Oyster Creek Nuclear Generating Station in New Jersey, to be retired in 2018.
• Entergy Corp.'s Pilgrim Nuclear Power Station in Massachusetts, to be retired in 2018.
• Exelon Corp.'s Three Mile Island in Pennsylvania, to be retired in 2019.
• Entergy Corp.'s Indian Point in New York, to be retired in 2020 and 2021.
• Entergy Corp.'s Palisades nuclear plant in Michigan, to be retired in 2022.
• PG&E's Diablo Canyon in California, to be retired in 2025.
• NextEra Energy's Duane Arnold in Iowa, likely to be retired at the end of 2025.

According to a May 2018 Bloomberg article, one-quarter of the nuclear power plants operating in the United States are either scheduled to close or probably won't make money through 2021. The at-risk sites have total generating capacity of 32.5 GW. Included among them are Pilgrim, Quad Cities, and Clinton Power Station, all of whose owners have announced that they will be early retired. Of these at-risk units, only 2 are rate regulated (Quad Cities Units 1 and 2), and the remaining 10 are merchant plants. In a June 2016 article, Fitch Ratings said that merchant plant closures are largely being driven by low natural gas prices and sluggish demand as well as the units' being vulnerable because of their high operating and capital costs.

Development of New Nuclear Facilities

Challenges that companies may encounter when developing nuclear facilities include long lead times, large capital requirements, extensive permitting processes, and uncertain future demand for more capacity. Regarding this latter challenge, most of the new nuclear capacity in development was proposed before 2010, when projected demand for electricity was significantly higher than it is now. New nuclear capacity recently licensed (one project), under construction (two projects), or for which companies applied for either a combined license that is currently under review (one project) or an early site permit (one project) is primarily associated with projects of utilities that investors own either wholly or in partnership with other companies, including municipal utilities.

As of May 2018, there are four nuclear units being built (discussed below); however, construction of Virgil C. Summer Nuclear Generating Station Units 2 and 3 in South Carolina has stopped because of cost overrun concerns in the aftermath of the Westinghouse bankruptcy. Southern Company has announced that it expects to complete construction of Vogtle Electric Generating Plant Units 3 and 4 in Georgia by 2021 and 2022, respectively.

In April 2018, the NRC authorized its staff to issue combined licenses for two new reactors proposed by Florida Power & Light Company at its existing Turkey Point site. Because of low gas prices and the cost overruns at Summer and Vogtle, however, it is unlikely that the new units will be built in the foreseeable future.

Tennessee Valley Authority's Watts Bar Unit 2

The United States' first new nuclear generation in 20 years achieved commercial operations on October 19, 2016. Watts Bar Unit 2, near Spring City, Tennessee, owned by the Tennessee Valley Authority (TVA),
is not a new nuclear reactor; the TVA started the project in 1973 but canceled construction in 1985 after spending $1.7 billion. For decades, the reactor lay dormant; in 2007, however, the TVA resumed the project.

When initial construction of Unit 2 was canceled in 1985, the estimated cost of completing the reactor was $2.5 billion. Some 30 years later, the actual cost of completion has turned out to be $4.7 billion. Watts Bar Unit 2 is one of six TVA units that supply more than a third of the region’s generating capacity for approximately 4.5 million homes.

Other Nuclear Facilities

- **Vogtle Electric Generating Plant Units 3 and 4** — In February 2012, the NRC issued construction and operating licenses for two new reactors at Vogtle's plant in eastern Georgia. The plant is 45.7 percent owned by the operator, Georgia Power, a subsidiary of the Southern Company; 30 percent owned by Oglethorpe Power Corp.; 22.7 percent owned by the Municipal Electric Authority of Georgia; and 1.6 percent owned by Dalton Utilities. The estimated initial costs for Georgia Power's share of constructing Units 3 and 4 were $6.1 billion, with scheduled completion dates in 2016 and 2017, respectively. The most recent cost estimates included in Georgia Power's recommendation filed with the Georgia PSC in August 2017 forecast the total capital cost of the project to be approximately $19 billion, with Georgia Power's share approximately $8.8 billion. The Georgia PSC has approved $5.68 billion in capital costs for Georgia Power's share. Unit 3 is now expected to be completed in November 2021 and Unit 4 in November 2022. Georgia Power recommended that the project should continue.

- **Virgil C. Summer Nuclear Generating Station Units 2 and 3** — In March 2012, the NRC issued construction and operating licenses for the two proposed reactors at the Virgil C. Summer plant in South Carolina. The new units are jointly owned, with 55 percent of the plant owned by the operator, SCANA Corporation, a subsidiary of SCE&G, and 45 percent owned by the South Carolina Public Service Authority (also known as Santee Cooper). The initial estimated costs for Units 2 and 3 were $6.3 billion, with scheduled completion dates in 2016 and 2019, respectively. After years of construction setbacks, including the Westinghouse bankruptcy, both entities decided to halt construction in July 2017.

Nuclear Energy Subsidies

Nuclear generation is carbon free; however, the CPP does not give credit toward clean power goals for existing plants. The CPP indicates that nuclear is a key component of states’ ability to meet their clean power goals but gives credit for uprates only for new equipment and construction of new nuclear facilities. Nuclear plants that have closed have been replaced by gas-powered generators, which increase greenhouse gas emissions and thus have a negative effect on the states’ ability to meet their goals. Although no federal credit is given for existing nuclear plants, state subsidies are viewed as one way to incentivize plant operators to continue to run the carbon- and emission-free plants.

In July 2017, a federal judge dismissed a lawsuit to block billions of dollars in subsidies from the state of New York from going to nuclear operators. These subsidies (i.e., zero-emission credits) will enable Exelon Corp. to continue to operate its James A. FitzPatrick, Nine Mile Point, and Ginna nuclear plants. (Entergy had previously announced the closure of FitzPatrick before Exelon purchased the plant.) The state’s goal is to spur clean energy development to cut greenhouse gas emissions, and New York Governor Andrew Cuomo has indicated that the state’s nuclear plants will play a key role in achieving its goals. Similarly, in July 2017, a federal judge also dismissed a case to block state nuclear subsidies in Illinois, a decision that will allow Exelon to keep Quad Cities Units 1 and 2 and Clinton Power Station operating. Exelon had previously announced its plans to retire the Quad Cities units and Clinton.
There is opposition to the subsidies, including from environmental groups and other energy companies that believe that the incentives will detract from the development of solar- and wind-power generation. Opponents also believe that the subsidies are a bailout of dangerous, aging, and unprofitable plants that should close. In Ohio, HB 178 and SB 128 would provide zero-emission credits to the state’s aging nuclear facilities. FirstEnergy Corp. has stated that it will be forced to retire its three nuclear plants, including Davis-Besse, Beaver Valley, and Perry, if the state does not provide assistance. Ohio Governor John Kasich opposes the legislation, and efforts have stalled in the state legislature. The FirstEnergy Corp. subsidiary that owns the three nuclear plants filed for Chapter 11 bankruptcy in March 2018 as it explores plans to restructure, sell assets, and seek government support.

On September 28, 2017, U.S. Secretary of Energy Rick Perry sent a letter and a proposed rule, the Grid Resiliency Pricing Rule, to FERC. If adopted, the proposed rule would have required FERC-approved organized wholesale power markets (i.e., RTOs and ISOs) to develop and implement market rules that give pricing incentives to traditional base-load generation facilities. The proposed rule would have allowed for full recovery of costs of certain eligible units within FERC-approved organized markets. Eligible units must also have been able to provide essential energy and ancillary reliability services and have a 90-day fuel supply on-site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters. Only coal-fired and nuclear units are currently able to maintain 90 days of fuel on-site. The proposed rule would also have required the organized markets to establish rate tariffs for the full recovery of costs and a fair rate of return for eligible units. The proposed rule met with significant opposition, which views it as the federal government’s providing another massive bailout to a failing industry. Secretary Perry cites the 2014 polar vortex, Superstorm Sandy, and Hurricanes Harvey, Irma, and Maria as recent events that emphasize the need to provide financial support to what he describes as fuel-secure base-load resources. Many of the outages caused by the hurricanes were a result of aging transmission and distribution systems, not generation constraints. On January 8, 2018, FERC issued an order formally rejecting the proposed rule and terminating the proceeding. FERC cited previous steps it has taken to address the resilience of the BPS and said the proposed rule did not show the existing RTO/ISO tariffs were unjust, unreasonable, unduly discriminatory, or preferential and thus did not satisfy the Federal Power Act. The White House is now exploring two rarely used statutes that could require electricity purchases from coal and nuclear sources for a two-year period. The administration is considering invoking a national security argument as a way to use its emergency powers under the Federal Power Act and the Defense Production Act to bolster the industry.

Most recently, on May 23, 2018, the governor of New Jersey, Phil Murphy, signed into law a bill that will subsidize the continued operation of nuclear power plants as a means of continuing the advancement of the state’s clean energy goals. Under this law, power plant owners will be eligible to receive zero-emission credits that will allow them to share in a $300 million annual subsidy if they (1) can demonstrate that they are significantly contributing in a positive manner to New Jersey’s air quality and (2) are at risk of closure within three years because of the cost of operating the facility.

**Nuclear Decommissioning**

In the United States, two options available to nuclear power plant operators that want to decommission their units are Safe Storage (SAFSTOR) or Decontamination (DECON). Under SAFSTOR, the dismantling of the facility is deferred, and it is placed into a safe storage configuration. Thirteen nuclear reactors are being decommissioned in accordance with this approach. Under DECON, the facility is immediately dismantled. Sixteen mostly single-unit nuclear reactors are being decommissioned in accordance with

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this approach.\textsuperscript{16} Proper disposal of spent nuclear fuel is required regardless of the method used and is one of the main challenges facing plant operators that are dismantling facilities.

Operators with closed reactors are using decommissioning trust funds that were set aside for dismantling to instead build waste storage on-site since the federal government’s promise to take highly radioactive spent fuel is still unfulfilled. This trend may raise some questions about the sufficiency of the funding levels.

Without an exemption, NRC rules do not permit the plant operators to take money from their decommissioning trust funds to pay for building the concrete pads and rows of concrete and steel casks where waste is stored after it is cooled in special storage pools. But the NRC has always granted exemptions from those rules when asked to do so.

During the operating life of nuclear plants that were subject to rate regulation, customer rates reflected the cost of eventually dismantling reactors, removing their radioactive components, and restoring the sites. Authorities never expected that customer rates would pay for indefinite storage of spent fuel.

The decommissioning trust fund usage has been necessitated by the failure to date of the DOE to open a permanent disposal site for spent nuclear fuel at Nevada’s Yucca Mountain.

In the absence of a permanent disposal site, plant owners have resorted to redesigning the racks in their spent fuel pools to accommodate more of the waste and expand into “dry cask” storage. The spent fuel bottleneck leaves closed and soon-to-close nuclear plants with the prospect that for the indefinite future, they will be storing radioactive spent fuel on-site, where it is required to be guarded 24 hours a day, seven days a week.

In April 2018, federal regulators began considering a plan to temporarily store spent fuel at a proposed site in southern New Mexico. The NRC opened a public comment period that lasted through May 2018. Holtec International is seeking an initial 40-year license to operate the facility. Holtec is a diversified energy technology company headquartered in Jupiter, Florida, that focuses on carbon-free power generation and manufactures a wide range of products. The company’s services include nuclear fuel and waste management; decommissioning; engineering and consulting services; site services, including pool-to-pad dry cask loading services, wet storage spent fuel capacity expansion, and site construction services; and project management services.

Net Metering

Many current rate structures are incompatible with the widespread adoption of distributed generation and may present electric utilities with financial challenges. This incompatibility is often most evident with net metering programs. In net metering programs, customers can sell to their electric utility excess electricity generated by their distributed generation systems, typically at close or equal to the full retail electricity rate. This mechanism may allow some customers to fully offset their monthly bills and shift an added burden onto non-distributed-generation customers for paying electric utilities’ fixed costs.

Examples of regulators dealing with net metering include the following:

\begin{itemize}
  \item \textit{Arkansas Public Service Commission (APSC)} — In 2016, the Arkansas General Assembly enacted Act 827, which directed the APSC to review the state’s rules for net metering. The APSC split this process into two efforts: (1) evaluating the size of rooftop solar systems that should be
\end{itemize}
determined eligible for net metering and (2) evaluating rate structure(s) associated with utilities’ cost related to net metering customers.

In March 2017, the APSC determined that existing solar customers should use retail net metering rates for a 20-year period. To address the determination of rates for new solar customers, the APSC commissioned a working group whose purpose was to evaluate costs and benefits of net metering. That working group was split into two subgroups, with one consisting of utilities and utility interests and the other of conservation and nonutility solar advocates.

In September 2017, those subgroups submitted two separate proposals, rather than a unified set of recommendations, to the APSC. The subgroups presented opposing views on the state’s current net metering policy, with the utilities’ subgroup positing that new solar customers should not be credited for excess generation at the full retail rate since doing so precludes a utility from fully recovering its entire cost of service to retail customers. The subgroup composed of conservation organizations and nonutility solar advocates contended that the full retail rate for net metering customers should remain in place, at least until a comprehensive study of costs and benefits could be completed. The APSC held a public hearing on November 30, 2017, but has yet to reach a decision.

• Arizona Corporation Commission (ACC) — In August 2017, the ACC approved a rate increase for Arizona Public Service Electric Company (APS), as well as a settlement between APS and certain solar companies related to the company’s general rate case proceeding.

As part of the settlement, APS agreed to grandfather existing rooftop solar customers into the current net metering rate for 20 years, as well as provide annual investments in rooftop solar programs and issue refunds to customers resulting from energy efficiency programs.

New rooftop solar customers will receive .129 cents per kWh for excess solar energy, and that rate will decline 10 percent each annual period for new rooftop solar systems installed. Once customers are registered, they will have the rate applicable to them locked in for a 10-year period.

• Public Utilities Commission of Nevada (PUCN) — In September 2017, the PUCN approved a draft order establishing revised rules and regulations for how solar customers will be compensated through net metering. The revisions were ultimately in response to a previous ruling in 2015 by the PUCN that increased fixed charges and lowered compensation for excess generation for both new and existing solar customers.

The draft order is intended to align with Assembly Bill 405 (“AB 405”). AB 405 was signed into law by Governor Brian Sandoval in June 2017 and sought to restore net metering rates for retail customers to a level that approximated those rates before the PUCN’s 2015 ruling. AB 405 set net metering rates for excess solar energy provided to the grid at 95 percent of the retail electric rate, which declines as MW of solar energy sold back into the grid increase, to a floor of 75 percent of the retail electric rate.

• Utah Public Service Commission (UPSC) — A proposed settlement was reached in August 2017 between Rocky Mountain Power and various stakeholders in rooftop solar in Utah. The settlement would grandfather current net metering customers and any additional customers who registered for the program before November 15, 2017, into the existing retail net metering rate structure through 2035.

The settlement, which is still subject to approval by the UPSC, also provides for a three-year transition period, at the end of which rooftop solar customers will switch to a new method of compensation that will be based on a rate determined by the UPSC as a result of a cost-of-solar
study to be performed by Rocky Mountain Power. During the transition period, net metering customers will be compensated at a rate of .092 cents per kWh.

Edison Electric Institute (EEI) identified the increasing effect of distributed generation and associated net metering policies on the grid as a key issue for the electric utility sector. As illustrated above, some net metering programs are structured so that ratepayers using rooftop solar, who rely on the grid 24 hours a day, pay less for the costs of the grid than they did before their systems were installed despite their continued reliance on the grid and its services. Net metering remains a divisive issue in many states.

**Electricity Storage**

The outlook for electricity storage in the United States remained strong in 2017 despite political uncertainty surrounding energy policy. Factors driving this positive outlook include (1) the rising role of renewable generation, (2) state-level renewable and energy storage mandates, and (3) the growth of multiple options for electricity consumers to better manage overall consumption and the shape of their load. The continued acceleration in research and development of various forms of electricity storage offers the promise of more economic deployment at scale in the near term, bringing load-shifting and electricity reliability within reach of more and more utilities and consumers.

There are a number of applications for which energy storage solutions can usefully be deployed. Some technologies are uniquely suited to specific applications, whereas others can be more broadly used across a range of applications. Matching the application to the technology in a way that is both effective and economical will be a key success factor in increasing the market presence of energy storage technologies.

The growth of new technologies, increased investment from high-profile market participants, changing consumer expectations and behaviors, and the structural evolution of the electricity generation and delivery system in recent years are providing fertile ground for maturing electricity storage technologies as key components of the new landscape in electric power. Wider deployment of electricity storage can benefit utilities by improving grid performance and reliability, allowing utilities to avoid the investment in peaking generation capacity and increase integration of renewable power into the grid. On the consumer side, electricity storage can enhance local, distributed generation by providing a load-matching capability under the control of the consumer, minimizing the need for net-metering arrangements. As solar rooftop installations grow and electric vehicle demand rises, the market for electricity storage is expected to expand as consumers become convinced of the availability, reliability, and economics of storage.

State renewable energy goals continue to influence advances in energy storage. According to GTM Research, 21 states now have at least 20 MW of energy storage projects proposed, in construction, or deployed, and the United States surpassed 1 GWh of deployed energy storage in 2017. Various states have passed energy storage legislation or launched energy storage targets:

- **Arizona** — In May 2017, Tucson Electric Power (TEP) signed a power purchase agreement (PPA) for a solar-plus-storage system at an all-in cost estimated at less than .045 cents per kWh over the life of the contract, according to a company official. TEP’s contract supports the view that solar-plus-storage can compete economically with gas peaker plants. In January 2018, a member of the ACC introduced the Energy Modernization Plan, which includes an 80 percent clean energy target by 2050 and a 3,000-MW energy storage procurement target by 2030.
• **California** — In October 2013, the California Public Utility Commission (CPUC) approved its proposed mandate that requires California’s large investor-owned utilities to procure 1,325 MW of energy storage by 2020, with installations required no later than the end of 2024.

In September 2016, California’s legislature passed new bills that increased funding to the CPUC’s Self-Generation Incentive Program and directed the state’s three investor-owned utilities to accelerate the deployment of energy storage with investments of up to 500 MW in addition to the 1,325-MW requirement established in 2013. However, in July 2017, the State Assembly deferred a hearing on SB 700, a bill passed by the State Senate directing the CPUC to create a 10-year rebate program for customer-sited energy storage systems. The State Assembly’s Utilities and Energy Committee expects to consider the bill during the latter part of the 2018 legislative session.

• **Hawaii** — In June 2015, Governor David Ige signed into law a bill that requires the state to achieve 100 percent renewable energy consumption by 2045. Hawaiian Electric Companies, the state’s largest utility, plans on meeting this goal through heavy reliance on battery-backed solar and wind farms and plans to achieve 100 percent renewable generation by 2040, five years sooner than required. Elsewhere in the state, the Kauai Island Utility Cooperative is working with Tesla subsidiary SolarCity and AES Distributed Energy to bring 41 MW of solar-plus-storage plants online through 2018 at prices under 14 cents per kWh.

• **Massachusetts** — In June 2016, Governor Charlie Baker’s administration announced a 200-MWh energy storage target to be achieved by January 1, 2020. In March 2018, Governor Baker introduced a bill titled the Clean Peak Standard that would allocate $1.4 billion for the deployment of additional energy storage to mitigate peak hour pricing spikes.

• **Nevada** — In June 2017, Nevada passed a bill requiring the PUCN to consider requiring utilities to purchase energy storage. The PUCN has until October 2018 to provide its recommendations on establishing annual storage procurement requirements to complement the state’s ample availability of solar resources.

• **New York** — In December 2015, the state set a goal of having 50 percent of electricity generated by carbon-free renewables by 2030. In June 2017, the state legislature passed Assembly Bill A6571, which requires the New York PSC to set a target for the installation of qualified energy storage systems in the state by 2030 to align with its 50 percent renewables goal. In January 2018, Governor Andrew Cuomo announced a proposal for a statewide energy storage deployment target of 1,500 MW by 2025. However, the PSC has until December 31, 2018, to establish its 2030 energy storage goal and a deployment policy to meet it.

• **Oregon** — In June 2015, the state enacted legislation requiring its investor-owned utilities to procure energy storage systems by January 1, 2020. The Public Utility Commission of Oregon released guidelines in January 2017 directing the state’s utilities to submit proposals for qualifying energy storage systems. In November 2017, Portland General Electric Company filed its proposal with the Public Utility Commission of Oregon outlining its plan to invest up to $100 million for the development of up to 39 MW of energy storage in its service area.

GTM Research estimates that the U.S. installed capacity of battery energy storage systems will increase to 2.6 GW by 2022, up from 220 MW in 2016. GTM attributes the growth to increased renewable deployment compelled by state renewable portfolio and energy storage mandates, climate-change concerns, and a decline in the price of battery energy storage systems.

Key players in the energy storage market continue to drive growth. Tesla’s Gigafactory 1 opened in 2016 with plans to double its size to meet production demand for its electric vehicles and its utility-scale storage projects. In May 2017, Tesla revealed that it intends to build two or three more Gigafactories
that analysts speculate will be sited in China and Europe. In July 2017, Google’s parent company, Alphabet, announced Malta, an early-stage project to build a prototype molten salt energy storage plant.

When teamed with wind and solar generating assets, pumped storage presents an opportunity for utilities to shift renewable energy generation to times of peak demand. In July 2017, Dominion Energy announced it was in the process of siting a pumped hydro storage plant in southwest Virginia; the plant is estimated to cost more than $1 billion. If constructed, this facility would complement Dominion Energy’s investment in solar generation throughout the region.

With regard to grid-connected energy storage projects, PJM leads the way with 22 battery systems and one flywheel system with a combined power rating of 301 MW. CAISO has 10 grid-connected energy storage facilities with a combined power rating of 114 MW.

For more information, see the Deloitte Center for Energy Solutions’ *Electricity Storage: Tracking the Technologies That Will Transform the Power Sector*.

**FERC Developments**

**Commission Back in Business (at Least for Now)**

FERC was without a quorum for six months during 2017. This was the first time in its history that FERC had been without a quorum, and as a result, decisions on a number of matters, including approvals of new pipeline projects, were delayed. With Kevin McIntyre sworn in as chairman on December 7, 2017, the commission was back to its full roster of five commissioners.

This will be the case until mid-August 2018, given that Robert Powelson announced in June 2018 that he will be stepping down from his position as FERC commissioner at that time.

**Electric Industry Issues**

**Formula Rate Standards**

Utilities establish most transmission rates by using a formula-based approach with rates updated annually. FERC requires utilities to share the annual rate updates with all interested parties and to file the updates with FERC on an informational basis.

On July 17, 2014, FERC released a paper that provides guidance on how utilities should update their transmission formula rates to ensure that they are just and reasonable. In separate orders that FERC also issued on July 17, 2014, the Commission directed two utilities to propose formula rate protocols and four utilities to revise their protocols or explain why such revision should not be required. Specifically, FERC directed the utilities to revise or provide formula rate protocols that (1) allow a broader range of interested parties to obtain formula rate information and participate in review processes; (2) boost transparency by making revenue requirements, cost inputs, calculations, and other information publicly available; and (3) detail the procedures that interested parties can use to both informally and formally challenge the implementation of the formula rates.

Annual updates to formula rates, including transmission rate incentives, must note the formula rate inputs related to each incentive, details on when FERC granted the incentives, and sufficient support to demonstrate that the input is consistent with the formula.

On March 19, 2015, FERC ordered six utilities to change their protocols regarding stakeholder participation in annual updates to their formula rates. The utilities were specifically ordered to modify
their protocols to allow broader stakeholder participation in the annual rate update process and make supporting documentation more widely available and accessible.

FERC continues to focus on increasing transparency of formula rates. In December 2015, it launched an investigation into formula transmission rates charged by ISO-NE, stating that the associated tariff lacked adequate transparency and challenge procedures with regard to the region's transmission owners. In its order, FERC had the following findings about specific rates:

- The “rates lack adequate safeguards to ensure that the input data is correct and accurate, that calculations are performed consistently with the formula rate, and that the costs to be recovered in the formula rate are reasonable and prudently incurred.”
- The “formula rates themselves lack sufficient detail to determine how certain costs are derived and recovered in the formula rates, and we have concerns involving the timing and synchronization between the [Regional Network Service] and [Local Network Service] formula rates” (footnote omitted).
- “The Commission's policy requires that all of the formula calculations be incorporated into rate schedules so that public utilities cannot unilaterally revise the calculations at their discretion. Further, formula rates must be stated with sufficient specificity, clarity, and transparency so as to be understandable and reviewable by those affected by them and by the Commission” (footnotes omitted).

**Method for Determining ROE**

In a June 19, 2014, press release, FERC announced its adoption of a new discounted cash flow method “for determining the rate of [ROE] for Commission-jurisdictional electric utilities.” The press release notes that the new method is the same as that used “for natural gas and oil pipeline ROEs: incorporating both short-term and long-term measures of growth in dividends.” FERC issued a number of orders from 2014 through 2016 dealing with ROE for New England Transmission Owners (NETOs), Midcontinent Independent System Operator transmission owners, and several others.

FERC applied the new method to a complaint involving the ROE of NETOs, as detailed in the Commission's Opinion 531. In the opinion, FERC established a paper hearing to give the participants in the matter “an opportunity to submit briefs on an issue regarding the application [of the new approach] to the facts of this proceeding.”

On the basis of this hearing, FERC released Opinion 531-A on October 16, 2014. In this order, FERC cut the base rate of NETOs’ ROE from 11.14 percent to 10.57 percent, finding that the existing rate was unjust and unreasonable. Also, it was determined that NETOs’ maximum base ROE, including any incentives, cannot exceed 11.74 percent. In addition to the base ROE, NETOs were previously granted in 2004 a 50-basis-point ROE premium applicable to legacy assets for being members of an RTO. The new base ROE became effective immediately, and FERC ordered NETOs to provide refunds with interest for the period from October 1, 2011, through December 31, 2012. New transmission projects are also eligible for an additional ROE premium that is determined on a case-by-case basis.

NETOs and their customers petitioned the D.C. Circuit for review of Opinion 531. On April 14, 2017, the court issued its opinion in Emera Maine v. FERC, which vacated Opinion 531. The court determined that FERC failed to find that the existing ROE for NETOs was unjust and reasonable before proceeding to determine what the new ROE should be, and also that FERC had not adequately justified its determination of the new ROE. FERC will have to revisit its ROE policy, and this decision could cause uncertainty to electric utilities given the importance of Opinion 531 to setting the ROE.
The new discounted cash flow method has been producing ROE estimates that are below those produced by several other widely accepted ROE estimation models. Given the court ruling’s vacating of Opinion 531, FERC will need to review its model and consider changes to the approach.

On June 5, 2017, NETOs amended their original compliance filing, seeking a reinstatement of the ROE levels that were in place before they were lowered from 11.14 percent to 10.57 percent by Opinion 531-A. In an order issued October 6, 2017, FERC denied the reinstatement request and required that NETOs continue to use the existing ROE levels until FERC is able to address the issue under a future order. In April 2016, the Eastern Massachusetts Consumers-Owned Systems (EMCOs) had asked FERC in a complaint to reduce NETOs’ base ROE to 8.93 percent or lower. On March 27, 2018, a FERC administrative law judge ruled that EMCOs failed to prove that NETOs’ base ROE of 10.57 percent was unjust and unreasonable.

**Recovery of Tax-Related Regulatory Assets in Formula Rates**

FERC’s standard formula rate template does not allow for recovery of tax-related “permanent” differences such as the income tax expense that occurs when the equity allowance for funds used during construction (AFUDC), which is a component of capitalized PP&E, is depreciated. Many companies in recent years have been successful in obtaining rate orders from FERC that permit modification of the formula rate template to recover these income tax effects, including recovery of past amounts that have never been recovered in formula rates.

FERC recently denied a utility company’s request to recover prior-year unrecovered tax-related regulatory assets in the utility company’s formula rates. FERC stated that “utilities do not have unfettered discretion to defer these tax amounts on their books for decades without timely seeking regulatory approval to collect them.” As a result of this order, utility companies that have FERC formula rates and have not previously received a FERC order to adjust the formula rate template for income tax permanent differences may now have an increased risk related to recovery of tax-related regulatory assets.

**Market-Based Rates**

On June 19, 2014, FERC proposed changes to the market-based-rate-authority process. The proposed rule would, among other things, (1) clarify that when sellers can demonstrate that all of their generation capacity in a relevant market area is fully committed, they are not required to submit indicative screens as part of their horizontal market power analysis; (2) eliminate entirely the requirement for a seller to submit indicative screens if the seller is in an RTO market and relies on FERC-approved monitoring and mitigation to prevent the exercise of market power; and (3) require all long-term firm purchases of capacity and energy by market-based rate sellers to be reported in the sellers’ indicative screens.

On October 15, 2015, FERC voted to approve the draft final rule for the market-based-rate-authority process. The order (Order 816) did not include the plan outlined in its Notice of Proposed Rulemaking (NOPR) of June 2014 (RM14-14) to relieve market-based rate sellers in organized markets of their obligation to submit horizontal market power indicative screens. However, the order, which addressed a market-based rate filing submitted by the Public Service Co. of New Mexico to report on a change in status, was intended to provide guidance developed after numerous companies submitted applications raising the same issues.

The draft final rule was similar to the June 2014 NOPR in many respects. Specifically, the draft final rule would, among other things:

- Establish a 100-MW change-in-status threshold for reporting new affiliates.
• Require market-based rate applicants to report all of their long-term firm purchases of capacity and energy for which they have associated long-term firm transmission reservations.

• Retain a proposal to expand the default relevant geographic market for an independent power producer located in a generation-only balancing-authority area to also include the balancing-authority areas of each transmission provider with which the generation-only balancing-authority area is directly interconnected.

• Provide that (1) sellers do not need to report behind-the-meter generation in their indicative screens and asset appendixes and (2) behind-the-meter generation will not count toward the 100-MW change-in-status threshold or the 500-MW Category 1 seller threshold.

FERC rejected the request of the Public Service Co. of New Mexico for market-based rate authority in its home balancing-authority area because of certain deficiencies in the performance of the company's delivered price test (DPT) analysis and preparation of its simultaneous transmission import limit (SIL) study. In addition, FERC (1) offered guidance on the proper modeling and scaling of jointly owned generating plants in an SIL study, (2) outlined how entities should account for variable-fuel and operations and maintenance (O&M) costs, and (3) clarified the type of transaction data that should be provided to corroborate the results of a DPT analysis.

On May 19, 2016, FERC issued Order 816-A, with the intent to provide clarification on Order 816. The order affirmed the determinations previously made and provided some clarification. Specifically, FERC did the following in Order 816-A:

• Denied a rehearing on the requirement to include the contract's expiration date when a seller claims that its capacity is fully committed.

• Clarified that the requirement for applicants to report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligation does not apply if the generation is from a qualifying facility exempt from Section 205 of the Federal Power Act. FERC also affirmed that a market-based rate seller must list all its long-term firm power purchases in its asset appendix (Appendix B), even if it does not have market-based rate authority in its home balancing-authority area.

• Clarified that (1) Order 816 did not change the definition of long-term firm transmission reservations and (2) long-term firm transmission reservations are longer than 28 days.

• Affirmed the 100-MW threshold requirement and provided clarification on which markets would constitute a seller's relevant geographic market under the reporting requirement.

• Affirmed that sellers are not required to (1) include behind-the-meter generation in the 100-MW change-in-status threshold or the 500-MW Category 1 status threshold or (2) include such generation in the asset appendixes and indicative screens.

• Clarified that a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirement of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission.

• Granted an additional extension of time so that market-based applicants and sellers will not be required to comply with the corporate organizational chart requirement until the Commission issues an order at a later date.

In September 2016, FERC issued a Notice of Inquiry (NOI) into revising how it assesses market power in applications for market-based rate authority. The NOI requested comments on how the Commission can improve its single pivotal supplier analysis in its review of market-based rate applications, whether
to precisely define “de minimis” in the context of the effect on competition, and whether to develop a specific test for determining whether a proposed transaction meets that definition.

**Electric Storage Resources**

In January 2017, FERC issued a policy statement providing guidance on the ability of electric storage resources to concurrently recover costs through cost-based rates for transmission or grid support services and market-based rates for other services such as power sales. The statement outlines possible approaches to avoid double recovery of costs and also offers recommendations for coordination between grid operators and storage assets to ensure independence. Further, FERC responded to concerns that there could be potential for adverse competitive impacts, noting that it is “not convinced that allowing such arrangements will adversely impact other market competitors.”

**Gas Industry Issues**

**Pipeline Investment**

In April 2015, FERC formally approved a policy statement that encourages pipeline modernization by allowing interstate natural gas pipeline companies to recover certain capital expenditures made to pipeline system infrastructure via either a surcharge or a tracker mechanism. Under the policy statement, a pipeline company seeking such a mechanism has to meet five standards:

- Its pipeline would be required to have had a recent base rate case in some form.
- Costs would be limited to one-time capital costs incurred to meet specific safety or environmental regulations.
- Captive customers would be protected from cost shifting if the pipeline loses shippers or increases discounts to retain business.
- Periodic reviews would be required to ensure that the rates remain just and reasonable.
- It would be required to work with shippers to seek support for any surcharge.

In July 2015, FERC denied requests for clarification and declined to specify which data and procedures a pipeline company must provide to justify a surcharge or tracker. FERC intends the policy statement “to be sufficiently flexible so as not to require any specific form of compliance but to allow pipelines and their customers to reach reasonable accommodations based on the specific circumstances of their systems.”

**Gas Pipeline Rates**

Historically, interstate pipeline companies had their rates examined by FERC only when they made requests for rate increases or if their rates were challenged by a customer in a formal complaint. This resulted in many pipeline companies’ going for years without having their rates examined by FERC, leaving customers vulnerable to overcharges.

In September 2015, the Industrial Energy Consumers of America, along with a coalition of three dozen companies and organizations, asked FERC to resume mandatory three-year reviews of interstate natural gas pipeline rates.

In January 2016, FERC launched formal rate investigations into the costs and revenues of four pipeline companies (Tuscarora Gas Transmission Co., Empire Pipeline Inc., Iroquois Gas Transmission System LP, and Columbia Gulf Transmission LLC) to determine whether they were “substantially over-recovering
their costs, resulting in unjust and unreasonable rates.”17 These four companies were chosen by FERC after a review of their 2013 and 2014 FERC Form 2 reports. Each had to file updated cost and revenue studies and participate in evidentiary hearings before a FERC administrative law judge (ALJ).

In September and October 2016, FERC approved the uncontested settlements filed by the four companies. In the settlements, each company agreed to a rate reduction of some sort and agreed to file new rate cases with FERC at some point before 2022.

In January 2017, FERC launched two more formal rate investigations into the costs and revenues of two Kinder Morgan interstate natural gas companies — Natural Gas Pipeline of America LLC and Wyoming Interstate Co. LLC. FERC chose these companies after reviewing their 2014 and 2015 FERC Form 2 and Form 2-A reports.

In September and November 2017, respectively, FERC approved the uncontested settlements filed by Natural Gas Pipeline of America LLC and Wyoming Interstate Co. LLC. In the settlements, both companies agreed to rate reductions. In March 2018, FERC initiated investigations into the costs and revenues of two pipeline companies, Dominion Energy Overthrust Pipeline LLC and Midwestern Gas Transmission Co., after reviews of their 2015 and 2016 FERC Form 2 reports. The companies must file full cost and revenue studies with FERC within 75 days.

On March 15, 2018, FERC released a revised policy statement related to the D.C. Circuit’s United Airlines, Inc. v. FERC decision. In this ruling, issued in July 2016, the court remanded an oil pipeline rate case to FERC because FERC failed to demonstrate that there was no double recovery of income tax costs in a situation in which a pipeline owned by a master limited partnership (MLP) charged rates reflecting both an income tax allowance and an ROE rate calculated under the discounted cash flow method. FERC’s revised policy statement eliminates an income tax allowance in cost of service rates for MLPs.

**Establishing ROEs**

Historically, when FERC has reviewed incremental rates for expansions of existing pipeline systems, its policy has been to use the rate of return components approved in the pipeline company’s last general rate case. However, since many pipeline rate cases result in settlements in which no ROE is specified, there are no comprehensive data on ROEs.

FERC uses the two-step discounted cash flow method in establishing a pipeline company’s authorized ROE. This method incorporates short-term and long-term growth measures, and gross domestic product has been used by FERC as the long-term growth rate.

In two previous cases, FERC has approved an ROE of 10.55 percent for El Paso Natural Gas Co. and 11.55 percent for Kern River Gas Transmission Co.

**Gas Storage**

In October 2015, FERC issued Opinion 538, which contains detailed market power guidance for natural gas storage operators that propose charging market-based rates.

This decision was in response to an initial decision by a FERC ALJ in January 2014 that denied the request of ANR Storage Co. (ANR) to charge market-based rates for gas storage.

The opinion states that “[t]his is the first fully-litigated proceeding where a gas storage provider has sought market-based rate authority. This case therefore presents an opportunity for the Commission

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17 Quoted from FERC's January 21, 2016, news release.
to set forth in detail its policies and procedures for market-based rate applications from gas storage providers, and allows the Commission to make clear how gas storage providers may meet the evidentiary burden they possess to demonstrate they lack significant market power.”

Upon review of the ALJ’s decision and further consideration of ANR’s market power analysis (which included competing firm gas storage service, local production, and intrastate storage), FERC agreed with the ALJ’s initial conclusion and found that ANR should not be permitted to charge market-based rates for gas storage.

**FERC Policy on M&A**

In May 2016, FERC issued a policy statement that clarified the hold harmless commitments offered by applicants to mitigate adverse rate effects from merger proposals. While applicants still have to demonstrate that the transaction would not have an adverse effect on rates, FERC declined to require hold harmless commitments to be of unlimited duration. In addition, FERC clarified the scope and definition of costs that should be subject to hold harmless commitments, identified the types of controls and procedures that applicants offering hold harmless commitments should implement, and clarified that applicants may be able to demonstrate that a transaction will not have an adverse effect on rates even if they do not offer a hold harmless commitment.

**Impact of the Tax Cuts and Jobs Act**

The Tax Cuts and Jobs Act (the “Act”) was signed into law in December 2017. One of the notable impacts of the Act is the reduction of the corporate income tax rate from 35 percent to 21 percent. On March 15, 2018, FERC issued a Notice of Proposed Rulemaking in which FERC proposes to require interstate pipelines to submit informational filings demonstrating the impact of the reduction in the tax rate, along with the removal of income tax allowances by MLPs (as discussed above). Further, each pipeline would be permitted to make a limited Natural Gas Act Section 4 filing to reduce its rates accordingly. Other options for the pipelines to address the effects of the Act would be to agree to a full Natural Gas Act Section 4 rate case or to file a statement explaining why a rate change is not necessary. FERC may consider initiating investigations against pipelines that take no action to reduce their rates.

FERC also issued an NOI requesting comments regarding other effects of the Act on jurisdictional rates for public utilities, interstate pipelines, and oil pipelines. In particular, FERC has requested comments on how it should address accumulated deferred income tax amounts after the tax rate reduction, as well as whether other features of the Act require FERC action. Comments on the NOI were due within 60 days.

**FERC Enforcement**

In November 2017, the FERC Office of Enforcement (OE) issued the 2017 edition of its report on enforcement (the “2017 Report”). Updated annually since 2007, the enforcement report provides greater transparency into the Commission’s enforcement activities and a breakdown of OE efforts for the year. It contains statistics and other details related to the investigation, auditing, and monitoring of entity activities under FERC’s jurisdiction, including information about (1) the conduct of companies and individuals in wholesale natural gas and electricity markets and (2) the Commission’s monitoring and use of data that entities provide to satisfy the myriad of FERC-mandated market and operations reporting requirements.

The 2017 Report notes that in fiscal year 2017, the OE will continue to focus on its priorities of the past few years:
• “Fraud and market manipulation.”
• “Serious violations of the Reliability Standards.”
• “Anticompetitive conduct.”
• “Conduct that threatens the transparency of regulated markets.”

The OE continues to view conduct involving fraud and market manipulation as a “significant threat to the markets the Commission oversees” and believes that “intentional misconduct undermines the Commission's goal of ensuring provision of efficient energy services at a reasonable cost, because the losses imposed by fraud and manipulation are ultimately passed on to consumers.” This view is reflected in the OE’s enforcement priorities and actions; the majority of investigations initiated by FERC focus on activities that may indicate manipulation in the markets.

2017 Common Audit Findings

Below are some of the areas in which the OE’s Division of Audits and Accounting (DAA) has identified consistent patterns of compliance concerns or noncompliance over the past several years (quoted material is from the 2017 Report, with footnotes omitted):

Allowance for Funds Used During Construction (AFUDC). Recent audit activity has shown deficiencies in how jurisdictional entities have calculated AFUDC, resulting in excessive accruals. Short-term debt is always regarded as the first source of funding construction activities in the AFUDC calculation, and the short-term debt rate is derived using an estimate of the cost of short-term debt for the current year. DAA has found instances where a company incorrectly included up-front and quarterly commitment fees associated with lines of credit in the calculation of the short-term debt rate; while this might be permitted in certain circumstances, it is not automatic, and Commission approval is required to include such fees as part of the short-term rate derivation. Other common findings during audits include: failure to exclude goodwill-related equity from the equity component of the AFUDC rate, absent Commission approval; failure to include short-term debt in computing the AFUDC rate; computing AFUDC on contract retention and other noncash accruals; compounding AFUDC more frequently than semi-annually; inclusion of unrealized gains and losses from other comprehensive income; and use of an AFUDC methodology not prescribed by the Commission in Order No. 561.

Formula Rate Matters. Compliance with the Commission’s accounting and FERC Form No. 1 requirements for costs that are included in formula rate recovery mechanisms used to determine billings to wholesale customers continues to be a focal point of DAA’s formula rate audits. DAA notes that certain areas of noncompliance could have been avoided, had there been more effective coordination between jurisdictional entities' accounting and rate staffs to prevent the recovery of costs that should be excluded from the formula rate. Additionally, formula rate audits in recent years have identified patterns of noncompliance in the following areas:

• Income Tax Overpayments — Utilities have incorrectly recorded income tax overpayments for which they elect to receive a refund and not apply to a future tax year's obligation as [income tax] prepayment[s] in Account 165, Prepayments. This has led to excess recoveries through formula rate billings. These costs are properly recorded in Account 146, Accounts Receivable from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate.

• Storm Damages — Utilities have collected excess amounts for storm damages from wholesale customers by either recovering estimates that do not reflect actual experience or recovering both estimated and actual storm damage expenses.

• Investment Tax Credits (ITCs) — Utilities have improperly accounted for ITCs associated with utility plant as income tax prepayments in Account 165. ITCs are generated as a result of investments made in utility plant. DAA found instances in which tax credits were used to reduce taxable income, but not all of the ITCs were used at once and resulted in an ITC carry-forward. DAA found the ITC carry-forwards were recorded in an incorrect account and factored into formula rate billings, leading to customer overbillings.

• Internal Merger Costs — Utilities have included merger-related costs in operating accounts, contrary to the directives of the Merger Order and long-standing Commission policy that such costs be recorded in non-operating accounts. This accounting resulted in companies misrepresenting utility operating income and expenses reported in their FERC Form No. 1, Annual Reports (Form No. 1). In these cases, utilities were subject to hold-harmless commitments to exclude merger-related costs from rates unless
the Commission approves recovery of such costs and were required to have appropriate controls and procedures to ensure that merger-related costs are tracked and excluded from formula rates.

- **Asset Retirement Obligation (ARO)** — Utilities have included ARO amounts in formula rates without explicit Commission approval, including the asset component that increases rate base, the depreciation expense related to the asset, the accretion expense related to the liability, and associated deferred taxes.

- **Commitment Fees** — Utilities improperly accounted for commitment fees in Account 165, Prepayments, which led to excess recoveries through formula rate billings.

- **Formula Rate Errors** — Utilities’ transmission formula rates contained errors, omissions, and miscalculations related to various accounts. Some accounts that should have been added were incorrectly subtracted. In other instances, the formula pulled information from the wrong Form No. 1 line. Finally, there were instances where items specifically excluded by formula rate protocols were included in the formula rate.

- **Merger Goodwill** — Utilities have included goodwill in the equity component of the capital structure, absent Commission approval. It is the Commission's long-standing policy that goodwill should be excluded from rates.

- **Allocated Labor** — Utilities have charged labor costs to transmission projects without using an appropriate cost allocation method or time tracking. Specifically, DAA observed that controls were not sufficient to ensure that labor costs charged were appropriately allocated between transmission and distribution capital projects when employees worked on both, resulting in an inappropriate or unsupported allocation of labor costs to transmission projects.

- **Administrative and General (A&G) Expenses** — Utilities have recorded non-operating expenses and functional operating and maintenance expenses in A&G expense accounts, leading to inappropriate inclusion of such costs in the formula rates.

- **Unused Inventory and Equipment** — Utilities have included the cost of materials, supplies, and equipment purchased for a construction project without removing the cost of items unused in whole or in part from the cost of a project.

**Open Access Transmission Tariffs (OATT).** An essential goal of open access transmission is to support efficient and competitive markets. During recent OATT audits, DAA noted instances where company actions did not support this goal due to noncompliance with the OATT’s terms and conditions. Specifically, DAA identified issues related to improper use of network transmission service, improper sales from designated network resources, transmission capacity not released in accordance with Commission-approved tariffs, inaccurate available transmission capacity data posted on the Open Access Same-Time Information System, and transmission service provided to customers under expired transmission service agreements.

**Natural Gas Accounting and Tariff Matters.** DAA continues to evaluate natural gas pipelines’ compliance with the Commission’s accounting and FERC Form No. 2 reporting requirements to ensure transparency and accuracy of data reported to the Commission. DAA’s evaluations also continue to cover the administration and application of transportation services and rates among customers in accordance with approved gas tariffs. In recent comprehensive natural gas audits, DAA has found noncompliance in the following areas:

- **Gas Tariff** — Natural gas pipelines did not comply with FERC gas tariff procedures, specifically with regard to: using the method specified in the tariff for valuing system gas activities; enforcing stipulations in operational balancing agreements to manage and monitor gas imbalance activities between interstate and intrastate pipelines; updating reservation credit procedures for force majeure and non-force majeure events to be consistent with Docket No. RP11-1538-000; and reporting operational available capacity data consistent with North American Energy Standards Board requirements.

- **Accounting and Reporting** — Natural gas pipelines did not comply with Commission accounting requirements, specifically with regard to: penalty revenues assessed to noncompliant shippers; transmission mains and compression station expenses; line pack inventory changes; shipper imbalances and cash-outs; lost and unaccounted-for gas; and fuel used in compressor stations. Other common areas of noncompliance included: derivation of allowance for funds used during construction; classification of non-operating activities associated with donations, fines, penalties and lobbying activities; and capital project reimbursements and advances from customers. Regarding FERC Form No. 2 reporting, there was inaccurate or incomplete information for affiliate transactions and other subsidiary investment activities. There were also omissions and incomplete information from various schedules supporting the financial statements.
• Pipeline Integrity Management Costs — Certain natural gas pipelines have misclassified integrity management costs that should be recorded as maintenance expenses. Commission accounting requirements, including the accounting guidance in Docket No. AI05-1-000, provide that costs to develop integrity management programs, prepare pipelines for inspection, conduct pipeline assessments, and make repairs are to be charged to maintenance expense in the period the costs are incurred.

• Capacity Transparency and Allocation — Interstate natural gas pipelines are required to post available pipeline capacity on their web sites. These postings promote transparency of available pipeline capacity and enable more competitive and efficient use of such capacity. Recent audits identified deficiencies in reporting available pipeline capacity because quantities were omitted or incorrectly reported. This means some shippers may not have been aware or able to avail themselves of operational opportunities for use of available pipeline capacity.

Oil Pipelines (Page 700). An essential part of oil pipeline audits is an examination of the accounting and operating data included on page 700 of FERC Form No. 6, Annual Cost of Service-Based Analysis Schedule. This information is sometimes used by the Commission and interested parties to evaluate interstate pipeline rates. Recent oil pipeline audits have identified accounting errors that impact the accuracy of amounts reported on page 700, including incorrectly designating intrastate amounts as interstate, and misclassification of carrier property, charitable donations, fines/penalties, and lobbying activities. DAA also found that some companies are not conducting depreciation studies as required, leading to depreciation rates not aligning with the actual service lives of the plants, and ultimately to plants with negative book balances.

Nuclear Decommissioning Trust Funds. The Commission’s regulations concerning nuclear decommissioning trust funds require utilities owning nuclear power plants to file annual trust fund reports. Recent audits have identified utilities that failed to submit annual decommissioning trust fund reports, clearly distinguish Commission-jurisdictional monies from non-jurisdictional monies held in the funds, and accurately report the amount of Commission-jurisdictional money in the trusts.

Consolidation. Commission accounting regulations require the equity method of accounting for all investments in subsidiaries. Recent audits continue to find jurisdictional companies incorrectly using the consolidation method of accounting for subsidiaries instead of the equity method. As a result, improper amounts were included in formula rate billings. Entities must seek a waiver from the Commission to use the consolidation method for an investment in a subsidiary.

Untimely Filing of Commission Reports. DAA identified several companies that failed to timely file various reports with the Commission, including decommissioning trust fund reports and required filings, and reports related to mergers. Failure to timely file these reports prevents the Commission and industry from using relevant data. It also negatively impacts transparency and creates doubt regarding the effectiveness of these companies’ compliance programs.
Section 2 — SEC Update
Key SEC leadership changes as well as recent SEC rulemaking activities and other developments that have occurred since the last edition of this publication are discussed below.

**SEC Leadership Changes**

On January 4, 2017, President-elect Donald Trump announced that he had nominated Walter J. ("Jay") Clayton III as SEC chairman. Mr. Clayton would replace Mary Jo White, who left the SEC at the end of the Obama administration. Mr. Clayton's appointment was contingent on a Senate confirmation vote. To fill the vacancy, President Trump appointed Michael S. Piwowar as acting SEC chairman on January 23, 2017.

On May 4, 2017, the Senate confirmed Mr. Clayton as chairman of the SEC. Mr. Clayton's term will end on June 5, 2021.

Further, on March 30, 2017, the SEC announced the appointment of Sagar S. Teotia as deputy chief accountant in the Office of the Chief Accountant (OCA). Mr. Teotia joined the SEC from Deloitte & Touche LLP, where he was a partner in the National Office Accounting Consultation Group. He also served as an OCA Professional Accounting Fellow from 2009 to 2011.

In addition, on May 12, 2017, the SEC appointed William H. Hinman as the director of the Commission's Division of Corporation Finance (the “Division”). Mr. Hinman replaced Acting Director Shelley Parratt, who led the Division after Keith Higgins's resignation in January 2017.

Further, on June 8, 2017, the SEC named Stephanie Avakian, who was the acting director of the Division of Enforcement, and former federal prosecutor Steven Peikin as codirectors of the Division of Enforcement. They replaced Andrew J. Ceresney, who resigned at the end of 2016.

On December 22, 2017, the Senate confirmed Hester M. Peirce and Robert J. Jackson as commissioners of the SEC. They were sworn in on January 11, 2018.

On February 15, 2018, the SEC announced the appointment of Kyle Moffatt as the chief accountant of the Division.

On May 7, 2018, SEC Commissioner Michael Piwowar announced that he will resign “on the earlier of July 7, 2018 or the swearing in of [his] successor.”

**SEC Rulemaking and Interpretive Guidance**

**SEC Issues Report on Modernization and Simplification of Regulation S-K**

In November 2016, the SEC issued a report on the modernization and simplification of Regulation S-K. The report was issued in response to a mandate in Section 72003 of the FAST Act, which requires the report to include “(1) all findings and determinations made in carrying out the study . . . ; (2) specific and detailed recommendations on modernizing and simplifying the requirements in regulation S-K in a manner that reduces the costs and burdens on companies while still providing all material information;
and (3) specific and detailed recommendations on ways to improve the readability and navigability of disclosure documents and to discourage repetition and the disclosure of immaterial information.”

The report includes staff recommendations on the following topics:

- Core company business information.
- Company performance, financial information, and future prospects.
- Management and certain security holders.
- Corporate governance.
- Registration statement and prospectus provisions.
- Exhibits.
- Manner of delivery recommendations.

In October 2017, the SEC issued a proposed rule\(^1\) in response to recommendations in the SEC staff’s November 2016 report on the modernization and simplification of Regulation S-K. The proposed rule would make specific revisions to a limited group of items in Regulation S-K and is intended to streamline and improve disclosures. Regulation S-K requirements, which are the central repository for nonfinancial statement disclosures in SEC registration statements and periodic filings, were established more than 30 years ago, and the modernization of these requirements has been called for as a result of evolving business models, new technology, and changing investor needs. Comments on the proposed rule were due by January 2, 2018. For additional information, see Deloitte’s October 16, 2017, *Heads Up*.

**SEC Issues Final Rule on Intrastate and Regional Securities Offerings**

In October 2016, the SEC issued a final rule that amends Rule 147 of the Securities Act to provide “a safe harbor for compliance with the Section 3(a)(11) exemption from registration for intrastate securities offerings.” In addition, the final rule establishes a new rule, Rule 147A, that is similar to Rule 147 “but will have no restriction on offers and will allow issuers to be incorporated or organized outside of the state in which the intrastate offering is conducted provided certain conditions are met.” Further, Rule 504 is being amended “to increase the aggregate amount of securities that may be offered and sold from $1 million to $5 million”; as a result, Rule 505 has been repealed.

The amendments to Rule 147 and the new Rule 147A became effective on April 20, 2017; the amendments to Rule 504 became effective on January 20, 2017; and the repeal of Rule 505 became effective on May 22, 2017.

For more information, see the press release on the SEC’s Web site.

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\(^1\) SEC Release No. 33-10425, *FAST Act Modernization and Simplification of Regulation S-K*.
SEC Issues Final Rule Granting Regulatory Access to Data Held by Security-Based Swap Data Repositories

In August 2016, the SEC issued a final rule that amends Rule 13n-4 of the Exchange Act to give certain regulators and other authorities access to security-based swap (SBS) data repositories. Specifically, the final rule:

- Requires “either a memorandum of understanding or other arrangement between the Commission and the recipient of the data to address the confidentiality of the security-based swap data provided to the recipient.”
- Identifies “the five prudential regulators named in the statute, as well as the Federal Reserve banks and the Office of Financial Research, as being eligible to access data.”
- Addresses “factors that the Commission may consider in determining whether to permit other entities to access data.”

The final rule became effective on November 1, 2016.

For more information, see the press release on the SEC’s Web site.

SEC Issues Final Rule on Regulation SBSR

In July 2016, the SEC issued a final rule that amends Regulation SBSR on the reporting and dissemination of SBS information. The purpose of the final rule, which implements requirements in Title VII of the Dodd-Frank Act, is to “increase transparency in the security-based swap market.”

The final rule became effective on October 11, 2016.

For more information, see the press release on the SEC’s Web site.

SEC Issues Final Rule on Administrative Proceedings

In July 2016, the SEC issued a final rule that amends its rules of practice related to administrative proceedings. According to former SEC Chair Mary Jo White, the final rule offers parties “additional opportunities to conduct depositions and add flexibility to the timelines of [the SEC’s] administrative proceedings, while continuing to promote the fair and timely resolution of the proceedings.”

The final rule became effective on September 27, 2016.

For more information, see the press release on the SEC’s Web site.

SEC Issues Final Rule on Inflation Adjustments

In March 2017, the SEC issued a final rule that updates the definition of “emerging growth company” (EGC) to include an “inflation-adjusted threshold” and amends the dollar amounts in the SEC’s Regulation Crowdfunding. In addition, the final rule contains technical amendments that “conform several rules and forms to amendments made to the Securities Act of 1933 and the Securities Exchange Act of 1934 by Title I of the Jumpstart Our Business Startups Act.”

SEC Issues Guidance on Exhibit Hyperlinks and HTML Format

In March 2017, the SEC issued a final rule that requires “registrants that file registration statements or reports subject to the exhibit requirements under Item 601 of Regulation S-K, or that file Forms F-10 or
20-F, to include a hyperlink to each exhibit listed in the exhibit index of these filings, and to submit such registration statements and reports on EDGAR in [HTML] format."

The final rule became effective on September 1, 2017.

For more information, see the press release on the SEC's Web site.

**President Trump Signs Resolution Eliminating SEC Disclosure Rule**

In February 2017, President Trump signed H.J. Resolution 41, which eliminates the SEC’s rule under which issuers engaged in the commercial development of oil, natural gas, or minerals must disclose certain payments made to U.S. federal and foreign governments. H.J. Resolution 41 repeals the Commission’s June 2016 final rule on disclosures of payments by resource extraction issuers, which was implemented as part of the Dodd-Frank Act.

**SEC Acting Chairman Makes Statements Regarding Conflict Minerals Rule**

In January 2017, Michael S. Piwowar, the SEC’s acting chairman, made public statements related to the Commission’s 2014 guidance on its August 2012 final rule on conflict minerals. The SEC partially stayed compliance with the conflict minerals rule after an April 2014 appellate court ruling found that the rule violated the First Amendment of the U.S. Constitution. Mr. Piwowar indicated that the “partial stay has done little to stem the tide of unintended consequences washing over the Democratic Republic of the Congo and surrounding areas.” He further noted:

> [T]he temporary transition period provided for in the Rule has expired. And the reporting period beginning January 1, 2017, is the first reporting period for which no issuer falls within the terms of that transition period. In light of this, as well as the unexpected duration of the litigation, I am directing the staff to consider whether the 2014 guidance is still appropriate and whether any additional relief is appropriate in the interim.

Mr. Piwowar’s statements on the conflict minerals rule and the reconsideration of the rule’s implementation are available on the SEC’s Web site.

**SEC Issues Small-Entity Compliance Guide on Intrastate Offering Exemptions**

In April 2017, the SEC issued a small-entity compliance guide that provides guidance on the SEC’s October 2016 final rules that “modernize how issuers can raise money to fund their businesses through intrastate offerings while maintaining investor protections.” Topics covered in the guide include requirements of Rules 147 and 147A, restrictions on resales, filing requirements and relationship with state securities laws, and integration.

**Federal Court Remands Conflict Minerals Case to SEC**

In April 2017, the U.S. District Court for the District of Columbia released its final judgment in the litigation related to the SEC’s final rule on conflict minerals and remanded the case to the Commission. After the April 3, 2017, ruling by the district court, the SEC announced that it is suspending enforcement of some requirements in the conflict minerals rule. Specifically, the public statement released by the Division notes:

> The court’s remand has now presented significant issues for the Commission to address. At the direction of the Acting Chairman, we have considered those issues. In light of the uncertainty regarding how the Commission will resolve those issues and related issues raised by commenters, the Division of Corporation Finance has determined that it will not recommend enforcement action to the Commission if companies, including those that are subject to paragraph (c) of Item 1.01 of Form SD, only file disclosure under the provisions of paragraphs (a) and (b) of Item 1.01 of Form SD. This statement is subject to any further
action that may be taken by the Commission, expresses the Division’s position on enforcement action only, and
does not express any legal conclusion on the rule. [Emphasis added]

Connecting the Dots
In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit (the “Appellate Court”) held that parts of the SEC’s conflict minerals rule and of Section 1502 of the Dodd-Frank Act violate the First Amendment of the U.S. Constitution to the extent that they require “regulated entities to report to the Commission and to state on their website that any of their products have ‘not been found to be “DRC conflict free.’” In August 2015, the Appellate Court upheld the ruling.

For more information, see Michael S. Piwowar’s public statement on the ruling on the SEC’s Web site. Also see the GAO’s letter to congressional committees about its review of disclosures provided in connection with the conflict minerals rule.

SEC Issues Interpretive Guidance on Cybersecurity
On February 21, 2018, the SEC issued interpretive guidance (the “release”) in response to the pervasive increase in digital technology as well as the severity and frequency of cybersecurity threats and incidents. The release largely refreshes SEC staff guidance related to cybersecurity and, like that guidance, does not establish any new disclosure obligations but rather presents the SEC’s views on how its rules should be interpreted in connection with cybersecurity threats and incidents. In a public statement about the release, SEC Chairman Jay Clayton noted that he has asked the Division to continue to closely monitor cybersecurity disclosures as part of its filing review process and that the SEC will continue to evaluate whether further guidance is needed.

In 2011, the Division issued principles-based guidance that provided the SEC’s views on cybersecurity disclosure obligations, including those related to risk factors, MD&A, and the financial statements. The release expands on the concepts discussed in that guidance and concentrates more heavily on cybersecurity policies and controls, most notably those related to cybersecurity escalation procedures and the application of insider trading prohibitions. Further, the release addresses the importance of (1) avoiding selective disclosure as well as (2) considering the role of the board of directors in risk oversight.

The release applies to public operating companies, including foreign private issuers, but does not address the specific implications of cybersecurity for other regulated entities under federal securities laws, such as registered investment companies, investment advisers, brokers, dealers, exchanges, and self-regulatory organizations.

The interpretation became effective on February 26, 2018.

For additional information, see Deloitte’s February 23, 2018, Heads Up. Also see the press release on the SEC’s Web site.

SEC Expands Eligibility for “Smaller Reporting Company” Classification
On June 28, 2018, the SEC issued a final rule that amends the definition of a “smaller reporting company” (SRC) to expand the number of companies that qualify for this classification and are therefore able to take advantage of the scaled disclosure requirements that apply to such companies. Under the final rule, smaller reporting companies “include registrants with a public float of less than $250 million, as well as registrants with annual revenues of less than $100 million for the previous year and either no

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public float or a public float of less than $700 million.” In view of this new definition of “smaller reporting company,” the final rule also revises other definitions, such as those for “accelerated filer” and “large accelerated filer,” in an effort to “preserve the existing thresholds in those definitions.” The final rule will become effective 60 days after the date of its publication in the Federal Register.

For more information, see Deloitte’s July 2, 2018, Heads Up. Also see the press release on the SEC’s Web site.

**SEC Issues Amendments Related to Inline XBRL Filing of Tagged Data**

On June 28, 2018, the SEC issued a final rule that requires registrants to use the inline XBRL (iXBRL) format for operating companies and funds when submitting financial statement information and fund risk/return summary information. In addition, the rule removes the requirement for operating companies and funds to post XBRL data on their Web sites. The final rule will become effective 30 days after the date of its publication in the Federal Register.

For more information, see Deloitte’s July 3, 2018, Heads Up. Also see the press release on the SEC’s Web site.

**SEC Issues SAB 117**

In November 2017, the SEC issued SAB 117, which amends certain SAB topics to make them consistent with current auditing and accounting guidance, specifically ASC 321. SAB 117 amends SAB Topic 5 to note that Topic 5.M is no longer applicable upon an entity’s adoption of ASC 321 because ASC 321 creates guidance that “eliminates the ability to present changes in the fair value of investments in equity securities within other comprehensive income, which eliminates the need for Topic 5.M.”

**SEC to Release Letters to Companies With Serious Deficiencies**

On June 12, 2018, the Division announced that letters sent to issuers that have “serious deficiencies” in their registration statement or offering document will be made available on EDGAR. Filings with serious deficiencies are those that are “not minimally compliant with statutory or regulatory requirements.” Letters issued on June 15, 2018, or later will be published first; these letters will appear on EDGAR within 10 calendar days of issuance.

**SEC Staff Updates C&DIs**

In October 2016, the Division updated its C&DIs related to the following:


- **Regulation S-K** — New guidance on Item 402(u) on pay ratio disclosure.

In April 2017, the Division issued the following C&DIs:

- **Question 141.06 of the Securities Act Rules C&DIs** — Discusses whether “an issuer making ongoing offers and sales pursuant to Rule 147 [is] able to transition to offers and sales in reliance on Rule 147A.”

- **Questions 201.02 and 202.01 of the Regulation Crowdfunding C&DIs** — Question 201.02 addresses the dollar amount an issuer should use “to determine the threshold at which

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disclosure of related party transactions is required under Rule 201(r),” and Question 202.01 covers how an issuer determines “the number of holders of record for purposes of determining eligibility to terminate its duty to file ongoing reports pursuant to Rule 202(b)(2) of Regulation Crowdfunding.”

In the fourth quarter of 2017 and in April 2018, the Division updated the following C&DIs:

- **Question 110.02 of the Exchange Act Form 8-K C&DIs** — Addresses whether the remeasurement of a DTA “to incorporate the effects of newly enacted tax rates or other provisions of the Tax Cuts and Jobs Act” requires a registrant to file under Item 2.06 of Form 8-K. See the Tax Cuts and Jobs Act section for further information.

- **Question 271.25 of the Securities Act Rules C&DIs** — Addresses whether companies can implement safeguards with respect to electronic access to Rule 701(e) disclosure information.

- **Questions 101.01 through 101.03 of the Non-GAAP Financial Measures C&DIs** — Question 101.01 addresses whether “financial measures included in forecasts provided to a financial advisor and used in connection with a business combination transaction” constitute non-GAAP measures. Question 101.02 addresses whether an entity can rely on the Division's response to Question 101.01 if “the same forecasts provided to its financial advisor are also provided to its board of directors or board committee.” Finally, Question 101.03 addresses the following scenario and question:

  A registrant provides forecasts to bidders in a business combination transaction. To avoid anti-fraud concerns under the federal securities laws or ensure that the other disclosures in the document are not misleading, it determines that such forecasts should be disclosed. Are the financial measures contained in forecasts disclosed for this purpose considered non-GAAP financial measures?

For additional information, see Deloitte’s *A Roadmap to Non-GAAP Financial Measures*.

**CAQ Releases Highlights of Joint Meetings Between IPTF and SEC Staff**

In February 2017, the Center for Audit Quality (CAQ) released the highlights of the November 17, 2016, joint meeting between the IPTF and the SEC staff. Topics discussed at the meeting included:

- “Monitoring Inflation in Certain Countries.”
- “Transition Questions related to the New Leasing Standard IFRS 16.”
- “Use of pre-acquisition and post-acquisition periods to satisfy S-X Rule 3-05 requirements for other than initial registration statements.”
- “Significant equity investee financial statements under S-X Rule 3-09.”
- “Use of IFRS XBRL Taxonomy by FPIs.”

In August 2017, the CAQ released the highlights of the May 16, 2017, joint meeting between the SEC staff and the IPTF. Topics discussed at the meeting included:

- “Monitoring Inflation in Certain Countries.”
- “FAST Act amendments to the JOBS Act and IFRS reporting (lack of comparable period).”
- “XBRL IFRS Taxonomy.”
- “Non-GAAP Financial Measures under IFRS.”
- “Staff Matters.”
In March 2018, the CAQ released the highlights of the November 21, 2017, joint meeting between the SEC staff and the IPTF. Topics discussed at the meeting included:

- “Use of General Instruction G accommodations upon making an unreserved statement of compliance with IFRS-IASB for the first time when Previous GAAP was substantially consistent with IFRS-IASB.”
- “Adoption of IFRS in an interim period in relation to Regulation S-X, Rule 3-05 financial statements.”
- “Application of New Securities Act Compliance and Disclosure Interpretations (C&DIs) to Foreign Private Issuers.”
- “Update on XBRL Implementation for IFRS Filers.”
- “Monitoring Inflation in Certain Countries.”

CAQ Releases Highlights of Joint Meetings Between CAQ SEC Regulations Committee and SEC Staff

In June 2017, the CAQ posted to its Web site the highlights of the March 23, 2017, CAQ SEC Regulations Committee joint meeting with the SEC staff (see Deloitte’s June 27, 2017, journal entry for additional information). Topics discussed at the meeting included:

- “SAB 74 Disclosures about Newly-Issued Standards.”
- “Non-GAAP Financial Measures.”
- “Definition of a Business — Interaction between the new GAAP definition of a business and the S-X Article 11 definition.”
- “The effects of accounting changes by a successor entity on the predecessor period financial statements.”
- “Adoption of ASC 606, Revenue from Contracts with Customers, when an Emerging Growth Company (EGC) that elected private-company adoption dates ceases to qualify as an EGC.”
- “Electronic Submission of Pre-Filing Correspondence.”

In November 2017, the CAQ posted to its Web site the highlights of the July 11, 2017, CAQ SEC Regulations Committee joint meeting with the SEC staff (see Deloitte’s November 20, 2017, journal entry for additional information). Topics discussed at the meeting included:

- “Waivers via Rule 3-13 of Regulation S-X.”
- “Process for requesting omission of selected financial data.”
- “ASC 606, Revenue from Contracts with Customers.”
- “Non-GAAP Financial Measures.”
- “Regulation A Submissions.”
- “Evaluating significance of a business disposal in connection with a proxy statement soliciting authorization for the disposal.”
- “Pro-Forma Financial Information presented in a Form 8-K for a significant acquisition made after a previously reported significant acquisition.”
In December 2017, the CAQ posted to its Web site the highlights of the September 26, 2017, CAQ SEC Regulations Committee joint meeting with the SEC staff (see Deloitte’s December 13, 2017, journal entry for additional information). Topics discussed at the meeting included:

- “Waivers per Rule 3-13 of Regulation S-X.”
- “Update on process for requesting omission of selected financial data.”
- “Draft registration statement processing.”
- “Public Business Entity (PBE) July 2017 EITF Announcement.”

In May 2018, the CAQ posted to its Web site the highlights of the March 13, 2018, CAQ SEC Regulations Committee joint meeting with the SEC staff (see Deloitte’s May 22, 2018, journal entry for more information). Topics discussed at the meeting included:

- “Financial reporting implications of tax reform legislation.”
- “Waivers of financial statements required by Rule 3-09 of Regulation S-X.”
- “New Accounting Standards.”
- “Use of most recent year-end financial statements in assessing Regulation S-X, Rule 1-02(w) significance in an IPO.”
- “Audit requirements for pre-transaction periods after a reverse merger involving two operating companies.”

**SEC Issues Interpretive Guidance on Pay Ratio Disclosure**

In September 2017, the SEC issued interpretive guidance on pay ratio disclosure. The interpretive guidance is designed to “assist companies in their efforts to comply with the pay ratio disclosure requirement mandated by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.” In addition, the SEC staff has issued guidance on the pay ratio rule that includes “hypothetical examples of use of sampling and other reasonable methodologies.”

For more information, see Deloitte’s October 17, 2017, *Heads Up* and the press release on the SEC’s Web site.

**SEC Provides Regulatory Relief and Assistance for Hurricane Victims**

In September 2017, the SEC staff announced measures to help publicly traded companies, investment companies, accountants, transfer agents, municipal advisers, and others affected by Hurricanes Harvey, Irma, and Maria comply with filing deadlines and federal securities laws and regulations. Such measures include the following Exchange Act annual or quarterly report filing deadline extensions for affected registrants:

- To October 10, 2017, for any filing due from August 25, 2017, to October 6, 2017, for those affected by Hurricane Harvey.
- To October 19, 2017, for any filing due from September 6, 2017, to October 18, 2017, for those affected by Hurricane Irma.
- To November 2, 2017, for any filing due from September 20, 2017, to November 1, 2017, for those affected by Hurricane Maria.

Additional exemptions were provided for proxy and information statement delivery requirements, investment companies, transfer agent compliance rules, and auditor independence rules. The auditor
independence exception was limited to reconstruction of previously existing accounting records that were lost or destroyed as a result of any of the identified hurricanes, and such services were required to cease as soon as the client’s lost or destroyed records were reconstructed, its financial systems were fully operational, and it was able to effect an orderly and efficient transition to management or another service provider. These services are still subject to preapproval by the issuer’s audit committee.

The SEC has also indicated that other requests for additional relief would be considered on a case-by-case basis. Entities are encouraged to consult with their auditors or SEC counsel and, if necessary, the SEC staff if they believe that specific facts and circumstances warrant other relief or additional guidance.


SEC Staff Updates Financial Reporting Manual

In August 2017, the Division updated its Financial Reporting Manual to clarify or add guidance on the following topics:

- A new section that “[d]escribes communications with CF-OCA and provides contact information.”
- Section 2065, Index — Clarification “that questions about applying the guidance on abbreviated financial statements to a predecessor entity should be directed to CF-OCA.”
- Paragraphs 10220.1 and 10220.5 — Clarification that “the guidance on the omission of financial information from draft and filed registration statements.” The updates in paragraph 10220.1 omit previous guidance, refer users via hyperlink to the newly issued Question 101.4 of the Securities Act C&DIs, and note that Question 101.5 of the C&DIs addresses similar matters for non-EGC issuers. The updates in paragraph 10220.5(c) delete previous guidance and refer users via hyperlink to Question 2 of the FAST Act C&DIs.

In December 2017, the Division updated its Financial Reporting Manual to clarify guidance on the following topics:

- Sections 3250.1(m) and 3250.1(n) — “The pro forma impact of adopting new accounting standards.”
- Section 10230.1 — Changes to “address adoption of new accounting standards after EGC status is lost.”
- Sections 11100 and 11200 — Clarification for certain PBEs of the effective dates of ASU 2014-09 and ASU 2016-02.

For more information, see the Financial Reporting Manual page on the SEC’s Web site.

Other SEC Matters

SEC Eliminates “Tandy” Representation Requirement

In October 2016, the Division announced that the Commission is no longer requiring registrants to provide “Tandy” representations in their disclosures related to comment-letter correspondence. Named after the Tandy Corporation — the first company that received an SEC comment letter requesting such a representation back in the 1970s — the Tandy requirements mandated a registrant “to acknowledge in writing that the disclosure in the document was its responsibility and to affirmatively state that it would not raise the SEC review process and acceleration of effectiveness as a defense in any legal proceeding.”
The announcement stresses that companies remain “responsible for the accuracy and adequacy of the disclosure in their filings” and that the staff will be including a statement to this effect in its comment letters to registrants going forward.

For more information, see the announcement on the SEC’s Web site.

**SEC Chair Discusses Global Accounting**

In January 2017, former SEC Chair Mary Jo White issued a [public statement](https://www.sec.gov) in which she urged the next SEC chairman to continue to pursue global accounting standards to protect investors and the strength of the U.S. market. While Ms. White acknowledged that the Commission has not taken “formal action” related to such standards since 2010, she described the past years as a success:

> Although the FASB and IASB have completed their agreed-upon, priority convergence projects, this milestone must not mark the end of the intense collaboration that has occurred between the two Boards over the last few years. These efforts have greatly enhanced the quality of accounting standards in a number of important areas, including recently narrowing many differences in the accounting standards for revenue recognition, leases, credit losses on financial instruments, and recognition and measurement of financial assets and liabilities.

Ms. White also suggested that such progress needs to continue. She concluded:

> The United States cannot afford to be myopic about this issue in light of the benefits of these efforts for all stakeholders. Strong support of both the FASB and the IASB by U.S. investors, companies, auditors, and others, including the Commission, is essential. Indeed, it should be self-evident that the pursuit of high-quality globally accepted accounting standards is part of the SEC’s continuing responsibility to encourage, facilitate and direct efforts to enhance the quality of all financial reporting that directly impacts the protection of investors and the strength of our markets.

**SEC Publishes Examination Priorities for 2018**

In February 2018, the SEC’s Office of Compliance Inspections and Examinations (OCIE) published its [examination priorities](https://www.sec.gov) for 2018: “This year, OCIE’s examination priorities are broken down into five categories: (1) compliance and risks in critical market infrastructure; (2) matters of importance to retail investors, including seniors and those saving for retirement; (3) FINRA and MSRB; (4) cybersecurity; and (5) anti-money-laundering programs.”

For more information, see the [press release](https://www.sec.gov) on the SEC’s Web site.

**SEC Issues Notice on EDGAR Phishing Scam**

In March 2017, the SEC issued a [notice](https://www.sec.gov) related to a phishing campaign in which fraudulent e-mails have been sent to certain EDGAR filers. The e-mails falsely indicate that the SEC has recently made changes to Form 10-K and may contain malicious attachments that are designed to gain access to the user’s computer or network. The SEC has confirmed that it has sent no such e-mails to EDGAR filers and that recipients should delete the e-mails.

**SEC to Expand Confidential Review Process for Draft Initial Registration Statements**

In June 2017, the Division [announced](https://www.sec.gov) that the SEC is expanding to all companies certain benefits related to the confidential review process for draft initial registration statements under the JOBS Act. According to the announcement, effective July 10, 2017:

- Any company will be able to provide a confidential draft initial public offering registration statement to the SEC staff for review before the company’s public filing. The company will be
required to publicly file this draft and any related amendments with the SEC no later than 15 days before its roadshow or requested effective date.

- An issuer may voluntarily submit a draft registration statement, for review on a nonpublic basis, within one year of the effective date of its initial Securities Act registration statement or its Exchange Act Section 12(b) registration statement.
- The SEC will not delay processing a draft registration statement if an issuer reasonably believes that omitted financial information will not be required at the time the registration statement is publicly filed.
- The SEC will continue to consider any waiver requests made under Regulation S-X, Rule 3-13.
- Foreign private issuers can elect to avail themselves of these benefits.

For more information, see the press release on the SEC's Web site and Deloitte’s June 30, 2017, news article.

**SEC Staff Releases FAQs on IFRS® Taxonomy and Updates FAQs on Inline XBRL**

In April 2017, the SEC staff issued FAQs on the IFRS taxonomy, which became available on March 1, 2017, for use by foreign private issuers that submit their financial statements in accordance with IFRS Standards. In addition, the SEC staff updated its FAQs on inline XBRL, which enables entities to embed XBRL data directly into HTML.

**SEC Updates Announcement Regarding Expansion of Nonpublic Review Process for Draft Registration Statements**

In August 2017, the SEC updated its June 29, 2017, announcement that it is extending to all companies benefits that are similar to those it has extended to EGCs regarding the confidential review process for draft registration statements under the JOBS Act. The updates are intended to clarify the factors a company considers in determining whether it is eligible to use the expanded nonpublic review process.

The announcement notes that the nonpublic review process is “available for Securities Act registration statements prior to the issuer's initial public offering date and for Securities Act registration statements within one year of the initial public offering. In identifying the initial public offering date, we will refer to Section 101(c) of the JOBS Act. The nonpublic review process is available for the initial registration of a class of securities under Exchange Act Section 12(b) on Form 10, 20-F or 40-F.”

In addition, the Division has published two new C&DIś related to Securities Act forms. The new C&DIś (Question 101.04 and Question 101.05) clarify when an EGC and a non-EGC, respectively, may omit from its draft registration statement interim and annual financial information that it reasonably believes will not need to be presented separately at the time it files its registration statement publicly. Question 101.04 was added to reflect the updates the SEC made to Question 1 of its FAST Act C&DIs.

For more information, see Deloitte’s July 11, 2017, Heads Up.

**SEC Allows Certain PBEs to Elect to Use Non-PBE Effective Dates When Adopting the FASB’s Revenue and Leases Standards**

At the July 20, 2017, EITF meeting, the SEC staff provided significant relief to registrants that are required to include financial statements or financial information of other reporting entities in their SEC filings. Specifically, the SEC staff announced that it would not object to elections by certain PBEs to use
the non-PBE effective dates for the sole purpose of adopting the FASB’s new standards on revenue (ASC 606) and leases (ASC 842).

The staff announcement makes clear that the ability to use non-PBE effective dates for adopting the new revenue and leases standards is limited to the subset of PBEs “that otherwise would not meet the definition of a public business entity except for a requirement to include or the inclusion of its financial statements or financial information in another entity’s filings with the SEC.”

For more information, see Deloitte’s July 20, 2017, *Heads Up.*

**SEC Updates Interpretive Guidance on Revenue Recognition**

In August 2017, the SEC issued *SAB 116* as well as two interpretive releases to update its interpretive guidance on revenue recognition and bring it into conformity with the FASB’s new revenue standard (ASC 606).

SAB 116, among other things, modifies SAB Topics 8, 11.A, and 13 as follows:

- SAB Topic 8, which is specific to retail companies, and SAB Topic 13, which provides the SEC staff's views regarding general revenue recognition guidance as codified in ASC 605, will no longer be applicable upon a registrant’s adoption of ASC 606.
- SAB Topic 11.A is amended to clarify that “revenues from operating-differential subsidies presented under a revenue caption should be presented separately from revenue from contracts with customers accounted for under ASC Topic 606.”

The following is among the interpretive releases:

- *Commission Guidance Regarding Revenue Recognition for Bill-and-Hold Arrangements* — Indicates that upon adopting ASC 606, “registrants should no longer rely on the guidance in Securities Exchange Act Release 23507 and Accounting and Auditing Enforcement Release 108, *In the Matter of Stewart Parness,* which set forth the criteria to be met in order to recognize revenue when delivery has not occurred."

For more information, see Deloitte’s August 22, 2017, journal entry. Also see the press release on the SEC’s Web site.

**2017 AICPA Conference on Current SEC and PCAOB Developments**

At the December 2017 AICPA Conference on Current SEC and PCAOB Developments, numerous speakers and discussion panelists shared their insights into current accounting, reporting, and auditing practice issues.

One of the key themes during the conference was “change,” with the FASB’s new standards on revenue recognition, leases, and credit losses (the “new GAAP standards”) and the PCAOB’s new auditor reporting model dominating the conversation.

- *New accounting standards* — The new GAAP standards will not only change reported results but also significantly improve the disclosures for investors. Successful implementation of the guidance requires appropriate oversight by audit committees and the keen focus of registrants on identifying and applying appropriate changes to internal control over financial reporting (ICFR).
- *PCAOB new auditor reporting model* — In addition to the financial statements themselves, the audit report that accompanies them will be significantly modified over the next few years as
the requirements of the final standard on the auditor’s reporting model are phased in. While the new section that describes critical audit matters (CAMs) were not required for the 2017 year-end, audit committees are encouraged to discuss the potential content of that section with their auditors to understand the nature and timing of CAMs that will be disclosed in the future.

Conference speakers also encouraged participants to remain diligent about cybersecurity and the need to keep abreast of technological developments such as distributed ledger (blockchain) technology. And of course no one could ignore what was the then imminent prospect of sweeping U.S. income tax reform and the potential effect it may have on year-end financial reporting (see Income Tax Update for details on the Tax Cuts and Jobs Act that was issued in December 2017).

In their keynote address, SEC Chairman Jay Clayton and SEC Chief Accountant Wesley Bricker discussed the importance of the SEC’s three-pronged mission: (1) investor protection, (2) capital formation, and (3) market integrity. Mr. Clayton noted that efficient capital formation in the U.S. public markets gives the average retail investor — colloquially referred to as Mr. and Mrs. 401(k) — a cost-effective opportunity to invest in the growth of America. Mr. and Mrs. 401(k) are protected by a disclosure regime that is the foundation of our capital markets, and the audited financial statements are the bedrock of that regime. For 15 years, the PCAOB (with oversight by the SEC) has played a central role in improving audit quality. As PCAOB Chairman James Doty reminded conference participants, the mandatory audit “is the linchpin of trust that holds our system of public market capital formation together.”

Instead of delivering separate speeches, Mr. Bricker and deputy chief accountants in the OCA issued a joint statement describing matters discussed at the deputy chief accountant panel discussion, including the new GAAP standards, interactions with other SEC divisions and offices, PCAOB matters, auditor independence, ICFR, audit committees, international accounting and auditing, and innovation.

For more information, see Deloitte’s December 10, 2017, Heads Up.

SEC Comment Letter Trends Affecting the P&U Sector

The focus of recent SEC staff comments to registrants in the P&U industry is largely consistent with that of staff comments issued in past years, which include (1) dividend restrictions; (2) accounting for the impact of rate making; (3) regulatory disallowance of PP&E; and (4) timing of impairment.

Dividend Restrictions

Reference is made to your disclosure . . . of [Company A’s] maximum ratio of consolidated financial indebtedness to consolidated total capitalization imposed by a credit agreement. Please tell us whether this covenant, other financial covenants and/or restrictions imposed by regulatory commissions restrict the ability of your subsidiaries or investments accounted for by the equity method to transfer funds to you in the form of loans, advances or cash dividends. If so, please tell us: (i) the amount of restricted net assets of consolidated subsidiaries and your equity in the undistributed earnings of investments accounted for by the equity method . . . and how you computed the amount; (ii) your consideration of providing the disclosures required by Rule 4-08(e)(3)(i) and (ii) of Regulation S-X; and (iii) your consideration of providing the condensed financial information prescribed by Rule 12-04 of Regulation S-X in accordance with Rule S-04 of Regulation S-X.

Given the nature of regulation in the P&U industry, there may be constraints on a P&U registrant’s financial flexibility and its relationships with affiliated parties, including the parent company. For example, a utility subsidiary may be subject to requirements imposed by federal and state regulators that establish a minimum equity capitalization ratio or set limits on the payment of dividends. In addition, the
capital-intensive demands of the P&U industry require significant financing agreements at the subsidiary level that may restrict (1) a subsidiary's transfer of assets in the form of advances, loans, or dividends to the parent company or another affiliated party or (2) other types of transactions between a subsidiary and its affiliates. The inability of a subsidiary to transfer assets to the parent company could, in turn, restrict the parent company's ability to pay dividends to its own shareholders.

Consequently, several P&U registrants have received comments from the SEC staff about their compliance with Regulation S-X, Rules 4-08(e) and 5-04. Those comments have included inquiries about whether consideration was given to regulatory or other limitations (e.g., debt agreements) that could restrict the transfer of assets from a subsidiary to the parent company through dividends, loans, advances, or returns of capital. As a result of the staff's comments, several P&U registrants have been required, or have agreed, to prospectively (1) expand their notes to the financial statements about potential dividend restrictions in accordance with Rule 4-08(e) and (2) include a Schedule I in their annual Form 10-K filing in accordance with Rule 5-04. Registrants should be aware that the calculations for determining the note disclosures required under Rule 4-08(e) should be performed independently of the calculations for determining the required Schedule I disclosures, and that compliance with one set of disclosure requirements does not satisfy the requirements of the other.

Accounting for the Impact of Rate Making

Example of an SEC Comment

We noted a significant increase in your regulatory asset related to [Matter X]. . . . We also note your disclosure . . . that the [state legislation] leaves the decision on cost recovery determinations related to [Matter Y] to the normal ratemaking processes before utility regulatory commissions and your disclosure . . . that you believe recovery is probable. We further note your disclosure in multiple instances . . . that an order from the regulatory authorities disallowing recovery of costs related to [Matter Z] could have an adverse impact on your financial statements. As it appears you do not have a regulatory order supporting the deferral of these costs, please tell us why you believe the amounts you have deferred as regulatory assets are probable of recovery under U.S. GAAP and provide us with your detailed analysis supporting this conclusion including both positive and negative evidence you considered. Refer to ASC 980-340-25-1.

The SEC staff's comments have focused on (1) ensuring that P&U registrants are thoughtful in determining the initial and continuing probability of cost recovery inclusive of the expected recovery period, (2) providing supplemental explanations or separate detailed analysis and evidence that support the P&U registrant's recognition of regulatory assets, and (3) whether a particular regulatory asset of the P&U registrant is earning a rate of return. Further, the SEC staff continues to issue comments on (1) how the P&U registrant's current regulated rates are designed to recover its specific costs of providing service, (2) the nature of the P&U registrant's material regulatory assets and liabilities, and (3) the P&U registrant's accounting policies for revenues subject to refund.

Regulatory Disallowance of PP&E

SEC staff comments to public utility registrants continue to focus on the guidance in ASC 980-360-35 on subsequent measurement and recognition of PP&E related to regulated operations. Under that guidance, an entity should record a disallowance related to a recently completed plant if it determines that a disallowed amount is probable and reasonably estimable; the entity must use judgment to make that determination. In light of recent regulatory orders by state public utility commissions that limit a public utility entity's cost recovery, registrants have been asked to explain their considerations related to the timing of recording a disallowance, particularly when a disallowance was not recorded until a rate order was received.
Timing of Impairment

Example of an SEC Comment

Please identify the impaired assets for us and tell us whether or not you tested them for impairment during the [preceding quarter]. If you did not test these assets for impairment during the [preceding quarter], explain to us your basis for concluding that an impairment test was not necessary. If you did test these assets for impairment during the [preceding quarter], describe for us in reasonable detail all material assumptions used in and the results of your test. See ASC 360-10-35-21(f).

As noted above, recently the SEC staff has increased its focus on impairment of long-lived assets, including comments on whether a registrant has recorded, or is at risk of recording, an impairment charge.

The SEC may also provide a reminder that a registrant may be required to disclose in MD&A risks and uncertainties associated with the recoverability of assets in the periods before an impairment charge is recorded. For example, even if an impairment charge is not required, a reassessment of the useful life over which depreciation or amortization is being recognized may be appropriate.

Section 3 — Industry
Hot Topics
Depreciation Adjustments

Certain regulatory mechanisms involving depreciation expense have been put in place to moderate or neutralize increases in utility customer rates. The U.S. GAAP considerations associated with these types of regulatory actions are discussed below.

“Mirror Depreciation”

If a utility records accelerated or additional depreciation in the interest of accelerating asset recovery and subsequently determines that the excess depreciation reserves are no longer necessary, such an action is referred to as “mirror depreciation” because of its similarity to the mirror construction work in progress (CWIP) referred to in ASC 980-340. In these situations, the utility can reverse the additional or accelerated depreciation taken in prior years to the extent that it exceeds depreciation that would have been recorded under nonregulated U.S. GAAP on the basis of a regulator's actions. The previously collected amount should be reversed in a manner consistent with the reduction in rates.

Nonlegal Cost of Removal

Estimated cost of removal is generally recognized as an element of depreciation expense for regulatory purposes. However, on the basis of SEC guidance, amounts reflected in rates charged to customers for cost of removal that are not legally required are considered a regulatory liability under U.S. GAAP because this expense is recognized in customer rates sooner than would be required or permitted under general U.S. GAAP. Essentially, the regulator is providing current rates for a cost that is expected to be incurred in the future. As a result, if the regulator orders or agrees to an adjustment of this regulatory liability, there are no restrictions under U.S. GAAP that would prohibit the reversal of a previously recorded and collected accumulated cost of removal. The regulator imposed the liability, and the regulator can eliminate or reduce the liability. Accordingly, a negative cost of removal amortization is permissible under U.S. GAAP, and the reversal of the regulatory liability should match the rate treatment.

Negative “True” Depreciation

Because of life extensions and other factors, some utilities have concluded that depreciable lives of some assets should be extended and, in some cases, have determined that depreciation reserves exceed the theoretical reserve levels that would be required. The theoretical depreciation reserve requirement is generally determined in connection with the performance of a depreciation study. The theoretical excess reserve may be (1) related to a change in the estimated depreciable lives, (2) from accruals of estimated removal costs (see discussion above), or (3) both. In some cases, utilities or their regulators have proposed negative depreciation or amortization to eliminate the theoretical excess of “true” depreciation reserves.

Under U.S. GAAP, generally only prospective changes in depreciation are permitted. However, although an entity is not allowed to reverse previously recorded “true” or regular depreciation under U.S. GAAP, reversals of previously recorded excess reserves are permitted. As a result, adjustments of depreciation expense to address theoretical excess depreciation reserves (excluding any cost of removal) should not cause net depreciation expense to be less than zero for any class of assets, as defined by the applicable depreciation study for any particular period. This would permit the assumed depreciable life of a class of
assets to be as low as zero for a period until the theoretical excess is eliminated, but it would not result in the actual reversal of previously recorded depreciation expense.

Further, a utility’s placement of any major, newly completed plant into service when it intends to record less depreciation or amortization than it would record under general U.S. GAAP may conflict with the guidance in ASC 980-340 (discussed below) if negative depreciation was not a ratemaking method routinely used by the regulator before 1982.

**Depreciation Reserve Transfers**

Depreciation reserve transfers, which can be ordered by a regulator, result in the transfer of some amount of one class of property’s accumulated depreciation to another class of property’s accumulated depreciation. For example, a regulator may order that transmission accumulated depreciation be decreased by a stated amount and that generation accumulated depreciation be increased by that amount.

Such depreciation reserve transfers are not permissible under U.S. GAAP since U.S. GAAP guidance does not allow for “write-ups” of property in the absence of a reorganization or an acquisition accounted for as a purchase; under ASC 980-360 or ASC 360-10-35, there must be an impairment basis for any “write-downs” of property. If there is a change in a depreciation-related accounting estimate, the effect is reflected in the current and future periods as a prospective change and not through restatement or retrospectively adjusting amounts previously reported.

A reserve transfer can be viewed as a reduction in current-year depreciation expense for one category of plant and an increase in current-year depreciation expense for another category of plant. However, the amount of a reserve transfer could result in negative depreciation expense for a class of property since the amount of that transfer may exceed one year’s depreciation expense for that class of assets. There is no basis in U.S. GAAP for reporting negative depreciation expense for an annual period since that would effectively result in writing up the asset.

If the amount of accumulated depreciation reduction ordered by a regulator exceeds the current year’s depreciation expense for a class of property, such excess would normally result in a difference between the regulatory basis of accounting and U.S. GAAP.

Further, “deferral” of depreciation expense for major and newly completed plants is an indication of a possible phase-in plan and would need to be addressed accordingly.

**Phase-In Plans**

ASC 980-340 defines a phase-in plan as follows:

Any method of recognition of allowable costs in rates that meets all of the following criteria:

a. The method was adopted by the regulator in connection with a major, newly completed plant of the regulated entity or one of its suppliers or a major plant scheduled for completion in the near future.

b. The method defers the rates intended to recover allowable costs beyond the period in which those allowable costs would be charged to expense under [U.S. GAAP] applicable to entities in general.

c. The method defers the rates intended to recover allowable costs beyond the period in which those rates would have been ordered under the rate-making methods routinely used prior to 1982 by that regulator for similar allowable costs of that regulated entity.

ASC 980-340 prohibits capitalization of the allowable costs that the regulator defers for future recovery under a phase-in plan. A rate decision that defers the recognition of depreciation or other allowable costs associated with a newly completed major capital project (including a capital lease) may meet the
definition of a phase-in plan. Under ASC 980-340, an entity is not permitted to record a regulatory asset for a phase-in plan regardless of whether it is probable that the deferred costs will be recovered in the future.

ASC 980-340 also addresses the concept of regulatory lag, which is defined as the delay between a change in a regulated entity’s costs and a change in rates ordered by a regulator as a result of that change in costs. The definition of a phase-in plan in ASC 980-340 is not intended to encompass actions of a regulator that are designed to protect a utility from the effects of regulatory lag in the absence of a rate order, nor is it intended to encompass the regulator’s subsequent treatment of any allowable costs that result from those actions. For example, a regulator may issue an order authorizing deferral of depreciation related to a major, newly completed plant from the in-service date until the next rate proceeding. A rate decision that defers the recognition of depreciation expense in this situation would not preclude recognition of a regulatory asset. In characterizing a rate decision as a phase-in plan or protection from the effect of regulatory lag, a utility must use significant judgment and evaluate the specific facts and circumstances.

Impact of Subsequent Events Related to Regulatory Matters

Regulatory developments often occur after the balance sheet date but before entities issue financial statements. The discussion below (1) outlines the accounting framework companies should use in considering the impact of subsequent events in general and (2) presents some examples illustrating application of the framework in the P&U industry.

ASC 855 prescribes the accounting for events and transactions that occur after the balance sheet date but before entities issue financial statements. Under ASC 855, there are two types of subsequent events. Recognized subsequent events provide additional evidence about conditions that existed as of the balance sheet date, including estimates inherent in the preparation of financial statements, and are recognized in the financial statements. Nonrecognized subsequent events provide evidence about conditions that did not exist as of the balance sheet date but arose after that date. Although nonrecognized subsequent events are not recognized in the financial statements, material nonrecognized subsequent events should generally be disclosed in the financial statements.

Loss Contingencies Versus Gain Contingencies

A loss contingency that was being evaluated as of the balance sheet date, including one in which no accrual had been recognized, should be recognized in the financial statements if the loss contingency is resolved after the balance sheet date but before issuance of the financial statements. This is a recognized subsequent event because the event that gave rise to the contingency occurred before the balance sheet date. The resolution, which may have been in the form of a court or regulatory order, a settlement agreement, or something similar, is a subsequent event that provides additional evidence about the probability and amount of the loss and should be reflected in the financial statements.

It would also be appropriate to reverse a contingent liability to the extent that the liability that had been recorded in a previous financial reporting period was in excess of the settlement amount and is settled after the balance sheet date but before issuance of the financial statements. A settlement generally constitutes additional evidence about conditions that existed as of the balance sheet date and would be considered a recognized subsequent event. For loss contingency events that occurred after the balance sheet date but before issuance of the financial statements, an entity would not recognize the loss but may need to disclose it. For example, if an accident occurred after the balance sheet date and the
company faced liability exposure, it would not recognize amounts related to the accident in the financial statements but may disclose it.

In addition, ASC 855-10-15-5 states that “gain contingencies . . . are rarely recognized after the balance sheet date but before the financial statements are issued or are available to be issued.” Further, ASC 450-30-25-1 states that a “contingency that might result in a gain usually should not be reflected in the financial statements because to do so might be to recognize revenue before its realization.” Thus, the resolution of a gain contingency after the balance sheet date but before issuance of the financial statements should generally be considered a nonrecognized subsequent event.

Entities should exercise considerable judgment when assessing contingencies and the effect, if any, of a subsequent event. While sometimes the accounting conclusion may be clear, in other cases entities may need to perform a careful analysis to address questions such as the following:

- Has the matter been resolved? If not, did developments occur?
- Was there a contingency or some uncertainty about the matter as of the balance sheet date? If not, did the loss event truly occur after the balance sheet date?

Considerations for Regulated Utilities

ASC 980 does not specifically address subsequent events unique to the P&U industry. Accordingly, entities should use the general guidance in ASC 855 to evaluate the accounting for subsequent events related to regulatory matters. Legislation does not constitute a regulatory matter. The enactment of a law or the issuance by a government agency of a new regulation after the balance sheet date but before issuance of the financial statements would be accounted for as a nonrecognized subsequent event (because the newly enacted law or regulation does not provide evidence of conditions that existed as of the balance sheet date).

Although a regulated utility’s application of the guidance in ASC 855 will depend on its particular facts and circumstances, the examples below illustrate how a regulated utility company might apply the guidance to typical subsequent events.

Subsequent-Event Examples

**Fuel Order Issued After the Balance Sheet Date**

On July 15, 2017, Utility A’s regulator issued an order with respect to a routine review of A’s fuel clause adjustment calculation for the period from January 1, 2016, to December 31, 2016. Utility A had not yet issued its June 30 financial statements. In this order, the regulator ruled that A should have credited certain wholesale sale margins to its retail fuel clause. The order required A to refund $5 million. Utility A was aware that intervenors were questioning this item on the basis of testimony that had been filed a few months earlier but had expected to prevail in this matter, which represented a loss contingency as of June 30. The July 15 order was a recognized subsequent event that provided additional information about the probability and amount of the loss as of June 30. Therefore, A accounted for the effect of this order in its financial statements as of and for the period ended June 30, 2017, and included the disclosures prescribed by ASC 980-605-50-1.

**Interim Rates Implemented — Final Rate Order Received**

Utility B was permitted to implement an interim rate increase that was subject to refund. Under ASC 980-605, when an entity initially records the revenue, it uses the criteria in ASC 450-20-25-2 to determine whether a provision for estimated refunds is accrued as a loss contingency. On the basis of past experience and an evaluation of all information in the proceeding, B concluded that a refund
was probable, was able to reasonably estimate an accrual for the revenue subject to refund, and appropriately recorded a provision for the estimated refunds in its most recently issued financial statements. After the balance sheet date but before B’s financial statements were issued, its regulator approved final rates and no portion of the interim rates was required to be returned to the ratepayers. In this example, the regulator’s decision is considered a recognized subsequent event. Therefore, B appropriately reversed the previously recorded reserve. If the approved final rates had been lower than the implemented interim rates and the previously recorded reserve was not sufficient to cover the amount required to be returned to the customers, the reserve would also be adjusted accordingly.

**Appeal of Prior Unfavorable Rate Order**

In a prior period, Utility C’s regulator ordered that a gain on a sale of an asset be used to reduce future rates. Therefore, C recorded a regulatory liability to recognize this obligation but appealed the ruling. After C’s balance sheet date but before its financial statements were issued, an appellate court decided in favor of C and ruled that it did not need to reduce future rates. Intervenors immediately announced their intent to appeal the court ruling. Because of the numerous uncertainties inherent in a litigation proceeding (e.g., additional appeals), C determined that the court order did not constitute the realization of a gain and concluded that this was a nonrecognized subsequent event. Utility C did not reverse the regulatory liability.

**Rate Order After the Balance Sheet Date — Order Includes a Disallowance**

In conjunction with its ruling on a rate case, Utility D’s regulator concluded that there was significant management error in the planning and construction of a recently completed power plant. In the order issued after the balance sheet date but before the financial statements had been issued, the regulator required that plant costs in excess of a specified amount not be recovered in rates. The recovery of this plant was a key issue throughout the proceedings and the primary basis for the request for an increase in rates. Before the issuance of the rate order, D had concluded that the likelihood of a disallowance was reasonably possible but less than probable. Utility D concluded that the post-balance-sheet ruling constituted additional significant objective evidence about the likelihood of disallowance as of the balance sheet date. Accordingly, D updated its assessment of the probability of a disallowance as a result of this recognized subsequent event and recorded a charge to earnings in the current period. Post-balance-sheet events other than a final order from a regulator may also constitute significant objective evidence about conditions that exist as of the balance sheet date.

**Rate Order After the Balance Sheet Date — Order Reverses a Previous Decision by the Regulator**

In a prior period, in conjunction with an order, Utility E’s regulator required that E prospectively track a particular cost included in its last rate determination and, in the next rate case, should refund any excess of the amount of allowable cost in rates over the actual cost incurred. As a result of the order, E began recording a regulatory liability for the difference. The regulator issued an order after the balance sheet date but before the financial statements had been issued. In this new order, the regulator concluded that E did not need to refund the difference. Utility E concluded that the post-balance-sheet order represented a nonrecognized subsequent event.

Given the circumstances in which this regulatory liability was established (an obligation imposed by the regulator through an order, as opposed to an assessment of a probable loss contingency), it was

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1 In accordance with ASC 980-360, when it becomes probable that part of the cost of a recently completed plant will be disallowed for ratemaking purposes and the amount of the disallowance can be reasonably estimated, the estimated amount of the probable disallowance is deducted from the reported cost of the plant and recognized as a loss. The terms “probable,” “reasonably possible,” and “remote” are defined in ASC 450-20, and entities must exercise considerable judgment when applying them.
acceptable for E to adopt the view that the settlement of a regulatory liability occurs only when it has been extinguished. Although this conclusion is not explicitly stated in ASC 980-405, it is consistent with the guidance in ASC 405 on liabilities that represent a legal obligation. ASC 405-20-05-2 states that an “entity may settle a liability by transferring assets to the creditor or otherwise obtaining an unconditional release.” Further, ASC 405-20-40-1 states that a “debtor shall derecognize a liability if and only if it has been extinguished. A liability has been extinguished if either of [two conditions is met, one of those conditions being that the] debtor is legally released from being the primary obligor under the liability, either judicially or by the creditor.” In this fact pattern, in which the regulatory liability is analogized to an ASC 405-20 liability, the liability is not satisfied until either the amounts have been refunded to the utility customers or the regulator releases E from the requirement to reduce rates. This approach is also consistent with the guidance in ASC 980-405-40-1, which states that “[a]ctions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator.” Accordingly, the rate order is the discrete event that removes the requirement to reduce future rates and resulted in E’s determination that the rate order was a nonrecognized subsequent event.

While there is no specific guidance in U.S. GAAP on when to recognize the impact of a regulator’s ruling, there may be interpretations or applications in practice that analogize to the guidance in ASC 450, in which case an entity would have to determine whether the ruling (1) represents the recovery of a previously recognized loss or (2) results in the recognition of a gain. As discussed above, gain contingencies are rarely recognized after the balance sheet date but before the financial statements are issued.

Subsequent Natural Disaster Affects Likelihood of Recovery of a Regulatory Asset

Utility F had recorded, as of the balance sheet date, a regulatory asset related to recovery of major maintenance costs in connection with a particular power plant. Utility F’s regulator had previously ordered that the incurred costs be recovered in rates over the period between planned major maintenance outages. After the balance sheet date, a hurricane severely damaged the power plant, and F decided to shut down the plant. Utility F had a rate-case proceeding in process at the time of the hurricane. On the basis of discussions F had with the staff of the regulatory commission, F learned that the staff was planning to propose that the deferred costs no longer be recovered. Utility F had not yet issued its financial statements and concluded, on the basis of precedent in which the commission agreed with these types of staff recommendations, that recovery of the deferred major maintenance costs was no longer probable.

Utility F concluded that the change in judgment about likelihood of recovery of the regulatory asset resulted from a nonrecognized subsequent event. Utility F, in its judgment, determined that the hurricane that occurred after the end of the period did not constitute additional evidence about facts and conditions that existed as of the balance sheet date. Utility F also believed that in the absence of the hurricane, the power plant would have continued to operate and that its regulator most likely would have continued to allow recovery of the deferred costs. Utility F issued its financial statements and continued to report the regulatory asset on its balance sheet but disclosed the expected impact of the hurricane in the notes to the financial statements.

Surprise Development in a Proceeding

Utility G had recorded a regulatory asset in prior periods in connection with storm damage costs. The regulator had previously ordered that costs related to a specific storm may be recovered in rates over a five-year period. Utility G had been recovering these costs in rates for the prior three years. As of the balance sheet date, the regulatory asset balance reflected two years of remaining costs to recover. Utility G had requested continued amortization of these costs in its current rate proceeding. As of the balance
Impact of Subsequent Events Related to Regulatory Matters

Sheet date, no testimony had been filed that had questioned the continued recovery of the storm damage costs, and G concluded that future recovery of its regulatory asset balance was probable.

In connection with its current rate proceeding, shortly after year-end, G commenced settlement discussions. Intervenors indicated that they were willing to settle the case if G would forgo the remaining amortization of the storm damage costs. While G strongly disagreed with the intervenors’ position on storm damage costs, in the context of the overall settlement proposal, G was likely to agree to the settlement. On the basis of the settlement terms, no other existing regulatory assets were at risk (i.e., G did not concede the storm cost asset to protect another regulatory asset whose loss was otherwise probable as of the balance sheet date), and the ROE was slightly higher than G was expecting. Shortly before the financial statements were issued, the parties agreed to the settlement. On the basis of precedent, G believed it was probable that its regulator would approve the settlement. Utility G concluded that this settlement represented a nonrecognized subsequent event and disclosed the settlement in the notes to the financial statements. Utility G, in its judgment, determined that the subsequent settlement discussions did not provide additional evidence about facts and conditions that existed as of the balance sheet date. Utility G believed that in the absence of its decision to agree to the settlement, its regulator most likely would have continued to allow recovery of the deferred costs over the remaining two years.

**Connecting the Dots**

Utilities need to exercise judgment when there are surprise developments. For example, had there been any discussions with intervenors before the balance sheet date about the potential to forgo recovery of the deferred costs, or had testimony been filed advocating no further recovery, questions would have been raised as of the balance sheet date about the probability of recovery and the settlement may have indicated a recognized subsequent event. In most cases in which a rate order issued after year-end contains an unexpected ruling affecting a regulatory asset as of the balance sheet date, such a rate order is considered a recognized subsequent event if commission staff or intervenors have questioned the matter as part of the rate proceedings that occurred before the balance sheet date or it was clear that the item disallowed was subject to a prudence review in the current regulatory process.

**Decision to Early Retire a Power Plant After the Balance Sheet Date**

Utility H had been performing an extensive analysis to determine whether it would early retire a power plant. As of the balance sheet date, H had not made a decision. After the balance sheet date but before the issuance of the financial statements, management obtained approval from its board of directors to early retire the plant and committed to a plan to do so. As of the date of the decision, H had determined that it was probable that the power plant would be abandoned and therefore that the remaining book value of the power plant should be removed from plant in service.

Utility H concluded that the decision to early retire the power plant represented a nonrecognized subsequent event and disclosed the plan to early retire the power plant in the notes to the financial statements. Utility H, in its judgment, determined that the decision to early retire the power plant after the balance sheet date did not provide additional evidence about facts and conditions that existed as of the balance sheet date. Utility H’s evaluation of the subsequent event can also be analogized to when held-for-sale accounting is recognized in accordance with ASC 360.
Plant Abandonments and Disallowances of the Costs of Recently Completed Plants

ASC 980-360 provides guidance on accounting for (1) plant abandonments and (2) disallowances of the costs of recently completed plants. Generally, “plant” should be viewed as anything capitalized in “plant in service” or in CWIP. The guidance applies to all operating assets or assets under construction, most commonly to electric generating plants. Regulated utilities should also consider whether this guidance is relevant for operating assets replaced by new projects and initiatives, such as new AMI projects resulting in the early retirement of existing meters.

For information about the related topics of impairment and disposal of long-lived assets, see Impairment Considerations.

Plant Abandonment

ASC 980-360 states that when it becomes probable that an operating asset or an asset under construction will be abandoned, the associated cost should be “removed from construction work-in-process or plant-in-service.” ASC 980-360 further indicates that if the regulator is likely to provide a full return on the recoverable costs, a separate asset should be established with a value equal to the original carrying value of the abandoned asset less any disallowed costs. A regulated utility should consider the length of time over which an abandoned asset will be recoverable to determine whether an indirect disallowance of the abandoned asset exists. Refer to Indirect Disallowances for additional considerations in the assessment of indirect disallowances.

If the regulator is likely to provide a partial return or no return, the new asset value should equal the present value of the future revenues expected to be provided to recover the allowable costs of the abandoned asset and any return on investment. The regulated utility’s incremental borrowing rate should be used to measure the present value of the new asset. Any disallowance of all or a part of the cost of the abandoned asset should be recognized as a loss when it is both probable and estimable. During the recovery period, the new asset should be amortized to produce zero net income on the basis of the theoretical debt and interest assumed to finance the abandoned asset.

ASC 980-360 does not specify where the separate asset should be classified on the balance sheet; it indicates only that the cost amount should be removed from CWIP or plant in service. In practice, most companies have classified the separate asset as a regulatory asset or as a category of plant other than CWIP or plant in service (when the plant meets the probable-of-abandonment criterion while still providing utility service).

Matters Related to Abandonment Accounting

The discussion above describes the overall accounting model for asset abandonments in a regulated environment; however, regulated utilities should carefully assess facts and circumstances to determine what constitutes abandonment of an asset and the likelihood that abandonment will occur. While ASC 980-360 provides no explicit guidance on what constitutes an abandonment of an operating asset, an asset that will be retired in the near future and much earlier than its previously expected retirement date typically is subject to potential abandonment accounting or to the ASC 980-360 disallowance test or both. Alternatively, if an asset is to be retired, but not in the near future or not much earlier than its previously expected retirement date, the use of abandonment accounting in accordance with ASC 980-360 may not be appropriate. Instead, the appropriate accounting may be to prospectively modify the remaining depreciable life of the asset in accordance with ASC 360-10-35. Under this accounting, depreciation would be accelerated to fully depreciate the asset to the expected early-retirement
date. Determining whether an early retirement of an asset constitutes an abandonment is a matter of judgment. Factors for regulated utilities to consider in evaluating whether a plant is being abandoned include the following:

- A change in the remaining depreciable life of the operating asset outside the regulated utility's normal depreciation study.
- Any accelerated depreciation because of a change in depreciable life that is not currently reflected in rates or expected to be reflected in rates in the near future.
- A retirement of the asset sooner than its remaining useful life and in the near future.
- A reduction in the estimated remaining depreciable life by more than 50 percent.

The determination of whether abandonment is probable in advance of a final decision to retire a plant is subject to judgment. Factors for a regulated utility to consider in assessing the likelihood of abandonment may include the following:

- If environmental rules require additional spending for the plant to continue operating after a certain date, whether management's cost-benefit analysis indicates that this additional spending is cost-justified.
- If a possible early-retirement decision will not be made for several years, whether the factors that most affect the decision (such as power and gas prices) could reasonably change in the next several years.
- If the decision to retire a plant requires approval from an RTO or a regulator, whether it is unclear that approval will be granted.

Regulated utilities concluding that a plant abandonment is probable should also consider the abandonment's impact on related items, such as materials and supplies, AROs, and deferred taxes directly associated with the asset.

In addition, regulated utilities should evaluate whether changes in facts and circumstances affect previous judgments related to abandonment accounting conclusions (e.g., whether an abandonment is probable or whether a disallowance is probable and reasonably estimable).

**Example — Reconsideration of Abandonment Decision**

A regulated utility previously concluded that an asset abandonment was probable and estimable and recorded a loss estimating less than a full return on and of the asset. In a subsequent period, the regulated utility concluded that the abandonment is no longer probable. On the basis of these general facts, we believe that it would be reasonable for the regulated utility to reclassify the carrying amount of the asset back to plant in service or CWIP, as applicable. Further, ASC 980-360-35-4 describes the notion of adjusting the amount of the abandoned asset as estimates change, which supports the reversal of a charge from a prior period if the likelihood of abandonment is no longer probable. The accounting for the decision to "unabandon" an asset requires judgment and a careful assessment of the regulated utility's facts and circumstances.

**Disallowances of Costs of Recently Completed Plants**

ASC 980-360 stipulates that when a direct disallowance of the cost of a recently completed plant becomes probable and estimable, the estimated amount of the probable disallowance must be deducted from the reported cost of the plant and recognized as a loss. Future depreciation charges should be based on the written-down asset basis.
Regulated utilities often do not record a disallowance before receipt of a rate order because the loss is not reasonably estimable. However, there could be circumstances in which a rate order has not been issued but a disallowance loss could be probable and reasonably estimable. If the prudency of a recently completed plant is being challenged in a current rate proceeding, a regulated utility must use significant judgment in evaluating the likelihood and estimate of a cost disallowance. If the regulated utility does not record the loss in its financial statements, it should disclose the range of a reasonably possible loss in the footnotes if the loss could be material.

Recently Completed Plant

There is no specific guidance in (1) ASC 980-360 or ASC 360-10-35 defining a “recently completed plant” or (2) ASC 980-340 defining a “newly completed plant.” In practice, these terms have been defined on the basis of facts and circumstances, resulting in some diversity. The starting point for determining what constitutes a recently completed plant or a major, newly completed plant is typically the time from the completion-in-service date until the plant owner files its initial rate request for inclusion of the plant in allowable costs. If an unregulated affiliate transfers a completed plant to a regulated utility affiliate, disallowances should be evaluated under ASC 980-360 at the time of the transfer because the costs of the plant are then subject to the provisions of ASC 980-10. The cost disallowance guidance in ASC 980-360 does not contain the concept of “major.” As a result, in the evaluation of potential cost disallowances, the guidance in ASC 980-360 on evaluating potential cost disallowances applies to all recently completed plants.

ASC 980-360 also indicates that a disallowance of plant cost resulting from a cost cap must be recorded as soon as it is evident that the estimated cost at completion of the project will exceed the cap. Therefore, the application of ASC 980-360 may result in disallowance losses before an asset is placed in service and before construction costs actually exceed the cap. If additional increases in the estimated cost of the plant become probable, those increases would also be recognized as disallowance losses.

Indirect Disallowances

ASC 980-360 also addresses explicit, but indirect, disallowances that occur when no return or a reduced return is provided for all or a portion of the recently completed plant. In the case of an indirect disallowance, if the regulator does not specify the amount of the disallowance, the amount must be calculated on the basis of estimated future cash flows. To determine the loss resulting from an indirect disallowance, entities should estimate and discount the future revenue stream/cash flows allowed by the regulator by using a rate consistent with that used to estimate the future cash flows. This amount should be compared with the estimated cost of the plant at completion, and the difference should be recorded as a loss and reduction to the recorded plant amount. Under this discounting approach, the remaining asset should be depreciated in a manner consistent with the ratemaking and in a manner that would produce a constant return on the undepreciated asset that is equal to the discount rate. Although an explicit but indirect disallowance must be recorded as a loss, ASC 980-360-35-15 notes that “an entity is not required to determine whether the terms of a settlement agreement or rate order contain a hidden, indirect disallowance.” For example, if a regulator provides a ROE on a recently completed plant that is lower than other rate-base items but still a reasonable return, we would generally not view the provision of a lower return by the regulator as an indirect disallowance. The determination of a reasonable return requires significant judgment.

Considerations for Disallowances Outside the Scope of ASC 980-360

Cost disallowances for plants that are not recently completed are recognized in accordance with general U.S. GAAP. For example, assume that (1) a regulated utility puts a new plant into service and then goes through a rate case when the prudency of the costs is scrutinized and (2) the regulator concludes that
the entire amount capitalized should be included in rate base, with depreciation expense on the entire
capitalized amount included in cost of service. The plant costs are questioned a few years later in the
next rate case, and the regulator disallows a specific amount of the plant cost. A disallowance charge
based on ASC 980-360 should not be recorded because that plant is no longer a recently completed
plant. Rather, an entity should apply the impairment criteria in ASC 360 when evaluating impairment of a
plant that is not recently completed. Refer to Impairment Considerations for more details.

Rate-Case Settlements

A utility company periodically files a rate case with its regulatory commission. This may be because of the
commission’s requirements that the utility company file a new rate case or because the utility company
has chosen to request new rates. When a rate case is fully litigated in front of the regulatory commission,
the process is often long, sometimes lasting more than a year from the date the utility company initially
files its rate-case request to the date the regulatory commission issues a final order addressing the
request. The rate-case process involves data requests from the commission staff and intervenors to the
rate case as well as multiple rounds of testimony and hearings.

However, in many regulatory jurisdictions, the utility company and the intervenors will hold settlement
discussions. The goal of the settlement discussions is for the utility company and the intervenors to
agree on the significant terms of the rate case. Once consensus is reached, the settlement is filed with
the regulatory commission in the form of a settlement agreement that the regulatory commission can
then review and approve or reject. The advantage of a settlement agreement is that it reduces the
period from the initiation of a rate case to the effective date of new customer rates because hearings
and testimony are not required. A settlement agreement may settle all aspects of a rate case, or it may
refer a portion of the rate case (e.g., recovery of a specific cost) back to the regulator.

Significant terms in a settlement agreement may include the revenue requirement, recovery of various
regulatory assets, or the return on rate base.

Determining the appropriate accounting for a settled rate case can sometimes be challenging when
the extent of the information included in the settlement agreement is limited. A settlement agreement
may include little more than the approved revenue requirement. It may not include any information
about the types of currently incurred costs that are to be recovered or about the recovery of previously
incurred costs that are deferred as regulatory assets. Utility companies must therefore exercise
significant judgment to determine the appropriate accounting for a settled rate case. When making this
determination, utility companies should take the following into account:

- A utility company should consider preparing a calculation of the hypothetical settled revenue
  requirement on the basis of the initially filed rate case, filed testimony and responses to
  intervenor requests, discussions with intervenors and the regulator, and the settlement
  agreement. This detailed calculation, which is based on the agreed-to revenue requirement,
  may help the utility company understand the components (e.g., those related to rate base, cost
  of service, and return on rate base) of the settled revenue requirement and the accounting
  implications of the settlement. To perform this calculation, the utility company may need input
  from various departments at the company, including regulatory, accounting, tax, and legal,
  and will need to use significant judgment depending on the level of detail in the settlement
  agreement. The calculation of the hypothetical settled revenue requirement should be
  sufficiently detailed for parties to understand the significant judgments and the allocations
  made.
• Additional considerations may include (1) the estimated capital structure ratio and cost of capital components, (2) a determination of how previously deferred costs will be recognized for both the amount of costs and the duration of recovery, and (3) whether any regulatory assets should be written off because they are no longer collectible.

The judgments about the capital structure ratio and cost of capital components will affect the amount of AFUDC (debt and equity) that are capitalized to utility plant for the periods after the rate-case settlement is approved. The judgments regarding the regulatory assets may be significant for both the current period (deferral of costs incurred or a write-off of costs previously incurred) and future periods for costs recovered in future rates.

In exercising its professional judgment, a utility company may consider weighting the evidence used to calculate the hypothetical settled rate requirement similarly to how it weights the evidence used to determine whether it is probable that a regulatory asset will be recovered. Such judgments will be based on the facts and circumstances of each settlement agreement. The SEC staff has unofficially suggested that evidence that could support future recovery of regulatory assets includes:

• Rate orders from the regulator specifically authorizing recovery of the costs in rates.
• Previous rate orders from the regulator allowing recovery for substantially similar costs.
• Written approval from the regulator approving future recovery in rates.
• Analysis of recoverability from internal or external legal counsel.

Impairment Considerations

ASC 360-10-35 addresses financial accounting and reporting related to the impairment or disposal of long-lived assets. In accordance with ASC 360-10-35, an entity must recognize an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and must measure an impairment loss as the difference between the carrying amount and fair value of the asset.

Asset Grouping and Identifiable Cash Flows for Impairment

Recognition and Measurement

In applying ASC 360-10-35, an entity must determine the asset grouping for long-lived assets.

ASC 360-10-35-23 states that “[f]or purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities.”

An entity should determine the level at which assets are grouped on the basis of the entity’s facts and circumstances. An important consideration may be whether the entity is regulated or nonregulated. For many rate-regulated utilities, the entire generating fleet, as well as PPAs, is used to meet the utility’s obligation to serve and the revenues from regulated customers cannot be identified with respect to any subset of assets. Accordingly, many utilities have concluded that the lowest level of identifiable cash flows is related to the entire regulated generating fleet or a larger group of regulated assets.

One example of a grouping concept could be an electric utility that is subject to traditional, cost-based rate regulation and uses various sources of generation to fulfill its service obligation. An electric utility’s generating mix could range from high-cost nuclear power plants and peaking units to lower-cost fossil fuel units and inexpensive hydroelectric, solar, or wind facilities. Because this collection of plant assets
Impairment Considerations

is used together to meet the electric utility’s service obligation and produce joint cash flows (generally based on system-wide average costs), such plant assets are interdependent and are typically grouped for recognition and measurement of an impairment loss under ASC 360-10-35.

By contrast, unregulated power plant businesses are typically able to identify cash flows at a lower level than the entire generating fleet, such as by region or individual plant.

When performing the asset grouping assessment, an entity may consider the following factors:

- **The presence and extent of shared costs** — Generally, individual plants have certain discrete costs that are directly attributable to the plant. However, a portion of the cost structure may also be shared. These shared costs may include legal; accounting; trading; marketing; and, in certain circumstances, fuel and hedging contracts. The degree of shared costs could serve as evidence of the interdependence of cash flows between plants.

- **The extent to which the entity manages its business at various levels, such as by state, ISO, or region** — An entity may manage its generation fleet as individual assets or as an asset group. For example, an entity may manage a group of assets within an ISO territory and plan to make the assets available for dispatch to the operator. Depending on the territory, each plant within the ISO may receive similar prices; in this case, management may operate the assets on a fleet basis. The determination would also depend on whether management makes operating decisions on a plant basis or maintains a diversified mix of generating assets to take advantage of various economic environments. An entity should also consider how the results of operations are reported to the executive team and those charged with governance as well as how employees are compensated. For example, employee compensation plans that are based on the profit of an individual plant may be a strong indicator that the plant’s cash flows represent the lowest level of identifiable cash flows that are largely independent of other assets.

- **The entity’s distribution characteristics, such as regional distribution centers, local distributors, or individual plants** — The entity may consider how it manages outages and maintenance for its various assets. If management adjusts output at one plant to compensate for an outage at another, interdependent cash flows may exist. By contrast, if each plant is managed individually and there is little coordination throughout the group, an asset grouping method may not be appropriate.

- **The extent to which purchases are made by an individual location or on a combined basis** — The assessment of this criterion may show that certain costs are incurred for the benefit of individual plants while certain purchases may be for the use of more than one plant. For example, fuel for plants may be purchased from a common fuel source and may be allocated by a central function. This may depend, among other things, on the similarity of the plants as well as their proximity to each other.

- **The interdependence of assets and the extent to which such assets are expected or required to be operated or disposed of together** — The entity may consider how it operates its assets. The more an entity enters into plant-specific commitments to provide power, for example, the more independent the plant may be. On the other hand, if an entity has an overall aggregate commitment, such as a portfolio of retail customer requirements contracts, and management has the ability to dispatch its fleet depending on market conditions, cash flows may be considered interdependent. Likewise, if a group of plants is committed to serve an ISO and dispatch decisions are controlled by the ISO, there may be a greater interdependence among the assets. Another consideration would be whether an entity is able to dispose of or deactivate an individual plant and whether this would affect the operation of other plants.
An entity should consider each of the relevant characteristics and make an informed judgment about its asset grouping. In determining the lowest level of identifiable cash flows, an entity must exercise significant judgment as well as identify and assess all relevant facts and circumstances. The determination should be revisited when there are changes to the entity, its operation strategy, and the environment in which it operates.

**Asset Group Impairment and Measurement**

When events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable, the utility should review its assets for impairment. Triggering events that often require recoverability evaluations for P&U companies include (but are not limited to):

- Significant adverse changes in energy and capacity prices.
- Changes in management’s long-term operational view, including considerations to sell, dispose of, or retire assets within the asset group earlier than expected.
- Expectation to retire an asset earlier than expected because of time and/or resource constraints associated with applicable regulations, such as environmental compliance laws.
- Losses of major customers.

Because triggering events can change rapidly from one period to the next, an entity should (1) identify potential triggering events that could affect significant asset groups and (2) establish processes and controls to monitor them in each reporting period. Further, an entity should consider whether cautionary “early warning” disclosures are necessary when significant impairments could reasonably be possible in future periods.

To test for impairment of an asset or asset group that is held and used, a utility should compare future cash flows from the use and ultimate disposal of the asset or asset group (i.e., cash inflows to be generated by the asset or asset group less cash outflows necessary to obtain the inflows) with the carrying amount of the asset or asset group. Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the carrying amount. ASC 360-10 suggests that if a test for impairment is necessary, a utility may need to review its depreciation policies even if it finds that the asset is not impaired.

If an impairment is found to exist, the impairment loss to be recorded is the amount by which the asset’s carrying amount exceeds its fair value. Determining the appropriate fair value for an asset requires considerable judgment based on the relevant facts and circumstances. Quoted market prices represent strong evidence of fair value. In the absence of quoted market prices for a particular asset, market comparables may provide relevant evidence for the fair value of the asset under consideration. Discounted cash flows (discounted at a rate commensurate with the risks involved) are another data point for fair value and are commonly used in the valuation of regulated utility property. A combination of some or all of these estimates is often used to represent a fair value for an asset under consideration.

For regulated utilities subject to the provisions of ASC 980, ASC 360-10 does not specify whether an impairment loss should be recorded as a reduction in the asset’s original cost or as an adjustment to the depreciation reserve. Adjustment to the original cost appears to be consistent with the notion that recognizing an impairment establishes a “new cost” for the asset. However, for enterprises that are subject to cost-based regulation and apply ASC 980, original historical cost is a key measure for determining regulated rates that may be charged to customers. Accordingly, rate-regulated enterprises may be directed by their regulators to retain original historical cost for an impaired asset and to charge the impairment loss directly to accumulated depreciation. Regulation S-X, Rule 5-02(13)(b), states:
Tangible and intangible utility plant[s] of a public utility company shall be segregated so as to show separately the original cost, plant acquisition adjustments, and plant adjustments, as required by the system of accounts prescribed by the applicable regulatory authorities. This rule shall not be applicable in respect to companies which are not required to make such a classification.

In addition, abandonments and disallowances of plant costs accounted for under ASC 980-360 are outside the scope of ASC 360-10. Companies subject to cost-based regulation should follow the provisions of ASC 980-360 when recording an impairment loss in those situations.

**Required Disclosures**

ASC 360-10 requires disclosures about impairments, including:

- A description of any impaired assets and the facts and circumstances leading to the impairment.
- The amount of the impairment loss and how fair value was determined.
- The caption in the income statement in which the impairment is recorded, if not shown separately on the face of the statement.
- The business segment affected (if applicable).

Further, because an impairment accounted for under ASC 360-10 results in an asset (or asset group) carrying value equal to fair value at the time of impairment, additional disclosures related to nonrecurring fair value measurements are required by ASC 820-10. In addition, see Timing of Impairment above for further discussion of the SEC staff's increased focus on this topic.

**Asset Retirement Obligations**

Accounting for AROs remains a topic of significant interest as a result of recent federal coal ash regulations and events that have resulted in changes in the amount and timing of estimated coal-ash-related cash outflows as well as the retirements of generation facilities, which may trip some legal requirements. The discussion below focuses on key topics related to the classification, recognition, and derecognition of AROs.

**Remediation Strategy**

There are often multiple ways to remediate AROs, and companies frequently weigh the level and cost of legal compliance when determining the best course of action to follow when retiring an asset. For example, one strategy might cost less but still comply with stipulations of the legal obligation, whereas another strategy might cost more but involve less risk and therefore be more desirable to the entity. Entities should consider whether any of the expected activities in the cost estimates are above and beyond what is legally required.

If the ultimate remediation scenario is unknown at the time the legal obligation is incurred, a best practice would be for entities to apply a probability weighting to each scenario and use the weighted-average probable cost in calculating the expected cash flows. This approach takes into account the uncertainties associated with timing and amount depending on which remediation scenario is ultimately chosen. As more certainty develops regarding the remediation strategy, the weighting should be adjusted to reflect the new information and ultimately the final remediation strategy.
Triggering Events That Affect ARO Balances

Entities should continue to monitor for events or changes in circumstances that may indicate a need for changes in recorded AROs. Events or changes in circumstances that may indicate a need for reassessment include:

- A change in the law, regulation, or contract (or new information about how laws, regulations or contracts are being interpreted and enforced) that gave rise to the ARO that results in a change to either the timing of settlement or the expected retirement costs.
- A change in management’s intended use of the asset, including a change in plans for maintaining the asset to extend its useful life or to abandon the asset earlier than previously expected.
- Advancements in technology that result in new methods of settlement or changes to existing methods of settlement.
- A change in economic assumptions, such as inflation rates.

An entity should analyze its specific facts and circumstances to determine whether the estimate of the ARO needs to be reassessed. As the estimate evolves toward the commencement of remediation, the likelihood of triggering events increases.

The following is an example of new information that can result in a change in the ARO estimate:

- In preparing the five-year financial forecast, management models ARCs for a particular group of assets that are higher than the amount of undiscounted cash flows used in management’s most recent original ARO estimate. After investigating the difference in estimates, management determined that the costs modeled in the five-year forecast reflect more current experience than the last time the ARO estimate was evaluated. Management considered the difference to be a triggering event and subsequently updated the ARO estimate to reflect the updated uninflated costs used in the five-year financial forecast.
- The key in this example is for management to regularly monitor for evidence that is contradictory to the inputs and assumptions it used in developing the original or most recent ARO estimate. This evidence could come from a variety of sources, including internal forecasting, third-party engineering studies, executed contracts, information resulting from regulatory actions, and actual cash expenditures for retirement costs.

Changes in Estimates

Accounting for changes in estimates on an ongoing basis can result in significant complexity. As ARO estimates are revised, specific consideration needs to be given to the appropriate discount rate used in the calculation of any additional ARO layer.

An entity should calculate changes in timing or estimated expected cash flows that result in upward revisions to its ARO by applying its then-current credit-adjusted risk-free interest rate to the new layer. That is, the credit adjusted risk-free rate in effect when the upward change in estimate occurs would be used to discount the new layer (the incremental undiscounted expected cash flows of the retirement activity). However, if the change in timing or estimated expected cash flows results in a downward revision of the ARO, the entity should discount the undiscounted revised estimate of expected cash flows by using the credit-adjusted risk-free rate in effect on the date of initial measurement and recognition of the original ARO and any subsequent layers. Two examples are as follows:
• **Example 1** — Assume that a new asset goes into service in year 1, the undiscounted cost to perform a retirement activity 10 years from now is $100, and the current credit-adjusted discount rate is 5 percent. In year 4, based on updated information, the undiscounted cost to perform the retirement activity in year 10 has increased by $5. The present value of the $5 increase in cost would become a new cost layer that would be discounted at the then-current credit-adjusted discount rate (i.e., the year 4 credit-adjusted risk-free rate).

• **Example 2** — Assume the same base facts as Example 1, except that in year 4, the estimated undiscounted cost to perform the retirement activity has decreased by $5. The $5 reduction in undiscounted cash flows is simply deducted from the original year 1 layer of undiscounted cash flows. The original 5 percent credit-adjusted discount rate is used for the one single layer.

Determining the appropriate unit of account for the ARO is essential to ensuring that increases and decreases in undiscounted cash flows or timing of cash flows are appropriately reflected in new layers or deducted from the appropriate existing layers. For example, consider a three-unit coal-fired generation plant whose coal ash resulting from burning the coal is subject to the EPA’s Disposal of Coal Combustion Residuals From Electric Utilities rule as well as requirements in the state in which the plant operates. Is the unit of account the total undiscounted cash flows related to the coal ash generated from (1) all three units in total, (2) all three units individually, (3) the individual ash ponds, or (4) something else? It is important for an entity to carefully define the ARO unit of account in the year the ARO is incurred to properly account for subsequent changes in estimates.

**Accounting for Settlements**

As remediation activities commence, entities should place specific focus on the classification of expenditures. This includes the determination of which payments are truly settlements associated with the remediation activity and are part of the recorded ARO estimate; these should be reflected as a reduction in the ARO liability. Often, there are other costs incurred as part of the overall project that are not part of the legal/contractual retirement obligation; those costs should be accounted for separately and recorded to the appropriate account as incurred. Further, rate-regulated entities that recover cost of removal in rates before the removal costs are actually incurred should separately identify the “nonlegal” removal activity and charge those expenditures to the associated regulatory liability. Since ASC 410-20 requires an entity to initially measure an ARO at its fair value, differences may occur between estimated future costs used in the calculation of the fair value of an entity's ARO and actual expenditures incurred by that entity to settle the ARO, resulting in a gain or a loss. For example, a gain is likely to result when an entity elects to settle an ARO by using internal resources because the entity's internal costs are most likely less than the initial fair value of the ARO, which would be a function of the costs, profit margin, and market risk premium of a third party. A gain or a loss resulting from settlement of an ARO should be recognized in the period in which the asset retirement activities are performed. When asset retirement activities are performed over more than one reporting period, gains or losses should be recognized pro rata according to the costs incurred during the period compared with the total costs that are expected to be incurred by the entity to settle the ARO. It would be inappropriate to defer recognition of the entire gain or loss to the period in which the asset retirement activities are completed and the ARO is settled. Doing so would result in overstating or understating the ARO because it would not be representative of the amount that the entity would have to pay a third party to assume it.

**Reporting Considerations**

ASC 210 defines current liabilities as “obligations whose liquidation is reasonably expected to require the use of existing resources properly classifiable as current assets, or the creation of other current liabilities.” Entities should consider whether the estimated ARO expenditures over the next 12 months
should be classified as current. Questions that entities should consider in making this evaluation include the following:

- Have the necessary permits been obtained to finish the work that is estimated to be completed in the next 12 months?
- Has approval been obtained to use existing resources to finish the work that is estimated to be completed in the next 12 months?
- Are there any contractual or legal deadlines that require the completion of certain projects included in the ARO cash flows within the next 12 months?

ASC 230-10-45-17 states that cash payments made to settle an ARO should be classified as operating activities.

**Accounting for AROs in a Business Combination**

ASC 805-20-30 states that an acquirer should measure identifiable assets acquired and liabilities assumed in a business combination at fair value. PP&E acquired in a business combination may be subject to legal obligations associated with its retirement. AROs should be recognized as of the acquisition date as a separate liability and measured at fair value. In the lower-interest-rate environment of recent years, this has often resulted in the acquiring entity’s recording a larger ARO balance than the acquired entity had reported.

Questions often arise about how to account for the associated ARC in PP&E. Companies should obtain an understanding of how the ARO was considered in the estimation of the fair value of PP&E. If the PP&E fair value measurement did not take into account the PP&E owner’s cash outflows related to the ARO, the PP&E fair value has effectively included an element for the ARC. If the fair value estimate took into account the cash outflows related to the ARO (and thus the plant value was effectively reduced from what the value would have been without the ARO), it would be appropriate to separately capitalize an ARC by increasing the carrying amount of the PP&E by the same amount as the liability.

The example below demonstrates how an entity would consider and account for the ARC in a business combination.

**Example**

Company A acquires a natural-gas-fired generating plant from Company B and assumes an ARO with a fair value of $50 million. The ARO arises from a contractual commitment to dismantle the plant and restore the land to a grassy field upon retirement. At closing, A pays B $1 billion.

Subsequently, A hires a valuation consultant, who concludes that the plant’s fair value on the acquisition date was $1 billion. The valuation is based on a discounted cash flow model that reflects cash outflows the year after plant retirement for dismantlement, disposal, landscaping, and so forth.

In this situation, A should record the following entries:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>PP&amp;E</td>
<td>1,000,000,000</td>
</tr>
<tr>
<td>PP&amp;E — ARC</td>
<td>50,000,000</td>
</tr>
<tr>
<td>ARO</td>
<td>50,000,000</td>
</tr>
<tr>
<td>Cash</td>
<td>1,000,000,000</td>
</tr>
</tbody>
</table>

As shown in the example above, it is important for companies to consider whether AROs have been factored into the calculation of the fair value of PP&E. If A had not done so, it might have inappropriately recorded the $50 million difference to goodwill or intangible assets.
Alternative Revenue Programs

Traditionally, rate-regulated utilities bill customers on the basis of approved rates and usage. In some jurisdictions, regulators have authorized the use of alternative revenue programs that allow rate-regulated utilities to bill customers certain incremental amounts associated with prior activities.

ASC 980-605-25-1 and 25-2 segregate the major alternative revenue programs into two categories, Type A and Type B. As ASC 980-605-25-2 explains:

- “Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the [rate-regulated] utility for demand-side management initiatives.” Examples include no-growth plans and similar conservation efforts.
- “Type B programs provide for additional billings (incentive awards) if the [rate-regulated] utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.”

ASC 980-605-25-3 states that “[b]oth types of programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events.” Accordingly, the key judgment is determining whether the adjustment to rates is for past activities or future activities.

ASC 980-605-25-4 identifies the following conditions that must be met for a rate-regulated utility to recognize additional revenue under an alternative revenue program once the specific events that permit billing of additional revenues under Type A and Type B programs have been completed:

a. The program is established by an order from the utility’s regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment to future rates by the regulator would not preclude the adjustment from being considered automatic.

b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.

c. The additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

These conditions are not to be used as guidelines; rather, they set a high hurdle for recognizing revenue under an alternative revenue program, and all of these conditions must be met.

This guidance is limited to rate-regulated utilities under ASC 980 and, as noted above, to situations in which future rates would be adjusted to provide additional revenue “in response to past activities or completed events.” It does not provide a basis, for example, for circumventing the limitation in ASC 980-340 on recording an ongoing equity carrying charge as revenue except in certain limited circumstances, such as a formula rate tariff that includes an equity return component.

Types of Alternative Revenue Programs

As discussed above, ASC 980-605-25-1 and 25-2 provide specific examples of alternative revenue programs, including programs that adjust billings for the effects of weather abnormalities or broad external factors as well as programs that compensate the utility for demand-side management initiatives (e.g., no-growth plans) or provide for additional billings if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service. These examples are programs that were popular at the time EITF Issue 92-7 was issued.

While these examples of Type A and Type B programs were specifically identified as programs that qualify as alternative revenue programs (assuming that the conditions in ASC 980-605-25-4 are met), we
do not believe that this guidance is restricted to those programs. Various ratemaking mechanisms have developed over time, and many are consistent with the philosophy underlying this literature.

Many programs exhibit characteristics that are similar to those in the examples in ASC 980-605-25. Careful analysis of each program’s purpose and details should be performed to determine whether it qualifies for alternative revenue program accounting. It may be helpful for an entity to think about these programs along a continuum that considers the qualitative characteristics of the programs in comparison with ratemaking mechanisms frequently encountered in the P&U industry. The following diagram illustrates such a continuum:

Programs that are in the middle of the continuum require a higher degree of professional judgment to determine whether they qualify as alternative revenue programs under ASC 980-605. For example, cost-based formula rate tariff structures with a true-up provision, such as those commonly seen at FERC transmission companies, often qualify as alternative revenue programs in accordance with ASC 980-605. In many of these scenarios, formula rates are established on the basis of forecasted capital expenditures and operating costs and include an ROE component. Billings to customers begin before actual expenditures and costs are known and are subject to an annual true-up mechanism. During the true-up process, amounts billed to customers under the estimated rates are compared with what could have been billed on the basis of actual costs, including an ROE. An automatic mechanism adjusts future rates for amounts that were over- or underbilled, typically in the following billing cycle.

Determining whether a program qualifies as an alternative revenue program in which revenue can be recorded currently depends on the specific facts and circumstances of each situation and requires judgment. Utilities are encouraged to consult with their independent auditor when such situations arise.
Considerations Related to 24-Month Collection Period

As discussed above, the condition in ASC 980-605-25-4(c) requires additional revenues to be collected within 24 months following the end of the annual period in which they are recognized (the “24-month collection period”). Sometimes, alternative revenue programs provide for collection over a period that begins before or during, or ends after, the 24-month collection period. In these instances, utilities must determine the appropriate accounting treatment for such collections.

One approach is to conclude that the additional revenues do not qualify for recognition under the alternative revenue program guidance because some of the additional revenues will not be collected within 24 months following the end of the annual period in which they were recognized. Under this approach, revenue is recognized when billed.

Another approach is to recognize the additional revenues for amounts that will be collected within 24 months following the end of the annual period in which they were recognized. For any remaining amounts, a utility could subsequently recognize revenue once the recognition criteria discussed above are met (i.e., when such amounts will be collected within 24 months of the end of the annual period).

Both of the approaches above are acceptable, and utilities should disclose their accounting policy related to this matter if material.

Accounting for Credit Balances

The guidance in ASC 980-605 does not address the accounting for credit balances (amounts due to customers) that may also result from alternative revenue programs. These credits should be recognized as liabilities because they are considered “refunds” of past revenues that are accounted for as (1) contingent liabilities that meet the conditions for accrual under ASC 450-20 or (2) regulatory liabilities in accordance with ASC 980-605-25-1.

Update on ASC 606

While ASC 606 supersedes much of the industry-specific revenue guidance in current U.S. GAAP, it retains the guidance in ASC 980-605 on rate-regulated operations when alternative revenue programs exist. P&U entities within the scope of ASC 980-605-15 will continue to recognize additional revenues allowable for alternative revenue programs if those programs meet the criteria in ASC 980-605-25-4.

In the statement of comprehensive income, ASC 606 requires that revenues arising from alternative revenue programs be presented separately from revenues arising from contracts with customers that are within the scope of ASC 606. Since ASC 606 does not explicitly address the accounting and financial statement presentation effects when revenues arising from alternative revenue programs are ultimately billed to customers, the AICPA’s Power and Utility Entities Revenue Recognition Task Force (the “Task Force”) raised a technical inquiry to the FASB about the appropriate approach to presentation. The FASB staff agreed with the Task Force’s view that there are two acceptable methods of presentation: (1) “recycling” the revenue associated with alternative revenue programs through ASC 606 revenue when billed to customers through the tariff or (2) treating the revenue as a balance sheet event, similar to accounting for a regulatory asset, with the incremental change recorded to the alternative revenue programs line item in the statement of comprehensive income for each financial reporting period. Regardless of the method selected, entities should choose an approach and apply it consistently, and they should consider disclosing that approach in the footnotes to the financial statements if it is determined to be material.
Section 4 — Accounting Standards Codification Update
This section provides details of significant accounting updates to U.S. GAAP resulting from FASB standard-setting activity and the issuance of accounting standards updates throughout the year. In addition, supplemental information is available on (1) the effective dates of final ASUs issued over the past few years and (2) the status of the various projects.

Financial Instruments

Classification and Measurement

Background

ASU 2016-01 amends the guidance on the classification and measurement of financial instruments. The amendments contain changes related to the following:

- Accounting for equity investments (apart from those that are accounted for under the equity method or those that are consolidated).
- Recognition of changes in fair value attributable to changes in instrument-specific credit risk for financial liabilities for which the fair value option has been elected.
- Determining the valuation allowance for deferred tax assets (DTAs) related to available-for-sale (AFS) debt securities.
- Disclosure requirements for financial assets and financial liabilities.

For PBEs, the new standard is effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, the standard is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. Early adoption of certain of the standard's provisions is permitted for all entities. Non-PBEs are permitted to adopt the standard in accordance with the effective date for PBEs. For more information about ASU 2016-01, see Deloitte's January 12, 2016, Heads Up.

Classification and Measurement of Equity Investments

The amendments will require entities to carry all investments in equity securities at fair value, with changes in fair value recorded through earnings, unless the equity investments are accounted for under the equity method or are consolidated. For equity investments that do not have a readily determinable fair value, the guidance will permit a measurement alternative under which the equity investments would be measured at cost less impairment, if any, plus or minus observable price changes in orderly transactions. This measurement alternative would not be available to reporting entities that are investment companies, broker-dealers, or postretirement benefit plans.

An entity that has elected the measurement alternative for equity investments that do not have a readily determinable fair value is required to assess whether the equity investment is impaired by qualitatively considering the indicators described in ASC 321-10-35-3. If, on the basis of the qualitative assessment, the equity investment is impaired, an entity would be required to record an impairment equal to the
amount by which the carrying value exceeds fair value. The entity should no longer evaluate whether such impairment is other than temporary.

**Connecting the Dots**

The requirement to classify and measure equity securities at fair value with changes recorded through earnings could significantly affect investors in bond and other debt funds. Although these funds invest in bonds or other debt securities, on the basis of existing guidance in ASC 320-10-50-4, investors in the bond funds are required to classify their investments as equity securities. Currently, such investments are often classified as AFS with changes in fair value recognized through OCI. Under the new guidance, however, investors will need to account for their investments in these bond funds at fair value with changes recorded through earnings (rather than recording the changes in fair value through OCI, which would be permitted only if the investor held the bond or debt securities in the fund directly).

**Changes in Fair Value of a Liability Attributed to Changes in Instrument-Specific Credit Risk**

For financial liabilities (excluding derivative instruments) for which the fair value option has been elected, the amendments will require an entity to separately recognize in OCI any changes in fair value associated with instrument-specific credit risk. The guidance indicates that the portion of the total change in fair value that exceeds the amount resulting from a change in a base market risk (such as a risk-free interest rate) may be attributable to instrument-specific credit risk, but also acknowledges that there may be other methods an entity may use to determine instrument-specific credit risk.

**Valuation Allowance on a DTA Related to an AFS Debt Security**

The new guidance eliminates the diversity in practice related to the evaluation of the need for a valuation allowance for DTAs associated with debt securities that are classified as AFS. Under current U.S. GAAP, entities may perform this evaluation either separately from their other DTAs or in combination with them. The new guidance clarifies that an entity should “evaluate the need for a valuation allowance on a [DTA] related to [AFS] securities in combination with the entity’s other [DTAs].”

**Changes to Disclosure Requirements**

For non-PBEs, the amendments eliminate the requirement to disclose the fair value of financial instruments measured at amortized cost. In addition, for such financial instruments, PBEs are not required to disclose (1) the information related to the methods and significant assumptions used to estimate fair value or (2) a description of the changes in the methods and significant assumptions used to estimate fair value. The guidance also clarifies U.S. GAAP by eliminating the provisions in ASC 825 that had been interpreted to permit an “entry” price notion for estimating the fair value of loans for disclosure purposes. The amendments require a PBE to disclose the fair value in accordance with the exit price notion in ASC 820. In addition, all entities are required to separately present in the statement of financial position or separately disclose in the notes to the financial statements all financial assets and financial liabilities grouped by (1) measurement category (i.e., amortized cost or fair value — net income or OCI) and (2) form of financial asset (i.e., securities and loans/receivables).

**Amendments**

In March 2018, the FASB issued ASU 2018-03 on technical corrections and improvements to ASU 2016-01 in response to feedback from stakeholders.
The amendments that clarify certain aspects of ASU 2016-01 are as follows:

- **Equity securities without readily determinable fair values** — The amendment clarifies that an entity measuring an equity security by using the measurement alternative may change its measurement approach to a fair value method in accordance with ASC 820 through an irrevocable election that would apply to that security and all identical or similar investments of the same issuer. Once the entity makes this election, it should measure all future purchases of identical or similar investments of the same issuer by using a fair value method in accordance with ASC 820.

  In addition, the amendment clarifies that the adjustments made under the measurement alternative are intended to reflect the fair value of the security as of the date that the observable transaction for a similar security took place.

- **Forward contracts and purchased options** — The amendment clarifies that remeasuring the entire value of forward contracts and purchased options is required when observable transactions occur on the underlying equity securities.

- **Presentation requirements for certain liabilities measured under the fair value option** — The amendments clarify that the guidance in ASC 825-10-45-5 (added by ASU 2016-01) related to the disclosure of instrument-specific risk (see the Changes in Fair Value of a Liability Attributed to Changes in Instrument-Specific Credit Risk section above) should be applied if the fair value option was elected under either ASC 815-15 or ASC 825-10.

- **Election of fair value option to measure liabilities denominated in a foreign currency** — The amendments clarify that for financial liabilities for which the fair value option is elected, the amount of change in fair value that relates to the instrument-specific credit risk should first be measured in the currency of denomination when presented separately from the total change in fair value of the financial liability. Then, both components of the change in the fair value of the liability should be remeasured into the functional currency of the reporting entity by using end-of-period spot rates.

- **Transition guidance for equity securities without readily determinable fair values** — The amendment clarifies that the prospective transition approach for equity securities without a readily determinable fair value in the amendments in ASU 2016-01 is meant only for instances in which the measurement alternative is applied. An insurance entity subject to the guidance in ASC 944 should apply a prospective transition method when applying the amendments related to equity securities without readily determinable fair values. The insurance entity should apply the selected prospective transition method consistently to the entity's entire population of equity securities for which the measurement alternative is elected.

**Receivables — Nonrefundable Fees and Other Costs**

**Background and Key Provisions of ASU 2017-08**

In March 2017, the FASB issued **ASU 2017-08**, which amends the amortization period for certain purchased callable debt securities held at a premium, shortening such period to the earliest call date.

Under the current guidance in ASC 310-20, entities generally amortize the premium on a callable debt security as an adjustment of yield over the contractual life (to maturity date) of the instrument. Accordingly, entities do not consider early payment of principal, and any unamortized premium is recorded as a loss in earnings upon the debtor’s exercise of a call on a purchased callable debt security held at a premium.
The amendments will require entities to amortize the premium on certain purchased callable debt securities to the earliest call date regardless of how the premium is generated (e.g., deferred acquisition costs and cumulative fair value hedge adjustments that increase the amortized cost basis of a callable security above par value). Therefore, entities will no longer recognize a loss in earnings upon the debtor’s exercise of a call on a purchased callable debt security held at a premium.

**Connecting the Dots**

Under the ASU, if an entity amortizes a premium to a call price greater than the par value of the debt security (e.g., because the debt security is callable at a premium to par on the earliest call date) and the debt security is not called on the earliest call date, the entity should reset the yield by using the payment terms of the debt security. If the security contains additional future call dates, the entity should consider whether the amortized cost basis exceeds the amount repayable by the issuer on the next call date. If the entity determines that the amortized cost basis does exceed the amount repayable, it should amortize the excess to the next call date.

**Scope**

Purchased callable debt securities within the scope of ASU 2017-08 are those that contain explicit, noncontingent call features that are exercisable at fixed prices and on preset dates. Because the ASU does not affect an entity's ability to elect to estimate prepayments under ASC 310-20-35-26, the amended guidance will not affect an entity that (1) applies ASC 310-20-35-26 to purchased callable debt securities and (2) estimates prepayments under the interest method.

Further, the ASU does not apply to any of the following:

- Loans and other financing receivables that do not meet the definition of a debt security.
- Purchased debt securities held at a discount; the discount continues to be amortized as an adjustment of yield over the contractual life (to maturity) of the instrument.
- Purchased debt securities held at a premium and for which the call date or call price is not known in advance, including debt securities with a prepayment feature whose prepayment date is not preset (i.e., immediately prepayable instruments). As a result, the following purchased debt securities held at a premium are not within the ASU’s scope:
  - Debt securities callable at fair value.
  - Debt securities callable at an amount that includes a make-whole provision that is based on the present value of future interest payments.
  - Asset-backed debt securities, including mortgage-backed securities, in which early repayment is based on the prepayment of the assets underlying the securitization as opposed to the issuer’s decision to prepay the debt security itself.
- Purchased debt securities held at a premium that are contingently callable.

**Effective Date and Transition**

For PBEs, the new standard is effective for fiscal years beginning after December 15, 2018, including interim periods therein. For all other entities, the standard is effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020.Earlier application is permitted for all entities, including adoption in an interim period. If an entity early adopts the ASU in an interim period, any adjustments must be reflected as of the beginning of the fiscal year that includes that interim period.
To apply the ASU, entities must use a modified retrospective approach and recognize the cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. Entities are also required to provide disclosures about a change in accounting principle in the period of adoption.

**Impairment**

**Background**

In June 2016, the FASB issued ASU 2016-13, which amends the Board's guidance on the impairment of financial instruments by adding to U.S. GAAP an impairment model (known as the current expected credit loss (CECL) model) that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes its estimate of expected credit losses as an allowance, which is presented as either (1) an offset to the amortized cost basis of the related asset (for on-balance-sheet exposures) or (2) a separate liability (for off-balance-sheet exposures). That is, the expected credit losses estimated over the lifetime of a financial instrument are recognized at inception (i.e., on day 1).

**Transition Resource Group**

In late 2015, the FASB established a credit losses transition resource group (TRG). Like the TRG established to discuss the new revenue recognition standard, the credit losses TRG does not issue guidance but provides feedback to the FASB on potential implementation issues. By analyzing and discussing such issues, the credit losses TRG helps the FASB determine whether it needs to take further action (e.g., by providing clarification or issuing additional guidance).

The credit losses TRG discussed the following topics related to ASU 2016-13 at its June 2017 and June 2018 meetings:

- Determining the effective interest rate under the CECL model.
- Scope of purchased financial assets with credit deterioration guidance for beneficial interests accounted for under ASC 325-40.
- Applying the transition guidance to pools of purchased credit-impaired assets under ASC 310-30.
- Accounting for troubled debt restructurings under the CECL model.
- Estimating the life of a credit card receivable under the CECL model.
- Consideration of capitalized interest by using a method other than a discounted cash flow method under the CECL model.
- Definition of “amortized cost basis” and the reversal of accrued interest on nonperforming financial assets.
- Transfer of loans from held for sale to held for investment and transfer of credit-impaired debt securities from available for sale to held to maturity.
- Accounting for recoveries under the CECL model.
- Refinancing and loan prepayments.

For more information, see TRG Memos 6 and 6B as well as Deloitte's June 23, 2017, and June 18, 2018, TRG Snapshot newsletters.

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Next Steps
The FASB staff acknowledges that certain of its recommendations may require amendments to the Codification. The staff's plan is to begin addressing such changes during the third quarter of 2018.

Ongoing Discussions
Industry groups, accounting firms, standard setters, and regulators are engaged in ongoing discussions of issues related to the ASU's implementation, including, but not limited to, (1) accounting for financial instruments when zero expected credit losses would be acceptable, (2) determining appropriate historical loss information for the loss reversion period (i.e., after the “reasonable and supportable” period), (3) accounting for recoveries from freestanding insurance contracts, and (4) consideration of subsequent events in the estimation of credit losses. We will continue to monitor the progress of these discussions and provide updates as appropriate.

Hedging

Background
In August 2017, the FASB issued ASU 2017-12, which amends the hedge accounting recognition and presentation requirements in ASC 815. The Board's objectives in issuing the ASU were to (1) improve the transparency and understandability of information conveyed to financial statement users about an entity's risk management activities by better aligning the entity's financial reporting for hedging relationships with those risk management activities and (2) reduce the complexity, and simplify the application, of hedge accounting by preparers.

For PBEs, the ASU is effective for fiscal years beginning after December 15, 2018, and interim periods therein. For all other entities, the ASU is effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020.

Entities are permitted to early adopt the new guidance in any interim or annual period after the ASU's issuance. An entity that early adopts the updated guidance in an interim period should record any transition adjustments as of the beginning of the fiscal year that includes that interim period.


Key Changes to the Hedge Accounting Model
The ASU makes a number of improvements to the hedge accounting model, including those outlined below.

Elimination of the Concept of Separately Recognizing Periodic Hedge Ineffectiveness
ASU 2017-12 eliminates the concept of separately recognizing periodic hedge ineffectiveness for cash flow and net investment hedges (however, under the mechanics of fair value hedging, economic ineffectiveness will still be reflected in current earnings for those hedges). The Board believes that requiring an entity to record the impact of both the effective and ineffective components of a hedging relationship in the same financial reporting period and in the same income statement line item will make that entity's risk management activities and their effect on the financial statements more transparent to financial statement users.

Note that it is possible that changes in the fair value of the hedging instrument may be presented in more than one income statement line item if the changes in the value of the hedged item affect more than one income statement line item.
Under this rationale, even a portion of the change in a hedging instrument’s fair value that is excluded from a hedging relationship’s effectiveness assessment is considered part of the hedging relationship and should be recognized in the same income statement line item as the earnings effect of the hedged item (other than amounts excluded from the assessment of effectiveness of net investment hedges).

However, in a departure from the proposed ASU that formed the basis for the guidance in ASU 2017-12, the Board determined that presentation should not be prescribed for “missed forecasts” in cash flow hedges. Thus, an entity that ultimately determines that it is probable that a hedged forecasted transaction will not occur will not be required to record the amounts reclassified out of accumulated other comprehensive income (AOCI) for that hedging relationship into earnings in the same income statement line item that would have been affected by the forecasted transaction.

**Components Excluded From the Hedge Effectiveness Assessment**

ASU 2017-12 continues to allow an entity to exclude the time value of options, or portions thereof, and forward points from the assessment of hedge effectiveness. The ASU also permits an entity to exclude the portion of the change in the fair value of a currency swap attributable to a cross-currency basis spread from the assessment of hedge effectiveness.

For excluded components in fair value, cash flow, and net investment hedges, the base recognition model under the ASU is an amortization approach. An entity still may elect to record changes in the fair value of the excluded component currently in earnings; however, such an election will need to be applied consistently to similar hedges.

Under the ASU’s amortization approach, an entity recognizes the initial value of the component that was excluded from the assessment of hedge effectiveness as an adjustment to earnings over the life of the hedging instrument by using a “systematic and rational method.” In each accounting period, the entity recognizes in OCI (or, for net investment hedges, the currency translation adjustment (CTA) portion of OCI) any difference between (1) the change in fair value of the excluded component and (2) the amount recognized in earnings under that systematic and rational method.
## Changes in the Fair Value of the Hedging Instrument and the Hedged Item

The following table summarizes the recognition and presentation requirements for the hedging instrument and the related hedged item under the updated hedge accounting and presentation model in ASU 2017-12:

<table>
<thead>
<tr>
<th>Component of Hedging Instrument Included in the Assessment of Hedge Effectiveness</th>
<th>Component of Hedging Instrument Excluded From the Assessment of Hedge Effectiveness</th>
<th>Hedged Item</th>
</tr>
</thead>
<tbody>
<tr>
<td>Where Fair Value Changes Are Initially Recorded</td>
<td>When Hedged Item Affects Earnings</td>
<td>Systematic and Rational Amortization Method</td>
</tr>
</tbody>
</table>

| Fair value hedge |
|---|---|---|---|
| Recognition | Income statement | N/A | Amortization of initial value — income statement |
|  |  |  | Record in OCI any difference between the change in fair value of the excluded component and amounts recognized in earnings under the systematic and rational method |
|  |  |  | Income statement |
| Presentation | Same income statement line item as the earnings effect of the hedged item | N/A | Same income statement line item as the earnings effect of the hedged item |
|  |  |  | Same income statement line item as the earnings effect of the hedged item |

The entire change in fair value of the hedged item attributable to the hedged risk is recorded currently in income/loss and as an adjustment to the carrying amount of the hedged item.
<table>
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<tr>
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<td>Systematic and Rational Amortization Method</td>
</tr>
<tr>
<td>Cash flow hedge</td>
<td>Income statement</td>
<td>Amortization of initial value — income statement</td>
</tr>
<tr>
<td>Recognition</td>
<td>OCI</td>
<td>Record in OCI any difference between the change in fair value of the excluded component and amounts recognized in earnings under the systematic and rational method</td>
</tr>
<tr>
<td>Presentation</td>
<td>OCI/AOCI (balance sheet)</td>
<td>Same income statement line item as the earnings effect of the hedged item (income statement presentation not prescribed for missed forecasts)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Same income statement line item as the earnings effect of the hedged item</td>
</tr>
<tr>
<td></td>
<td></td>
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</tr>
</tbody>
</table>
(Table continued)

<table>
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<td><strong>When Hedged Item Affects Earnings</strong></td>
<td><strong>Systematic and Rational Amortization Method</strong></td>
</tr>
</tbody>
</table>

### Net investment hedge

**Recognition**
- **OCI (CTA)**: Income statement
- **Amortization of initial value — income statement**
- **Record in OCI (CTA) any difference between the change in fair value of the excluded component and amounts recognized in earnings under the systematic and rational method**

**Presentation**
- **OCI/AOCI (CTA)**: Same income statement line item as the earnings effect of the hedged item (e.g., gain or loss on sale of investment)
- **Income statement presentation not prescribed**

When the hedged net investment affects earnings (i.e., upon a sale or liquidation), amounts will be reclassified out of the CTA and be presented in the same income statement line item in which the earnings effect of the net investment is presented (e.g., gain or loss on sale of investment).

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**Hedge Effectiveness Assessments and Documentation Requirements — Quantitative Versus Qualitative Assessments of Hedge Effectiveness**

ASU 2017-12 requires an entity to perform an initial prospective quantitative hedge effectiveness assessment (by using either a dollar-offset test or a statistical method such as regression) unless the hedging relationship qualifies for application of one of the expedients that permits an assumption of perfect hedge effectiveness (e.g., the shortcut method or critical-terms-match method). An entity may complete this initial prospective quantitative assessment after hedge designation, generally until the first quarterly hedge effectiveness assessment date, by using information available at hedge inception.

Further, if (1) an entity’s initial prospective quantitative hedge effectiveness assessment of a hedging relationship demonstrates that there is a highly effective offset and (2) the entity can, at hedge inception, “reasonably support an expectation of high effectiveness on a qualitative basis in subsequent periods,” the entity may elect to perform subsequent retrospective and prospective effectiveness assessments qualitatively. To do so, in the hedge documentation it prepares at hedge inception, the entity must
(1) specify how it will perform the qualitative assessments and (2) document the alternative quantitative assessment method that it would use if it later concludes, on the basis of a change in the hedging relationship's facts and circumstances, that subsequent quantitative assessments will be necessary. The entity may make this election on a hedge-by-hedge basis.

After an entity makes its initial election to perform qualitative assessments, it must “verify and document whenever financial statements or earnings are reported and at least every three months that the facts and circumstances related to the hedging relationship” continue to support the entity’s ability to make qualitative assessments. If the entity determines that there no longer is a sufficient basis to support continued qualitative assessments, it must subsequently assess effectiveness quantitatively by using the method that it specified in the initial hedge documentation. In future reporting periods, the entity could return to making qualitative assessments if it can support them on the basis of the same factors it had used in its original qualitative assessments.

**Shortcut Method and Critical-Terms-Match Method**

ASU 2017-12 retains both the shortcut method and critical-terms-match method and provides additional relief for entities applying those methods. Under the ASU, an entity that determines that a hedging relationship no longer meets the shortcut criteria can subsequently account for the hedging relationship by using a long-haul method (and avoid having to redesignate the original hedging relationship) if the entity can show both of the following:

a. [It] documented at hedge inception . . . which quantitative method it would use to assess hedge effectiveness and measure hedge results if the shortcut method was not or no longer is appropriate during the life of the hedging relationship.

b. The hedging relationship was highly effective on a prospective and retrospective basis in achieving offsetting changes in fair value or cash flows attributable to the hedged risk for the periods in which the shortcut method criteria were not met.

If criterion (a) is not satisfied, the hedging relationship would be invalid in the period in which the shortcut method criteria were not satisfied and all subsequent periods; otherwise (if criterion (a) is met), the hedging relationship would be invalid in all periods in which criterion (b) was not satisfied.

In addition, ASU 2017-12 updates certain shortcut-method criteria to allow partial-term fair value hedges of interest rate risk to qualify for the shortcut method.

ASU 2017-12 also expands an entity’s ability to apply the critical-terms-match method to cash flow hedges of groups of forecasted transactions. If all other critical-terms-match criteria are satisfied, such hedges will qualify for the critical-terms-match method “if those forecasted transactions occur and the derivative matures within the same 31-day period or fiscal month.”

**Hedges of Interest Rate Risk**

ASU 2017-12 eliminates the benchmark interest rate concept for variable-rate financial instruments but retains it for fixed-rate financial instruments. For recognized variable-rate financial instruments and forecasted issuances or purchases of variable-rate financial instruments, the ASU defines interest rate risk as “the risk of changes in the hedged item’s cash flows attributable to changes in the contractually specified interest rate in the agreement.” Thus, for example, in a hedge of the interest rate risk associated with variable debt indexed to a specified prime rate index, an entity could hedge the variability in cash flows attributable to changes in the contractually specified prime rate index. Fair value hedges of interest rate risk would continue to hedge the changes in fair value associated with changes in a specified benchmark interest rate. The ASU also adds the SIFMA Municipal Swap Rate to the list of permissible U.S. benchmark interest rates.
Other Targeted Improvements to Fair Value Hedges of Interest Rate Risk

ASU 2017-12 makes a number of improvements that simplify the accounting for fair value hedges of interest rate risk and make that accounting better reflect an entity's risk management activities.

Measuring Changes in the Hedged Item's Fair Value by Using Benchmark Component Cash Flows

Before the ASU, an entity had to use the total contractual coupon cash flows to determine the change in fair value of the hedged item attributable to changes in the benchmark interest rate. However, ASU 2017-12 allows an entity to calculate the change in fair value of the hedged item in a fair value hedge of interest rate risk by using either (1) the full contractual coupon cash flows or (2) the cash flows associated with the benchmark interest rate component determined at hedge inception.

An entity's ability to use only the benchmark component cash flows for measurement allows the entity to reduce the net earnings effect of its hedge accounting by eliminating recognition of any economic ineffectiveness related to credit spreads.

Measuring the Fair Value of a Prepayable Instrument

For prepayable instruments such as callable debt, ASU 2017-12 states that an entity “may consider only how changes in the benchmark interest rate affect the decision to settle the hedged item before its scheduled maturity” when it calculates the change in the fair value of the hedged item attributable to interest rate risk. That is, when adjusting the carrying amount of the hedged item, an entity would consider the same factors that it considered when assessing hedge effectiveness. Before the ASU, practice had evolved to require an entity to consider all factors that might lead an obligor to settle the hedged item before its scheduled maturity (e.g., changes in interest rates, credit spreads, or other factors) even if the entity had designated only interest rate risk as the risk being hedged. The ASU allows an entity to ignore factors other than changes in the benchmark interest rate that could affect the settlement decision when it assesses hedge effectiveness and makes it easier for the hedging relationship to meet the “highly effective” threshold.

For example, when an entity (1) assesses hedge effectiveness in a fair value hedge of interest rate risk of callable debt and (2) measures the change in the fair value of callable debt attributable to changes in the benchmark interest rate, it can now consider only how changes in the benchmark interest rate (and not changes in credit risk or other factors) would affect the obligor's decision to call the debt.

After the issuance of ASU 2017-12, the FASB staff received technical inquiries on the intended scope of the guidance for prepayable instruments. At a February 14, 2018, FASB meeting, the Board agreed with the FASB staff's interpretations that the guidance that links to the definition of “prepayable” should cover a broad scope of instruments:

- Financial instruments that meet the definition of prepayable include the following:
  a. Instruments that are currently exercisable and prepayable at any time
  b. Instruments with certain contingent prepayment features (that is, based on the passage of time, the occurrence of a specified event other than the passage of time, and the movement in a specified interest rate)
  c. Instruments with conversion features.

However, instruments for which contractual maturity can be accelerated due to credit would not meet the definition of prepayable.
In addition, an entity should consistently apply the analysis of whether an instrument is prepayable to “(a) the designation and measurement guidance for hedges of interest rate risk in paragraphs 815-20-25-6B and 815-25-25-13A, (b) the eligibility for the last-of-layer method for prepayable financial assets in accordance with paragraph 815-20-25-12A, and (c) the ability to apply the transition guidance in paragraph 815-20-65-3(e)(7) that permits an entity to transfer held-to-maturity debt securities to the available-for-sale category upon adoption.”

**Partial-Term Hedges of Interest Rate Risk**

ASU 2017-12 also provides relief to entities that wish to enter into fair value hedges of interest rate risk for only a portion of the term of the hedged financial instrument. Successful hedging of such partial-term exposures was typically unachievable under preadoption guidance because it was difficult to find a hedging derivative that would be highly effective at offsetting changes in the fair value of the hedged exposure as a result of the difference in timing between the hedged item’s principal repayment and the maturity date of the hedging derivative.

Under the ASU, an entity may measure the change in the fair value of the hedged item attributable to changes in the benchmark interest rate by “using an assumed term that begins when the first hedged cash flow begins to accrue and ends when the last hedged cash flow is due and payable.” Also, the hedged item’s assumed maturity will be the date on which the last hedged cash flow is due and payable; therefore, a principal payment will be assumed to occur at the end of the specified partial term.

After the issuance of ASU 2017-12, the FASB staff received technical inquiries on whether it is permissible to have multiple partial-term fair value hedges of interest rate risk in a single financial instrument. At a March 28, 2018, FASB meeting, the Board agreed with the FASB staff’s interpretation that the partial-term fair value guidance should apply to “simultaneous multiple partial-term hedging relationships for a single debt instrument (for example, consecutive interest cash flows in Years 1–3 and consecutive interest cash flows in Years 5–7 of a 10-year bond).” However, the FASB staff cautioned that “this conclusion should not be analogized to the last-of-layer method until further research is conducted” for a multiple-layer hedging strategy under the last-of-layer method (see discussion below).

**Last-of-Layer Method**

To address constituent feedback received on the hedge accounting improvements project after the initial proposal, the FASB added to ASU 2017-12 a last-of-layer method that enables an entity to apply fair value hedging to closed portfolios of prepayable assets without having to consider prepayment risk or credit risk when measuring those assets. An entity can also apply the method to one or more beneficial interests (e.g., a mortgage-backed security) secured by a portfolio of prepayable financial instruments.

Under the last-of-layer method, an entity would designate as the hedged item in a fair value hedge of interest rate risk a stated amount of the asset or assets that the entity does not expect “to be affected by prepayments, defaults, and other factors affecting the timing and amount of cash flows” (the “last of layer”). This designation would occur in conjunction with the partial-term hedging election discussed above.

To support the designation, the entity would include in the initial hedge documentation evidence that the entity performed an analysis that supported its expectation that the hedged item (i.e., the last of layer) would be outstanding as of the assumed maturity date of the hedged item that was documented in the partial-term hedge election. That analysis should reflect the entity’s current expectations about factors that can affect the timing and amount of the closed portfolio’s (or, for beneficial interests, the underlying assets’) cash flows (e.g., prepayments and defaults); however, the ASU allows the entity to
assume that the effects of any events that occur, such as prepayments or defaults, would first apply to the portion of the closed portfolio or beneficial interests that is not part of the hedged item (last-of-layer) designation.

On each subsequent hedge effectiveness assessment date, the entity must continue to prepare and document its analysis supporting the expectation that the hedged item (i.e., the last of layer) will be outstanding on the assumed maturity date. The updated analysis should reflect the entity’s current expectations about the level of prepayments, defaults, or other factors that could affect the timing and amount of cash flows, and it should use the same methods as those used at hedge inception. Also, on each reporting date, the entity will adjust the basis of the hedged item for the gain or loss on the hedged item attributable to changes in the hedged risk (i.e., interest rate risk), as it would do for any other fair value hedge.

**Connecting the Dots**

When an entity considers how it will allocate the basis adjustments that result from hedge accounting by using the last-of-layer method, it should factor in possible interactions with the application of other accounting requirements. For example, adjustments to the carrying value of the assets in the closed portfolio that are being hedged under the last-of-layer method might affect multiple pools of financial assets for which credit losses will be estimated on a collective basis. The identification of such pools may become an even more significant issue when an entity adopts ASU 2016-13.

An entity that concludes on any hedge effectiveness assessment date that it no longer expects the entire hedged last of layer to be outstanding on its assumed maturity date must, at a minimum, discontinue hedge accounting for that portion of the hedged last of layer that is not expected to be outstanding. Moreover, the entity must discontinue the entire hedging relationship on any assessment date on which it determines that the hedged last of layer currently exceeds the outstanding balance of the closed portfolio of prepayable assets or one or more beneficial interests in prepayable assets. A full or partial hedge discontinuation will also trigger the need for the entity to allocate, in a systematic and rational manner, the outstanding basis adjustment (or portion thereof) that resulted from the previous hedge accounting to the individual assets in the closed portfolio. Such allocated amounts must be amortized over a period “that is consistent with the amortization of other discounts or premiums associated with the respective assets” under U.S. GAAP. The last-of-layer method does not, however, incorporate a tainting threshold; therefore, an entity that is required to discontinue a last-of-layer hedging relationship is not precluded from designating similar hedging relationships in the future.

After the issuance of ASU 2017-12, the FASB staff received multiple inquiries related to the application of the last-of-layer method. At a March 28, 2018, FASB meeting, the Board agreed with the FASB staff’s recommendations to:

- Add a narrow-scope project to the Board’s agenda to address accounting for last-of-layer basis adjustments and hedging multiple layers under the last-of-layer method. In their discussion, Board members noted that ASU 2017-12 did not contemplate last-of-layer hedging strategies that involved multiple layers.
- Exclude from the narrow-scope project any consideration of expanding the scope of the last of layer to include prepayable liabilities or nonprepayable financial assets.

**Ability to Designate Components of Nonfinancial Assets as Hedged Items**

Under U.S. GAAP before the ASU’s adoption, when an entity desired to cash flow hedge a risk exposure associated with a nonfinancial asset, it could designate as the hedged risk only the risk of changes
in cash flows attributable to (1) all changes in the purchase or sales price or (2) changes in foreign exchange rates. Alternatively, for cash flow hedges of financial instruments, an entity could designate as the hedged risk either the risk of overall changes in cash flows or one or more discrete risks.

ASU 2017-12 enables an entity to designate the “risk of variability in cash flows attributable to changes in a contractually specified component” as the hedged risk in a hedge of a forecasted purchase or sale of a nonfinancial asset. The ASU defines a contractually specified component as an “index or price explicitly referenced in an agreement to purchase or sell a nonfinancial asset other than an index or price calculated or measured solely by reference to an entity’s own operations.” The Board believes that enabling an entity to component hedge purchases or sales of nonfinancial assets better reflects its risk management activities in its financial reporting and will allow the entity to more easily hedge cash flow variability associated with commodities received from multiple suppliers or delivered to multiple locations. The ASU also creates greater symmetry in the hedging models for financial and nonfinancial items by allowing an entity to hedge components of the total change in cash flows for both types of items when certain criteria are satisfied.

Connecting the Dots

In the ASU, the Board declined to provide additional guidance on the nature and form of contracts that could contain a contractually specified component; however, ASC 815-20-55-26A states that the “definition of a contractually specified component is considered to be met if the component is explicitly referenced in agreements that support the price at which a nonfinancial asset will be purchased or sold.”

The ASU may have an impact on the hedging of basis risk within the natural gas industry. For example, for contracts for natural gas, location basis differences can be excluded from the assessment of hedge effectiveness when an entity designates a contractually specified component as the hedged item in the hedging relationship. Thus, if the relevant criteria for hedging a contractually specified component are met (e.g., the price of the natural gas purchase being hedged is contractually specified as the quoted NYMEX Henry Hub price of natural gas plus a specified location differential), a NYMEX natural gas futures contract (which assumes delivery at Henry Hub) could be used to hedge only the contractually specified Henry Hub component of the price of the forecasted natural gas physical purchase (thereby excluding the specified location differential from the hedge effectiveness assessment).

An entity’s determination of whether it may designate as the hedged risk the variability in cash flows attributable to changes in a contractually specified component for the purchase or sale of a nonfinancial asset depends on the nature of the contract, as follows:

• If the contract is a derivative in its entirety and the entity applies the normal purchases and normal sales scope exception, the entity may designate any contractually specified component in the contract as the hedged risk (failure to apply the normal purchases and normal sales scope exception precludes designation of any contractually specified component).

• If the contract is not a derivative in its entirety, the entity may designate any remaining contractually specified component in the host contract (i.e., after bifurcation of any embedded derivatives) as the hedged risk.

At a March 28, 2018, FASB meeting, the FASB staff shared the following interpretations of how to apply the contractually specified component hedging model:

• A hedging relationship must meet the criteria in ASC 815-20-25-22A and 25-22B to qualify for the contractually specified component hedging model.
When the contractually specified component is explicitly referenced in supporting documents or sub-agreements (and not in the contract itself), the hedging relationship still must meet the requirement in ASC 815-20-25-22A.

An entity must analyze a not-yet-existing contract both (1) at hedge inception to determine whether it will meet the criteria in ASC 815-20-25-22A and (2) at the contract execution date to ensure the criteria were met.

The FASB staff acknowledged that an entity will need to exercise judgment to satisfy this requirement, for example, when it assesses whether a supporting document or not-yet-existing contract or receipts in spot market transactions (1) would qualify for the normal purchases and normal sales scope exception or (2) will contain embedded derivatives that would need to be excluded from the analysis. However, the staff expects that practice will evolve and entities will be able to develop methods for making such assessments. The staff indicated that one acceptable approach might be to use a hypothetical contract to assess whether the criteria would be satisfied.

The FASB staff noted that in contractually specified component hedging relationships, when “an entity does not have a contract at hedge inception, it must develop an expectation . . . that when the transaction is entered into:

i. The written agreement for a forecasted purchase or sale will contain an explicitly referenced contractually specified component.

ii. The pricing formula that references the explicitly referenced contractually specified component will determine the price of the nonfinancial item.

iii. The requirements for cash flow hedge accounting will be met.

iv. The agreement will be substantive.”

The FASB staff also noted that, at hedge inception, an entity will need to exercise some level of judgment to develop its expectations about the contracts and transactions, and that it will be easier for the entity to develop such expectations if it has previous experience with the type of transaction that is anticipated.

In addition, the FASB staff recommended monitoring implementation issues related to the contractually specified component hedging model through the creation of a project resource group composed of a cross-section of stakeholders.

The Board agreed with the FASB staff's conclusions and supported the formation of a project resource group to monitor implementation issues related to the contractually specified component hedging model and other topics if needed.

In addition, the ASU permits an entity to designate a hedge of a contractually specified component (1) for a period that extends beyond the contractual term or (2) when a contract does not yet exist to sell or purchase the nonfinancial asset if the criteria specified above will be met in a future contract and all the other cash flow hedging requirements are met. When the entity executes the contract, it will reassess the criteria specified above to determine whether the contractually specified component continues to qualify for designation as the hedged risk. If, at the time the contract is executed, there is a change in the contractually specified component (e.g., the hedge documentation specified a commodity grade different from that in the executed contract), the entity will not be required to automatically dedesignate the hedging relationship; however, the entity must demonstrate that the hedging relationship continues to be highly effective at achieving offsetting cash flows attributable to the revised hedged risk to justify continuation of hedge accounting.
Connecting the Dots

The ASU's amendments do not limit this guidance on changes in the designated hedged risk to hedges of nonfinancial items. Therefore, for example, an entity also would be permitted to continue applying hedge accounting to a cash flow hedge of a financial item if (1) the designated hedged risk changes during the life of the hedging relationship (e.g., if the interest rate index referenced in the final transaction differs from that specified in the hedge documentation for the forecasted transaction) and (2) the entity can conclude that the hedging instrument is still highly effective at achieving offsetting cash flows attributable to the revised hedged risk.

At the March 28, 2018, FASB meeting, the FASB staff responded to various technical inquiries received on changes in the hedged risk. At the meeting, the FASB staff recommended the following clarifications (i.e., potential Codification improvements) in the guidance on changes in the hedged risk:

- “The hedged forecasted transaction and hedged risk are distinct.”
- An entity may continue to apply hedge accounting when the hedged risk changes if the revised hedging relationship remains highly effective, even if the original hedge documentation did not distinguish between the hedged risk and the hedged forecasted transaction.
- “The hedged forecasted transaction may not be documented so broadly such that if a change in hedged risk occurs, it does not share the same risk exposure as the originally designated hedged forecasted transaction.”
- When the hedging relationship is no longer highly effective as a result of a change in the hedged risk, an entity must cease hedge accounting. Any amounts associated with the hedge will remain in AOCI until the hedged forecasted transaction affects earnings unless it becomes probable that the forecasted transaction will not occur.
- “Hindsight may be applied in identifying transactions as hedged transactions. However, an entity must first identify transactions as hedged transactions based on the originally documented hedged risk. Only when there are no transactions or insufficient transactions based on the originally documented hedged risk may the entity consider transactions based on other risks. If a transaction occurred in a prior reporting period, it may be retrospectively identified as a hedged transaction if it has not yet affected reported earnings.”

The Board directed the FASB staff to solicit external review feedback on these proposed improvements.

Disclosure Requirements

ASU 2017-12 updates certain illustrative disclosure examples in ASC 815. Also, to align the disclosure requirements with the updates to the hedge accounting model, the ASU removes the requirement for entities to disclose amounts of hedge ineffectiveness. In addition, an entity must now provide tabular disclosures about:

- Both (1) the total amounts reported in the statement of financial performance for each income and expense line item that is affected by fair value or cash flow hedging and (2) the effects of hedging on those line items.
- The carrying amounts and cumulative basis adjustments of items designated and qualifying as hedged items in fair value hedges. As part of such disclosures, an entity also must provide details about hedging relationships designated under the last-of-layer method, including (1) the closed portfolio's (beneficial interest's) amortized cost basis, (2) the designated last-of-layer amounts, and (3) the related basis adjustment for the last of layer.
These disclosures are required for every annual and interim reporting period for which a statement of financial position and statement of financial performance are presented.

**Transition**

Entities will adopt the ASU's provisions by applying a modified retrospective approach to existing hedging relationships as of the adoption date. Under this approach, entities with cash flow or net investment hedges will make (1) a cumulative-effect adjustment to AOCI so that the adjusted amount represents the cumulative change in the hedging instruments' fair value since hedge inception (less any amounts that should have been recognized in earnings under the new accounting model) and (2) a corresponding adjustment to opening retained earnings as of the most recent period presented on the date of adoption.

In all interim periods and fiscal years ending after the date of adoption, entities should prospectively (1) present the entire change in the fair value of a hedging instrument in the same income statement line item(s) as the earnings effect of the hedged item when that hedged item affects earnings (other than amounts excluded from the assessment of net investment hedge effectiveness, for which the ASU does not prescribe presentation) and provide the amended disclosures required by the new guidance.

In addition, the ASU allows entities to make certain one-time transition elections. See Deloitte’s August 30, 2017, *Heads Up* for a detailed discussion of the one-time transition elections provided by ASU 2017-12 and the deadlines for making such elections.

**Connecting the Dots**

An entity that is considering early adoption of the ASU's provisions should ensure that it has appropriate financial reporting internal controls in place to ensure compliance with the ASU's accounting and disclosure requirements. The entity also should give appropriate advance consideration to determining which transition elections it wishes to make since those elections must be made within a specified time after adoption. Also, ASC 815's general requirement for an entity to assess effectiveness for similar hedges in a similar manner, including the identification of excluded components, will apply to hedging relationships entered into after adoption; therefore, it will be important for the entity to determine its desired future methods for assessing the effectiveness of its hedging relationships when it adopts the ASU.

**Down-Round Provisions**

**Background**

In July 2017, the FASB issued ASU 2017-11, which makes limited changes to the Board's guidance on classifying certain financial instruments as either liabilities or equity. The ASU's objective is to improve (1) the accounting for instruments with “down-round” provisions and (2) the readability of the guidance in ASC 480 on distinguishing liabilities from equity by replacing the indefinite deferral of certain pending content with scope exceptions.

A down-round provision is a term in an equity-linked financial instrument (e.g., a freestanding warrant contract or an equity conversion feature embedded within a host debt or equity contract) that triggers a downward adjustment to the instrument's strike price (or conversion price) if equity shares are issued at a lower price (or equity-linked financial instruments are issued at a lower strike price) than the instrument's then-current strike price. The purpose of the feature is to protect the instrument's counterparty from future issuances of equity shares at a more favorable price. For example, a warrant

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3 This refers to hedging relationships in which “the hedging instrument has not expired, been sold, terminated, or exercised” and that have not been dedesignated by the entity as of the date of adoption.
may specify that the strike price is the lower of $5 per share or the common stock offering price in any future initial public offering of the shares. Similarly, a debt instrument may include an embedded conversion feature whose conversion price is the lower of $5 per share or the future public offering price. Such provisions are frequently included in warrants, convertible shares, and convertible debt issued by private entities and development-stage companies.

Before an issuer adopts ASU 2017-11, a contract (or embedded equity conversion feature) that contain a down-round provision does not qualify as equity because such an arrangement precludes a conclusion that the contract is indexed to the entity's own stock under ASC 815-40-15 (as illustrated in ASC 815-40-55-33 and 55-34). For a contract to be considered indexed to an entity's own equity under ASC 815-40-15, the only variables that could affect the settlement amount must be inputs into the pricing of a fixed-for-fixed option or forward on the entity's equity shares (i.e., a contract whose settlement amount equals the difference between the fair value of a fixed number of the entity's equity shares and a fixed monetary amount or a fixed amount of a debt instrument). Neither the issuance of new equity securities at the current market price nor the issuance of an equity-linked financial instrument with a lower strike price than a previously issued instrument, however, is an input into the pricing of a fixed-for-fixed option or forward on equity shares.

**Connecting the Dots**

Economically, a down-round provision is different from an antidilution feature. Antidilution adjustments protect the holder against the impact of dilutive events (e.g., stock splits) but do not put the holder in an economically better position than it was before the event, or relative to existing holders of the underlying equity shares. Under ASC 815-40, an antidilution adjustment would not necessarily preclude a conclusion that the contract is indexed to the entity’s own equity. Down-round adjustments are different because they (1) enable the holder to obtain equity shares at an economically more favorable price than before the event and (2) benefit the holder relative to existing holders of the underlying equity shares.

Since down-round protection is not an input into the pricing of a fixed-for-fixed option or forward on equity shares, contracts and features that include down-round provisions have not qualified for the scope exception from derivative accounting in ASC 815-10 for contracts that are indexed to, and classified in, stockholders’ equity. Therefore, freestanding contracts on an entity's own equity that contain a down-round feature and meet the definition of a derivative (including net settlement) have been accounted for at fair value, with changes in fair value recognized in earnings. Similarly, embedded equity conversion features that contain down-round provisions have been separated and accounted for as derivative instruments at fair value as long as they met the bifurcation criteria in ASC 815-15.

**Connecting the Dots**

When a financial instrument is accounted for as a derivative instrument under ASC 815-10, it is marked to its fair value each reporting period, with changes in fair value reflected through earnings. This accounting can result in outcomes that may seem counterintuitive for instruments with down-round features, because the existence of down-round protection is only one of the factors that affect the instrument’s fair value, and the provision would be triggered only if the stock price declines below the strike price. If the price of the entity’s common stock increases, there will be a decrease in the likelihood and amount of any potential transfer of value to the holder as a result of a down-round adjustment in a warrant that is accounted for as a derivative liability solely because of the existence of that down-round provision. However, the fair value of the warrant liability exclusive of the down-round feature increases, which results in a negative earnings impact (even though the value of the down-round protection the issuer is providing to the holder has declined). Conversely, if the issuer’s stock price decreases, the value the issuer is providing to the holder in the form of down-round protection increases even though the fair
value of the warrant exclusive of the down-round provision has declined, which has a positive earnings impact.

**Key Provisions of the ASU**

ASU 2017-11 applies to issuers of financial instruments with down-round features. It amends (1) the classification of such instruments as liabilities or equity by revising the guidance in ASC 815 on the evaluation of whether instruments or embedded features with down-round provisions must be accounted for as derivative instruments and (2) the guidance on recognition and measurement of the value transferred upon the trigger of a down-round feature for equity-classified instruments by revising ASC 260.

**Derivative Analysis — Amendments to ASC 815**

The ASU amends ASC 815 to exclude consideration of a down-round feature in the evaluation of whether an instrument is indexed to an entity's own stock under ASC 815-40-15-7C. That is, a down-round provision would not preclude an entity from concluding that an instrument or feature that includes a down-round feature is indexed to the entity's own stock. This guidance applies to both freestanding financial instruments and embedded conversion options (e.g., in convertible instruments with beneficial conversion features (BCFs) or cash conversion features (CCFs)). For example, an entity's evaluation of whether it is required to classify a freestanding warrant that gives the counterparty the right to acquire the entity's common stock as a liability or equity under ASC 815-40 would not be affected by the existence of the down-round feature. If the warrant otherwise meets the condition for equity classification, therefore, it would be classified as equity. Similarly, in the analysis of whether an embedded conversion feature in a debt host contract must be bifurcated as an embedded derivative under ASC 815-15, the existence of a down-round provision would not prevent the contract from qualifying for the scope exception in ASC 815-10-15-74 that applies to contracts indexed to an entity's own stock and classified in stockholders' equity. While instruments that contain down-round features would no longer be expressly precluded from equity classification, such instruments may still not qualify for equity classification for other reasons (e.g., if the issuer could be forced to net cash settle the contract). In summary, the classification of instruments as liabilities or equity is not dictated by the down-round feature under the ASU.

**Connecting the Dots**

The ASU affects the evaluation of whether convertible instruments contain CCPs or contingent BCFs that must be accounted for separately under ASC 470-20. For example, a contingent BCF that was previously separated and accounted for as an embedded derivative instrument in accordance with ASC 815 solely because of the down-round feature would instead, under the ASU, fall within the scope of the guidance on contingent BCFs unless the convertible instrument contains a CCF.

**Recognition and Measurement for Equity-Classified Instruments — Amendments to ASC 260**

As discussed above, the ASU amends the guidance on the recognition and measurement of freestanding equity-classified instruments (e.g., warrants) by adding requirements to ASC 260 for entities that disclose earnings per share (EPS). The amendments do not apply to convertible instruments.

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4 ASC 815-40-15-7C states, “An instrument (or embedded feature) shall be considered indexed to an entity's own stock if its settlement amount will equal the difference between the following:
   a. The fair value of a fixed number of the entity's equity shares
   b. A fixed monetary amount or a fixed amount of a debt instrument issued by the entity.”
As noted in paragraph BC41 of the ASU, convertible instruments are subject to specialized accounting models in ASC 470-20. Because the Board decided not to amend those models, convertible instruments with down-round features that no longer are required to be bifurcated as derivative instruments under ASC 815 will be within the scope of ASC 470-20 once the ASU is adopted. The ASU does not change the EPS guidance for these instruments (e.g., the if-converted method of calculating diluted EPS).

For entities that have equity-classified instruments and disclose EPS, the down-round feature would affect the accounting only if it was triggered (i.e., the entity issued shares at a price below the strike price). Once the feature was triggered, entities would determine the value that was transferred to the holder when the price adjustment occurred. They would determine this value in accordance with the fair value measurement guidance in ASC 820 by using a "with and without method," under which they would compare the fair values the instrument would have with and without the feature. The ASU states that entities would measure the fair value as the difference between:

a. The fair value of the financial instrument (without the down round feature) with a strike price corresponding to the currently stated strike price of the issued instrument (that is, before the strike price reduction)

b. The fair value of the financial instrument (without the down round feature) with a strike price corresponding to the reduced strike price upon the down round feature being triggered.

After determining the value that was transferred to the holder, the entity would recognize the value transferred as a reduction of retained earnings and an increase of additional paid-in capital (i.e., as a deemed dividend). Further, the transfer of value would be reflected as a deduction to income available to common stockholders in the basic EPS calculation. The feature would not be subsequently remeasured.

The amendments to ASC 815 apply to all entities with financial instruments that have down-round features; however, the ASU's requirement to recognize the value transferred upon the trigger of a down-round feature in a freestanding equity-classified instrument affects only companies that disclose EPS. Accordingly, private companies that do not disclose EPS will reevaluate the classification of financial instruments with down-round features under ASC 815 and the applicability of the CCF and BCF guidance in ASC 470-20 to convertible instruments, but the ASU will not require them to recognize the impact of a down-round feature that is triggered for a freestanding equity-classified instrument. If a private company discloses EPS, however, it will be subject to the ASU's recognition model for equity-classified instruments.

Example

On January 1, 2017, Entity A grants warrants to Investor X to acquire A's common shares. The warrants have an exercise price of $3.00 per share, subject to adjustment if A issues new shares of its common stock. If A issues new shares of its common stock for less than $3.00 per share, the exercise price is adjusted to that issue price. Entity A evaluated the warrants in accordance with ASC 815-40 and concluded that they should be classified in equity since they are considered indexed to the entity's own stock if the down-round provision is disregarded. On July 1, 2017, A issues new shares of its common stock to Investor Y at a price of $2.50 per share. Accordingly, the exercise price of the warrants is adjusted to $2.50.

On July 1, 2017, A would determine the value transferred to X when it lowered the exercise price of the warrants from $3.00 to $2.50 and would treat that amount as a reduction in retained earnings, with an offsetting increase to the carrying value of the warrants in additional paid-in capital. The amount would also be reflected as a reduction to the income available to common stockholders in the basic EPS calculation.
**Connecting the Dots**
As a result of recognizing the impact of the trigger, an entity may be required to adjust the diluted EPS calculation. Under the treasury stock method, options and warrants are assumed to be exercised as of the beginning of the period. As a result, under the treasury stock method, the assumption is that the options or warrants are exercised before the trigger of the down-round feature. Therefore, the impact would be added back to income available for common stockholders to calculate diluted EPS if the option or warrant is dilutive. The ASU's Example 16 in ASC 260-10-55-95 through 55-97 illustrates this guidance. As noted in ASC 260-10-45-25, warrants or options have a dilutive effect under the treasury stock method if the options or warrants are in the money (i.e., “the average market price of the common stock during the period exceeds the exercise price of the options or warrants”).

**Disclosures**
ASU 2017-11 specifies that upon the trigger of a down-round feature, entities are required to disclose:

a. The fact that [a down-round] feature has been triggered
b. The value of the effect of the down round feature that has been triggered.

In addition, the ASU amends ASC 505-10-50-3, which requires entities to disclose all pertinent rights and privileges of the equity securities outstanding. Under the amended guidance, entities must disclose terms that may change conversion or exercise prices (excluding standard antidilution provisions).

**Effective Date and Transition**
For PBEs, the ASU is effective for annual reporting periods beginning after December 15, 2018, including interim periods therein.

For all other entities, the ASU is effective for annual reporting periods beginning after December 15, 2019, and interim periods within annual reporting periods beginning after December 15, 2020.

Early adoption is permitted in any interim or annual period for which financial statements have not yet been issued or have not been made available for issuance.

Under the ASU’s transition requirements, entities may elect to do either of the following:

- Recognize the cumulative effect of the change as an adjustment to the opening balance of retained earnings in the period of adoption.
- Apply the amendments retrospectively for each prior reporting period presented in accordance with the guidance on accounting changes in ASC 250-10-45-5 through 45-10.

**Connecting the Dots**
It may be particularly challenging to determine the appropriate transition accounting for a convertible instrument that, before adoption of the ASU, had a conversion feature that was bifurcated as a derivative instrument but that must be separated into liability and equity components in accordance with the guidance on CCFs or BCFs in ASC 470-20 after adoption
of the ASU (e.g., a contingent BCF that was triggered before the ASU’s effective date). Some companies may not previously have tracked the information necessary for application of the accounting guidance in ASC 470-20 on CCFs, noncontingent BCFs, or contingent BCFs, as applicable.

In the period of adoption, entities must provide disclosures in accordance with ASC 250-10-50.⁵

**Removal of the Indefinite Deferral Under ASC 480**

Before ASU 2017-11, the transition guidance in ASC 480-10 indefinitely deferred the application of some of that subtopic’s requirements for certain instruments and entities (i.e., certain mandatorily redeemable financial instruments of nonpublic entities that are not SEC registrants and certain mandatorily redeemable noncontrolling interests). Accordingly, such instruments may qualify as equity under U.S. GAAP even though ASC 480-10-25 suggested (before ASU 2017-11) that they should be classified as liabilities.

**Connecting the Dots**

Because of the indefinite deferral noted above, these requirements were labeled “pending content” in the Codification, but the transition guidance in ASC 480-10-65 provided no effective date for them.

The ASU replaces the indefinite deferral in ASC 480-10 with scope exceptions that have the same applicability. The Board’s objective is to improve the navigability of the Codification without changing its application. Since the ASU is not intended to change how GAAP is applied to items within its scope, no transition guidance is provided.

**Simplifying the Classification of Debt in a Classified Balance Sheet**

In January 2017, the FASB issued a proposed ASU that would simplify the classification of debt as either current or noncurrent on the balance sheet. The guidance currently in ASC 470-10 consists of an assortment of fact-specific rules and exceptions, the application of which varies depending on the terms and conditions of the debt arrangement, management’s expectations of when debt may be settled or refinanced, and certain post-balance-sheet events. The objective of the proposed ASU is to reduce the cost and complexity of applying this guidance while maintaining or improving the usefulness of the information provided to financial statement users.

The FASB is expected to issue a final ASU sometime during the second quarter of 2018. For more information about the proposed ASU, see Deloitte’s January 12, 2017, *Heads Up*.

**FASB’s Research Project on Liabilities and Equity**

In 2016, the FASB decided to remove from its technical agenda its project on simplifying the equity classification conditions for contracts on an entity’s own equity under ASC 815-40-25, with the exception of the targeted changes in ASU 2017-11. The Board acknowledged the complexity of the current guidance and also observed that few practitioners have a good understanding of the numerous rules and exceptions in it and that improperly distinguishing liabilities from equity therefore continues to be one of the most common reasons for accounting restatements. The Board is engaged in a preagenda

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⁵ These disclosures include:
1. The nature of the change in accounting principle
2. The method of applying the change
3. The cumulative effect of the change on retained earnings in the statement of financial position as of the beginning of the earliest period presented in which [the ASU] is effective.
research project in which it is evaluating its guidance on distinguishing liabilities from equity to determine whether to undertake a comprehensive project.

In August 2016, the FASB issued an invitation to comment to gather public input on whether the Board should recommence a comprehensive project on distinguishing liabilities from equity. On June 14, 2017, the FASB staff gave the Board an update of its outreach related to the invitation to comment, which was intended to help the FASB understand (1) how financial statement users evaluate relevant disclosures to determine an entity’s capital structure and (2) the complexities associated with the guidance on liabilities and equity. No decisions were made, and the Board asked the FASB staff to perform further research to present at a future Board meeting.

In September 2017, as a result of the FASB staff’s additional research and outreach, the Board decided to add to its agenda a project on distinguishing liabilities from equity with the objective of improving understandability and reducing complexity without sacrificing the information that users of financial statements need. The project will focus on “indexation and settlement (within the context of the derivative scope exception), convertible debt, disclosures, and earnings per share.” On December 13, 2017, the FASB discussed the project plan.

Business Combinations

Intangibles — Goodwill and Other

Background

In January 2017, the FASB issued ASU 2017-04, which amends the guidance in ASC 350 on the accounting for goodwill impairment. The ASU was issued as part of the FASB's simplification initiative and in response to stakeholder feedback regarding the cost and complexity of the annual goodwill impairment test.

Key Provisions of the ASU

Under the current guidance in ASC 350, impairment of goodwill “exists when the carrying amount of goodwill exceeds its implied fair value.” To determine the implied fair value of goodwill, an entity must “assign the fair value of a reporting unit to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination.” This process, known as step 2, is often expensive and complicated given the inability to measure goodwill directly. ASU 2017-04 seeks to simplify the accounting for goodwill impairments by eliminating step 2 from the goodwill impairment test and enabling an entity to recognize an impairment loss when the “carrying amount of a reporting unit exceeds its fair value.” Any such loss will be “limited to the total amount of goodwill allocated to that reporting unit.”

Connecting the Dots

The ASU requires goodwill impairment to be measured on the basis of the fair value of a reporting unit relative to the reporting unit’s carrying amount rather than on the basis of the implied amount of goodwill relative to the goodwill balance of the reporting unit. The goodwill impairment test under the ASU is therefore less precise than the test performed under current guidance. As a result of applying the new guidance, an entity may record a goodwill impairment that is entirely or partly due to a decline in the fair value of other assets that, under existing GAAP, would not be impaired or have a reduced carrying amount.

6 FASB Invitation to Comment, Agenda Consultation. The comment period ended October 17, 2016.
The ASU does not change the qualitative assessment; however, it removes “the requirements for any reporting unit with a zero or negative carrying amount to perform a qualitative assessment and, if it fails that qualitative test, to perform Step 2 of the goodwill impairment test.” Rather, all reporting units, including those with a zero or negative carrying amount, will apply the same impairment test.

**Connecting the Dots**

Under ASU 2017-04, reporting units with a zero or negative carrying value would essentially never be impaired. Accordingly, judgments related to the assignment of assets and liabilities to a reporting unit may become more relevant. The FASB considered, but ultimately rejected, prescribing additional guidance on allocating assets and liabilities to reporting units. The ASU’s Basis for Conclusions states that “the amendments in this Update should not necessarily trigger changes to the composition of a reporting unit,” noting that “preparers, auditors, and regulators should pay close attention to any change to a reporting unit that results in a zero or negative carrying amount, including changes made leading up to the adoption of the new guidance given the length of time until the effective dates.” It further states that “the allocation of assets and liabilities to reporting units should not be viewed as an opportunity to avoid impairment charges and should only be changed if there is a change in facts and circumstances for a reporting unit.”

The ASU also:

- Clarifies the requirements for excluding and allocating foreign CTAs to reporting units related to an entity’s testing of reporting units for goodwill impairment.
- Clarifies that “an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.”
- Makes minor changes to the Overview and Background sections of certain ASC subtopics and topics as part of the Board’s initiative to unify and improve those sections throughout the Codification.


**Convergence With IFRS Standards**

The removal of step 2 from the goodwill impairment test under ASC 350 more closely aligns U.S. GAAP with IFRS Standards, which also prescribe a one-step goodwill impairment test. However, the impairment test required under IAS 36 is performed at the cash-generating-unit or group-of-cash-generating-units level rather than the reporting-unit level as required by U.S. GAAP. Further, IAS 36 requires an entity to compare the cash-generating unit’s carrying amount with its recoverable amount, whereas the ASU requires an entity to compare a reporting unit’s carrying amount with its fair value.

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7 The optional assessment described in ASC 350-20-35-3A through 35-3G to determine whether it is more likely than not that the carrying amount of a reporting unit exceeds its fair value is commonly referred to as the qualitative assessment or step 0.
Effective Date and Transition

For PBEs that are SEC filers, the ASU is effective for annual and any interim impairment tests for periods beginning after December 15, 2019. PBEs that are not SEC filers should apply the new guidance to annual and any interim impairment tests for periods beginning after December 15, 2020. For all other entities, the ASU is effective for annual and any interim impairment tests for periods beginning after December 15, 2021. Early adoption is allowed for all entities as of January 1, 2017, for annual and any interim impairment tests occurring on or after January 1, 2017.

Clarifying the Definition of a Business

Background

In January 2017, the FASB issued ASU 2017-01, which provides guidance related to the first phase of the Board's project on the definition of a business. The ASU is in response to concerns that the current definition of a business is too broad and that many transactions are accounted for as business combinations when they are more akin to asset acquisitions.

The ASU:

• Provides a “screen” that, if met, eliminates the need for further evaluation. Entities are required to use this screen when determining whether an integrated set of assets and activities (commonly referred to as a "set") is a business. When substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the screen is met and the set is therefore not a business. The objective of the screen is to reduce the number of transactions that need to be further evaluated.

• Provides that if the screen is not met, a set constitutes a business only if it includes, at a minimum, an input and a substantive process that together significantly contribute to the ability to create outputs.

• Removes the evaluation of whether a market participant could replace missing elements.

• Narrows the definition of the term “output” to make it consistent with how outputs are described in ASC 606.

Connecting the Dots

The ASU could affect the P&U industry as a result of the different accounting for business combinations and asset acquisitions. For example, acquisition costs are expensed in a business combination and capitalized in an asset acquisition. Thus, a narrower definition of a business will result in more asset acquisitions and, therefore, more capitalized costs.

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The ASC master glossary defines an “SEC filer” as follows:

"An entity that is required to file or furnish its financial statements with either of the following:
  a. The Securities and Exchange Commission (SEC)
  b. With respect to an entity subject to Section 12(i) of the Securities Exchange Act of 1934, as amended, the appropriate agency under that Section.

Financial statements for other entities that are not otherwise SEC filers whose financial statements are included in a submission by another SEC filer are not included within this definition."

An SEC filer does not include an entity's financial statements or financial information that is required to be or is included in a filing with the SEC (e.g., in accordance with SEC Regulation S-X, Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons;” or SEC Regulation S-X, Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired;” and SEC Regulation S-X, Rule 4-08(g), “Summarized Financial Information”).
Single or Similar Asset Concentration

Under the ASU, cash and cash equivalents, DTAs, and goodwill resulting from the effects of deferred tax liabilities (DTLs) would be excluded from an entity's assessment of gross asset concentration when an entity applies the screen described above. If the fair value of the gross assets is not concentrated in accordance with the screen, the entity would apply the ASU's framework for evaluating whether an input and a substantive process are both present and together contribute to the ability to produce outputs.

Connecting the Dots

In the determination of gross asset concentration, neither a financial asset and a nonfinancial asset (e.g., investments and customer relationships) nor different major classes of financial assets (e.g., cash, accounts receivable, and marketable securities) could be combined. Also, identifiable assets within the same major asset class that have significantly different risk characteristics could not be combined.

Input and Substantive Process Requirement

The ASU provides a framework for determining whether a set has an input and a substantive process that collectively contribute to the ability to create outputs. When a set does not yet have outputs, the set would have a substantive process only if it has an organized workforce (or an acquired contract that provides access to an organized workforce) that has the necessary skills, knowledge, or experience to perform an acquired process (or group of processes) that, when applied to an acquired input or inputs, is critical to the ability to continue producing outputs. For a set with outputs, the ASU includes less stringent criteria for determining that the set has a substantive process. An organized workforce may represent a substantive process. However, a set may have a substantive process even without an organized workforce if an acquired process or processes contribute to the ability to continue producing outputs and cannot be replaced without significant cost, effort, or delay or are considered unique or scarce.

Definition of Outputs

Under current guidance (ASC 805-10-55-4(c)), outputs are defined as the “result of inputs and processes applied to those inputs that provide or have the ability to provide a return in the form of dividends, lower costs, or other economic benefits directly to investors or other owners, members, or participants.” The ASU amends the definition of an output to be the “result of inputs and processes applied to those inputs that provide goods or services to customers, investment income (such as dividends or interest), or other revenues.” The revised definition of outputs aligns with the description of outputs in ASC 606 (the new revenue standard).

Effective Date and Transition

The ASU is effective for PBEs for annual periods beginning after December 15, 2017, including interim periods therein. For all other entities, the ASU is effective for annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019.

Early application is permitted as follows:

- For transactions for which the acquisition date occurs before the issuance date or effective date of the ASU, application is permitted only when the transaction has not been reported in financial statements that have been issued or made available for issuance.
- For transactions in which a subsidiary is deconsolidated or a group of assets is derecognized that occur before the issuance date or effective date of the ASU, application is permitted only
when the transaction has not been reported in financial statements that have been issued or made available for issuance.

**Connecting the Dots**

Within the P&U industry, acquisitions of power plants and other generating assets (which are not considered in-substance real estate) have generally been accounted for as business combinations under the current guidance. Given the changes resulting from the ASU on clarifying the definition of business, there may be more transfers of nonmonetary assets that do not meet the definition of a business. Therefore, as a result of the updated guidance, fewer acquisitions in the P&U sector may qualify as business combinations.

Further, acquisitions such as those of proven gas reserves would need to be evaluated under the new guidance to determine whether the set includes a substantive process. The energy and resources industry as a whole, including P&U entities, should consider the amendments to the definition of a business as described above and continue to monitor the additional phases of the project and their potential effects on the industry.

For more information, see Deloitte’s January 13, 2017, *Heads Up*.

**Share-Based Payment Accounting Improvements**

**Employee Share-Based Payments — Modification Accounting**

In May 2017, the FASB issued ASU 2017-09, which amends the scope of modification accounting for share-based payment arrangements. The ASU provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. Specifically, an entity would not apply modification accounting if the fair value, vesting conditions, and classification of the awards are the same immediately before and after the modification.

**Background**

The Board decided to change the scope of the modification guidance in ASC 718 given that ASC 718-20-20 defines a modification as a “change in any of the terms or conditions of a share-based payment award” (emphasis added). As a result of that broad definition, there may be diversity in practice regarding the types of changes to share-based payment awards to which an entity applies modification accounting. Accordingly, to provide clarity and reduce diversity, cost, and complexity, the FASB issued ASU 2017-09.

Examples 1 and 2 below illustrate the effects of an entity’s application of modification accounting depending on whether the original awards are expected to vest.
Example 1

Entity A grants employees restricted stock units that are classified as equity and have a fair-value-based measure of $1 million on the grant date. Before the awards vest, A subsequently modifies them to provide dividend participation during the vesting period. Assume that the addition of dividend participation changes the fair-value-based measurement of the awards and that the fair-value-based measure on the modification date is $1.5 million immediately before the modification and $1.6 million immediately after it. In addition, there are no other changes to the awards (including their vesting conditions or classification). If A applies modification accounting, and the awards are expected to vest on the modification date, A would recognize incremental compensation cost of $100,000 over the remaining requisite service period (for a total of $1.1 million of compensation cost). However, if A applies modification accounting, and the awards are not expected to vest on the modification date, any compensation cost to be recognized (if the awards are subsequently expected to vest or actually do vest) will be based on the modification-date fair-value-based measure of $1.6 million.

Example 2

Entity B grants employees restricted stock units that are classified as equity and have a fair-value-based measure of $1 million on the grant date. Before the awards vest, B subsequently modifies them to add a contingent fair-value repurchase feature on the underlying shares. Assume that the addition of the repurchase feature does not change the fair-value-based measurement of the awards or their classification and that the fair-value-based measure on the modification date is $1.5 million (both immediately before and after the modification). In addition, there are no other changes to the awards (including their vesting conditions). If B applies modification accounting, and the awards are expected to vest on the modification date, there is no accounting consequence associated with the modification because there is no increase in the fair-value-based measurement; any compensation cost will continue to be based on the grant-date fair-value-based measure of $1 million. However, if B applies modification accounting, and the awards are not expected to vest on the modification date, any compensation cost to be recognized (if the awards are subsequently expected to vest or actually do vest) will be based on the modification-date fair-value-based measure of $1.5 million.

In accordance with the ASU’s provisions (see discussion below), B would not apply modification accounting because the fair-value-based measurement, vesting conditions, and classification of the awards are the same immediately before and after the modification. Accordingly, irrespective of whether the awards are expected to vest on the modification date, any compensation cost recognized will continue to be based on the grant-date fair-value-based measure of $1 million.

Key Provisions of the ASU

Scope of Modification Accounting

The ASU limits the circumstances in which an entity applies modification accounting. When an award is modified, an entity does not apply the guidance in ASC 718-20-35-3 through 35-9 if it meets all of the following criteria:

- “The fair value (or calculated value or intrinsic value, if such an alternative measurement method is used) of the modified award is the same as the fair value (or calculated value or intrinsic value, if such an alternative measurement method is used) of the original award immediately before the original award is modified.”

- “The vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award is modified.”

- “The classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified.”
Connecting the Dots
Upon an equity restructuring, it is not uncommon for an entity to make employees “whole” (in accordance with a preexisting nondiscretionary antidilution provision) on an intrinsic-value basis when the awards are stock options. In certain circumstances, the fair-value-based measurement of modified stock options could change as a result of the equity restructuring even if the intrinsic value remains the same. Under the ASU, an entity compares the intrinsic value before and after a modification in determining whether to apply modification accounting only “if such an alternative measurement method is used”; thus, if an entity uses a fair-value-based measure to calculate and recognize compensation cost for its share-based payment awards, it would still be required to apply modification accounting when the fair-value-based measurement has changed, even if the intrinsic value is the same immediately before and after the modification.

Clarification Related to the Fair Value Assessment
ASC 718-20-35-2A(a) states, “If the modification does not affect any of the inputs to the valuation technique that the entity uses to value the award, the entity is not required to estimate the value immediately before and after the modification.”

Connecting the Dots
In paragraph BC16 of ASU 2017-09, the Board noted that it does not expect that an entity will always need to estimate the fair-value-based measurement of a modified award. An entity might instead be able to determine whether the modification affects any of the inputs used in the valuation technique performed for the award. For example, if an entity changes the net-settlement terms of its share-based payment arrangements related to statutory tax withholding requirements, that change is not likely to affect any inputs used in the method performed by the entity to value the awards. If none of the inputs are affected, the entity would not be required to estimate the fair-value-based measurement immediately before and after the modification (i.e., the entity could conclude that the fair-value-based measurement is the same).

Examples From the ASU’s Basis for Conclusions
The ASU’s Basis for Conclusions provides examples (that “are educational in nature, are not all-inclusive, and should not be used to override the guidance in paragraph 718-20-35-2A”) of (1) changes to awards for which modification accounting generally would not be required and (2) those for which it generally would be required. The following table summarizes those examples:

<table>
<thead>
<tr>
<th>Examples of Changes for Which Modification Accounting Would Not Be Required</th>
<th>Examples of Changes for Which Modification Accounting Would Be Required</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Administrative changes, such as a change to the company name, company address, or plan name</td>
<td>• Repricings of stock options that result in a change in value</td>
</tr>
<tr>
<td>• Changes in net-settlement provisions related to tax withholdings that do not affect the classification of the award</td>
<td>• Changes in a service condition</td>
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<td></td>
<td>• Changes in a performance condition or a market condition</td>
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<tr>
<td></td>
<td>• Changes in an award that result in a reclassification of the award (equity to liability or vice versa)</td>
</tr>
<tr>
<td></td>
<td>• Addition of an involuntary termination provision in anticipation of a sale of a business unit that accelerates vesting of an award</td>
</tr>
</tbody>
</table>
Connecting the Dots
Share-based payment plans commonly contain clawback provisions that allow an entity to recoup awards upon certain contingent events (e.g., termination for cause, violation of a noncompete provision, material financial statement restatement). Under ASC 718-10-30-24, such clawback provisions are generally not reflected in estimates of the fair-value-based measure of awards. Accordingly, we believe that the addition of a clawback provision to an award would typically not result in the application of modification accounting because such clawbacks generally do not change the fair value, vesting conditions, or classification of an award.

Effective Date
For all entities, the ASU is effective for annual reporting periods, including interim periods therein, beginning after December 15, 2017.

Early adoption is permitted, including adoption in any interim period.

Transition and Related Disclosures
The ASU’s amendments should be applied prospectively to awards modified on or after the effective date. Transition disclosures are not required, because modifications typically are not recurring events for most entities.

Retirement Benefits
Background
In March 2017, the FASB issued ASU 2017-07, which amends the requirements in ASC 715 related to the income statement presentation of the components of net periodic benefit cost for an entity’s sponsored defined benefit pension and other postretirement plans.

Under current U.S. GAAP, net benefit cost (i.e., defined benefit pension cost and postretirement benefit cost) consists of several components that reflect different aspects of an employer’s financial arrangements as well as the cost of benefits earned by employees. These components are aggregated and reported net in the financial statements. However, many stakeholders have criticized such net presentation because it does not permit financial statement users to evaluate different types of components separately when they assess an entity’s current and future financial performance. In addition, there is no specific guidance on where in the income statement an entity should present net benefit cost.

Key Provisions of the ASU
ASU 2017-07 requires entities to (1) disaggregate the current service cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components of net benefit cost elsewhere in the income statement and outside of income from operations if such a subtotal is presented.

The ASU also requires entities to disclose the income statement lines that contain the other components if they are not presented on appropriately described separate lines.
Connecting the Dots

While the ASU does not require entities to further disaggregate the other components, they may do so if they believe that the information would be helpful to financial statement users. However, entities must disclose which financial statement lines contain the disaggregated components.

In addition, only the service cost component of net benefit cost is eligible for capitalization (e.g., as part of inventory or PP&E). This is a change from current practice, under which entities capitalize the aggregate net benefit cost when applicable.

Effective Date and Transition

The ASU’s amendments are effective for PBEs for interim and annual periods beginning after December 15, 2017. For other entities, the amendments are effective for annual periods beginning after December 15, 2018, and interim periods in the subsequent annual period. Early adoption is permitted as of the beginning of any annual period for which an entity’s financial statements (interim or annual) have not been issued or made available for issuance (i.e., an entity should early adopt the amendments within the first interim period if it issues interim financial statements).

Entities must use (1) a retrospective transition method to adopt the requirement for separate presentation in the income statement of service costs and other components and (2) a prospective transition method to adopt the requirement to limit the capitalization of benefit costs (e.g., as part of PP&E) to the service cost component. Further, entities must disclose the nature of and reason for the change in accounting principle in both the first interim and annual reporting periods in which they adopt the amendments.

The ASU also establishes a practical expedient upon transition that permits entities to use their previously disclosed service cost and other costs from the prior years’ pension and other postretirement benefit plan footnotes in the comparative periods as appropriate estimates when retrospectively changing the presentation of these costs in the income statement. Entities that apply the practical expedient need to disclose that they did so.

Connecting the Dots

As part of the ratemaking process for determining the prices utilities are permitted to charge customers for utility service, utility regulators generally provide specific requirements on how P&U entities should account for net benefit costs for ratemaking purposes. The most common accounting and ratemaking treatment for most jurisdictions before the issuance of this ASU was to record all components of net benefit cost as an operating expense and allow for the capitalization of a percentage of all the components of net benefit cost on qualifying construction projects.

Upon adoption of this ASU, some companies have continued their ratemaking calculations in a manner consistent with this method. This approach requires some additional accounting to first reflect the requirements of the ASU and then overlay certain aspects of ratemaking that differ from that guidance. Other companies have worked with their respective regulatory commissions to modify their ratemaking to be consistent with the new guidance.

In those situations in which ratemaking was not changed, the accounting is different depending upon whether service cost is less than net benefit cost or exceeds net benefit cost. If service cost is less than net benefit cost, the company would capitalize less to PP&E because it would apply its capitalization percentage to a lower base (i.e., service cost). Because the ratemaking
Share-Based Payment Accounting Improvements

allows for capitalization of a larger amount, the company would record the incremental amount as a regulatory asset. The total amount capitalized is not changed; however, a portion is reflected in the PP&E balance and a portion is recorded as a regulatory asset. Both amounts would be depreciated and amortized in a manner consistent with the PP&E's economic life included in the company's ratemaking.

If service cost exceeds net benefit cost and the ratemaking is not changed, the company would apply its capitalization percentage to a higher base (i.e., service cost) and create a higher balance in PP&E than is provided for in its ratemaking. This scenario creates a credit to expense (essentially a gain) that the regulators will effectively view as a reduction to the amount collected from ratepayers in the future since the depreciation is recorded on the incremental PP&E balance. Because this gain will reduce future rates, it should be recorded as a regulatory liability in accordance with the provisions of ASC 980. An additional view to consider in this scenario would be that the regulator immediately allows for recovery of the incremental PP&E capitalized by an immediate recognition of the regulatory liability. This theory would provide that the balance sheet for PP&E starts out with only the net PP&E that is allowed for regulatory recovery by the appropriate commission.

There is an important additional consideration in the application of this ASU. Should the company experience the scenario in which service cost exceeds net benefit cost and ratemaking does not change, it will end up with a regulatory asset as described above. We believe that the amounts eligible for capitalized financing costs (i.e., AFUDC) should include amounts within PP&E and this regulatory asset.

For additional information, see Deloitte's March 14, 2017, *Heads Up*.

**FASB Simplifies Guidance on Nonemployee Share-Based Payments**

On June 20, 2018, the FASB issued ASU 2018-07, which simplifies the accounting for share-based payments granted to nonemployees for goods and services. Under the ASU, most of the guidance on such payments to nonemployees would be aligned with the requirements for share-based payments granted to employees.

**Background**

Currently, share-based payment arrangements with employees are accounted for under ASC 718, while nonemployee share-based payments issued for goods and services are accounted for under ASC 505-50. ASC 505-50, before the ASU’s amendments, differs significantly from ASC 718. Differences include (but are not limited to) the guidance on (1) the determination of the measurement date (which generally is the date on which the measurement of equity-classified share-based payments becomes fixed), (2) the accounting for performance conditions, (3) the ability of a nonpublic entity to use certain practical expedients for measurement, and (4) the accounting for (including measurement and classification) share-based payments after vesting. The ASU eliminates most of the differences.

**Connecting the Dots**

In the ASU’s Basis for Conclusions, the FASB discusses the issuance of the guidance in ASC 505-50, noting that the differences between the accounting for employee and nonemployee awards were originally based on “the view that there is a fundamental difference between the

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9 The ASU was issued as part of the FASB’s simplification initiative, which is intended to reduce the cost and complexity of current U.S. GAAP while maintaining or enhancing the usefulness of the related financial statement information. In March 2016, the Board issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting*, also as part of the initiative, to simplify several aspects of the accounting for employee share-based payment arrangements.
relationship that employees and nonemployees have with the entity granting the awards.” However, the Board concluded that awards granted to employees are economically similar to awards granted to nonemployees and that therefore two different accounting models were not justified.

Effective Date

For public business entities, the amendments in ASU 2018-07 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted if financial statements have not yet been issued (for public business entities) or have not yet been made available for issuance (for all other entities), but no earlier than an entity's adoption date of ASC 606. If early adoption is elected, all amendments in the ASU that apply must be adopted in the same period. In addition, if early adoption is elected in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period.

Transition and Related Disclosures

ASU 2018-07 generally requires an entity to use a modified retrospective transition approach, with a cumulative-effect adjustment to retained earnings as of the beginning of the fiscal year, for all (1) liability-classified nonemployee awards that have not been settled as of the adoption date and (2) equity-classified nonemployee awards for which a measurement date has not been established. In the application of a modified retrospective transition approach:

- The ASU's transition provisions do not apply to equity-classified awards for which a measurement date was previously established under ASC 505-50 because of the existence of a performance commitment or because performance was complete.

- It may be difficult for some entities to determine the grant-date fair-value-based measure of nonemployee equity-classified awards. The ASU therefore requires equity-classified awards (for which a measurement date has not been previously established) to be remeasured on the basis of their adoption-date fair-value-based measure.

- An entity applies the guidance on modifications of an award from liability to equity classification (i.e., the unsettled liability award as measured on the adoption date would be reclassified to equity) to determine the cumulative-effect adjustment to equity for unsettled awards that are currently classified as a liability but will be classified as equity under the ASU.

- An entity should not adjust the basis of assets that include nonemployee share-based payment costs if the assets are completed (e.g., finished goods inventory or fixed assets for which amortization has commenced).

However, if a nonpublic entity changes its measurement of nonemployee awards to calculated value instead of a fair-value-based measure, the ASU requires the entity to use a prospective approach.

Connecting the Dots

In applying a modified retrospective transition approach, an entity is required to adjust the basis of any assets that include nonemployee share-based payment costs if the assets are not completed. For example, any change in nonemployee share-based payment costs resulting

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10 The FASB retained the current definitions in ASC 718 of a "public entity" and a "nonpublic entity" for use in the determination of whether a nonpublic entity practical expedient can be elected. However, an entity will determine the ASU's effective date on the basis of whether it meets the ASC master glossary's definition of a "public business entity."
from adoption of ASU 2018-07 that are capitalizable as part of assets under construction or in progress will require an entity to adjust those asset balances.

In addition, while a change in measurement associated with the use of a calculated value is applied prospectively, an entity should apply other changes to its measurement approach by using a modified retrospective transition approach. For example, a nonpublic entity that has elected to apply the practical expedient in determining expected term should apply that revised measurement approach when measuring the awards subject to transition on the effective date.

In the first interim and fiscal year of adoption, an entity is required to disclose the following:

- The nature of and reason for the change in accounting principle.
- The cumulative effect of the change on retained earnings (or other components of equity or net assets) in the statement of financial position as of the beginning of the period of adoption.

For additional information, see Deloitte’s June 21, 2018, *Heads Up.*

**Other FASB Standard Setting Activities**

**Service Concession Arrangements**

**Background**

Some government or public-sector entities (“grantors”) enter into contracts with private-sector entities (“operating entities”) to manage the operation of the infrastructure that is used to provide public services (the operating entity may also manage construction, maintenance, or both). Such contracts are referred to herein as “service concession contracts.” Airports, roads, bridges, and hospitals are common asset types that are subject to service concession contracts.

ASU 2014-05 (based on EITF Issue 12-H) states that operating entities are prohibited from accounting for service concession contracts as leases (i.e., leasing the infrastructure from the grantor) when the grantor:

- “[C]ontrols or has the ability to modify or approve the services that the operating entity must provide with the infrastructure, to whom it must provide them, and at what price.”
- “[C]ontrols, through ownership, beneficial entitlement, or otherwise, any residual interest in the infrastructure at the end of the term of the arrangement.”

In such circumstances, operating entities should look to other ASC topics (e.g., ASC 605) for guidance on accounting for service concession contracts. However, since the issuance of ASU 2014-05, questions have arisen regarding how the operating entity should recognize revenue with respect to various stages of these contracts, such as initial construction, ongoing operations, and periodic major maintenance.

In May 2017, the FASB issued ASU 2017-10 in response to a consensus reached by the EITF at its March 2017 meeting.

**Key Provisions of the ASU**

ASU 2017-10 addresses “diversity in practice in how an operating entity determines the customer of the operation services for transactions within the scope of Topic 853” by “clarifying that the grantor is the customer of the operation services in all cases for those arrangements.” The amendments also allow
for a “more consistent application of other aspects of the revenue guidance, which are affected by this customer determination.”

**Effective Date and Transition**

For entities that have not yet adopted ASC 606, the effective date is aligned with that for ASC 606. For PBEs that have adopted ASC 606, the ASU is effective for fiscal years beginning after December 15, 2017, including interim periods therein. For most other entities, the ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. Early adoption is permitted.

See Deloitte’s March 2017 *EITF Snapshot* for additional information.
### Summary of Significant ASU Adoption Dates

The table below describes significant adoption dates for the various ASUs that have been issued by the FASB.

<table>
<thead>
<tr>
<th>FASB/EITF</th>
<th>Effective Date for PBEs</th>
<th>Effective Date for Non-PBEs</th>
<th>Early Adoption Allowed (Yes/No)</th>
<th>Deloitte Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Final Guidance</strong></td>
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<tr>
<td>ASU 2018-08, <em>Clarifying the Scope and the Accounting Guidance for Contributions Received and Contributions Made</em> (issued June 21, 2018)</td>
<td>For entities that serve as a resource recipient, the amendments should be applied to contributions received for annual periods beginning after June 15, 2018, and interim periods within those fiscal years. For entities that serve as a resource provider, the amendments should be applied to contributions made for annual periods beginning after December 15, 2018, and interim periods within those fiscal years.</td>
<td>For entities that serve as a resource recipient, the amendments should be applied to annual periods beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. For entities that serve as a resource provider, the amendments should be applied to annual periods beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020.</td>
<td>Yes</td>
<td>June 22, 2018, US GAAP Plus news item</td>
</tr>
<tr>
<td>ASU 2018-04, Investments — Debt Securities (Topic 320) and Regulated Operations (Topic 980): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 117 and SEC Release No. 33-9273 (issued March 9, 2018)</td>
<td>The effective date for the amendments to ASC 320 is the same as the effective date of ASU 2016-01. Other amendments are effective upon issuance.</td>
<td>The effective date for the amendments to ASC 320 is the same as the effective date of ASU 2016-01. Other amendments are effective upon issuance.</td>
<td>N/A</td>
<td>March 9, 2018, US GAAP Plus news item</td>
</tr>
<tr>
<td>ASU Number</td>
<td>Description</td>
<td>Effective Dates</td>
<td>Adoption Conditions</td>
<td>Adoption Dates</td>
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<tr>
<td>ASU 2018-03, Technical Corrections and Improvements to Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities (issued February 28, 2018)</td>
<td>Fiscal years beginning after December 15, 2017, and interim periods within those fiscal years beginning after June 15, 2018. Entities with fiscal years beginning between December 15, 2017, and June 15, 2018, are not required to adopt these amendments until the interim period beginning after June 15, 2018, and entities with fiscal years beginning between June 15, 2018, and December 15, 2018, are not required to adopt these amendments before adopting the amendments in ASU 2016-01. For all other entities, the effective date is the same as the effective date in ASU 2016-01.</td>
<td>The effective date is the same as the effective date in ASU 2016-01.</td>
<td>Yes, if the entity has adopted ASU 2016-01.</td>
<td>March 2, 2018, journal entry</td>
</tr>
<tr>
<td>ASU</td>
<td>Description</td>
<td>Effective Period</td>
<td>Yes/No</td>
<td>Effective Date</td>
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<tr>
<td>ASU 2017-13, Revenue Recognition (Topic 605), Revenue From Contracts With Customers (Topic 606), Leases (Topic 840), and Leases (Topic 842): Amendments to SEC Paragraphs Pursuant to the Staff Announcement at the July 20, 2017 EITF Meeting and Rescission of Prior SEC Staff Announcements and Observer Comments (issued September 29, 2017)</td>
<td>Effective upon adoption of ASC 606, Revenue From Contracts With Customers, and ASC 842, Leases.</td>
<td>Effective upon adoption of ASC 606, Revenue From Contracts With Customers, and ASC 842, Leases.</td>
<td>Yes</td>
<td>October 2, 2017, US GAAP Plus news item and July 20, 2017, Heads Up</td>
</tr>
<tr>
<td>ASU 2017-11, (Part I) Accounting for Certain Financial Instruments With Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests With a Scope Exception (issued July 13, 2017)</td>
<td>The amendments in Part I are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. No transition guidance is required for the amendments in Part II because those amendments do not have an accounting effect.</td>
<td>Yes</td>
<td>July 21, 2017, Heads Up, A Roadmap to Accounting for Contracts on an Entity’s Own Equity, and A Roadmap to Distinguishing Liabilities From Equity</td>
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<tr>
<td>ASU 2017-10, Determining the Customer of the Operation Services — a consensus of the FASB Emerging Issues Task Force (issued May 16, 2017)</td>
<td>For PBEs that have not adopted ASU 2014-09, the amendments are effective at the same time ASU 2014-09 is effective. For entities that have adopted ASU 2014-09, the amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, for a PBE; a not-for-profit (NFP) entity that has issued, or is a conduit bond obligor for, securities that are traded, listed, or quoted on an exchange or an over-the-counter market; and an employee benefit plan that files or furnishes financial statements with or to the SEC.</td>
<td>Yes</td>
<td>March 2017 EITF Snapshot</td>
<td></td>
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<tr>
<td>ASU Number</td>
<td>Description</td>
<td>Effective Dates</td>
<td>Heads Up</td>
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<tr>
<td>ASU 2017-04, Simplifying the Test for Goodwill Impairment (issued January 26, 2017)</td>
<td>For PBEs that are SEC filers, the amendments in the ASU are effective for annual and interim goodwill impairment tests in fiscal years beginning after December 15, 2019. For PBEs that are not SEC filers, the ASU’s amendments are effective for annual and interim goodwill impairment tests in fiscal years beginning after December 15, 2020.</td>
<td>February 1, 2017, Heads Up</td>
<td>Yes</td>
<td></td>
</tr>
</tbody>
</table>

**Examples:**

- **ASU 2017-08:**
  - Fiscal years and interim periods beginning after December 15, 2018.
  - March 14, 2017, Heads Up
  - Yes

- **ASU 2017-07:**
  - Annual periods beginning after December 15, 2017, including interim periods within those annual periods.
  - November 16, 2016, EITF Snapshot
  - Yes

- **ASU 2017-06:**
  - February 14, 2017, Heads Up
  - Yes

- **ASU 2017-05:**
  - See effective date information for ASU 2014-09 below.
  - February 14, 2017, Heads Up
  - Yes

- **ASU 2017-04:**
  - See effective date information for ASU 2014-09 below.
  - February 1, 2017, Heads Up
  - Yes, for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017

- **ASU 2017-01:**
  - Yes, in certain circumstances.
  - January 13, 2017, Heads Up and A Roadmap to Accounting for Asset Acquisitions
<table>
<thead>
<tr>
<th>ASU</th>
<th>Description</th>
<th>Adoption Dates</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASU 2016-13, Measurement of Credit Losses on Financial Instruments (issued June 16, 2016)</td>
<td>For PBEs that are SEC filers, the amendments in the ASU are effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. For all other PBEs, the amendments in the ASU are effective for fiscal years beginning after December 15, 2020, including interim periods within those fiscal years.</td>
<td>Yes, as of fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.</td>
<td>June 17, 2016, <em>Heads Up</em></td>
</tr>
<tr>
<td>---</td>
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<td>---</td>
</tr>
<tr>
<td>ASU 2016-12, Revenue From Contracts With Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients (issued May 9, 2016)</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>Yes</td>
</tr>
<tr>
<td>ASU 2016-10, Identifying Performance Obligations and Licensing (issued April 14, 2016)</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>Yes</td>
<td>April 15, 2016, <em>Heads Up</em></td>
</tr>
<tr>
<td>---</td>
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<td>---</td>
<td>---</td>
</tr>
<tr>
<td>ASU 2016-08, <em>Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)</em> (issued March 17, 2016)</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>Yes</td>
</tr>
</tbody>
</table>
| ASU 2016-02, *Leases* (issued February 25, 2016) | Effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, for any of the following:  
- PBEs.  
- NFPs that have issued, or are a conduit bond obligor for, securities that are traded, listed, or quoted on an exchange or an over-the-counter market.  
- Employee benefit plans that file financial statements with the SEC. | For all other entities, the amendments in the ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. | Yes | March 1, 2016, and April 25, 2017, *Heads Up* newsletters |
<p>| ASU 2016-01, <em>Recognition and Measurement of Financial Assets and Financial Liabilities</em> (issued January 5, 2016) | Fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. | For all other entities, including NFPs and employee benefit plans within the scope of ASC 960 through ASC 965 on plan accounting, the amendments in the ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. | Certain provisions only | January 12, 2016, <em>Heads Up</em> |</p>
<table>
<thead>
<tr>
<th>ASU</th>
<th>Description</th>
<th>Implementation Dates</th>
<th>Early Adoption Permitted</th>
<th>Effect Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASU 2015-14, Revenue From Contracts With Customers (Topic 606): Deferral of the Effective Date (issued August 12, 2015)</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>See effective date information for ASU 2014-09 below.</td>
<td>Yes</td>
<td>August 13, 2015, journal entry</td>
</tr>
<tr>
<td>ASU 2014-09, Revenue From Contracts With Customers (issued on May 28, 2014; effective date amended by ASU 2015-14, which was issued on August 12, 2015)</td>
<td>For PBEs, certain NFPs, and certain employee benefit plans, the ASU is effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2017.</td>
<td>Annual reporting periods beginning after December 15, 2018, and interim reporting periods beginning after December 15, 2019.</td>
<td>For PBEs, certain NFPs, and certain employee benefit plans, early application is permitted only as of annual reporting periods beginning after December 15, 2018.</td>
<td>A Roadmap to Applying the New Revenue Recognition Standard May 28, 2014, January 22, 2018, and April 11, 2018, Heads Up newsletters</td>
</tr>
</tbody>
</table>
# Current Status of Other FASB Projects

The table below summarizes the current status and next steps for the FASB’s active standard-setting projects (selected projects only and excluding research initiatives).

<table>
<thead>
<tr>
<th>Project</th>
<th>Status and Next Steps</th>
<th>Deloitte Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Recognition and Measurement Projects</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Codification improvements                    | On October 3, 2017, the FASB issued a proposed ASU that would make Codification improvements to a wide variety of topics. Comments were due by December 4, 2017. On April 11, 2018, the FASB redeliberated the proposed amendments and directed the staff to draft a final ASU for a vote by written ballot. The final ASU is expected to be issued in the third quarter of 2018.  
In May 2018, the FASB issued ASU 2018-06, which supersedes outdated guidance in ASC 942 related to bank regulatory accounting principles. The ASU became effective upon issuance. | Journal Entry — Hedging — FASB Discusses Feedback on Key Implementation Issues (April 10, 2018)                                                                                       |
<p>| Codification improvements: financial instruments | On March 28, 2018, the FASB directed its staff to obtain external-review feedback on potential Codification improvements related to the concept of the change in hedged risk in ASC 815-30-35-37A. |                                    |
| Collaborative arrangements: targeted improvements | On April 26, 2018, the FASB issued a proposed ASU that would amend ASC 808 to clarify when transactions between participants in a collaborative arrangement should be accounted for as revenue transactions under ASC 606. Comments were due by June 11, 2018. | Heads Up — FASB Proposes Guidance on Collaborative Arrangements (April 30, 2018)                                |
| Consolidation reorganization and targeted improvements | On September 20, 2017, the FASB issued a proposed ASU that would reorganize the consolidation guidance in ASC 810 by dividing it into separate subtopics for voting interest entities and variable interest entities (VIEs). The new subtopics would be included in a new topic, ASC 812, which would supersede ASC 810. Comments on the proposal were due by December 4, 2017. | Heads Up — FASB Proposes to Reorganize Its Consolidation Guidance (October 5, 2017)                                |
| <strong>Consolidation: targeted improvements to related-party guidance for VIEs</strong> | On June 22, 2017, the FASB published a <strong>proposed ASU</strong> under which (1) private companies “would not have to apply VIE guidance to legal entities under common control . . . if both the parent and the legal entity being evaluated for consolidation are not [PBEs]”; (2) “[i]ndirect interests held through related parties in common control arrangements would be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests”; and (3) consolidation would no longer be mandatory when “power is shared among related parties or when commonly controlled related parties, as a group, have the characteristics of a controlling financial interest but no reporting entity individually has a controlling financial interest.” Comments on the proposal were due by September 5, 2017. On <strong>May 16, 2018</strong>, and <strong>June 6, 2018</strong>, the Board directed the staff to draft a final ASU that reflects the <strong>tentative decisions</strong> reached to date for a vote by written ballot. The FASB expects to issue the final ASU in the third quarter of 2018. |
| <strong>Customer's accounting for implementation costs incurred in a cloud computing arrangement that is considered a service contract (EITF Issue 17-A)</strong> | On March 1, 2018, the FASB issued a <strong>proposed ASU</strong> that would amend ASC 350-40 to address a customer's accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. Comments were due by April 30, 2018. On June 7, 2018, the EITF discussed the comment letters received and reached a final consensus. The FASB expects to issue a final ASU in the third quarter of 2018. |
| <strong>Distinguishing liabilities from equity (including convertible debt)</strong> | The FASB <strong>added</strong> this project to its technical agenda on September 20, 2017. The purpose of the project is “to improve understandability and reduce complexity, without sacrificing the information that users of financial statements need.” The project will focus on “indexation and settlement (within the context of the derivative scope exception), along with convertible debt, disclosures, and earnings per share.” On December 13, 2017, the FASB <strong>discussed</strong> the project plan. On <strong>June 6, 2018</strong>, the Board discussed the direction of the project with respect to convertible instruments and indexation. |</p>
<table>
<thead>
<tr>
<th>Topic</th>
<th>Description</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hedging: last-of-layer method</td>
<td>On March 28, 2018, the FASB decided to add a narrow-scope project to address the accounting for last-of-layer basis adjustments and hedging multiple layers under the last of layer method in accordance with ASU 2017-12.</td>
<td><em>Journal Entry — Hedging — FASB Discusses Feedback on Key Implementation Issues (April 10, 2018)</em></td>
</tr>
<tr>
<td>Improvements to accounting for episodic television series (EITF Issue 18-B)</td>
<td>On March 28, 2018, the FASB decided to add a narrow-scope project to the EITF’s agenda to address the capitalization, amortization, and impairment of, and disclosures about, episodic television series costs. On June 7, 2018, the EITF began deliberating this issue.</td>
<td><em>EITF Snapshot (June 2018)</em></td>
</tr>
<tr>
<td>Improving the accounting for asset acquisitions and business combinations</td>
<td>On August 2, 2017, the FASB tentatively decided that this project should (1) address differences between the accounting for acquisitions of assets and that for acquisitions of businesses and (2) focus on the accounting for transaction costs, in-process research and development, and contingent consideration. On May 8, 2018, the FASB discussed how certain aspects of the accounting for asset acquisitions could be aligned with those for business combinations.</td>
<td></td>
</tr>
<tr>
<td>Inclusion of the Overnight Index Swap (OIS) Rate based on the Secured Overnight Financing Rate (SOFR) as a benchmark interest rate for hedge accounting purposes</td>
<td>On February 20, 2018, the FASB issued a proposed ASU that would add the OIS rate based on the SOFR to the list of permissible benchmark rates for hedge accounting purposes. Comments were due by March 30, 2018.</td>
<td><em>Journal Entry — FASB Adds Project on New Benchmark Interest Rate (December 20, 2017)</em></td>
</tr>
<tr>
<td>Topic</td>
<td>Description</td>
<td></td>
</tr>
<tr>
<td>-------</td>
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</tr>
<tr>
<td>Insurance: targeted improvements to the accounting for long-duration contracts</td>
<td>On September 29, 2016, the FASB issued a <strong>proposed ASU</strong> that would make targeted improvements to the recognition, measurement, presentation, and disclosure requirements for long-duration contracts issued by insurance entities. Comments on the proposal were due by December 15, 2016. On June 6, 2018, the FASB concluded its redeliberations and directed the staff to draft a final ASU that reflects the <strong>tentative decisions</strong> reached to date for a vote by written ballot. The FASB expects to issue the ASU in the third quarter of 2018. For PBEs, the ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. For all other entities, the ASU will be effective for fiscal years beginning after December 15, 2021, and interim periods within fiscal years beginning after December 15, 2022. Early adoption is permitted for all entities.</td>
<td></td>
</tr>
<tr>
<td>Leases: targeted amendments to ASC 842</td>
<td>On January 5, 2018, the FASB issued a <strong>proposed ASU</strong> that would make targeted improvements to certain aspects of its new leasing standard, ASU 2016-02. Comments were due by February 2, 2018. On March 7, 2018, the FASB discussed feedback received. On March 28, the FASB directed the staff to draft a final ASU for a vote by written ballot. The final ASU is expected to be issued in the third quarter of 2018. Except for early adopters of ASC 842, entities will apply the same effective date and transition requirements as those for ASC 842.</td>
<td></td>
</tr>
<tr>
<td>Practical expedients for sales taxes and certain lessor costs paid by lessees in lease contracts</td>
<td>On March 28, 2018, the FASB decided to add to its agenda a project to permit lessors to analogize to certain revenue recognition guidance and directed the staff to begin drafting a proposed ASU for external review.</td>
<td></td>
</tr>
<tr>
<td>Nonemployee share-based payment accounting improvements</td>
<td>On June 20, 2018, the FASB issued <strong>ASU 2018-07</strong>, which aligns the accounting guidance on share-based payments to nonemployees with that for employees. The ASU is effective for PBEs for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. For non-PBEs, the ASU is effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, but no earlier than an entity’s adoption of ASU 2014-09.</td>
<td></td>
</tr>
</tbody>
</table>

**Journal Entry** — **FASB Concludes Redeliberations on Targeted Improvements to the Long-Duration Insurance Contracts Accounting Model and Authorizes Staff to Proceed to a Final ASU (June 7, 2018)**

**Insurance Spotlight** — **FASB Proposes Improvements to the Accounting for Long-Duration Contracts (October 7, 2016)**

**Journal Entry** — **FASB Discusses Feedback on Proposed Targeted Improvements to New Leasing Standard (March 8, 2018)**

**Heads Up** — **FASB Tentatively Decides to Relieve Entities From Implementing Certain Aspects of the New Leasing Standard (December 5, 2017)**

**Heads Up** — **FASB Simplifies the Accounting for Share-Based Payment Arrangements With Nonemployees (June 21, 2018)**
**Current Status of Other FASB Projects**

<table>
<thead>
<tr>
<th>Recognition under ASC 805 for an assumed liability in a revenue contract (EITF Issue 18-A)</th>
<th>On March 28, 2018, the FASB decided to add a project to the EITF’s agenda to address the recognition of an assumed liability in a revenue contract acquired in a business combination. On June 7, 2018, the EITF reached a consensus-for-exposure. The FASB expects to issue the proposed ASU in the third quarter of 2018.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue recognition of grants and contracts by NFPs</td>
<td>On June 21, 2018, the FASB issued ASU 2018-08, which clarifies whether grants and certain other transactions should be accounted for as either a contribution under ASC 958-605 or an exchange transaction under ASC 606 or other GAAP.</td>
</tr>
<tr>
<td>Technical corrections and improvements: leases</td>
<td>On September 27, 2017, the FASB issued a proposed ASU that would make technical corrections and improvements related to leases (ASU 2016-02). Comments were due by November 13, 2017. On January 24, 2018, the Board discussed feedback received and directed the staff to draft a final ASU for a vote by written ballot. The FASB expects to issue the final ASU in the third quarter of 2018.</td>
</tr>
<tr>
<td>Updating the definition of collections</td>
<td>On June 26, 2018, the FASB issued a proposed ASU that would update the definition of collections (i.e., works of art, historical treasures, or similar assets that meet specific criteria) in the ASC master glossary. Comments are due by August 10, 2018.</td>
</tr>
</tbody>
</table>

**Presentation and Disclosure Projects**

<table>
<thead>
<tr>
<th>Disclosure framework: disclosure review — defined benefit plans</th>
<th>On January 26, 2016, the FASB issued a proposed ASU that would modify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. Comments on the proposal were due by April 25, 2016. On March 14, 2018, the FASB directed its staff to draft a final ASU that reflects the tentative decisions it has reached for a vote by written ballot. The final ASU is expected to be issued in the third quarter of 2018. The ASU will be effective for fiscal years ending after December 15, 2020, for public business entities and December 15, 2021, for all other entities. Early adoption will be permitted.</th>
</tr>
</thead>
</table>

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**EITF Snapshot (June 2018)**

**Journal Entry — FASB Adds Three Projects to the Technical Agenda (April 3, 2018)**

**Heads Up — FASB Proposes Amendments to New Leasing Standard (October 3, 2017)**

**Journal Entry — FASB Votes to Finalize Proposed Changes to the Disclosure Requirements for Defined Benefit Plans (March 16, 2018)**

**Heads Up — FASB Proposes Guidance on Presentation of Net Periodic Benefit Cost and Disclosures Related to Defined Benefit Plans (January 28, 2016)**
<table>
<thead>
<tr>
<th>Disclosure framework: disclosure review — fair value measurement</th>
<th>On December 3, 2015, the FASB issued a proposed ASU that would modify the disclosure requirements related to fair value measurement. Comments on the proposal were due by February 29, 2016. On March 7, 2018, the FASB directed its staff to draft a final ASU that reflects the tentative decisions it has reached for a vote by written ballot. The final ASU is expected to be issued in the third quarter of 2018. The ASU will be effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption will be permitted. <em>Heads Up — FASB Proposes Amendments to the Disclosure Requirements for Fair Value Measurements (December 8, 2015)</em></th>
</tr>
</thead>
<tbody>
<tr>
<td>Disclosure framework: disclosure review — income taxes</td>
<td>On July 26, 2016, the FASB issued a proposed ASU that would modify existing and add new income tax disclosure requirements. Comments on the proposed ASU were due by September 30, 2016. On January 25, 2017, the Board discussed the feedback received on the proposed ASU. <em>Heads Up — FASB Proposes Updates to Income Tax Disclosure Requirements (July 29, 2016)</em></td>
</tr>
<tr>
<td>Disclosure framework: disclosure review — inventory</td>
<td>On January 10, 2017, the FASB issued a proposed ASU that would modify or eliminate certain disclosure requirements related to inventory and establish new requirements. Comments on the proposed ASU were due by March 13, 2017. On June 21, 2017, the Board discussed a summary of comments received. <em>Heads Up — FASB Proposes Updates to Inventory Disclosures (January 12, 2017)</em></td>
</tr>
<tr>
<td>Disclosure framework: disclosures — interim reporting</td>
<td>The purpose of this project is to improve the effectiveness of interim disclosures. At its May 28, 2014, meeting, the FASB decided to amend ASC 270 “to reflect that disclosures about matters required to be set forth in annual financial statements should be provided on an updated basis in the interim report if there is a substantial likelihood that the updated information would be viewed by a reasonable investor as significantly altering the ‘total mix’ of information available to the investor.”</td>
</tr>
</tbody>
</table>
### Disclosures by business entities about government assistance

On November 12, 2015, the FASB issued a [proposed ASU](#) that would require specific disclosures about government assistance received by businesses. Comments on the proposed ASU were due by February 10, 2016.

At its June 8, 2016, meeting, the FASB made [tentative decisions](#) about the project’s scope, whether to require disclosures about government assistance received but not recognized directly in the financial statements, and omission of information when restrictions preclude an entity from disclosing the information required. On April 5, 2018, the Board directed the staff to perform additional research.

### Financial performance reporting: disaggregation of performance information

The FASB [added](#) this project to its technical agenda on September 20, 2017, “to focus on the disaggregation of performance information either through presentation in the statement of income or disclosure in the notes.” On December 13, 2017, the FASB [discussed](#) the project plan. On March 28, 2018, the FASB [directed](#) its staff to perform additional outreach.

### Segment reporting

The FASB [added](#) this project to its technical agenda on September 20, 2017. The purpose of the project is to improve “the aggregation criteria and segment disclosures.” On December 13, 2017, the FASB [discussed](#) the project plan. On February 7, 2018, the FASB [discussed](#) potentially reordering the reportable segments process. On June 13, 2018, the FASB [discussed](#) a plan to perform extended outreach.

### Simplifying the balance sheet classification of debt

On January 10, 2017, the FASB issued a [proposed ASU](#) that would reduce the complexity of determining whether debt should be classified as current or noncurrent in a classified balance sheet. Comments on the proposal were due by May 5, 2017. On June 28, 2017, the Board discussed a [summary of comments](#) received. On September 13, 2017, the Board concluded its redeliberations and [directed](#) the staff to draft a final ASU for a vote by written ballot. The FASB expects to issue this ASU in the third quarter of 2018.
Section 5 — New Revenue Recognition Model
Background

In May 2014, the FASB and IASB® issued their final standard on revenue from contracts with customers. The standard, issued as ASU 2014-09 by the FASB and as IFRS 15 by the IASB, outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most legacy revenue recognition guidance, including industry-specific guidance. The main provisions of the ASU are codified in ASC 606.

The goals of the ASU are to clarify and converge the revenue recognition principles under U.S. GAAP and IFRS Standards and to develop guidance that would streamline and enhance revenue recognition requirements while also providing “a more robust framework for addressing revenue issues.” The boards believe that the standard will improve the consistency of the requirements, the comparability of revenue recognition practices, and the usefulness of disclosures.

The ASU states that the core principle for revenue recognition is that an “entity shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.”

As a result of the ASU, entities will need to comprehensively reassess their current revenue accounting and determine whether changes are necessary. Entities are also required to provide significantly expanded disclosures about revenue recognition, including both quantitative and qualitative information about (1) the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers; (2) the judgment, and changes in judgment, used in applying the revenue model; and (3) the assets recognized from costs to obtain or fulfill a contract with a customer.

Largely as a result of feedback provided by the TRG, the FASB has issued the following final ASUs and proposed ASU to amend and clarify the scope and accounting guidance in the new revenue standard:

- **ASU 2016-08 on principal-versus-agent considerations** — Issued in March 2016, ASU 2016-08 addresses issues regarding how an entity should assess whether it is the principal or the agent in contracts that include three or more parties. Specifically, the ASU includes guidance on (1) how to determine the unit of account for the principal-versus-agent assessment, (2) how the principal-versus-agent indicators in ASC 606 would help an entity determine whether it obtains control of a good or service (or a right to a good or service) before the good or service is transferred to the customer, and (3) how certain indicators are related to the general control principle in ASC 606. In addition, the ASU clarifies that an entity (1) should evaluate whether it is the principal or the agent for each specified good or service in a contract and (2) could be the principal with respect to certain distinct performance obligations in a contract and the agent with respect to others.

- **ASU 2016-10 on identifying performance obligations and licensing** — Issued in April 2016, ASU 2016-10 clarifies the new revenue standard’s guidance on an entity’s identification of certain performance obligations. The ASU adds guidance on immaterial promised goods and services. Other amendments include (1) a policy election for shipping and handling activities performed after control of a good is transferred to a customer and (2) clarifications related to licenses.
Key Accounting Issues

**ASU 2016-12 on narrow-scope improvements and practical expedients** — Issued in May 2016, ASU 2016-12 (1) clarifies how to assess whether collectibility of consideration to which an entity is entitled is probable under certain circumstances, (2) adds a practical expedient to allow entities to present amounts collected and remitted for sales taxes on a net basis in revenue, (3) clarifies how to account for noncash consideration at contract inception and throughout the contract period, and (4) adds a practical expedient for assessing the impact of historical contract modifications upon transition.

**ASU 2016-20 on technical corrections and improvements** — Issued in December 2016, ASU 2016-20 amends certain aspects of the new revenue standard. Included in the amendments are new optional exemptions from the disclosure requirements related to the performance obligations in specific situations in which it is unnecessary for an entity to estimate variable consideration to recognize revenue. The amendments also require expanded disclosures when an entity applies one of the optional exemptions.

**Proposed ASU on accounting for contributions for NFP entities** — In August 2017, the FASB issued a proposed ASU that would clarify the scope and accounting guidance for contributions received and made by NFP entities. Specifically, the proposed ASU notes that it is intended to “clarify and improve current guidance about whether a transfer of assets is an exchange transaction or a contribution. The proposed amendments would clarify how an entity determines whether a resource provider is participating in an exchange transaction by evaluating whether the resource provider is receiving commensurate value in return for the resources transferred.”

### Connecting the Dots

For more information on final and proposed ASUs, see Section 19.2.2 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*, a comprehensive resource to help entities understand and implement the final guidance.

Consistency in application of the new revenue standard to similar circumstances both within and across industries has been stressed by the SEC and discussed publicly to emphasize its importance. To help achieve this objective, the AICPA formed 16 industry-specific task forces composed of auditors and company representatives from the affected industry sectors. The task forces were charged with addressing implementation questions that have a pervasive effect across a given industry in order to publish interpretive guidance that can be used as a resource to promote consistency among preparers.

The P&U industry task force, which is one of the 16, developed interpretive guidance on revenue recognition for the P&U industry. This guidance was reviewed by the AICPA’s revenue recognition working group (RRWG) and the AICPA’s Financial Reporting Executive Committee (FinREC) and then was subjected to public comment. As of the date of this publication, all P&U industry issues addressed by the task force have been resolved and included in the AICPA Audit and Accounting Guide *Revenue Recognition* (the “AICPA Revenue Guide”).

### Key Accounting Issues

Although the new revenue standard may not significantly change how P&U entities typically recognize revenue, certain requirements of the standard may mandate a change from current practice. In addition, we expect that entities will expand revenue-related disclosures to comply with the provisions of the new revenue standard. Discussed in this section are some key provisions of the new revenue standard that may affect P&U entities as well as how the guidance might be considered in some typical transactions.
Each of the implementation issues that were considered by the P&U industry task force is summarized in the table below and is linked to further discussion throughout this section.

<table>
<thead>
<tr>
<th>Issue No.</th>
<th>Description</th>
<th>Summary/Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-1</td>
<td>Scope clarification regarding tariff sales to regulated customers</td>
<td>Tariff sales (other than alternative revenue program amounts) are within the new revenue standard's scope.</td>
</tr>
<tr>
<td>13-2</td>
<td>Requirements and similar contracts with variable quantities</td>
<td>Volume variability will often represent optional purchases (will not represent variable consideration).</td>
</tr>
<tr>
<td>13-3</td>
<td>Step vs. strip price arrangements</td>
<td>Different pricing for same performance may lead to different recognition patterns.</td>
</tr>
<tr>
<td>13-4</td>
<td>Determining stand-alone selling price (SASP) for forward sales of commodities (formerly application of series guidance to storable commodities)</td>
<td>SASP must be determined on the basis of facts and circumstances. The forward curve is not necessarily appropriate in all circumstances.</td>
</tr>
<tr>
<td>13-5</td>
<td>Accounting for contract modifications (blend and extend (B&amp;E))</td>
<td>Either of two methods is acceptable.</td>
</tr>
<tr>
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**Scope Considerations**

**Tariff Sales of a Regulated Utility**

One of the issues that the P&U industry task force reviewed was whether sales to tariff-based customers are within the scope of the new revenue standard and, if so, how to determine the term of the contractual relationship with each customer as well as any rights or obligations arising from the contract.

The RRWG and FinREC agreed with the task force’s consensus that sales to tariff-based customers are within the scope of the new revenue standard. As a result, tariff sales are subject to the presentation
Key Accounting Issues

Connecting the Dots
With respect to the term of the contractual relationship with the customer, in the absence of an explicit or implied term, an entity would look to performance completed to date to determine the legal rights and obligations each party has under the contract.

Day-Ahead Electricity Sales
ASC 606 is not applicable to derivatives within the scope of ASC 815. Accordingly, companies will need to distinguish customer revenue from derivative revenue either on the face of the income statement or in a financial statement disclosure. This requirement generally exists for other revenue sources outside of the scope of ASC 606, including lease revenue.

Given the requirement to separately present or disclose derivative revenue, some companies have inquired about the treatment of day-ahead electricity sales. Specifically, companies have assessed whether day-ahead physical sales of electricity are derivatives, despite their very short-term nature, and therefore must be separated from customer revenue under ASC 606. Many companies treat day-ahead sales as spot, or real-time, sales, viewing the one-day forward period as a scheduling mechanism required by the market operator. Under this view, day-ahead sales are not treated as derivatives for accounting purposes — that is, they are not marked to market, not subjected to derivative or fair value disclosures, and so forth. We do not believe that ASC 606 changes this view, and therefore we would accept an accounting policy that includes day-ahead sales within the scope of ASC 606. We believe that companies should establish a policy for treatment of day-ahead sales, apply it consistently, and consider disclosure of the policy if such sales are material. Companies that treat these transactions as customer revenue should apply the full ASC 606 model, including the related disclosure requirements.

Contract Modifications
P&U entities should consider how they are affected by the new revenue standard's guidance on accounting for modifications to contracts with customers. The approval of a contract modification can be in writing, by oral agreement, or implied by customary business practices, and a contract modification is considered approved when it creates new, or changes existing, enforceable rights or obligations. A contract modification must be accounted for as a separate contract when (1) it results in a change in contract scope because of additional promised “distinct” goods or services (see Distinct Performance Obligations below) and (2) the additional consideration reflects the entity’s SASP for those additional promised goods or services (including any appropriate adjustments to reflect the circumstances of the contract). That is, the entity would continue to account for the existing contract as if it were not modified and account for the additional goods or services provided in the modification as a “new” contract.

If a contract modification is not considered a separate contract (i.e., it does not meet the criteria above), an entity should evaluate the remaining goods and services in the modified contract and determine whether to account for the modification prospectively (if the remaining goods and services are distinct from those already transferred) or retrospectively in accordance with the new revenue standard. If the remaining goods and services are distinct from those already transferred, the modification is accounted for prospectively, the transaction price is updated (i.e., it now includes both the remaining consideration from the original contract and the additional consideration in the modification), and the updated transaction price is allocated to the remaining goods and services to be transferred. In contrast, if the goods or services are not distinct and are part of a single performance obligation, the modification is treated retrospectively and the amount of revenue recognized to date is adjusted to reflect the new
modified contract (e.g., the measure of progress is adjusted to account for the new expectation of performance completed), resulting in a cumulative-effect catch-up adjustment.

As previously discussed, in May 2016, the FASB issued ASU 2016-12, which adds a practical expedient to facilitate how to evaluate historical contract modifications at transition. The ASU also defines completed contracts as those for which all (or substantially all) revenue was recognized under the applicable revenue guidance before the new revenue standard was initially applied.

**Blend-and-Extend Contract Modifications**

For B&E contract modifications, stakeholders have questioned how the payment terms affect the evaluation of the contract modification (i.e., whether the modification should be accounted for as a separate contract). In a typical B&E modification, the supplier and customer may renegotiate the contract to allow the customer to take advantage of lower commodity pricing while the supplier increases its future delivery portfolio. Under such circumstances, the customer and supplier agree to extend the contract term and “blend” the remaining original, higher contract rate with the lower market rate of the extension period for the remainder of the combined term. The supplier therefore defers the cash realization of some of the contract fair value that it would have received under the original contract terms until the extension period, at which time it will receive an amount that is greater than the market price for the extension-period deliveries as of the date of the modification.

**Potential Impact of the New Revenue Model on B&E Contract Modifications**

This is best illustrated by a simple example. Assume that a supplier and a customer enter into a fixed-volume, five-year forward sale of electricity at a fixed price of $50 per unit. Further assume that years 1 through 3 have passed and both parties have met all of their performance and payment obligations during that period. At the beginning of year 4, the customer approaches the supplier and asks for a two-year contract extension, stretching the remaining term to four years. Electricity prices have gone down since the original agreement was executed; as a result, a fixed price for the two-year extension period is $40 per unit based on forward market price curves that exist at the beginning of year 4. The customer would like to negotiate a lower rate now while it is agreeing to extend the term of the original deal.

The supplier and customer agree to a B&E contract modification. Under the modification, the $50-per-unit fixed price from the original contract with two years remaining is blended with the $40-per-unit fixed price for the two-year extension period. The resulting blended rate for the remaining delivery years is $45 per unit.

There was uncertainty about whether the supplier should compare (1) the total increase in the aggregated contract price with the total SASP of the remaining goods or services (“View A”) or (2) the price the customer will pay for the additional goods or services (i.e., the $45-per-unit blended price paid for the goods or services delivered during the extension period) with the stand-alone selling price of those goods or services (“View B”). In addition, there was uncertainty about whether a B&E contract would inherently include a significant financing component as a result of the blending of the prices for the remainder of the combined term.

The P&U industry task force was unable to reach a consensus on whether a B&E contract modification should be accounted for as (1) a separate contract for the additional goods or services in accordance with ASC 606-10-25-12 (View A) or (2) the termination of an existing contract and the creation of a new contract in accordance with ASC 606-10-25-13(a) (View B).
This issue was discussed with the RRWG but was ultimately elevated to a discussion with the FASB staff through the staff’s technical inquiry process. During that process, the FASB staff indicated that both views are acceptable but noted that View B is more consistent with the staff’s interpretation of the contract modification guidance in the new revenue standard. The staff also indicated that entities will still need to assess whether B&E transactions include significant financing components; however, the staff noted that it did not think that every B&E contract modification inherently involves a financing.

FinREC believes that either View A or View B is a reasonable interpretation of the guidance; however, companies should select an approach on the basis of the facts and circumstances, to be applied consistently to contracts with similar fact patterns. Further, companies should consider disclosing their approach if it is material to the financial statements. FinREC also believes that there is no presumption of an inherent financing element that companies should account for separately. Rather, companies should evaluate the facts and circumstances to determine whether there is a significant benefit of financing provided to the customer that would warrant an adjustment to the transaction price to account for the effects of the time value of money. This issue is included in the latest edition of the AICPA Revenue Guide.

Partial Terminations

A P&U entity may enter into a contract with a customer for a performance obligation satisfied over time and later agree with the customer to terminate only a discrete unsatisfied portion of that contract. For example, in the second year of a five-year forward electricity sale, a P&U entity may agree to cancel the fifth in exchange for a payment from the buyer to make the seller whole for any forgone fair value related to year 5 of the arrangement. Alternatively, a P&U entity may agree to terminate the sale of 20 percent of the total electricity to be sold in each of the five years in exchange for a payment from the buyer to make the seller whole for any forgone fair value related to those deliveries.

The P&U industry task force addressed whether the consideration received to terminate a discrete performance obligation (or a discrete product or service within a single performance obligation) should be (1) recognized currently (as revenue or other income) or (2) deferred and recognized as revenue over the remaining contract term.

The task force reached a consensus that an entity should account for the consideration related to partial terminations by recognizing the consideration currently. However, the RRWG disagreed with the industry task force’s consensus, and this issue was elevated to a discussion with the FASB staff through the staff’s technical inquiry process and then discussed with the RRWG and FinREC. The ultimate consensus was that partial terminations are modifications of existing contracts and should be assessed in the context of the contract modification framework. However, ASC 606-10-25-12 is not applicable, since this guidance addresses circumstances in which the scope of a contract increases. ASC 606-10-25-13(a) would be applicable, since the remaining goods and services are distinct from those that have already been transferred. A seller must apply modification guidance to a partial termination, which would generally result in recognition over the remaining term of the contract as the remaining performance obligations are satisfied. This applies to payments made or received in connection with a partial termination. This issue is included in the latest edition of the AICPA Revenue Guide.
Distinct Performance Obligations

The new revenue standard provides guidance on evaluating the promised “goods or services” in a contract to determine each performance obligation (i.e., the unit of account). A performance obligation is each promise to transfer either of the following to a customer:

- “A good or service (or a bundle of goods or services) that is distinct.”
- “A series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer.”

Under the new revenue standard, a series of distinct goods or services has the same pattern of transfer if both of the following criteria are met: (1) each distinct good or service in the series meets the criteria for recognition over time and (2) the same measure of progress is used to depict performance in the contract. Therefore, a simple forward sale of electricity for which delivery of the same product is required over time and is immediately consumed by the customer would generally be treated as a single performance obligation that is satisfied over the contract term. In this case, a P&U entity would determine an appropriate method for measuring progress toward complete satisfaction of the single performance obligation (e.g., an output method based on electricity delivered) and would recognize the transaction price in revenue as progress is made.

Assessing Multiperiod Commodity Contracts

An entity will need to evaluate the customer’s ability, action, or intent to determine whether the customer will simultaneously receive and consume a commodity that is delivered. If so, the entity’s promised commodity deliveries would meet the criteria for recognizing revenue over time as a series of distinct goods or services accounted for as a single performance obligation (i.e., by meeting the criterion that the customer simultaneously receives and consumes the benefits provided by the entity’s performance as the entity performs). Customers in certain industries (e.g., oil and gas, P&U) may take different actions or have different intents for the commodity delivered by the entity.

For example, a gas utility customer of an entity that explores for and produces natural gas may store natural gas in a pool until demand from its own customers requires the natural gas to be used.

Conversely, residential customers of the gas utility may not have the necessary infrastructure to store natural gas in their homes and therefore must simultaneously receive and consume any natural gas delivered by the utility (e.g., to heat a stove).

An entity will need to carefully evaluate “all relevant facts and circumstances, including the inherent characteristics of the commodity, the contract terms, and information about infrastructure or other delivery mechanisms,” to determine whether the criterion in ASC 606-10-25-27(a) for recognizing revenue over time is met. For companies that do not have performance obligations that meet the criteria of ASC 606-10-25-14(b) (the “series guidance”) and instead have consecutive individual point-in-time deliveries, the next step would be to allocate the selling price to all of the individual point-in-time deliveries. For more information, see Section 8.4.1 in Deloitte’s A Roadmap to Applying the New Revenue Recognition Standard.

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1 Although the new revenue standard does not define goods or services, it includes several examples, such as goods produced (purchased) for sale (resale), granting a license, and performing contractually agreed-upon tasks.
2 Quoted from TRG Agenda Paper 43.
**Determining the SASP for Multiperiod Commodity Contracts**

When the transaction is deemed to represent multiple distinct performance obligations, each satisfied at a point in time, the seller will need to allocate the consideration on the basis of the relative stand-alone selling price of each distinct good or service. P&U companies often enter into multiyear contracts with their customers to provide commodities at a fixed price per unit. For certain types of commodities, there may be a forward commodity pricing curve and actively traded contracts for all or a portion of the contract’s duration. The forward commodity pricing curve may provide an indication of the price at which an entity could currently buy or sell a specified commodity for delivery in a specific month.

Sometimes, “strip” pricing may be available. In strip pricing, a single price is used to represent a single-price “average” of the expectations of the individual months in the strip period, which is typically referred to as a seasonal or annual strip. Terms of the multiperiod contracts are often derived, in part, in contemplation of the forward commodity pricing curve.

Certain arrangements for storable commodities may not meet the criteria in ASC 606-10-25-15 to be accounted for as a series of distinct goods that have the same pattern of transfer to the customer (and, therefore, as a single performance obligation). In these situations, when each commodity delivery is determined to be distinct, stakeholders have questioned whether entities are required to use the forward commodity pricing curve, the spot price, or some other value as the SASP for allocating consideration to multiperiod commodity contracts. A technical inquiry was submitted by the P&U industry task force and was completed by the FASB staff. The staff concluded that the forward curve may not be required in many cases. FinREC also believes that the use of a forward curve to determine the SASP is not required simply because there are observable commodity price curves. FinREC believes that an entity must evaluate the facts and circumstances of each contract to determine the SASP and allocate the transaction price to the individual performance obligations. This issue is included in the latest edition of the AICPA Revenue Guide.

**Connecting the Dots**

Entities should consider all of the relevant facts and circumstances, including market conditions, entity-specific factors, and information about the customer, in determining the SASP of each promised good. Certain situations may indicate that the forward curve provides the best indicator of the SASP. In other circumstances, the contract price may reflect the SASP for the commodity deliveries under a particular contract. The determination of the contract price and the resulting allocation of the transaction price need to be consistent with the overall allocation objective (i.e., to allocate the transaction price to each distinct good or service in an amount that depicts the amount of consideration to which the entity expects to be entitled in exchange for transferring the goods or services to the customer). Entities will need to use significant judgment in determining the SASP in these types of arrangements. For more information, see Section 7.2.3 in Deloitte’s *A Roadmap to Applying the New Revenue Recognition Standard*.

**Variable Pricing**

The new revenue standard requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is included in the transaction price only to the extent that it is probable that subsequent changes in the estimate would not result in a “significant reversal” of revenue. This concept is commonly referred to as the “constraint.” The new revenue standard requires entities to perform a qualitative assessment that takes into account the likelihood and magnitude of a potential revenue reversal and provides factors that could indicate that an

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3 “Probable” in this context has the same meaning as in ASC 450-20: “the event or events are likely to occur.” In IFRS 15, the IASB uses the term “highly probable,” which has the same meaning as the FASB’s “probable.”
estimate of variable consideration is subject to significant reversal (e.g., susceptibility to factors outside the entity's influence, long period before uncertainty is resolved, limited experience with similar types of contracts, practices of providing concessions, or a broad range of possible consideration amounts). This estimate would be updated in each reporting period to reflect changes in facts and circumstances.

The use of variable consideration (e.g., index or formula-based pricing) may present challenges related to estimating and allocating the transaction price and applying the new revenue standard's constraint guidance. For example, a P&U entity may have a multiyear contract to sell a fixed quantity of electricity each hour at a price derived from a formula, which also includes a performance bonus tied to availability. When the transaction price includes a variable amount, an entity must estimate the variable consideration by using either an “expected value” (probability-weighted) approach or a “most likely amount” approach, whichever is more predictive of the amount to which the entity expects to be entitled.

When an arrangement includes variable consideration, P&U entities should also consider whether (1) the practical expedient for measuring progress completed for performance obligations satisfied over time can be applied or (2) changes in variable consideration can be allocated to satisfied portions of distinct services provided to the customers.

P&U entities that have arrangements that include both price and volume variability should consider whether the volume variability is actually the result of optional purchases. Options for customers to purchase additional goods or services from a P&U entity would not be considered performance obligations (and, therefore, the resulting consideration would not be included in the transaction price) unless the options give rise to a material right. If the optional purchases do not give rise to a material right, the P&U entity would account for the optional purchases only once the options are exercised.

The P&U industry task force concluded that volume variability will often represent optional purchases (e.g., purchase decisions under a full requirements contract) and that pricing often represents a marketing offer as opposed to granting a material right. This view applies whether volumes are dictated by the customer or the customer’s customer (e.g., a utility buying from an independent power producer to serve end-user demand). This issue is included in the latest edition of the AICPA Revenue Guide.

**Power Purchase Agreements**

PPAs typically give the power purchaser the right, over the term of the contract, to buy from the power producer an amount of energy in exchange for a fixed price, a variable price, or a combination of fixed and variable pricing.

**Identifying the Contract With a Customer**

Two P&U entities will often enter into collaborative arrangements to develop a new generating plant or other asset; in such contracts, one of the two parties may agree to off-take part or all of the power produced. For example, an industrial manufacturer or utility that wants to obtain power and green attributes may collaborate with a supplier (that will construct, own, and retain tax benefits from the generating asset) to design and develop a solar or wind farm. The parties in such collaborative arrangements will need to consider all facts and circumstances to determine whether a supplier/customer relationship exists.
Identifying the Performance Obligation(s) in the Contract

When PPAs for electricity do not qualify as leases or derivatives, P&U entities are likely to conclude under the new revenue standard that a PPA represents a single performance obligation satisfied over time because:

- The product (electricity) is substantially the same and will be transferred consecutively in the series (see ASC 606-10-25-14(b)) — for example, in consecutive hourly deliveries of electricity over multiple years.
- The customer will simultaneously receive and consume the benefits of each distinct delivery of electricity (i.e., the delivery of electricity meets the criterion in ASC 606-10-25-27(a) and, as a result, the series meets the criterion in ASC 606-10-25-15(a)).
- The same measure of progress for each distinct delivery of electricity (e.g., a unit-based measure) would be used, thereby satisfying the criterion in ASC 606-10-25-15(b).

Note that an entity may need to consider additional factors when electricity is bundled with other products and services, as is frequently the case under a PPA. See Bundled Arrangements below for more information.

Determining the Transaction Price

The amount and timing of contract pricing in a PPA can vary as a result of a number of commercial terms and contract provisions. PPAs, including those related to renewable energy sources such as wind, often contain explicit variable pricing provisions. Other PPAs might also include payment amounts related to a minimum availability requirement — for example, to ensure that the supplier's investment in the generation asset is recovered. This minimum availability payment may be relatively large compared with variable payments.

In the determination of the transaction price, the evaluation of the constraint (i.e., whether a significant revenue reversal may occur) may be eased as the magnitude of any potential subsequent reversal is mitigated by the relative portion of consideration that is fixed (i.e., the minimum availability payment). See Variable Pricing above for additional discussion.

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

A supplier recognizes revenue in a PPA that is determined to be a performance obligation satisfied over time by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer (see Distinct Performance Obligations above for more details). Certain types of pricing provisions in a PPA may warrant a careful examination of the measure of progress to be used. Possible approaches for measuring progress may include (1) an output measure of progress (e.g., based on kWh delivered), (2) the invoicing method as an output measure of progress (i.e., as a practical expedient), or (3) an input measure of progress (e.g., costs incurred).

Connecting the Dots

The industry task force considered contracts that include strip-price or step-price conventions and whether different pricing conventions for the same performance could result in different revenue recognition patterns, as well as whether such price changes are indicative of a significant financing component. The industry task force concluded that different revenue profiles owing to different pricing conventions can be supported.

A straight-line revenue recognition pattern is in accordance with treatment as a single performance obligation satisfied over time and the application of an output method measure of
progress (assuming the same number of units is delivered each period). It is generally expected that deliveries under strip-price contracts will be recognized at the contract price and will usually not have embedded financing elements.

A step, or shaped, revenue recognition pattern is supportable if the contract price is consistent with the value that is delivered to the customer in the specified delivery period. That is, P&U entities may be able to use the invoicing practical expedient noted above when measuring progress toward complete satisfaction of the performance obligations in contracts with other pricing conventions (e.g., step-price arrangements). Doing so, however, would require P&U entities to use judgment to determine how the pricing was established (e.g., because of market-specific factors or entity-specific factors) and to assess whether the value transferred to the customer under step-price arrangements is consistent with the amount that the entities have the right to bill the customer.

The RRWG and FinREC agreed with the industry task force’s consensus that different revenue profiles can be supported. This matter is included in the latest edition of the AICPA Revenue Guide.

**Take-or-Pay Arrangements**

In a take-or-pay arrangement, a customer pays a specified price to a supplier for a minimum volume of product or level of services. Such an arrangement is referred to as “take-or-pay” because the customer must pay for the product or services regardless of whether it actually takes delivery. Power, natural gas, and other energy commodity off-take contracts, as well as certain service arrangements (e.g., those related to natural gas storage or transportation), may be structured as take-or-pay. These arrangements may have characteristics similar to those of other “stand ready” obligations in which an entity is required to pay for the availability of a resource regardless of whether the entity actually uses the resource.

**Identifying the Performance Obligation(s) in the Contract**

As in a PPA, in a take-or-pay arrangement for electricity, the supplier would generally conclude under the new revenue standard that it has entered into a contract with a customer to deliver a series of distinct, but substantially the same, goods delivered consecutively over time (see discussion above in **Distinct Performance Obligations**). The supplier should account for that series of distinct goods as a single performance obligation — and as a single unit of account — because:

- The customer simultaneously receives and consumes the benefits of each distinct delivery (or period of availability) of electricity (i.e., the delivery of electricity meets the criterion in ASC 606-10-25-27(a) and, as a result, the series meets the criterion in ASC 606-10-25-15(a)).
- The same measure of progress for each distinct delivery of electricity (e.g., a unit-based measure) would be used, thereby satisfying the criterion in ASC 606-10-25-15(b).

**Recognizing Revenue When (or as) Performance Obligations Are Satisfied**

Because the performance obligation in a take-or-pay arrangement is satisfied over time, the supplier recognizes revenue by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer. The best depiction of the supplier’s performance in transferring control of the goods and satisfying its performance obligation may differ depending on the terms of the take-or-pay arrangement:

- Consider a vanilla take-or-pay arrangement for monthly deliveries of power whereby the customer pays irrespective of whether it takes delivery and does not have the ability to make up
deliveries not taken. In this case, it may be appropriate to use an output measure of progress based on time to recognize revenue because the supplier could be satisfying its performance obligation as each month passes.

- In a take-or-pay arrangement for monthly deliveries of power whereby the customer can make up deliveries not taken later in the contract period, an output measure of progress based on units delivered may be appropriate. In this case, the supplier should recognize revenue for volumes of power actually delivered to the customer each month and recognize a contract liability for volumes not taken since the supplier's performance obligation associated with those volumes is unsatisfied despite receipt of customer payment.

**Bundled Arrangements**

Electricity is often sold in conjunction with other energy-related products and services, including capacity, various ancillary services such as voltage control, and renewable energy certificates (RECs). Companies regularly enter into transactions in which such items as energy, RECs, and capacity are bundled together in a single contract, often with one transaction price.

Companies should first consider whether there are scope considerations that need to be addressed, such as whether the arrangement contains a lease that is within the scope of ASC 840 (or ASC 842) or a derivative that is within the scope of ASC 815 or both.

The new revenue standard explicitly states that if other Codification topics address how to separate and account for the different products and services in a contract with a customer, entities should look to those topics first. Specifically, ASC 606-10-15-4 states:

A contract with a customer may be partially within the scope of this Topic and partially within the scope of other Topics . . .

a. If the other Topics specify how to separate and/or initially measure one or more parts of the contract, then an entity shall first apply the separation and/or measurement guidance in those Topics. . .

b. If the other Topics do not specify how to separate and/or initially measure one or more parts of the contract, then the entity shall apply the guidance in this Topic to separate and/or initially measure the part (or parts) of the contract.

A P&U entity should carefully consider its contracts with customers for multiple products and services and assess (1) whether products or services separated in accordance with the guidance in other Codification topics should be accounted for under the new revenue standard and (2) whether it should apply the new revenue standard's guidance on distinct performance obligations when separating multiple products and services in contracts with customers.

**Identifying the Performance Obligation(s) in the Contract**

As discussed above, P&U entities that sell, for example, RECs or capacity together with the related energy may need to assess whether the promise to deliver RECs represents a performance obligation that is “distinct” from the promise to deliver electricity (see discussion above in Distinct Performance Obligations). Under the new revenue standard, a performance obligation is distinct if it meets both of the following criteria in ASC 606-10-25-19:

- The good or service in the performance obligation is capable of being distinct (i.e., the customer can benefit from the good or service on its own or with readily available resources).
- The good or service is distinct in the context of the contract (i.e., it is separately identifiable from other goods or services in the contract).
If an entity concludes that the promise to deliver the RECs as part of a bundled arrangement, for example, meets both criteria, that promise will be considered a distinct performance obligation. Therefore, the transaction consideration will be proportionally allocated to each performance obligation (e.g., to the electricity and RECs). The industry task force and FinREC generally believe that when capacity is bundled with electricity in a single sale arrangement, the electricity will often be a distinct performance obligation. We would generally expect the same to be true in green energy sales consisting of electricity and RECs. Companies will need to consider the criteria of ASC 606-10-25-19 before coming to this conclusion. This issue is included in the latest edition of the AICPA Revenue Guide.

**Recognizing Revenue When (or as) Performance Obligations Are Satisfied**

After identifying the distinct performance obligations in a bundled arrangement, a P&U entity must assess when control of the good or service within each performance obligation is transferred (i.e., over time or at a point in time) to determine the appropriate pattern of revenue recognition.

Control of a good or service (and, therefore, satisfaction of the related performance obligation) is transferred over time when at least one of the following criteria is met:

- “The customer simultaneously receives and consumes the benefits provided by the entity’s performance as the entity performs.”
- “The entity's performance creates or enhances an asset . . . that the customer controls as the asset is created or enhanced.”
- “The entity's performance does not create an asset with an alternative use to the entity . . . and the entity has an enforceable right to payment for performance completed to date.”

If a performance obligation is not satisfied over time, it is deemed satisfied at a point in time. Under the new revenue standard, entities would consider the following indicators in evaluating the point at which control of an asset has been transferred to a customer:

- “The entity has a present right to payment for the asset.”
- “The customer has legal title to the asset.”
- “The entity has transferred physical possession of the asset.”
- “The customer has the significant risks and rewards of ownership of the asset.”
- “The customer has accepted the asset.”

The recognition of revenue is determined separately for each distinct performance obligation within a bundled arrangement. Therefore, there may be delays in the recognition of revenue attributable to other products and services that are sold with the related energy. Considerations related to this determination for two items frequently included in bundled PPAs — capacity and RECs — are discussed in more detail below.

**Sale of Capacity**

When an entity, such as an owner of a generation facility, commits to a forward sale agreement to deliver capacity, the nature of the seller’s promise is that of a stand-ready obligation. In other words, the nature of the seller’s performance obligation is not to deliver electricity but rather to be available to provide electricity when the customer needs it.
The question then becomes: Is a generator’s promise in a forward sale of capacity a performance obligation satisfied over time or at a point in time? This question applies to circumstances in which capacity and electricity are sold in a bundled arrangement or sold separately.

This matter has been addressed by the industry task force, the RRWG, and FinREC. The task force has concluded that the generator’s promise in a forward sale of capacity must meet the requirements in ASC 606-10-25-15 to be accounted for as a single performance obligation satisfied over time. If those requirements are met, the generator would (1) allocate the transaction price to the single performance obligation and (2) recognize revenue by using an output method that is based on time elapsed. Given that the performance obligation qualifies as a series and will use an output method to measure progress toward completion, the task force has also concluded that the performance obligation may qualify for the invoice practical expedient in ASC 606-10-55-18 when the seller’s right to consideration corresponds directly to the value of the capacity for the given month. Under this approach, it is likely that a shaped deal, whereby the shaped pricing reflects market rates for capacity, would result in a revenue pattern that follows the contract price. In some circumstances, it may be appropriate to use an input method to measure progress; judgment is required to come to this conclusion. However, in most cases, the use of the output method that is based on time elapsed is the most appropriate measure of progress, because it is assumed that the customer benefits equally throughout the contract period. This issue is included in the latest edition of the AICPA Revenue Guide.

Sale of RECs

RECs are frequently linked to output of renewable energy facilities (e.g., 1 MWh of renewable energy generated will equate to 1 REC). However, there is typically a certification process related to the RECs that lags behind the delivery of the associated electricity. Some entities have historically concluded that, although the transfer of the title to RECs may lag behind the selling of the energy, certification is perfunctory after generation of the energy is complete, and the patterns of revenue recognition for RECs should therefore match those for the energy. The timing of revenue recognition for RECs was addressed by the task force.

Under the new revenue standard, a seller of RECs should consider whether the delivery of RECs is (1) a single performance obligation satisfied over time or (2) multiple performance obligations that are each satisfied at a point in time. The P&U industry task force has reached a consensus that (1) the delivery of RECs reflects multiple performance obligations that are each satisfied at a point in time and (2) that control of the RECs is transferred to the customer at the same time as delivery of the electricity — regardless of whether there is any sort of certification lag. At the time the electricity is delivered, no further transfer of control by the seller is required. That is, revenue for RECs should be recognized upon delivery of the electricity to the customer. The RRWG reviewed and agreed with the task force’s conclusion. FinREC also agreed with the task force’s conclusion but also indicated that it may be acceptable to recognize revenue upon certification of the RECs, depending on the facts and circumstances. This would require evaluation of the indicators that control has transferred in ASC 606-10-25-30. This view is reflected in the latest edition of the AICPA Revenue Guide.

Contributions in Aid of Construction

Regulated P&U entities will often require a contribution in aid of construction (CIAC) from third parties to make the P&U entities’ investment in PP&E economical and fair to all ratepayers, including those that are not parties to the requested additional infrastructure. Typically, a utility that receives a request for service will determine a maximum allowable investment by the utility for that specific service connection by using an economic feasibility model that projects the margin to be received from the use of the new infrastructure over time. If the expected margin is not adequate to support the full cost of the
infrastructure, CIAC is typically required for the unsupported portion. Amounts in excess of the allowable investment are typically required to be provided by the party making the request of the utility.

Utility companies receive CIACs under various scenarios, including (but not limited to) the following:

- A governmental entity (e.g., a township) asks the utility to move a gas line to facilitate a road expansion.
- A developer asks the utility to build infrastructure necessary to connect essential utility services to homes in a new housing development.
- A prospective customer requests utility service in a remote area of the utility’s service territory, or in a neighborhood not currently equipped for the particular utility service requested.
- An active customer requests that a service connection be moved or added.

Utility companies have historically accounted for the receipt of CIAC as a reduction in the total cost basis of their PP&E (not as revenue), so that only the net cost to the utility is included in plant balances. This net amount (after the deduction of CIAC) is also the amount subject to ratemaking.

As noted in the examples above, CIAC may be received from customers or may be received from noncustomers. The P&U industry task force addressed whether CIAC received from customers should be treated as revenue and, if so, whether the recognition of such revenue should occur upon receipt or be deferred.

The task force reached a consensus that CIAC received from governmental entities is outside the scope of the new revenue standard. For CIAC received from governmental entities, the task force concluded that utility companies should continue to follow historical accounting for the receipt of CIAC.

FinREC believes that accounting for CIAC is an area subject to interpretation that requires the application of judgment. Generally, CIAC is viewed as a cost reimbursement from a customer and is therefore not within the scope of ASC 606. FinREC agreed with the task force’s consensus that in a regulated environment, CIAC can continue to be treated as a reduction in utility plant (and is therefore outside the scope of ASC 606). This matter is included in the latest edition of the AICPA Revenue Guide.

**Connecting the Dots**

On the basis of the work of the P&U industry task force, it is our expectation that the treatment of CIAC will not change with the adoption of ASC 606. However, if a P&U entity plans to change its treatment for CIAC and include such amounts in revenue under ASC 606, further consultation with the SEC staff is recommended.

**Sales of PP&E**

P&U entities often enter into arrangements that include the full or partial sale of PP&E (e.g., transactions involving the sale of all or a part of power plants, solar farms, and wind farms). Under current U.S. GAAP, depending on the nature of the transaction, an entity might conclude that the transaction is the sale of a business and account for it under ASC 810-10 or, alternatively, conclude that it is the sale of real estate and account for it under ASC 360-20. In addition, entities evaluate the disposal of equipment attached to real estate assets in accordance with ASC 360-20 if the equipment is considered integral equipment.

The new revenue standard supersedes the guidance in ASC 360-20 and provides guidance on the recognition and transfer of nonfinancial assets that is codified in ASC 610-20.
In response to stakeholder feedback indicating that (1) the meaning of the term “in-substance nonfinancial asset” is unclear because the new revenue standard does not define it and (2) the scope of the guidance on nonfinancial assets is confusing and complex and does not specify how a partial sales transaction should be accounted for or which model entities should apply, the FASB issued ASU 2017-05, which clarifies the scope of the Board’s recently established guidance on nonfinancial asset derecognition (ASC 610-20) as well as the accounting for partial sales of nonfinancial assets. The newly established guidance in ASC 610-20 (which consists of guidance in ASU 2014-09, as amended by ASU 2017-05) conforms the derecognition guidance on nonfinancial assets with the model for transactions in the new revenue standard. As a result of this amendment, this issue did not require further consideration by the P&U industry task force.

**Accounting for Partial Sales**

Under the legacy guidance in ASC 360-20, a sale is considered a partial sale if the seller retains an equity interest in the property (or the buyer). Profit (the difference between the sales price and the proportionate cost of the partial interest sold) is recognized only if the buyer is independent of the seller (i.e., not a consolidated subsidiary of the seller) and if certain other requirements are met.

“Partial sales” are sales or transfers of a nonfinancial asset to another entity in exchange for a noncontrolling ownership interest in that entity. Such sales are common in the real estate industry (e.g., a seller transfers an asset to a buyer but either retains an interest in the asset or has an interest in the buyer). Before adopting the new revenue standard, entities account for partial sales principally under the transaction-specific guidance in ASC 360-20 on real estate sales and the industry-specific guidance in ASC 970-323, and partly under ASC 845-10-30. ASU 2017-05 amends the guidance in ASC 970-323 to align it with the requirements in ASC 606 and ASC 610-20. It also eliminates ASC 360-20 as well as the guidance in the “Exchanges of a Nonfinancial Asset for a Noncontrolling Ownership Interest” subsection of ASC 845-10 to simplify the accounting treatment for partial sales (i.e., entities would use the same guidance to account for similar transactions) and to remove inconsistencies between ASC 610-20 and the noncash consideration guidance in the new revenue standard. As a result of these changes, any transfer of control of a nonfinancial asset (including when control is transferred to a group of third parties) in exchange for the noncontrolling ownership interest in another entity (including a noncontrolling ownership interest in a joint venture or other equity method investment) would be accounted for in accordance with ASC 610-20.

In addition, if the reporting entity no longer retained a controlling financial interest in the nonfinancial asset, it would derecognize the asset when it transferred control of that asset in a manner consistent with the principles in ASC 606. Further, any retained noncontrolling ownership interest (and resulting gain or loss to be recognized) would be measured at fair value in a manner consistent with the guidance on noncash consideration in ASC 606-20-32-21 through 32-24.

However, if the entity retained a controlling financial interest in a subsidiary (i.e., when the entity sold a noncontrolling ownership interest in a consolidated subsidiary), the entity would account for the transaction as an equity transaction in accordance with ASC 810 and would not recognize a gain or loss on the derecognition of nonfinancial assets. Only when the entity no longer had a controlling financial interest in a former subsidiary, and transferred control of the nonfinancial asset in accordance with ASC 606, would the entity apply the derecognition guidance in ASC 610-20.

**Collectibility of Consideration in Sales to Customers With Low Credit Quality**

For a contract to fall within the scope of ASC 606, it needs to meet all the criteria of ASC 606-10-25-1, one of which is that it is probable the seller “will collect substantially all of the consideration to which it will be entitled in exchange for the goods or services that will be transferred to the customer.” The
criteria in general are intended to ensure that a substantive transaction exists between the entity and the customer. Public utilities are required by statute to serve all customers within their service territory, including those with poor creditworthiness. The industry task force addressed the question of whether sales made to regulated utility customers with low credit quality represent valid and genuine transactions within the scope of ASC 606. In making this assessment, a utility would need to determine whether sales made to customers with low credit quality met the collectibility criterion of ASC 606-10-25-1(e) when service was provided.

On the basis of direct discussions between the industry and the FASB, the P&U industry task force concluded that such sales are indeed valid and genuine transactions that are within the scope of ASC 606 and should be accounted for under it. One reason the task force reached this conclusion is its belief that utilities' legal and regulatory structure provides prima facie evidence that such arrangements are substantive transactions. Further, regulated utilities’ tariff rates are established so that they provide recovery of substantially all of their costs, including bad debt, thereby supporting the conclusion that it is probable that they will collect the amounts to which they are entitled.

Given the feedback received from the FASB, the task force has lowered the priority of resolving this issue and will consider addressing it in the future if warranted by constituent feedback.

**Presentation of Alternative Revenue Programs**

While the new revenue standard supersedes much of the industry-specific revenue guidance in current U.S. GAAP, it retains the alternative revenue program guidance in ASC 980-605. P&U entities with alternative revenue programs within the scope of ASC 980-605-15 will continue to recognize additional revenues allowable for “Type A” and “Type B” alternative revenue programs, as defined in ASC 980-605-25-2, if those programs meet the criteria in ASC 980-605-25-4. However, because alternative revenue program revenues are not within the scope of the new revenue recognition standard and because ASC 980-605 specifies separate presentation in the statement of comprehensive income, revenues arising from such alternative revenue programs should be presented separately from revenues arising from contracts with customers that are within the scope of the new revenue standard.

Alternative revenue program revenues are recognized through regulator-ordered adjustments to utility rates and are recovered or refunded in subsequent periods as utility service is provided to end-user customers. The P&U industry task force evaluated two views on the treatment of such revenues. Under both views, total revenue recognized each period is the same; the difference is whether revenue from the alternative revenue program is “reclassified” as revenue from contracts with customers when such amounts are included in the tariff price charged to customers. Under one view, the amount of revenue recognized under the new standard would reflect all changes in the alternative revenue program’s regulatory assets and liabilities within a period, and the adjustment of subsequent tariff rates to recover amounts originally recorded as alternative revenue program revenue would be recorded as revenue from contracts with customers (with an equal and offsetting amount recorded to alternative revenue program revenue). Under the other view, the revenue amount would reflect only the initial accrual of alternative revenue program revenues when regulator-specified criteria are met, and the subsequent billing of those amounts would be recorded as a reduction of the regulatory asset or liability with an offsetting amount in accounts receivable when those amounts are included in subsequent tariff rates. The task force agreed that either approach is acceptable and that public utilities should select an approach and apply it consistently, as well as disclose the approach if it is considered to be material to the financial statements. The RRWG and FinREC agreed with this conclusion, and this matter is included in the latest edition of the AICPA Revenue Guide.
Connecting the Dots

Many questions have arisen about what types of programs qualify as alternative revenue programs. See Alternative Revenue Programs above for Deloitte’s views on considerations related to the scope of the alternative revenue program guidance.

Disclosures

For most P&U entities, the new revenue standard is not expected to have a significant impact on recognition and measurement requirements; however, all entities will need to carefully consider the standard’s new and modified quantitative and qualitative disclosure requirements.

The new revenue standard requires significantly more disclosures, including additional quantitative and qualitative information that enables “users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.” The new revenue standard’s disclosure requirements include:

- Presentation or disclosure of revenue and any impairment losses recognized separately from other sources of revenue or impairment losses from other contracts.

- A disaggregation of revenue to “depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors” (the new revenue standard also provides implementation guidance).

- Information about contract assets and liabilities (including changes in those balances) and the amount of revenue recognized in the current period that was previously recognized as a contract liability and the amount of revenue recognized in the current period that is related to performance obligations satisfied in prior periods.

- Information about performance obligations (e.g., types of goods or services, significant payment terms, typical timing of satisfying obligations, and other provisions).

- Information about an entity’s transaction price allocated to the remaining performance obligations, including (in certain circumstances) the “aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied)” and when the entity expects to recognize that amount as revenue.

- A description of the significant judgments, and changes in those judgments, that affect the amount and timing of revenue recognition (including information about the timing of satisfaction of performance obligations, the determination of the transaction price, and the allocation of the transaction price to performance obligations).

- Information about an entity’s accounting for costs to obtain or fulfill a contract (including account balances and amortization methods).

- Information about the policy decisions (i.e., whether the entity used the practical expedients for significant financing components and contract costs allowed by the new revenue standard).

The new revenue standard requires entities, on an interim basis, to disclose information required under ASC 270 as well as to provide disclosures similar to the annual disclosures (described above) about (1) the disaggregation of revenue, (2) contract asset and liability balances and significant changes in those balances since the previous period-end, and (3) information about the remaining performance obligations.

As a company analyzes each disclosure requirement, it should consider materiality, relevance, the information that will be needed, how to get that information, and the controls necessary for the preparation and review of the disclosures and the related underlying data. Because a company can
use similar information (or information from similar sources) to comply with some of the disclosure requirements (e.g., information related to performance obligations and estimates of variable consideration), the company should develop a comprehensive strategy to collect the information and draft disclosures that effectively and efficiently describe its revenue “story.”

For more information, see Chapter 14 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

**Connecting the Dots**

In recent years, segment reporting has been a perennial topic of focus for the SEC (and of SEC comment letters) and therefore a topic of focus for many companies. Focus areas related to segments include (1) the identification and aggregation of operating segments, (2) changes in reportable segments, (3) product and service revenue by segment, (4) operating segments and goodwill impairment, and (5) information about geographical areas. Because of the historical challenges related to segment disclosures and the new revenue standard's requirements related to the disaggregation of revenue, it is critical for each organization to evaluate the appropriate level at which to present its disaggregated revenue balances. As stated in ASC 606-10-55-90, when determining the appropriate level of disaggregation, an entity should consider (1) “[d]isclosures presented outside the financial statements (for example, in earnings releases, annual reports, or investor presentations),” (2) “[i]nformation regularly reviewed by the chief operating decision maker for evaluating the financial performance of operating segments,” and (3) other similar information “that is used by the entity or uses of the entity's financial statements to evaluate the entity's financial performance or make resource allocation decisions.”

At the 2016 AICPA Conference on Current SEC and PCAOB Developments, the SEC staff highlighted that the disclosure guidance in ASC 606 on disaggregation of revenue is similar to the segment reporting guidance, but it noted that ASC 606 does not provide an impracticability exception. Further, the SEC staff stated that its reviews of filings will include reviews of other materials, such as investor presentations and earnings releases, to determine whether the appropriate amount of disaggregation is disclosed.

Entities should consider the standard’s overall disaggregation principle in ASC 606-10-50-2. The guidance in ASC 606-10-50-2 prescribes neither methods of aggregation or disaggregation nor the form or format of disclosures, but it does indicate that aggregation or disaggregation of revenue information should occur so that “useful information is not obscured by either the inclusion of a large amount of insignificant detail or the aggregation of items that have substantially different characteristics.” More specifically, the new standard contains guidance on the disaggregation of entities’ contracts with their customers that requires entities to (1) disaggregate revenue into categories that depict how revenue and cash flows are affected by economic factors and (2) provide sufficient information to understand the relationship between disaggregated revenue and each disclosed segment’s revenue information.

Because there is no prescribed format or method for applying the new standard's disaggregation principles, disclosures will be entity-specific and, accordingly, a company will need to exercise significant judgment in determining the appropriate level of disaggregation. Consequently, it will be important for an entity to determine what information will be useful for key stakeholders such as investors, lenders, and regulatory bodies and which form of presentation (e.g., tabular or text) will be more effective in achieving the disclosure principles.
We understand that P&U entities are considering various industry-specific distinctions as they consider their disaggregation disclosures, including the following:

- Customer class.
- Type of commodity.
- Regulated and nonregulated.
- Regulatory jurisdiction (state by state, state versus federal).
- Service line (e.g., electric generation, transmission, and distribution).

**Effective Date and Transition**

In August 2015, the FASB issued ASU 2015-14, which defers the effective date of the new revenue standard, ASU 2014-09, by one year for all entities and permits early adoption as of the original effective dates. For PBEs, the standard is effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2017.

The effective date for non-PBEs is annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019. Non-PBEs may also elect to apply the new revenue standard as of any of the following:

- Annual periods beginning after December 15, 2016, including interim reporting periods.
- Annual periods beginning after December 15, 2016, and interim reporting periods within annual reporting periods beginning one year after the annual reporting period in which the new standard is initially applied.

Entities have the option of using either a full retrospective or a modified approach to adopt the guidance in the new revenue standard:

- **Full retrospective application** — Retrospective application would take into account the requirements in ASC 250 (with certain practical expedients). Under this approach, entities would need to reevaluate their contracts from inception to determine the income recognition pattern that best depicts the transfer of goods and services. Further, for comparative financial statement purposes, public entities with a calendar year-end would be required to present income under the new revenue model beginning on January 1, 2016.

**Connecting the Dots**

At the December 2016 AICPA Conference on Current SEC and PCAOB Developments, during a discussion regarding transition-period activities when an entity is adopting the new revenue standard using the full retrospective method, the SEC staff highlighted the requirements for revised financial statements in new or amended registration statements.

In particular, the SEC staff discussed the requirement in Form S-3, Item 11(b), for registrants to provide revised financial statements in a new registration statement. If a registrant elects to adopt the new revenue standard by using the full retrospective method and subsequently files a registration statement on Form S-3 that incorporates by reference interim financial statements reflecting the impact of the adoption of the new revenue standard, it would be required to retrospectively revise its annual financial statements that are incorporated by reference in that Form S-3 (i.e., the annual financial statements in its Form 10-K). Those annual financial statements would include one more year of retrospectively revised financial statements (the “fourth year”) than what would otherwise be required if the registrant did not file a registration
statement. Filing the registration statement would also accelerate the timing related to when a registrant would be required to provide revised information for previously completed years.

Although the SEC staff recognized preparers’ concerns, the staff reiterated that there are no plans to modify the requirements of Form S-3. Therefore, when adopting the new revenue standard, an entity may look to the guidance in current U.S. GAAP or IFRS Standards on the adoption of new accounting standards and contemplate the impracticability exception to retrospective application. The staff observed that the impracticability exception is a high hurdle and that companies may opt to consult the OCA regarding this topic.

It is important to note that the above guidance also applies to any new or amended registration statement (other than Form S-8) that is filed after a registrant files a Form 10-Q that reports the material retrospective change.

For more information, see Chapter 19 in Deloitte’s *A Roadmap to Applying the New Revenue Recognition Standard*.

- **Modified retrospective application** — Under the modified approach, an entity recognizes “the cumulative effect of initially applying [the new revenue standard] as an adjustment to the opening balance of retained earnings . . . of the annual reporting period that includes the date of initial application” (revenue in periods presented in the financial statements before that date is reported under guidance in effect before the change). Under the modified approach, the guidance in the new revenue standard is applied only to existing contracts (those for which the entity has remaining performance obligations) as of, and new contracts after, the date of initial application. The new revenue standard is not applied to contracts that were completed before the effective date (i.e., an entity has no remaining performance obligations to fulfill). Entities that elect the modified approach must disclose an explanation of the impact of adopting the new revenue standard, including the financial statement line items and respective amounts directly affected by the standard’s application. The following chart illustrates the application of the new revenue standard and legacy GAAP under the modified approach for a public company with a calendar year-end:

<table>
<thead>
<tr>
<th>January 1, 2018</th>
<th>2018</th>
<th>2017</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Application Year</td>
<td>Current Year</td>
<td>Prior Year</td>
<td>Prior Year 2</td>
</tr>
<tr>
<td>New contracts</td>
<td>New revenue standard</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing contracts</td>
<td>New revenue standard + cumulative catch-up</td>
<td>Legacy GAAP</td>
<td>Legacy GAAP</td>
</tr>
<tr>
<td>Completed contracts</td>
<td>Legacy GAAP</td>
<td>Legacy GAAP</td>
<td></td>
</tr>
</tbody>
</table>

**Connecting the Dots**

The modified transition approach provides entities relief from having to restate and present comparable prior-year financial statement information; however, entities will still need to evaluate existing contracts as of the date of initial adoption under the new revenue standard to determine whether a cumulative-effect adjustment is necessary. Therefore, entities may need to consider the typical nature and duration of their contracts to understand the impact of applying the new revenue standard and determine the transition approach that is practical to apply and most beneficial to financial statement users.
For additional information about effective date and transition, see Chapter 15 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

**SAB Topic 11.M Considerations**

SAB Topic 11.M provides disclosure requirements for those accounting standards not yet adopted. Specifically, when an accounting standard has been issued but need not be adopted until some future date, a registrant should include disclosure of the impact that the recently issued accounting standard will have on the financial position and results of operations of the registrant when such standard is adopted in a future period. The SEC staff believes that this disclosure guidance applies to every issued accounting standard not yet adopted by the registrant unless the standard's impact on the registrant's financial position and results of operations is not expected to be material.

Members of the SEC staff have emphasized on numerous occasions the importance of providing investors with transition-period disclosures in accordance with SAB Topic 11.M. Such disclosures should include not only an explanation of the transition method elected but also disclosures that explain the impact that the new revenue standard is expected to have on an entity's financial statements. Further, disclosures must address the full scope of the new standard, which includes recognition, measurement, presentation, and disclosure.

In providing key stakeholders with information about the expected impact of adoption on the financial statements, entities may need to develop pro forma financial statements on the basis of their anticipated transition method (full retrospective or modified retrospective) to appropriately estimate the impact of adoption. There will not be a one-size-fits-all model for communicating the impact of adoption, but entities could consider providing (1) a short narrative that qualitatively discusses the impact of the change or (2) tabular information (or ranges) comparing historical revenue patterns with the expected accounting under ASC 606, to the extent that such information is available. See Section 20.6.1 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard* for illustrative SAB Topic 11.M disclosures related to the adoption of the new revenue standard.
Section 6 — New Lease Accounting Model
Background

In February 2016, after working with the IASB on a joint leases project for almost a decade, the FASB finally issued its new standard on accounting for leases, ASU 2016-02. The leases project’s primary objective was to address the off-balance-sheet financing concerns related to lessees’ operating leases. Accordingly, the FASB’s new standard introduces a lessee model that brings most leases onto the balance sheet. In addition, the standard aligns certain underlying principles of the new lessor model with those in ASC 606, the FASB’s new revenue recognition standard (e.g., those that help entities evaluate how collectibility should be considered and determine when profit can be recognized). The ASU also addresses other concerns related to the current leases model, which is almost 40 years old. For example, the new standard eliminates the requirement that entities use bright-line tests to determine lease classification. The standard also requires lessors to be more transparent about their exposure to risks regarding the changes in value of their residual assets and about how lessors manage that exposure.

The changes introduced by the new leases standard are effective January 1, 2019, for public companies and may significantly affect entities in the P&U industry because of their extensive use of fixed assets under contracts that may qualify as leases under the new guidance. P&U entities often enter into agreements that are frequently customized and include services and other components critical to completing the contracts. While under current guidance the accounting for operating leases is often similar to that for service contracts, this will no longer be the case under the new standard. The FASB has stated its concern that existing contracts that meet the definition of a lease under both ASC 840 and ASC 842 may not have historically been identified as leases (likely because the accounting for operating leases under ASC 840 is often similar to that of service contracts, as stated above, and therefore less scrutiny was used in lease identification). Therefore, entities should carefully evaluate the completeness of their population of contracts, or portions thereof, that meet the new definition of a lease.

Connecting the Dots

At the 2017 AICPA Conference on Current SEC and PCAOB Developments, FASB Technical Director Susan Cosper noted that the FASB has no plans to defer the effective date of the new leasing standard. She emphasized that the Board’s recent final ASU on easements, ASU 2018-01, and recent proposal of optional practical expedients related to transition and lessor requirements for separation of the components within a contract should provide preparers with relief regarding many of the implementation issues that have arisen.

Scope

Like the scope of the current guidance on leases, the scope of the new guidance is limited to leases of PP&E. The scope excludes (1) leases of intangible assets; (2) leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources; (3) leases of biological assets; (4) leases of inventory; and (5) leases of assets under construction.

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1 The ASU supersedes ASC 840 and creates ASC 842. On January 13, 2016, the IASB issued IFRS 16, its final standard on leases.
2 For more information, see Deloitte’s December 5, 2017, Heads Up.
Connecting the Dots

The FASB decided to include guidance on a lessee's control of an underlying asset that is being constructed before lease commencement. That is, if a P&U entity that is involved in the construction of PP&E it intends to lease is determined to control the asset during the construction period, it will be considered the owner of the CWIP for accounting purposes and will need to assess the arrangement under the new standard's sale-leaseback guidance once construction is completed.

In addition, questions have arisen about whether pole attachments and easements or rights-of-way would or could be within the scope of the new standard. See our discussion of pole attachments and easements in the Implications for P&U Entities section below.

Definition of a Lease

Identified Asset

The new standard defines a lease as “a contract, or part of a contract, that conveys the right to control the use of identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration.” Control is considered to exist if the customer has both of the following:

- The “right to obtain substantially all of the economic benefits from the use of [an identified] asset.”
- The “right to direct the use of the [identified] asset.”

The notion of an identified asset is mostly consistent with that in current U.S. GAAP. Under this concept, a leased asset must be identifiable either explicitly (e.g., by a named generating asset) or implicitly (e.g., the asset is the only one available to meet the requirements of the contract). A specified asset can also be a physically distinct portion of a larger asset (e.g., one floor of a building). However, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a natural gas pipeline's or storage facility's total capacity) will generally not be a specified asset unless that capacity portion represents substantially all of the larger asset's overall capacity.

The evaluation of whether there is an identified asset also depends on whether a supplier has a substantive substitution right throughout the period of use. Substitution rights are considered substantive if the supplier has the practical ability to substitute alternative assets throughout the period of use (i.e., the customer cannot prevent the supplier from doing so, and alternative assets are readily available to, or can be quickly sourced by, the supplier), and the supplier could benefit economically from the substitution.

An entity must use significant judgment when determining whether a substitution right is substantive. The entity should consider the facts and circumstances at the inception of the contract and exclude from its assessment circumstances that are not likely to occur over the contract term. The entity should also consider the asset’s physical location. For example, it is more likely that the supplier will benefit from the substitution right if the identified asset is located at the supplier’s rather than at the customer's premises (i.e., because the costs of substituting the asset may be lower). It may be difficult for a customer to determine whether the supplier's substitution right is substantive. For example, the customer may not know whether the substitution right gives the supplier an economic benefit. A customer should presume that a substitution right is not substantive if it is impractical to prove otherwise.
**Connecting the Dots**

The requirement that a substitution would provide an economic benefit to the supplier is a higher threshold than that in current U.S. GAAP. Accordingly, we expect more arrangements to be subject to lease accounting by virtue of the new standard's changes to the evaluation of substitution rights.

**Convey the Right to Control the Use**

With regard to a customer's right to control the use of the identified asset, the definition of a lease under the new standard represents a significant change from previous guidance. Under current U.S. GAAP, an entity's taking substantially all of the outputs of an identified asset was considered indicative of the customer's right to control the use of that asset if the pricing per unit in the arrangement was neither fixed nor equal to the market price per unit at the time of delivery (e.g., a PPA in which the off-taker purchases substantially all of the outputs of a generating asset).

By contrast, the new standard aligns the assessment of whether a contract gives the customer the right to control the use of the specified asset with the concept of control developed as part of the FASB's new revenue standard. Accordingly, a contract evaluated under the new standard is deemed to convey the right to control the use of an identified asset if the customer has both the right to direct, and obtain substantially all of the economic benefits from, the use of that asset. The right to direct the use of the specified asset would take into account whether the customer has the right to determine — or predetermine — how and for what purpose the asset is used. Economic benefits from the use of the specified asset would include its primary products and by-products or other economic benefits that the customer can realize in a transaction with a third party (e.g., renewable energy credits).

**Connecting the Dots**

In determining whether a lease exists under the new standard, an entity would emphasize its ability to direct the use of the asset. This guidance is significantly different from today's model, under which a lease can exist on the basis of the level of output taken by the customer, and, therefore, we expect fewer off-take arrangements to be leases in the P&U industry. Dispatch rights held by an off-taker will generally convey control; however, off-take arrangements with predefined delivery schedules or weather-driven production may not meet the control requirement. To help illustrate the factors for an entity to consider when evaluating whether a contract is or contains a lease, the final standard provides three examples that apply to the P&U sector (see ASC 842-10-55-108 through 55-123).

**Lessee Accounting Model**

**Initial Measurement**

The initial measurement of a lease is based on a right-of-use (ROU) asset approach. Accordingly, once the standard is effective, all leases (finance and operating leases) other than those that qualify for the short-term lease exception must be recognized as of the lease commencement date on the lessee's balance sheet. A lessee will recognize a liability for its lease obligation, measured at the present value of lease payments not yet paid (excluding variable payments based on usage or performance), and a corresponding asset representing its right to use the underlying asset over the lease term. The initial measurement of the ROU asset will also include (1) initial direct costs (e.g., legal fees, consultant fees, commissions paid) that are incremental costs of a lease that would not have been incurred had the lease not been executed and (2) any lease payments made to the lessor before or as of the commencement of the lease. The ROU asset will be reduced for any lease incentives received by the lessee (i.e., consideration received from the lessor will reduce the ROU asset).
In addition to those payments that are directly specified in a lease agreement and fixed over the lease term, lease payments include variable lease payments that are considered in-substance fixed payments (e.g., when a variable payment includes a floor or a minimum amount). However, the fact that a variable lease payment is virtually certain (e.g., a variable payment for highly predictable output under a renewable PPA) does not make the payment in-substance fixed. Therefore, it will not be included in the determination of a lessee's lease obligation and ROU asset or a lessor's net investment in the lease.

**Connecting the Dots**

PPAs for the output of a wind farm may include payment terms that are 100 percent contingent on production. The wind farm developer may undertake an engineering production case to support the wind farm's expected annual energy output at a particular level (e.g., 95 percent probability, or P95 production level). Although the off-taker from the wind farm may consider the expected P95 production to indicate a relatively fixed or minimum amount of annual delivered energy, that expected amount is contingent (i.e., if the wind does not blow, payment will be zero). Therefore, the expected amount in this case would not constitute an in-substance fixed lease payment. Some renewable PPAs provide for a guaranteed minimum production level to give the buyer price certainty over a minimum volume of electricity and to facilitate compliance with renewable portfolio standards. In general, we would not expect such provisions to establish a fixed lease payment obligation, since these provisions typically settle financially with a payment to the off-taker (e.g., current market price of power multiplied by volume shortfall) and therefore do not establish a minimum obligation on the part of the lessee. In other words, it is not possible to guarantee physical output from these facilities, given their dependence on weather, and these provisions are designed to protect the off-taker from the financial burden of buying replacement power, not to ensure a minimum level of revenue for the seller. Note that this concept holds true for other renewable energy power-generating facilities (e.g., solar farms) as well.

In contrast to usage-based variable payments described above, we believe that capacity payments under PPAs generally represent fixed payments and therefore will be included in lease payments for classification and measurement purposes. While capacity payments are technically at risk (that is, they are often subject to clawback or refund if the generating unit has an unplanned outage), we believe that there is a premise in lease accounting that the asset is ready for its intended use and therefore capacity payments should be deemed fixed. In a scenario in which capacity payments are refunded to a customer because of an unplanned outage, we would expect those to be treated as negative variable payments (akin to negative contingent rents under ASC 840) in the period incurred.

**Subsequent Measurement**

The FASB decided in the ASU to maintain a dual-model approach, in which a lessee classifies the lease on the basis of whether the control of the underlying asset is effectively transferred to the lessee (e.g., substantially all the risks and rewards incidental to ownership of the underlying asset are transferred to the lessee). Lessees would classify a lease as either a finance lease or an operating lease by using classification criteria similar to those in IAS 17.

Therefore, lessees will classify a lease as a finance lease if any of the criteria below are met at the commencement of the lease:

- “The lease transfers ownership of the underlying asset to the lessee by the end of the lease term.”

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3 Quoted text is from ASC 842-10-25-2.
• “The lease grants the lessee an option to purchase the underlying asset that the lessee is reasonably certain to exercise.”

• “The lease term is for the major part of the remaining economic life of the underlying asset.”

• “The present value of the sum of the lease payments and any residual value guaranteed by the lessee . . . equals or exceeds substantially all of the fair value of the underlying asset.”

• “The underlying asset is of such a specialized nature that it is expected to have no alternative use to the lessor at the end of the lease term.”

An entity determines the lease classification at lease commencement and is not required to reassess its classification unless (1) the lease is subsequently modified and the modification is not accounted for as a separate contract or (2) there is a change in lease term or a change in the assessment of the exercise of a purchase option.

Connecting the Dots

The FASB adopted the dual-model approach on the premise that all leases are not created equal. That is, some leases are more akin to an alternate form of financing for the purchase of an asset, while others are truly the renting of the underlying property.

While the ASU’s classification criteria are similar to those in IAS 17, they vary from the current requirements in U.S. GAAP (i.e., the specific quantitative thresholds have been removed, and a fifth criterion, which does not exist under ASC 840, has been added). As a result, a lease that would have been classified as an operating lease may be classified as a finance lease under the ASU. In addition, as a reasonable approach to assessing significance, an entity is permitted to use the bright-line thresholds that exist under ASC 840 when determining whether a lease would be classified as a finance lease.

An entity will also assess land and other elements in a real estate lease as separate lease components under the new standard unless the accounting result of doing so would be insignificant. This approach is also similar to current guidance under IFRS Standards but will reflect a change from that in U.S. GAAP, under which a lessee is required to account for land and buildings separately only when (1) the lease meets either the transfer-of-ownership or bargain-purchase-option classification criterion or (2) the fair value of the land is 25 percent or more of the total fair value of the leased property at lease inception. This change may result in more bifurcation of real estate leases into separate lease components and may affect the allocation of the lease payments to the various elements.

Finance Leases

For finance leases, the lessee will use the effective interest rate method to subsequently account for the lease liability. The lessee will amortize the ROU asset in a manner similar to that used for other nonfinancial assets; that is, the lessee will generally amortize the ROU asset on a straight-line basis unless another systematic method is appropriate. Together, the amortization and resulting interest expense will result in a front-loaded expense profile similar to that of a capital lease arrangement under current U.S. GAAP. Entities will separately present the interest and amortization expenses in the income statement.

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4 The ASU provides an exception to this lease classification criterion for leases that commence “at or near the end” of the underlying asset’s economic life. The ASU indicates that a lease that commences in the final 25 percent of an asset’s economic life is “at or near the end” of the underlying asset’s economic life.
Operating Leases

For operating leases, the lessee will also use the effective interest rate method to subsequently account for the lease liability. However, the subsequent measurement of the ROU asset will be linked to the amount recognized as the lease liability (unless the ROU asset is impaired). Accordingly, the ROU asset will be measured as the lease liability adjusted by (1) any accrued or prepaid rents, (2) unamortized initial direct costs and lease incentives, and (3) impairments of the ROU asset. As a result, the total lease payments made over the lease term will be recognized as lease expense (presented as a single line item) on a straight-line basis unless another systematic method is more appropriate.

Connecting the Dots

While the ASU discusses subsequent measurement of the ROU asset arising from an operating lease primarily from a balance sheet perspective, a simpler way to describe it would be from the viewpoint of the income statement. Essentially, the goal of operating lease accounting is to achieve a straight-line expense pattern over the term of the lease. Accordingly, an entity effectively takes into account the interest on the liability (i.e., the lease obligation consistently reflects the lessee’s obligation on a discounted basis) and adjusts the amortization of the ROU asset to arrive at a constant expense amount. To achieve this, the entity first calculates the interest on the liability by using the discount rate for the lease and then deducts this amount from the required straight-line expense amount for the period (determined by taking total payments over the life of the lease, net of any lessor incentives, plus initial direct costs, divided by the lease term). This difference is simply “plugged” as amortization of the ROU asset to result in a straight-line expense for the period. By using this method, the entity recognizes a single operating lease expense rather than separate interest and amortization charges, although the effect on the lease liability and the ROU asset in the balance sheet reflects a bifurcated view of the expense. Note, however, that the periodic lease cost cannot be less than the calculated interest on the lease liability (i.e., the amortization of the ROU asset, or plug amount, cannot be negative).

Regulated utilities will be pleased that the FASB carried forward the guidance that allows the timing of lease expense recognition to be consistent with the effects of rate-making. Specifically, ASC 980-842-45-1 through 45-4 state, in part, the following (emphasis added):

- 45-1: “Topic 842 specifies criteria for classification of leases and the method of accounting for each type of lease. For rate-making purposes, a lease may be treated as an operating lease even though the lease would be classified as a finance lease under those criteria. In effect, the amount of the lease payment is included in allowable costs as rental expense in the period it covers.”

- 45-2: “For financial reporting purposes, the classification of the lease is not affected by the regulator’s actions. The regulator cannot eliminate an obligation that was not imposed by the regulator (see paragraph 980-405-40-1). . . . Accordingly, regulated entities shall classify leases in accordance with Topic 842.”

- 45-3: “The nature of the expense elements related to a finance lease (amortization of the right-of-use asset and interest on the lease liability) is not changed by the regulator’s action; however, the timing of expense recognition related to the lease would be modified to conform to the rate treatment. Thus, amortization of the right-of-use asset shall be modified so that the total of interest on the lease liability and amortization of the right-of-use asset shall equal the lease expense that was allowed for rate-making purposes.”
• 45-4: “Paragraph 842-20-45-4 states that an entity is not required to classify the interest expense and amortization of the right-of-use asset in a finance lease as separate items in an income statement. For example, the amounts of amortization of the right-of-use asset and interest on the related lease liability could each be combined with other costs and presented in a manner consistent with how the entity presents depreciation or amortization of similar assets and other interest expense.”

The above paragraphs clarify that although an entity can treat a finance lease as an operating lease for rate-making purposes, this does not override the classification of the lease as a finance lease in accordance with ASC 842. However, a regulator’s action can change the timing of expense recognition of a finance lease; that is, the total periodic lease cost (amortization of the ROU asset and interest on the lease liability) should be adjusted to represent the lease expense that was permitted for rate-making purposes. Finally, under the presentation requirements in ASC 842-20-45-4, the ratemaking treatment of the lease expense does not change the requirement that the interest on the lease liability and the amortization of the ROU asset be presented in a manner consistent with how the entity presents other interest expense and depreciation or amortization of other assets, respectively. The guidance above is virtually identical to the guidance currently in ASC 980-840-45 and, accordingly, we do not expect a change in practice in this area as a result of ASC 842.

**Impairment**

Regardless of the lease classification, a lessee will subject the ROU asset to impairment testing in a manner consistent with that for other long-lived assets (i.e., in accordance with ASC 360). If the ROU asset for a lease classified as an operating lease is impaired, the lessee will amortize the remaining ROU asset under the subsequent measurement requirements for a finance lease — evenly over the remaining lease term unless another systematic method is appropriate. In addition, in periods after the impairment, a lessee will continue to present the ROU asset amortization and interest expense as a single line item.

**Lessor Accounting**

After proposing various amendments to lessor accounting, the FASB ultimately decided to keep the lessor model’s classification and resulting accounting largely unchanged; however, there are key differences between the new guidance and the previous guidance that companies should focus on during their implementation of the new leasing standard. The most significant changes align the profit recognition requirements under the lessor model with those under the FASB’s new revenue recognition requirements and amend the lease classification criteria to be consistent with those for a lessee.

Accordingly, the ASU requires a lessor to use the classification criteria discussed above to classify a lease, at its commencement, as a sales-type lease, direct financing lease, or operating lease:

• **Sales-type lease** — The lessee effectively gains control of the underlying asset. The lessor derecognizes the underlying asset and recognizes a net investment in the lease (which consists of the lease receivable and unguaranteed residual asset). Any resulting selling profit or loss is recognized at lease commencement. Initial direct costs are recognized as an expense at lease commencement unless there is no selling profit or loss. If there is no selling profit or loss, the initial direct costs are deferred and recognized over the lease term. In addition, the lessor recognizes interest income from the lease receivable over the lease term.

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5 The FASB decided not to allow leveraged lease treatment for new leases after the effective date of ASC 842. Existing leverage leases are grandfathered unless modified after adoption.
In a manner consistent with ASC 606, if collectibility of the lease payments plus the residual value guarantee is not probable, the lessor does not record a sale. That is, the lessor will not derecognize the underlying asset and will account for lease payments received as a deposit liability until (1) collectibility of those amounts becomes probable or (2) the contract has been terminated or the lessor has repossessed the underlying asset. Once collectibility of those amounts becomes probable, the lessor derecognizes the underlying asset and recognizes a net investment in the lease. If the contract has been terminated or the lessor has repossessed the underlying asset, the lessor derecognizes the deposit liability and recognizes a corresponding amount of lease income.

- **Direct financing lease** — The lessee does not effectively obtain control of the asset, but the lessor relinquishes control. This occurs if (1) the present value of the lease payments and any residual value guarantee (which could be provided entirely by a third party or consist of a lessee guarantee coupled with a third-party guarantee) represents substantially all of the fair value of the underlying asset and (2) it is probable that the lessor would collect the lease payments and any amounts related to the residual value guarantee(s). The lessor derecognizes the underlying asset and recognizes a net investment in the lease (which consists of the lease receivable and unguaranteed residual asset). The lessor’s profit and initial direct costs are deferred and amortized into income over the lease term. In addition, the lessor recognizes interest income from the lease receivable over the lease term.

- **Operating lease** — All other leases are operating leases. In a manner similar to current U.S. GAAP, the underlying asset remains on the lessor’s balance sheet and is depreciated consistently with other owned assets. Income from an operating lease is recognized on a straight-line basis unless another systematic basis is more appropriate. Any initial direct costs (i.e., those that are incremental to the arrangement and would not have been incurred if the lease had not been obtained) are deferred and expensed over the lease term in a manner consistent with the way lease income is recognized.

**Connecting the Dots**

While the FASB’s goal was to align lessor accounting with the new revenue guidance in ASC 606, an important distinction may affect P&U lessors, particularly those in the renewable energy sector. Under ASC 606, variable revenues are estimated and included in the transaction price, subject to a constraint. By contrast, under the new leases standard, variable lease payments would generally be excluded from the determination of a lessor’s lease receivable. Accordingly, a direct financing lease or a sales-type lease that has a significant variable component may result in a loss at commencement (i.e., a day 1 loss) for the lessor if the lease receivable plus the unguaranteed residual asset is less than the net carrying value of the underlying asset being leased. This could occur if payments on a lease of, for example, a solar farm are based entirely on the production of electricity (i.e., 100 percent variable). At the FASB’s November 30, 2016, meeting, the Board discussed whether a day 1 loss would be appropriate in these situations or whether other possible approaches would be acceptable, including the use of a negative discount rate to avoid the loss at commencement. The Board asserted that while stakeholders may disagree with the day 1 loss outcome, ASC 842 is clear on how the initial measurement guidance should be applied to sales-type and direct financing leases. In addition, the Board stated that the use of a negative discount rate would not be appropriate and should not be applied under ASC 842. The FASB is expected to issue a final ASU sometime during the second quarter of 2018 that amends certain aspects of ASU 2016-02 and includes a technical correction.

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6 If the present value of lease payments plus a lessee-provided residual value guarantee represents substantially all of the fair value of the underlying asset, the lessor classifies the lease as a sales-type lease.
that clarifies that if the rate implicit in the lease was determined to be less than zero, a rate of zero should be used.

For those leases that are classified as sales-type or direct financing leases, there are still open questions on the accounting for nonroutine capital projects, such as major maintenance to a plant, that are typically performed and capitalized by the asset owner under a defer and amortize model. Because the lessor will derecognize the underlying asset, there is an open question about whether it would be appropriate to capitalize the major maintenance costs for an asset that is no longer recorded on the balance sheet.

Lessors affected by these issues should consult with their professional advisers and monitor developments during the ASU’s implementation phase.

**Connecting the Dots**

At its meeting on March 28, 2018, the FASB discussed comments received on its proposed ASU on targeted improvements to ASU 2016-12 and voted to move forward with the drafting of a final ASU related to a practical expedient for lessors to elect not to separate lease and nonlease components when certain conditions are met. The practical expedient, as drafted in the proposed ASU, allows lessors to elect not to separate lease and nonlease components, provided that both of the following conditions are met:

- **Criterion A** — “The timing and pattern of revenue recognition for the lease components and nonlease component(s) . . . are the same.”

- **Criterion B** — “The combined single lease component is classified as an operating lease.”

Further, the amendment in the proposed ASU required that a lessor disclose (1) that it has elected the practical expedient and (2) the nature of the items that are being combined.

At the meeting, the FASB reaffirmed its prior decision to provide lessors with a practical expedient to elect not to separate lease and nonlease components in a contract and voted to amend the two criteria (noted above) for applying the practical expedient as follows:

- **Criterion A** — The Board agreed to amend the language in Criterion A from “the timing and pattern of revenue recognition” to “the timing and pattern of transfer.”

- **Criterion B** — The Board agreed to change Criterion B to require that the lease component, if accounted for separately, would be classified as an operating lease under ASC 842. That is, a lessor should consider the classification of only the lease component when determining whether this criterion is met rather than the classification of the combined lease and nonlease components. The Board suggested that this could be performed on a qualitative basis in many circumstances.

The practical expedient could offer relief to lessors in the P&U industry in situations in which contracts provide a lease and related maintenance services (e.g., a contract that contains a lease of a natural gas–fired electric generating facility and the related operations and maintenance services associated with that facility). The practical expedient would allow lessors to account for such contracts as a single deliverable.

**Effective Date and Transition**

The new guidance is effective for PBEs for annual periods beginning after December 15, 2018 (i.e., calendar periods beginning January 1, 2019), and interim periods therein. For all other entities, the ASU is effective for annual periods beginning after December 15, 2019 (i.e., calendar periods beginning
January 1, 2020, and interim periods thereafter. Early adoption is permitted for all entities. Entities are required to apply a modified retrospective method of adoption (see discussion on a proposed practical expedient regarding transition below), and the FASB has proposed several forms of transition relief that should significantly ease the burden of adoption.

At its November 29, 2017, meeting, the FASB tentatively decided to amend ASU 2016-02 so that entities may elect not to restate their comparative periods in transition. Effectively, the amendment would allow entities to change their date of initial application to the beginning of the period of adoption.

Therefore, a PBE (for which the standard becomes effective on January 1, 2019) could elect to change its date of initial application to January 1, 2019. In doing so, the entity would:

- Apply ASC 840 in the comparative periods.
- Provide the disclosures required by ASC 840 for the comparative periods.
- Recognize the effects of applying ASC 842 as a cumulative-effect adjustment to retained earnings as of January 1, 2019.

The entity would not:

- Restate 2017 and 2018 for the effects of applying ASC 842.
- Provide the disclosures required by ASC 842 for 2017 and 2018.

The FASB discussed this amendment at its March 7, 2018, meeting and voted to move forward with drafting a final ASU.

**Connecting the Dots**

The FASB received feedback from preparers that were experiencing additional and unexpected costs related to the current transition requirements in ASU 2016-02. Those stakeholders indicated that they lack the IT solutions and systems providers to handle the comparative-period reporting requirements of the modified retrospective transition approach, thereby increasing the cost and complexity to those stakeholders of restating comparative periods under ASC 842.

The Board was sympathetic to this feedback and, accordingly, voted to amend the standard. In doing so, several Board members noted that the tentative decisions effectively delay lessees' recognition of lease assets and lease liabilities by one year (i.e., PBEs need to present only two years of balance sheet information). Those Board members noted that, in this instance, the benefits to preparers of delaying balance sheet recognition by one year exceeded the costs of requiring them to provide comparative balance sheet information. Further, they indicated that given ASC 842's dual approach to lessee accounting, the new standard does not significantly affect the income statement. Therefore, comparability will not be significantly affected if entities do not restate two years of comparative income statement information.

The Board expects that the new transition election will relieve entities from the cost burdens — described above — that are associated with providing comparative information under the modified retrospective transition approach. However, many entities will still need to enhance their lease-related IT systems as a result of the new standard's data requirements. In addition, the new standard's requirements related to judgments and estimations have not changed, and new processes and internal controls will still need to be instituted accordingly. Therefore, we do not think that the Board's decision suggests that entities should slow their implementation efforts.
Implications for P&U Entities

Power Purchase Agreements

Under current lease accounting guidance, a PPA is accounted for as a lease if the off-taker (1) agrees to buy all, or substantially all, of the output(s) of a specified generating asset and (2) pays for the output(s) at pricing terms that are neither fixed per unit nor equal to the current market price per unit at the time of delivery. However, the new definition of a lease focuses on whether the off-taker has control of the right to use the specified generating asset. That is, an arrangement is not considered a lease solely on the basis of the pricing, and the extent, of outputs purchased under the contract. Rather, P&U entities have to determine whether a PPA gives the off-taker control of an identified generating asset because the off-taker has the right to direct, and obtain substantially all of the economic benefits from, the use of the asset.

Right to Direct the Use of the Asset

An off-taker has the right to direct the use of a specified generating asset if it can determine how and for what purpose that asset is used. Further, the extent to which an off-taker determines how and for what purpose the specified generating asset is used will depend on whether the PPA grants the off-taker decision-making rights over that asset. Therefore, an off-taker should (1) identify the decision-making rights that most affect how and for what purpose the generating asset is used throughout the off-taker’s period of use (i.e., which decision-making rights most affect the economic benefits to be derived from the use of the generating asset) and (2) determine who controls those rights. Dispatch rights will generally convey control to the off-taker. Curtailment rights should also be analyzed. If the decisions related to how and for what purpose the asset is used are predetermined (by contract or the nature of the asset), the assessment will focus on whether the off-taker controls O&M or designed the asset, either of which would be deemed to convey the right to direct the use of the identified asset to the off-taker. We expect that the decisions related to how and for what purpose the asset is used will be predetermined for many arrangements involving renewable energy generation, given the limited number of strategic decisions about generating assets that are made during the commercial operations phase.

Connecting the Dots

As described above, we expect that dispatch rights held by the buyer will constitute control under the new standard. In some markets, however, dispatch decisions are ultimately made by an ISO on the basis of a consideration of bid prices and any transmission system constraints (i.e., assuming no constraints, generating units will be dispatched economically by accepting the lowest bids first), and therefore neither the owner nor the off-taker can mandate physical production. While the bid-in process is not explicitly the same as dispatch rights held by an off-taker, companies should consider whether controlling the bidding process conveys control to the off-taker, since that is the right that an owner would normally exercise in these markets to influence whether and when the owner’s plant runs. We do not believe that it would be appropriate to conclude that a generating asset in an ISO can’t be leased simply because the ISO has the final say on dispatch.

In the renewable energy sector, off-takers typically buy under must-take arrangements and dispatch rights are not present because of the weather-dependent nature of the generating assets. However, it is common for off-takers to have curtailment rights for both operational (e.g., to protect the grid) and economic (e.g., to avoid buying at a loss when locational marginal prices are negative) reasons. While such rights should be analyzed to understand their purpose and financial consequences to the off-taker, we do not expect curtailment rights to convey control in most circumstances. We believe that the important control decisions (those about
how and for what purpose) have effectively been predetermined for weather-dependent assets such as wind and solar farms. Curtailment rights protect a purchaser from unforeseen operational and market pricing anomalies but are inherently different from dispatch rights on a unit that is standing ready to produce.

It is important to note that the decision-making rights that most affect the economic benefits to be derived from a generating asset will differ depending on the nature of the asset. The table below discusses decision-making rights that an off-taker may be granted in a PPA and presents our current thinking on whether those rights determine how and for what purpose fossil fuel and alternative generating assets are used.

<table>
<thead>
<tr>
<th>Nature of Generating Asset</th>
<th>Off-Taker’s Decision-Making Rights</th>
<th>Do the Off-Taker’s Decision-Making Rights Determine How and for What Purpose the Generating Asset Is Used?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil fuel (e.g., coal, natural gas)</td>
<td>Dispatch rights (i.e., rights to make decisions about whether, and how much, to produce from the generating asset).</td>
<td>Yes. Dispatch rights provide the off-taker with the right to change whether electricity is produced from the generating asset and the quantity of the electricity that is produced, which are the decision-making rights that most affect the economic benefits to be derived from the generating asset and together represent the right to determine how and for what purpose the asset is used throughout the period of use.</td>
</tr>
<tr>
<td>Rights to provide the fuel used by the generating asset to generate electricity and determine generation timing (i.e., a tolling arrangement).</td>
<td>Yes. The off-taker's right to toll fuel through the generating asset for conversion into electricity inherently provides the off-taker with the right to change when, whether, and how much the electricity is produced from the generating asset. Those decision-making rights most affect the economic benefits to be derived from the generating asset and thus determine how and for what purpose the asset is used throughout the period of use.</td>
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<tr>
<td>Rights to make decisions about the operation and maintenance of the generating asset throughout the period of use.</td>
<td>No. Although operating and maintaining the generating asset is essential to its efficient use, decisions about those activities do not by themselves most affect how and for what purpose the generating asset is used; rather, they are contingent upon the decisions about how and for what purpose the generating asset is used (e.g., dispatch rights, contractually stated production schedule).</td>
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<tr>
<td>Rights that require the supplier to follow prudent utility operating practices in running the generating asset.</td>
<td>No. Requirements that either party in an off-take arrangement must follow appropriate utility operating practices define the scope of the parties’ rights related to the generating asset but do not affect which party has the right to direct the use of the asset.</td>
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<tr>
<td>Alternative (e.g., wind, solar)</td>
<td>Design of the generating asset before its construction.</td>
<td>Yes. The relevant decisions about how and for what purpose the asset is used are predetermined on the basis of the nature of the asset. However, the off-taker made the decisions about the generating asset’s design before contract inception that predetermined how and for what purpose the generating asset will be used throughout the off-taker’s period of use.</td>
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<tr>
<td>Rights to make decisions about the operation and maintenance of the generating asset throughout the period of use.</td>
<td>Yes. The relevant decisions about how and for what purpose the asset is used are predetermined on the basis of the nature of the asset. Accordingly, decisions about operating and maintaining an alternative generating asset are often among the only decisions available to be made throughout the period of use that do affect the economic benefits to be derived. Thus, the off-taker’s decision-making rights over O&amp;M — and the lack of any rights held by the supplier to change those instructions — give the off-taker the right to direct the asset’s use throughout the period of use.</td>
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<td>Rights that require the supplier to follow prudent utility operating practices in running the generating asset.</td>
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**Connecting the Dots**

We anticipate that the assessment of an entity’s involvement in design will require the use of significant judgment under the new standard and will be particularly relevant for arrangements involving renewable generating assets. Because those assets are not dispatchable, an entity is likely to conclude that how and for what purpose a generating asset is used are predetermined (on the basis of the nature of the asset). Accordingly, the analysis will focus on control over O&M or design. Control over O&M will probably be easy to determine; typically, the asset owner (the supplier) retains responsibility for O&M. However, it will often be more difficult to determine whether the off-taker had sufficient involvement in the design of the facility to effectively convey control. Important decisions regarding design are likely to include siting and determining the specific technology to be used. In addition, we understand that the industry is considering whether configuration decisions are a critical element of design. We understand that as of the date of this publication, EEI’s lease accounting group is still working on guidance in this area to assist companies in making informed judgments about design and to drive consistency across the sector.

The discussion above is premised on the notion that many renewable generating assets cannot be dispatched by the customer. This premise may need to be revisited as advances in battery technology provide for temporary storage of renewable energy. We believe that it will also be important for companies to identify the appropriate unit of account when dealing with battery storage solutions (i.e., is the appropriate unit of account for performing the lease analysis the entire installation or just the battery?).

Other important decision-making rights that affect the economic benefits to be derived from a generating asset should also be considered in the assessment of whether the off-taker’s decision-
making rights most affect how and for what purpose the asset is used. Such rights may include but are not limited to:

- The off-taker’s right to determine the facility’s operator.
- The off-taker’s right to determine specific operating procedures, outside those requiring the operator to follow prudent utility operating practices.

In all scenarios, the off-taker needs to evaluate, on the basis of the specific facts and circumstances, whether it has the right to determine how and for what purpose a generating asset is used and, thus, the right to direct the use of the asset. The off-taker will need to use judgment when performing this evaluation.

**Right to Obtain Substantially All of the Benefits From the Use of the Asset**

For a PPA to be considered a lease, the off-taker must also have the right to obtain substantially all of the economic benefits from the use of the generating asset throughout the period of use. Although the FASB did not define “economic benefits,” the term as used in the new standard encompasses all economic benefits from the use of an asset (whether tangible or intangible), including products, by-products, and other benefits that may be realized through a subsequent transaction with a third party. Therefore, an off-taker will conclude that certain other benefits provided in a PPA (e.g., capacity, renewable energy credits, or steam) constitute economic benefits. An off-taker will have to consider how the receipt or nonreceipt of such additional benefits from the use of a facility affects the accounting for a particular contract. Note that tax attributes related to ownership of the asset are not considered economic benefits (e.g., ITCs and production tax credits (PTCs)).

**Connecting the Dots**

Questions have arisen about whether PTCs should be deemed economic benefits, given that they are tied to the use of the productive asset (as opposed to ITCs, which are tied to installed cost). We believe that all tax attributes should be excluded from the economic benefits test, as they all belong to the owner(s) of the asset and cannot be sold in a market transaction. This approach is consistent with the way outputs are determined today in the identification of leases under ASC 840.

**Transportation and Storage Contracts**

Contracts to transport or store gas or other fuel products will need to be evaluated under the new definition of a lease. To be considered a specified asset under the new leases standard, a capacity portion of a larger asset has to be physically distinct or have substantially all of the larger asset’s capacity. Because the terms of pipeline and storage contracts vary significantly (e.g., regarding the rights to a percentage of an asset’s capacity or other economic benefits), P&U entities need to evaluate such contracts to determine whether to account for them under the guidance on leases, revenue recognition (suppliers), derivatives, or other U.S. GAAP.

**Last-Mile Scenarios**

In addition, P&U companies should also be aware that the new standard specifically highlights by way of example that a pipeline lateral that is dedicated to one user is a distinct portion of a larger asset that would be considered an identified asset. On the surface, this seems to capture any arrangements for transportation service that include dedicated stretches of service — most notably those involving infrastructure connecting a single customer (e.g., a commercial or industrial customer) to the natural gas pipeline in a utility’s territory. These are commonly called last-mile scenarios in reference to the connection to the customer site using infrastructure that is effectively dedicated. P&U entities should
consider the potential ramifications of this guidance for elements of their distribution systems, including wires, meters, and other equipment that serve a single customer. While the lateral example is highlighted as an identified asset, questions have arisen about “how an entity determines whether the customer has the right to control the use of that pipeline lateral throughout the period of use (that is, whether there is a lease of the pipeline lateral).”

At a public meeting in May 2017, the FASB agreed that under ASC 842-10-15-16, a pipeline lateral is an identified asset and that the assessment of whether it is a lease must be focused on whether the customer has the right to control the use of the identified asset in accordance with ASC 842-10-15-4. While highlighting that the specific facts and circumstances of each arrangement must be considered, the Board agreed with the staff’s analysis of two types of pipeline laterals (below) and did not suggest any additional standard setting was required at the time of the meeting:

- **Type 1** — These “typically are connected to an integrated pipeline system” and are the most common type of pipeline laterals. While they are not capable of operating on their own, they share “supply sources with the main line and other customers.” The pipeline owner retains both (1) economic benefits from the asset’s use that are more than insignificant and (2) the right to direct the use of the asset over the period of use. Depending on the significance of retained rights, the Board agreed with the staff’s analysis that Type 1 pipeline lateral contracts do not contain a lease.

- **Type 2** — These “are fully capable of operating using their own dedicated assets” and “the customer has the right to substantially all the pipeline lateral’s capacity.” The Board agreed with the staff’s analysis that in this case there is a lease since the customer has “the right to obtain substantially all the economic benefits . . . and the right to direct the use of the pipeline lateral throughout the period of use.”

**Connecting the Dots**

The guidance that supports laterals as being identified assets could have much broader implications for P&U entities. In particular, it raises a question about whether certain P&U electric transmission and distribution assets would represent identified assets. For example, an analogy could be made that power lines connecting one customer to the broader distribution system would represent identified assets under the new standard. Similarly, questions could be raised about whether meters and other equipment maintained at a customer location would be considered identified assets (as indicated above, an assessment of control would also be required, and this aspect is not presupposed by ASC 842). From a practical standpoint, equipment supporting at-will customers will probably not be subject to a lease because of the lack of a term arrangement between the utility and the customer. However, where term arrangements do exist (e.g., with some commercial and industrial customers), this guidance could be relevant.

We believe that the observations made by the FASB in May 2017 regarding control of pipeline laterals are informative when an entity is thinking about electric transmission and distribution (T&D) infrastructure and will generally support a conclusion that such connections do not give rise to leases. The electric wires a P&U entity uses in its T&D infrastructure less commonly function as Type 2 pipeline laterals because (1) they are less likely to have a cutoff point after which the customer has the right to use the wires and cables independently from the larger system and (2) a cutoff point, if one exists, is most likely to be very close to the customer’s facility. While these wires may not function as Type 1 laterals because the supplier typically cannot use the first-mile/last-mile connection to manage its larger network, the important

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7 Quoted material is from the FASB’s May 10, 2017, meeting handout.
8 See footnote 7.
point is that they rarely function alone, without the assistance of the larger system. Accordingly, we think that it will be rare for the customer to have the right to control the use of first-mile/last-mile connections of electric wires. However, this will ultimately depend on the facts and circumstances of each arrangement.

**Pole Attachments**

Questions have arisen regarding pole attachment arrangements, whereby either a utility attaches its lines to a pole owned by a third party (e.g., a phone company), or a third party (e.g., a cable company) attaches its wires to a pole owned by a utility. Such arrangements have been referred to as secondary-use arrangements, in which a customer shares the use of part of a larger asset for a defined period. In the case of pole attachments, the owner of the pole continues to use the entire asset while allowing another party to use a portion of the asset for a different purpose over a defined period. We understand that shared-use utility pole arrangements often allow the owner of the pole to relocate the attached equipment (e.g., wires or cables) as long as service is not compromised. This may represent a substantive substitution right held by the pole’s owner, in which case there will not be an identified asset in the arrangement.

In the absence of any substantive substitution rights held by the pole owner, we are often asked (1) what unit of account to use for the evaluation of control (the larger asset or the portion being shared) and (2) how to assess economic benefits when two parties contemporaneously use the same asset.

In determining what unit of account to use for the evaluation of control (i.e., the entire utility pole or just the portion being shared with a nonowner), entities should consider (1) whether all parts of the pole are functionally identical and are not physically distinct and (2) whether the attachment by the nonowner is a secondary use of the pole.

To the extent that the portion of the asset being used by the customer has a discrete functional use (e.g., a specific hosting location on a cell tower), it could be more likely that the portion being used is physically distinct and would represent an identified asset (similar to a specific floor of a building). On the other hand, and as is generally the case for a portion of a utility pole, if the portion being used is not functionally distinguishable from the larger asset, there may be a reasonable basis for viewing the larger asset as the identified asset in the arrangement.

We also believe that it is useful for an entity to consider whether the attachment by the nonowner is a secondary use of the pole and what the commercial objectives of the asset owner were when it built or purchased the utility pole. Because utility poles are generally built or purchased without the commercial objective of leasing a specific portion or portions of the pole to others, there may be a reasonable basis to view the larger asset (i.e., the entire utility pole) as the identified asset in the arrangement. On the other hand, assets such as cell towers (which possess specific hosting locations designed to be leased to third parties) are generally designed to lease specific portions of the entire asset to others, in which case we believe that the identified asset, or unit of account, in those arrangements is the specific portion of the larger asset being leased.

Once an entity has identified the unit of account (i.e., the identified asset), the next step is to assess economic benefits in the context of that accounting unit. If the identified asset is deemed to be the entire pole, we would expect the entity to conclude that the arrangement does not contain a lease because the pole owner retains substantial benefits from use.

We believe that there is a reasonable basis for an entity to view the entire utility pole as the identified asset. We would also accept a view that the specific pole location is the identified asset or unit of
account and that the party using that location is receiving substantially all of the economic benefits from the use of that location on the utility pole.

**Easements**

Questions have arisen about whether easements would or could be within the scope of the new standard and, if so, whether the benefit to financial statement users of entities’ assessing those arrangements in accordance with the new definition of a lease would outweigh the cost to the entities of doing so (both upon transition and on an ongoing basis).

Generally, an easement is a right to access, cross, or otherwise use someone else’s land (i.e., PP&E) for a specified purpose. Most easements provide limited rights to the easement holder, such as the right to cross over land or the right to construct and maintain specified equipment on the land. For example, an electric utility will typically obtain a series of contiguous easements so that it can construct and maintain its electric transmission system on land owned by third parties. Easements can be perpetual or term-based, be paid in advance or over time, and provide the customer with exclusive or shared use.

Historically, some companies have considered easements to be intangible assets under ASC 350. In fact, ASC 350 contains an illustrative example of easements acquired to support the development of a natural gas pipeline. By contrast, some companies may have considered easements to be leases or executory contracts. When preparing their financial statements, many companies have presented prepaid amounts related to easements in the PP&E section of their balance sheets because easements are closely associated with the PP&E they support. We understand that FERC’s reporting requirements may have also influenced the balance sheet geography for companies regulated by that agency.

In January 2018, the FASB issued ASU 2018-01 to address various questions about the impact of ASC 842 on existing and new easements. The stated objectives of the amendments in ASU 2018-01 were to:

- Clarify that land easements entered into (or existing land easements modified) on or after the effective date of the new leasing standard must be assessed under ASC 842.
- Provide an optional transition practical expedient for existing or expired land easements that were not previously accounted for in accordance with ASC 840. The practical expedient would allow entities to elect *not* to assess whether those land easements are, or contain, leases in accordance with ASC 842 when transitioning to the new leasing standard.

**Connecting the Dots**

The Board indicated at its November 29, 2017, meeting that it would not provide additional, formal guidance on determining the unit of account with respect to performing the lease assessment for an easement. However, several Board members pointed out that an entity will need to use judgment in determining the unit of account and that diversity in practice could arise in this area. Board members have publicly expressed this view at previous meetings, including a July 2017 roundtable and an August 2017 meeting. Further, it was noted that the need to use judgment is not limited to scenarios involving subsurface rights (e.g., rights to run gas pipelines underground). Board members specifically discussed easements that convey only surface rights, including rights to construct renewable energy assets (e.g., wind or solar), noting that an entity will also be required to employ judgment in considering these arrangements and that there could be more than one approach to determining the unit of account.

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9. ASU 2018-01 amended this guidance to clarify that the easements in the example did not meet the definition of a lease under ASC 842. The effective date and transition requirements under ASU 2018-01 are the same as those under ASU 2016-02. An entity that early adopted ASC 842 should apply the amendments in ASU 2018-01 upon its issuance.
10. See Deloitte’s October 3, 2017, Heads Up for a detailed discussion of the ASU.
On the basis of these views, we believe that, in practice, some will conclude that the unit of account is the entire land area defined by the easement contract (e.g., a larger area) while others will decide that a new unit of account should be established and assessed each time the easement holder occupies a portion of the land (e.g., a smaller area, such as the area taken up by a concrete pad used to serve as the foundation for a windmill or a transmission tower). We believe that either of these approaches is acceptable.

The FASB makes its objective for new land easements very clear — that all new land easements must first be assessed under ASC 842 to determine whether the arrangement is, or contains, a lease. If an arrangement is not a lease, other GAAP may be applicable (e.g., ASC 350, ASC 360). However, in paragraph BC11 of ASU 2018-01, the Board explains that it intentionally did not address the appropriate accounting guidance to apply in these situations:

> While there may be diversity about which guidance an entity should apply when a land easement is not a lease, that diversity is outside the scope of the amendments in this Update and, accordingly, the amendments do not modify an entity’s accounting for land easements that are not leases.

It is important to note that not all land easements are expected to be (or contain) leases, and the FASB decisions simply require companies to make an assessment under ASC 842 for new or modified easements. To determine whether a new or modified land easement contract is, or contains, a lease in accordance with ASC 842-10-15-2 through 15-27, entities may find it helpful to group the contracts into one of two categories, further discussed below: (1) perpetual easements and (2) term-based easements. This may streamline the process since many easements will have similar or identical provisions and therefore would be expected to result in similar accounting.

### Perpetual Easements

ASC 842-10-15-3 states, in part, “A contract is or contains a lease if the contract conveys the right to control the use of identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration” (emphasis added). When a land easement is perpetual, we would not expect the arrangement to meet the definition of a lease given the lack of a stated term. In accordance with ASC 842-10-15-3, rights conveyed in a land easement into perpetuity (i.e., for an unlimited time) are not conveyed “for a period of time.”

Arrangements with stated terms are not considered perpetual even if the terms are very long (e.g., 100 years). On the other hand, a use condition contained in a perpetual easement (e.g., when an easement conveys rights to the customer into perpetuity, as long as those rights are used only to run fiber-optic cable) would not affect the conclusion that a land easement is perpetual.

### Term-Based Easements

For term-based easements, the analysis will most likely be more extensive and involve a consideration of the right to control the use of the underlying land. That is, in accordance with ASC 842-10-15-4, entities will need to assess whether the customer in the arrangement has the right to (1) obtain substantially all of the economic benefits from using the land throughout the period of use and (2) direct the use of the land throughout the period of use. Accordingly, many easement arrangements may not convey the right to control the use of the land to the customer given that the supplier continues to enjoy economic benefits derived from the use of the land and that the rights to direct the use of the land that are conveyed to the customer are limited (i.e., generally only for a specified purpose).

For example, in an arrangement in which a utility (as the easement holder) is allowed to run electric transmission assets through a farmer’s fields (i.e., transmission lines that run over or under the farmer’s fields), it will be important to understand whether the farmer can still use the acreage subject to the
easement (i.e., the acreage under or over which the lines run). If so, the utility may conclude that it does not have the right to control the use of the land because the farmer retains (1) rights to direct the use of the land (e.g., rights to farm the land), (2) economic benefits associated with the land that are not insignificant (e.g., the crops yielded from farming), or (3) both (1) and (2). On the other hand, there may be easement arrangements that effectively convey the right to control the use of the land to the easement holder through the rights conveyed or through use restrictions imposed on the landowner.

In addition, to appropriately identify the unit of account, an entity sometimes may need to more carefully consider the identified asset in an easement arrangement, as illustrated in the common scenarios below.

Example 1

A customer enters into a land easement arrangement with a farmer for the right to pass a natural gas pipeline under the farmer’s land. At issue is whether the identified asset includes the entire plot of land or whether the land should be broken down into surface and subsurface rights, the latter of which the parties would evaluate to determine whether the customer has the right to control the use of the land.

If the identified asset is the entire plot of land, the parties are less likely to conclude that the customer has the right to obtain substantially all the economic benefits from use of the land because the farmer retains the surface rights (e.g., to farm the land). However, if the identified asset is only the subsurface rights, the customer might have the right to obtain substantially all the economic benefits from using the area below the surface of the land. Further, subsurface rights for the same plot of land may also be stacked in such a way that one customer has an easement for the depth of 5 to 10 feet below the surface while another customer has an easement for the depth of 10 to 20 feet below the surface.

Example 2

A customer enters into a land easement arrangement with a farmer for the right to construct and maintain 25 wind turbines on the farmer’s 500-acre plot of land. Each wind turbine will be constructed on 25 individual square-acre plots. At issue is whether the identified asset is the entire 500-acre plot of land or whether there are 25 identified assets, each one square acre of land.

As in the previous example, if the identified asset is the entire 500-acre plot of land, the parties are less likely to conclude that the customer has the right to obtain substantially all the economic benefits from use of the land because the farmer retains all of the rights to the economic benefits of the remaining 475 acres. However, if the identified assets are 25 individual square-acre plots of land, the customer may have the right to obtain substantially all the economic benefits from using each square-acre plot.

As discussed above, FASB members have consistently described this analysis as an area of judgment, and we believe that either approach to the determination of the unit of account in the examples above would be supportable.
This section summarizes FASB, FERC, and IRS pronouncements related to accounting for income taxes as well as federal and state income tax developments affecting the financial and regulatory reporting of income taxes. The accounting for Treasury grants, ITCs, and PTCs is discussed in Section 8. Tax accounting developments related to share-based payments are discussed in Employee Share-Based Payment Accounting Improvements.

Normalization

Tax Cuts and Jobs Act

The Act, enacted on December 22, 2017, amends the Internal Revenue Code (IRC) of 1986 and includes significant income tax law that has not been codified as part of the IRC but is essential to the implementation of the numerous changes resulting from the Act. Many of the tax law changes have prospective effective dates, but some of the Act’s provisions are effective upon enactment or retroactively. Under ASC 740, the financial reporting for income taxes is based on enacted tax law and, thus, financial reporting for periods that include the date of enactment must reflect the Act, including the effects of applicable provisions with prospective effective dates. This section addresses the financial and regulatory reporting associated with the decrease in the corporate federal income tax rate from 35 percent to 21 percent for taxable years beginning after December 31, 2017. In addition, the SEC issued SAB 118 (codified as SAB Topic 5.EE and incorporated into the Codification through ASU 2018-05) and Question 110.02 of the Exchange Act Form 8-K C&DIs on December 22, 2017, to provide guidance on the application of ASC 740 to the accounting for the Act’s changes in tax law for the financial reporting period that includes the date of enactment and for subsequent reporting periods.

Financial Reporting by Rate-Regulated Utilities

ASC 740-10-25-47, which addresses changes in income tax laws or rates, requires adjustments of DTLs and DTAs for the effects of a change in tax laws or rates in the quarterly and annual periods that include the enactment date. ASC 740-10-35-4 indicates that DTAs and DTLs “shall be adjusted for the effect of a change in tax laws or rates” and that a “change in tax laws or rates may also require a reevaluation of a valuation allowance” for DTAs.

An entity with a calendar fiscal year-end would be required to recognize the effects of the legislation in its 2017 annual financial statements. A company with a fiscal year-end ending in a month other than December 2017, January 2018, or February 2018 would also apply the rules for interim period tax accounting of ASC 740-270 to the Act’s changes to its period that includes December 22, 2017, and subsequent interim periods of its fiscal year including such date.

Except as described below, ASC 740-10-45-15 states that the effect of remeasurements of DTAs and DTLs is recognized as a component of income tax expense or benefit from continuing operations in the financial statements for the interim or annual period that includes the enactment date. This includes DTLs and DTAs associated with deferred tax expense or benefit previously recognized as a component of OCI or shareholders’ equity. In general, the reduction of tax rates reduces DTA balances, thereby increasing deferred income tax expense, and reduces DTL balances, resulting in deferred income tax benefit.
To the extent that the deferred tax expense associated with remeasured DTLs has previously been recovered from customers through regulated rates, customers and commissions are likely to expect a refund or a reduction in future rates for the portion of DTLs accrued and associated deferred tax expense recovered on the basis of the higher pre-Act tax rates. In this situation, the excess deferred taxes upon the remeasurement of future tax liabilities is an example of a regulatory liability described in ASC 980-405-25-1 as pertaining to rates “intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts.” Thus, the portion of the DTL that is no longer expected to be paid to the federal government owing to the enacted change in tax rates may be used to reduce rates to customers. Similarly, to the extent that DTAs have previously reduced recoverable tax expense, utilities are likely to seek recovery of the increase in costs resulting from the change in tax law and remeasured DTAs. A utility should record a regulatory asset for a decrease in DTAs if it is probable that the regulator will allow such recovery.

ASC 980-740 addresses the remeasurement of DTAs and DTLs of a regulated utility and indicates that DTAs and DTLs are to be measured on the basis of enacted tax rates and that any resulting regulatory asset or liability is recorded separately. Specifically, ASC 980-740-25-1(c) requires adjustment of DTAs and DTLs for an enacted change in tax laws or rates. ASC 980-740-25-2 provides that “[i]f, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable . . . [related to ASC 980-740-25-1(c)] will be recovered from or returned to customers through future rates, [a tax-related regulatory asset or liability] shall be recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 980-340-25-1 and 980-405-25-1.” The resulting regulatory asset or liability is a temporary difference for which a DTL or a DTA, respectively, is recognized. Recognition of the DTA related to a tax-related regulatory liability or the DTL related to a tax-related regulatory asset correlates with the tax-on-tax gross-up associated with the future recovery of the regulatory asset or settlement of the regulatory liability and results in measurement of the tax-related regulatory asset or liability at the revenue requirement level. The Act requires a utility to compute the DTA or DTL recorded with respect to the tax-related regulatory liability or asset at the enacted 21 percent tax rate. The grossed-up amount of the tax-related regulatory asset or liability reflects the impact on the future revenue requirement, not the revenues associated with the recovery of net deferred taxes in prior years when the tax rate was higher than 21 percent. The “gross-up” described above recognizes that, at a 21 percent tax rate applicable in the year(s) that the regulatory liability will be settled, customer rates must be reduced by $126.58 to return a $100 federal income tax benefit to customers.

Remeasuring DTAs and DTLs

The process of remeasuring DTAs or DTLs as a result of the enactment of the change in the corporate tax rate requires the assessment of each underlying temporary difference or tax attribute. As discussed below, not every federal DTA or DTL requires remeasurement. Further, for regulated utilities, not every remeasured DTA or DTL necessarily results in recognition of a tax-related regulatory asset or liability. ASC 980 requires continual reassessment of the recoverability of regulatory assets and probability of settlement of regulatory liabilities. As further regulatory guidance and authoritative interpretation of the Act become available, it is likely that utilities will have to adjust their estimates of the regulatory assets and liabilities recorded in the period of enactment.

Regardless of the impact of the Act on the estimates of regulatory assets and liabilities, SAB 118 acknowledges that registrants will potentially encounter a situation in which the accounting for certain income tax effects of the Act will be incomplete by the time financial statements are issued for the reporting period that includes the Act's enactment date. According to the press release on the SEC's Web site, SAB 118 provides the SEC staff's views on the “application of U.S. GAAP when preparing an
initial accounting of the income tax effects of the Act,” while Question 110.02 of the Exchange Act Form 8-K C&DIs provides views on the “applicability of Item 2.06 of Form 8-K with respect to reporting the impact of a change in tax rate or tax laws pursuant to the Act.” The guidance in SAB 118 is intended to help registrants address any uncertainty or diversity of views in applying ASC 740 in the reporting period in which the Act was enacted. In summary, if a registrant’s accounting for certain income tax effects of the Act is incomplete, the SEC staff would not object to a registrant’s including in its financial statements the reasonable estimate that it had determined. Conversely, the SEC staff does not believe that it would be appropriate for a registrant to exclude a reasonable estimate from its financial statements if a reasonable estimate (provisional amount) has been determined. If a registrant does not have the necessary information available, prepared, or analyzed (including computations) for certain income tax effects of the Act to determine a reasonable estimate, the SEC staff expects that no related provisional amounts would be included in the registrant’s financial statements for the specific income tax effects for which a reasonable estimate cannot be determined.

DTAs that do not require remeasurement include those related to credit carryforwards and those related to deductible temporary differences for rate refunds for which the utility expects to realize tax benefits under the tax computation rules of IRC Section 1341 (those pertaining to amounts recognized as taxable income in a higher tax rate year that become refundable/deductible in a lower tax rate year if certain criteria are satisfied).

Remeasured DTAs and DTLs that are not expected to result in regulatory assets or liabilities include items for which associated deferred tax expense or benefit has been reported as nonoperating (i.e., below the line) and has not affected prior revenue requirements, if it is expected that the reversal of such DTAs and DTLs will not affect future revenue requirements. Another example of a DTA or a DTL that is not expected to result in a regulatory asset or liability upon remeasurement is any DTA or DTL related to disallowed plant costs. Consistency between the rate treatment of the cost of public utility property (i.e., return on and recovery of plant costs) and the rate treatment of the tax benefits associated with depreciable plant costs is required under the normalization rules of the accelerated depreciation provisions of the IRC. Therefore, there are restrictions regarding whether excess deferred taxes that are related to depreciable basis without full rate recovery or that do not fully earn a return may reduce regulatory tax expense or rate base.

In addition, the remeasurement of DTLs and DTAs for which the rate recovery of the associated deferred tax benefits or costs have previously been deferred, as indicated by the existence of a related regulatory asset or liability, should result in the remeasurement of the preexisting tax-related regulatory asset or liability rather than an increase in a regulatory liability or asset recorded as a result of the change in tax law. Examples include regulatory assets related to (1) the use of the flow-through method of accounting for deferred taxes or (2) the use of after-tax accounting for the equity portion of AFUDC.

**Example of Accounting for a Regulatory Liability Resulting From a Decrease in Tax Rate**

To assess the likely regulatory treatment of excess deferred taxes related to specific DTAs and DTLs in future rate proceedings, a utility should thoroughly review the individual DTAs and DTLs in current-period financial reporting supporting schedules as well as in the filings and supporting schedules for recent rate filings and regulatory financial statements. This assessment of the prior ratemaking treatment of individual DTAs and DTLs is critical in the determination of the appropriate financial reporting for excess deferred taxes.
Example

A rate-regulated utility has recorded $10,000 of DTLs on the basis of a 35 percent tax rate before the Act’s passage. Upon remeasurements arising from the decrease in the corporate tax rate to 21 percent, its DTLs are now $6,000. It is probable that the utility’s regulator will order the refund or reduction of future revenues because of the excess deferred taxes of $4,000. The impact of this expected ratemaking would be a reduction of future revenues of $5,063 ($4,000 ÷ (100 percent – the 21 percent tax rate expected to be in effect under enacted tax law when the regulatory refund is settled)). A journal entry to record the remeasurement of the DTL and the resulting regulatory liability and DTA is:

<table>
<thead>
<tr>
<th>Debit</th>
<th>Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>DR Deferred tax liability (on plant)</td>
<td>CR Regulatory liability</td>
</tr>
<tr>
<td>$4,000</td>
<td>$5,063</td>
</tr>
<tr>
<td>DR Deferred tax asset (on regulatory liability)</td>
<td>CR Regulatory liability</td>
</tr>
<tr>
<td>$1,063</td>
<td>$5,063</td>
</tr>
</tbody>
</table>

The DTA on the regulatory liability temporary difference is computed as 21 percent of $5,063. The remeasurement would not affect pretax income, after-tax income, or the effective tax rate.

Depending on the nature of the book/tax temporary difference underlying the DTL, the regulatory liability may reduce future rates on the basis of the reversal pattern of the temporary difference or an amortization schedule otherwise ordered by the applicable regulatory commission. If the regulatory liability were to be settled over a 10-year period, the annual journal entries to adjust tax-related regulatory liability, to record the impact of reduced revenue from customer billings because of amortization of the regulatory liability, and to record the current tax effects of the reduction in revenue would be:

<table>
<thead>
<tr>
<th>Debit</th>
<th>Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>DR Regulatory liability</td>
<td>CR Deferred tax asset (on regulatory liability)</td>
</tr>
<tr>
<td>$506</td>
<td>$106</td>
</tr>
<tr>
<td>DR Deferred tax benefit</td>
<td>CR Deferred tax benefit</td>
</tr>
<tr>
<td></td>
<td>$400</td>
</tr>
<tr>
<td>DR Revenue</td>
<td>CR Accounts receivable</td>
</tr>
<tr>
<td>$506</td>
<td>$506</td>
</tr>
<tr>
<td>DR Current tax payable</td>
<td>CR Current tax expense</td>
</tr>
<tr>
<td></td>
<td>$106</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The entry above reflecting the reduction in revenue and customer billings would not likely be separately recorded; instead, it would likely be recorded in the normal course of business as a function of the prices charged as adjusted by the settlement of the tax-related regulatory liability through customer rates. Similarly, the effects of the reduction in customer billings on taxable income without effects on other taxable or deductible amounts would result in the incremental effects reflected above on taxes currently payable and current tax expense. However, this entry would also not necessarily be recorded separately from the entries that are normally recorded to reflect ongoing customer billings. Settlement of the tax-related regulatory liability in future years would reduce pretax income and decrease the effective tax rate but have no effect on after-tax income.

Normalization Requirements for Excess Deferred Taxes

Section 13001(d) of the Act contains a normalization requirement that is similar to the normalization requirement included in the Tax Reform Act of 1986 with respect to the depreciation-related excess deferred income tax reserves resulting from the decrease in the corporate tax rate. In general, the normalization requirement for excess tax reserves allows (but does not require) the excess tax reserves to reduce customer rates and limits any such reduction to those amounts that do not reduce the excess tax reserve more rapidly or to a greater extent than such a reserve would be reduced under the average rate assumption method (ARAM).
Section 13001(d)(3)(A) of the Act states that the excess tax reserve is computed as of the day before the corporate rate reductions provided in the amendments made by Section 13001 of the Act take effect.

Under ARAM, the excess in the reserve for deferred taxes is reduced over the remaining regulatory lives of the property that gave rise to the reserve for deferred taxes. During the period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying the amount of the timing differences reversing during that period by the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period.

In effect, an average tax rate embedded in the deferred tax reserve (as defined under the normalization regulations) is computed at the beginning of the year in which the depreciation differences for a depreciable asset constituting public utility property begin to reverse. Because the depreciation differences for various vintages/classes of property begin to reverse at different times, the reduction in excess deferred tax reserves and the resulting reduction in revenue requirement will begin in different years. For a utility with relatively consistent levels of annual additions of depreciable plant, the amortization of excess tax reserves under ARAM would be likely to increase each year for the first several years after the Act's passage because the excess deferred tax reserves for the more recent vintages would not immediately be permitted to reverse under ARAM.

The normalization requirement under Section 13001(d) of the Act also permits certain taxpayers to use an alternative method to ARAM. Under the alternative method (essentially the same as the reverse South Georgia method applicable to the Tax Reform Act of 1986's guidance on excess deferred tax reserves in accordance with IRS Revenue Procedure (“Rev. Proc.”) 88-12), a taxpayer reduces its aggregate excess tax reserve for all public utility property in a given plant account (regardless of vintage) ratably over the remaining regulatory depreciable life of the property on the basis of the weighted average life or composite rate used to compute regulatory depreciation expense. Reversal of excess deferred taxes under the alternative method begins immediately for all vintages, in contrast to the result under ARAM. The alternative method is available to taxpayers required by a regulatory agency to compute depreciation for public utility property on the basis of an average life or composite rate method if the taxpayer's books and underlying records did not contain the vintage account data necessary to apply ARAM. By statute, eligibility for the alternative method is available on a regulatory jurisdiction-by-jurisdiction basis. In private letter rulings (PLRs) issued with respect to excess deferred taxes under the Tax Reform Act of 1986, the IRS has held that the reverse South Georgia method could be applied to certain property subject to a particular regulatory jurisdiction while ARAM must be applied to other property subject to regulation by the same commission. In one such ruling, the IRS held that the reverse South Georgia method may be applied to public utility property placed in service before a year in which vintage-level information was available and that ARAM must be applied to the vintages with sufficient vintage-level information. In another ruling, the IRS held that the reverse South Georgia method may be applied to public utility property in certain asset classes without sufficient vintage-level information and that ARAM must be applied to the asset classes with sufficient vintage-level information.

The normalization requirements of Section 13001(d) of the Act apply to depreciation-related excess tax reserves. Those reserves include method and life differences as described in IRC Section 168(i)(9)(A)(i) as well as deferred taxes related to certain taxable CIAC in accordance with IRS Notice 87-82 and the applicable portion of depreciation-related net operating loss (NOL) carryforwards in accordance with Treas. Regs. Section 1.167(l)-1(h)(1)(iii).

Finally, Section 13001(d)(4) of the Act details the sanctions applicable to violation of the Act’s normalization requirement for excess deferred taxes. Section 13001(d)(4)(B) of the Act states that the sanction applicable to all deferred tax normalization violations (i.e., loss of the company’s right to deduct
accelerated tax depreciation and mandate for the company to use its regulatory depreciable lives and method as the basis of its depreciation deduction for tax return filing purposes) applies and, in addition, that a company violating the normalization requirements with respect to excess deferred taxes resulting from the decrease in the tax rate from 35 percent must also increase its tax liability for the taxable year of the violation by the amount by which it reduces its excess tax reserve more rapidly than permitted under a normalization method of accounting.

In view of the onerous consequences of violating the normalization requirements, it is important that utilities and their commissions be mindful of the applicable rules when determining the effects of the excess deferred taxes resulting from the Act on their regulatory books of account and in ratemaking, in the contexts of amounts reducing regulatory tax expense and rate base (or, if applicable, weighted average cost of capital).

On February 14, 2018, the FASB issued ASU 2018-02, which amends ASC 220 to “allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the [Act]” and requires entities to provide certain disclosures regarding stranded tax effects. The ASU is effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. See the press release on the FASB’s Web site for more information about ASU 2018-02.

The FASB staff has also released the following Q&As on Act-related issues:

- Whether Private Companies and Not-for-Profit Entities Can Apply SAB 118.
- Whether to Discount the Tax Liability on the Deemed Repatriation.
- Whether to Discount Alternative Minimum Tax Credits That Become Refundable.
- Accounting for the Base Erosion Anti-Abuse Tax.
- Accounting for Global Intangible Low-Taxed Income.

For more information about the Q&As, see the January 11, 2018, and January 22, 2018, press releases on the FASB’s Web site.

In addition, Deloitte’s January 3, 2018, Financial Reporting Alert (last updated on June 20, 2018) contains responses to frequently asked questions on how an entity should account for the tax effects of the Act in accordance with ASC 740. The publication addresses accounting questions related to SAB 118, ASU 2018-02, and the FASB staff Q&As; the change in the corporate tax rate; modifications of carryforwards and certain deductions; the deemed repatriation transition tax; global intangible low-taxed income; foreign-derived intangible income; the base erosion anti-abuse tax; the corporate alternative minimum tax; non-ASC 740 topics affected by tax reform; separate-company financial statements; and considerations related to disclosures, IFRS Standards, and interim reporting.

**Deferred Tax Assets for Net Operating Loss and Minimum Tax Credit Carryforwards**

In recent years, the normalization debate regarding the proper treatment of DTAs for NOL carryforwards in ratemaking has involved:

- Whether the DTA for the portion of an NOL or MTC carryforward attributable to accelerated depreciation must be included in rate base.
- Whether the full amount of the depreciation-related DTL may reduce rate base despite the existence of an NOL carryforward (i.e., when the DTA for the portion of an NOL carryforward
attributable to accelerated depreciation is considered a component of the depreciation-related DTL for ratemaking purposes notwithstanding its classification as a DTA for financial, and often regulatory, reporting purposes).

- How to compute the depreciation-related portion of an NOL carryforward.
- Consideration of alternative approaches for reducing the revenue requirement when an NOL carryforward exists and some or all of the DTA for the NOL carryforward is included in rate base.

In 2018 and beyond, normalization issues involving the ratemaking treatment of NOL carryforwards may also arise in the context of excess deferred taxes resulting from the reduction in the corporate federal income tax rate in accordance with the Act and sequestration of a refundable MTC carryforward.

The most recent PLRs issued before 2017 addressing the application of the deferred tax normalization requirements when an NOL carryforward exists are:

- PLR 201418024.
- PLR 201436037.
- PLR 201436038.
- PLR 201438003.
- PLR 201519021.
- PLR 201534001.
- PLR 201548017.

The latest PLR regarding the normalization rules for NOL carryforwards is PLR 2017090008. The utility subsidiary in PLR 201709008 incurred NOLs in prior years, resulting in an NOL carryforward at the time of its rate case filing. The utility maintains a reserve account, accumulated deferred federal income tax (ADFIT), showing the amount of tax liability that is deferred as a result of the accelerated depreciation. In addition, the utility maintains an offsetting series of entries — a “deferred tax asset” and a “deferred tax expense” — that reflects the portion of those “tax losses” that although caused by accelerated depreciation did not actually defer tax because of the existence of an NOL carryforward. In the utility's rate proceeding, the DTL used to reduce rate base was reduced by the amount of the DTA for the NOL carryforward. The commission accepted a settlement agreement that included the DTA for the NOL carryforward in rate base and ordered the utility to seek a PLR regarding the ratemaking treatment of the DTA for the NOL carryforward.

In PLR 201709008, the IRS stated that because the reserve account for deferred taxes reduces rate base, it is clear that the portion of the NOL carryover that is attributable to accelerated depreciation must be taken into account in the calculation of the account's balance. The IRS held that the order to include in rate base the DTA resulting from the NOL carryforward, given the inclusion in rate base of the full amount of the deferred tax reserve resulting from accelerated tax depreciation, is in accord with the normalization requirements. The IRS further stated that the with-or-without method proposed by the taxpayer ensures that “the portion of the [NOL carryforward] attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the [carryforward] attributable to accelerated depreciation.” Further, the method “prevents the possibility of ‘flow through’ of the benefits of accelerated depreciation to ratepayers.” Accordingly, the IRS held that exclusion from rate base of the entire DTA resulting from the NOL carryforward, or the inclusion in rate base of a portion of that DTA that is less than the amount attributable to accelerated tax depreciation, computed on a with-and-without basis, would violate the normalization requirements.
Future Test Periods

The deferred tax normalization regulations contain rules applicable to the computation of the maximum amount of deferred tax reserve excludable from rate base when rates are set with reference to future test periods. Five PLRs issued in 2015 provide guidance on how to apply these rules to annual formula rates with true-up adjustments. One of these rulings also addresses stand-alone rate adjustments for the recovery of certain costs of public utility property without a full base rate proceeding.

Additional PLRs issued in 2017 provide further guidance regarding how to apply the proration rules to annual formula rates with true-up adjustments, to interim rates subject to refund, and to computations of weighted average cost of capital when DTLs are treated as zero-cost capital rather than as reductions to rate base.

The PLRs issued in 2015 — PLRs 201531010, 201531011, 201531012, 201532018, and 201541010 — specifically addressed how the deferred tax normalization rules apply to FERC formula rates, reset annually with true-up adjustments, for electric transmission businesses.

The FERC-approved formula uses a rate-of-return, cost-of-service model. Before the year in which the rates become effective (e.g., by September 1 of year 1), a utility estimates its revenue requirement for the following calendar year, the service year (i.e., year 2), partly on the basis of the facilities in service at that time and expected to be placed in service during the service year and a FERC-approved rate of return. Rates charged during the service period are based on this projected revenue requirement. The formula rate template also contains a “true-up” mechanism under which a utility compares (1) its actual revenue requirement determined on the basis of amounts reported in its FERC Form No. 1 for the service year filed by April of year 3 (i.e., actual costs incurred and actual rate base amounts) with (2) its revenues billed for the service year. If billed revenue is greater than the actual revenue requirement for the service year, the overcollection is refunded in customer bills within two years of the service year (i.e., by the end of year 4). If billed revenue is less than the actual revenue requirement for the service year, the undercollection is collected two years after the service year. For both undercollections and overcollections, a carrying charge computed with reference to FERC’s standard refund interest rate is imposed.

In computing their projected and actual annual revenue requirements under their FERC-approved formulas, the taxpayers in the PLRs calculate average rate base. All elements of average rate base are computed on the basis of the same test period and the same service year. The taxpayers compute average rate base by using monthly averages for plant balances, including accumulated depreciation. For this purpose, depreciation begins when the asset is placed in service. To calculate certain other elements of average rate base, including ADFIT, the taxpayers use averages of the beginning- and end-of-year balances. The taxpayers reduce their gross rate base amounts by forecasted ADFIT balances not computed in accordance with the proration formula required by Treas. Regs. Section 1.167(l)-1(h)(6) for future test periods. In periods of increasing ADFIT balances, application of the proration formula would decrease average ADFIT, increase average rate base, and increase the revenue requirement. The deferred tax computations are pursuant to the provisions of the taxpayers’ FERC-approved templates.

The IRS held that the computations of average rate base by the taxpayers with reference to 13-month averages for plant and accumulated depreciation for a given service year and simple averages of the beginning- and end-of-year balances for ADFIT for the same service years comply with the consistency requirement of the normalization rules for accelerated depreciation under IRC Section 168(i)(9)(B). For this aspect of the normalization requirements to be satisfied, there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and ADFIT. The IRS explained that the taxpayers computed the averages of rate base, depreciation expense, and ADFIT in a consistent fashion in terms of averaging over the same period. Although there are minor differences...
in the convention used to average all elements of rate base, the IRS concluded that for purposes of
the deferred tax consistency requirement, it is sufficient that both depreciation expense and ADFIT are
(1) determined by averaging and (2) determined over the same period.

The IRS also held in the five 2015 PLRs that the computations of ADFIT for the projected revenue
requirement (computed with reference to a test period ending after the effective date of rates) involve
future test periods requiring application of the proration formula to comply with the normalization
requirements. In PLRs 201531010, 201531011, 201531012, and 201532018, the IRS ruled that
the computation of ADFIT for purposes of calculating average rate base without application of the
proration rules for future test periods for the taxpayer’s actual revenue requirement used for the
true-up mechanism (determined after the end of the service period) complies with the deferred tax
normalization requirements because the test year is no longer a future test period in this context.

In PLR 201541010, the IRS similarly held that the true-up component is determined by reference
to a purely historical period, and that there is no need to use the proration formula to calculate the
differences between the projected and actual ADFIT balances during the period. However, the IRS also
indicated in PLR 201541010 that when the true-up is calculated, (1) the proration formula applies to the
original projection amount, but (2) the actual amount added to the ADFIT balance over the test year is
not modified by application of the proration formula.

In PLR 201541010, the IRS addressed a revision by the commission to adjust the utility's already
approved cash working capital allowance specifically to mitigate the effect of using the proration
method. The IRS indicated that in general, taxpayers may not adopt any accounting treatment
that directly or indirectly circumvents the normalization rules. The IRS held that in this situation,
an adjustment to eliminate from the cash working capital allowance any provision for accelerated
depreciation-related ADFIT if the proration method is employed conflicts with the normalization rules.

Finally, the IRS held that if the taxpayers take specific corrective actions prescribed in the PLRs, and
assuming compliance by FERC with methods described in the PLRs on a prospective basis, sanctions
for violation of the deferred tax normalization requirements involving disallowance of accelerated
depreciation would not apply despite the taxpayers’ historical use of the method held not to comply with
the normalization requirements.

In PLR 201717008, the IRS again addressed the application of the normalization requirements to
utilities employing annual formula rates with true-up adjustments. PLR 201717008 provides clarity and
additional guidance with respect to the holdings regarding true-up adjustments in the five PLRs issued
by the IRS in 2015 and also addresses issues that utilities may not have considered when analyzing and,
in many cases, revising formula rate templates to comply with the interpretations of the normalization
requirements in the previous rulings.

In PLR 201717008, the IRS:

- Confirmed that the normalization requirements apply not only to full rate proceedings but
  also to limited scope rate proceedings focused on cost recovery of recent additions of public
  utility property (e.g., environmental compliance additions, transmission additions, gas main
  replacement programs).

- Held in a manner consistent with the 2015 PLRs in characterizing a given time frame as a future
test year subject to the proration formula because rates became effective on the first day of the
test year notwithstanding a true-up computation determined after the end of the test period.
• Held in a manner consistent with the 2015 PLRs in characterizing the same period as a historical test year when referenced after the end of the test period for purposes of computing an actual revenue requirement and determining a true-up adjustment, but also:
  ◦ Clarified the sentence in PLR 201541010 regarding preservation of the effect of the proration formula on the projected revenue requirement in the determination of the true-up adjustment.
  ◦ Provided specific guidance on how to compute deferred taxes for purposes of calculating the actual revenue requirement and the true-up adjustment in situations in which the actual deferred tax activity differed from the forecasted deferred tax activity used in the computation of the projected revenue requirement.
• Held in a manner consistent with the 2015 PLRs in providing that minor differences in the conventions used to average components of rate base, including ADFIT, are permissible under the consistency requirement as long as the plant-related rate base amounts included in rate base and the deferred tax amounts reducing rate base are both determined by averaging and both are determined over the same period (e.g., 13-month averaging for plant and accumulated depreciation for a given service year and a simple average of the beginning- and end-of-year balances for ADFIT for the same service year are compliant).
• Effectively distinguished the holdings in PLRs 9202029, 9224040, and 9313008 involving utilities with average rate base computations with reference to test years that were part historical and part future by holding that when an entirely future test year and average rate base are used, it is necessary to apply only the proration requirement (i.e., unlike under the prior holdings, it is not necessary to then compute an average with reference to a prorated ending balance to satisfy the consistency requirement).
• Held that any reduction to rate base by the taxpayer in PLR 201717008 for an amount of ADFIT in excess of the limitations in the normalization rules in any year before the taxpayer takes the necessary corrective action was not a violation of the normalization rules.

PLRs 201739001 and 201817006 reinforce the holdings of recent proration PLRs and provide guidance regarding the application of the proration rules to rate proceedings that are not based on annual formula rate filings with true-up adjustments to reflect differences between projected amounts and actual balances. PLRs 201739001 and 201817006 address periodic rate filings in state jurisdictions that permit interim rates to become effective before a rate proceeding’s conclusion. The interim rates become effective during the test period and before a full review of the filing to increase general base rates. Final rates become effective after the end of the test period. Interim rates are subject to refund or credit to customers, plus interest. An interim rate refund results if, at the end of a contested case, amounts collected under the interim rate schedule exceed amounts that would have been collected under final rates. The amounts estimated for the test year (including, but not limited to, costs, plant additions, ADFIT, and other factors affecting the computation of the revenue requirement) are not generally “trued-up” to actual amounts after the end of the test period for the determination of final rates. Final rates reflect the resolution of contested items such as the allowed return, the recovery of specific categories of operating expenses or the amount of certain operating expenses, and the inclusion of specific investments and certain costs in rate base.

PLRs 201739001 and 201817006 address whether the proration formula must be applied to interim rates, final rates, and any interim rate refund. The rulings also address whether a reduction of tax expense or depreciation expense recoverable in final rates or reflected in the computation of any interim rate refund that has the effect of offsetting some or all of the revenues resulting from required ADFIT proration would comply with the normalization requirements.
On the basis of the specific dates involved in the rate proceedings (redacted from the PLRs released to the public), the IRS held that the test periods used for interim rate calculation purposes were part-historical, part-future test periods and, thus, that the proration formula must be applied. One of the holdings of PLR 201739001 confirmed the taxpayer’s computation of the length of the future portion of the part-historical, part-future test period for proration computation purposes. (Note that the denominator used to prorate ADFIT activity in an entirely future test period is normally 365 days.)

A party to the rate case in PLR 201739001 proposed that any interim rate refund be determined in a manner that reverses the effects of the proration formula on interim rates charged during the entire period in which interim rates are effective (including during the test period) or, alternatively, in a manner that reverses the effects of the proration formula on interim rates charged after the end of the test period. The IRS held that (1) the computation of an interim rate refund in such a way that the effects of the proration formula rules on interim rates charged during the test period are returned to customers (by causing or increasing an interim rate refund) would violate the normalization requirements but that (2) the computation of an interim rate refund in such a way that the effects of the proration formula rules on interim rates charged after the test year is completed are returned to customers would not violate the normalization requirements. PLR 201739001 states, in part, that “[t]o permit the effects of the proration formula on interim rates charged during the Year 1 test year to be reversed in a subsequent phase of the ratemaking would be economically equivalent to not applying the proration formula in the first place.” A similar statement is included in PLR 201817006.

The IRS held in PLR 201739001 that if a utility computes ADFIT to determine its final rates (apart from consideration of an interim rate refund) without applying the proration formula, it would not violate the normalization requirements because final rates are determined by reference to a purely historical period. Finally, the IRS ruled that any reduction in tax expense or depreciation expense recoverable in final rates or the computation of any interim rate refund that has the effect of offsetting some or all of the level of revenues resulting from prorated ADFIT in setting interim rates that may be required under the proration formula rules would violate the normalization requirements.

PLRs 201741004 and 201741005 both address an electric transmission formula rate template used to determine a basic rate and a true-up. For the basic rate, historical income statement and balance sheet amounts are used, and plant additions are projected. Notwithstanding that the associated book depreciation and incremental DTL are not also projected, the IRS held that this practice did not violate the consistency requirement of the normalization rules. The taxpayers did not request normalization guidance regarding the true-up component.

PLR 201741004 also addresses three annual riders in a state jurisdiction that each employ a projected rate and a true-up. Under the facts of the ruling, the IRS held that (1) the projected rate is based on a future test period and therefore is subject to the proration requirement and (2) the true-up is based on a purely historical period and therefore is not subject to the proration requirement. The ruling does not address any other aspects of the computation of the DTL for true-up purposes, particularly the guidance in PLRs 201541010, 201717008, and 201739001 addressing preservation of the effects of proration in a projected revenue requirement in the computation of a true-up.

PLR 201741004 also states that the taxpayer's historical practices that did not comply with the proration requirement did not constitute a normalization violation and prescribes necessary corrective actions that the taxpayer represented that it will take. The remedial actions are similar to the criteria in the safe harbor revenue procedure regarding inadvertent noncompliance with the normalization rules, but one of the requirements in the ruling is relaxed relative to the wording in Rev. Proc. 2017-47, which states, in part, that it applies to the taxpayer that “changes its Inconsistent Practice or Procedure . . . to a Consistent Practice or Procedure . . . at the Next Available Opportunity . . . in a manner that
totally reverses the effect of the Inconsistent Practice or Procedure." PLR 201741004 provides that
(1) "prospectively adhering to the Service's interpretation of" the normalization requirements and (2) to
the extent permissible under applicable state or federal regulatory law, adjusting or correcting any rates
currently in effect, or which have been in effect as calculated by using procedures inconsistent with the
ruling, must be considered to not have violated the normalization rules.

PLRs 201743009 and 201745002 address base rates and three cost recovery clauses of vertically
integrated electric utilities. In each ruling, the taxpayer treats ADFIT as a component of its weighted
average cost of capital at a zero cost rather than as a reduction to rate base (as had been the
computational alternative in numerous recent proration PLRs).

For base rate cases, the taxpayer projects its capital structure, including the ADFIT component. However,
the taxpayer has not historically applied the proration formula applicable to future test periods in
computing its weighted average cost of capital. The IRS held that the taxpayer must follow the proration
requirement applicable to future test periods to determine the amount of ADFIT included in its capital
structure for the projected revenue requirement determinations.

**Deferred Tax Consistency Requirement**

Many of the PLRs summarized above regarding future test periods address the application of both
the consistency rules and the proration rules of the deferred tax normalization requirements. The
consistency requirement holdings of these PLRs are summarized below, as is PLR 201752002 regarding
deferred taxes associated with disallowed capital expenditures resulting from commission-mandated
safety enhancement costs.

Following an incident and ensuing investigations, the utility in PLR 201752052 was ordered by its
commission to incur costs to fund safety-related programs and projects to be identified by the
commission. A portion of the costs were to be funded by shareholders, and therefore, the utility
was denied a return of and a return on such costs (i.e., such costs were neither allowed in rate base
nor recoverable in depreciation expense). The commission intended that neither the utility nor its
shareholders would be able to realize the accelerated depreciation-related tax benefits related to these
assets.

The ratemaking for mandated costs borne by shareholders was accomplished in two steps:

- The initial computation of the revenue requirement included the disallowed costs in rate base,
  included the depreciation of such costs in recoverable depreciation expense, and reduced rate
  base by associated ADFIT.
- In addition, a regulatory liability was created to offset the amount of costs included in rate
  base. Amortization of the regulatory liability offset depreciation expense related to these costs
  included in ratemaking as described above. The reduction in rate base attributable to the ADFIT
  on the disallowed costs remained in place and was not counteracted.

IRC Section 168(j)(9)(B) provides that there must be consistency in the treatment of costs for rate
base, regulated depreciation expense, tax expense, and deferred taxes. Consequently, the IRS held
in PLR 201752052 that the consistency rules would be violated if, as described in the proposed
decision, capital additions are removed from rate base (and from future depreciation expense) while
the deferred taxes associated with those same capital additions are retained as a rate base reduction.
This implementation would result in reduction of rate base by ADFIT produced by depreciable assets
because the commission has disallowed recovery. The proposed treatment of the reserve for deferred
taxes is inconsistent with respect to (1) the depreciation expense and (2) the rate base and thus violates
the consistency requirement of the deferred tax normalization rules.
The IRS has interpreted and applied the deferred tax consistency requirement in several contexts and provided the following guidance in PLRs since 2015:

- **PLRs 201531010, 201531011, 201531012, 201532018, 201541010, and 201717008** — The taxpayers computed average rate base with reference to a 13-month average for plant and accumulated depreciation for a given service year and a simple average of the beginning- and end-of-year balances for ADFIT for the same service year. The IRS held that minor differences in the convention used to average all elements of rate base complied with the consistency requirement because it was sufficient that plant and ADFIT were both determined by averaging and were both averaged over the same period.

- **PLR 201717008** — The IRS indicated that averaging conventions, when applied to entirely future test periods, should presumptively be treated as having the same purpose as the proration requirement, thereby negating the necessity to apply both conventions serially to changes in ADFIT balances. The IRS held that the consistency requirement does not mandate that any averaging convention applied to other elements of rate base also apply to a taxpayer’s prorated ADFIT balance.

- **PLR 201817006** — The IRS indicated that the consistency requirement does not mandate that the regulatory averaging procedure applied to other components of rate base in the relevant computation be applied to the prorated ADFIT balance.

- **PLRs 201741004 and 201741005** — All elements of rate base, including plant in service, accumulated depreciation, and ADFIT, used balances determined, at least initially, as of the end of a historical calendar test year. Depreciation expense and all other operation and maintenance expenses reflected in the calculation were also amounts based on the historical calendar test year. In addition, the taxpayers used a projection of plant additions to be placed in service during the calendar year in which rates were being set to compute a weighted amount added to rate base. The IRS held that taxpayers’ projections of plant additions for inclusion in rate base in conjunction with the use of historical ADFIT and depreciation expense amounts did not violate the deferred tax consistency requirement.

- **PLRs 201743009 and 201745002** — The IRS held that a facial inconsistency between (1) the date at which ADFIT is computed for weighted average cost of capital calculation purposes and (2) the date through which plant is included in rate base does not violate the normalization requirements unless the ADFIT amount included in weighted average cost of capital exceeds the maximum allowable deferred tax reserve permitted under the overall deferred tax normalization requirements. The rulings direct the taxpayers to keep as part of their normal retention of records under IRC Section 6001 the calculations necessary to determine the ADFIT limitation in their ratemaking processes related to their riders (to support whether the taxpayers’ ADFIT amounts used in their rate proceedings exceed such limitation).

FERC issued an order on June 21, 2018 (EL18-155), that initiated FPA Section 206 proceedings to examine the utilities’ use of the two-step method addressed in PLR 201717008 that results in their averaging by using a prorated ending ADFIT balance. FERC stated that their transmission formula rates may be “unjust, unreasonable, or unduly discriminatory or preferential.” FERC indicated that the practice used by some utilities in calculating their ADFIT reduction of rate base was not necessary to comply with the IRS’s deferred tax normalization requirements. Numerous utilities have used the two-step method for years, but on the basis of PLR 201717008, FERC is now asserting that this practice may be understating ADFIT balances while having customers pay “unreasonably higher rates.”
Definition of “Public Utility Property” and Scope of Application of the Normalization Requirements

The deferred tax normalization requirements and the ITC normalization requirements apply to “public utility property” as defined in each of the operative statutory provisions and regulations issued thereunder. The definitions are consistent with each other, but there are wording differences. The IRS has ruled in the past and ruled again in PLR 201619005, PLR 201718017, PLR 201722006, PLR 201825025, and PLR 201825026 that the definitions of public utility property are the same for purposes of the ITC and deferred tax normalization rules. The determination of whether property is public utility property for normalization purposes is based on whether the property is used in a public utility activity (e.g., the furnishing or sale of electrical energy) and whether the rates for such furnishing or sale are established or approved by a public utility commission or similar body on a rate-of-return basis.

The utility in PLR 201619005 requested guidance on whether the normalization requirements apply to the portions of solar generation facilities with energy output allocated to customer groups at rates set under three pricing-specific arrangements. The IRS ruled that the portion of the facilities with pricing set under a market index rate adjustment clause subject to the regulatory jurisdiction of one of the utility’s commissions does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not set on a rate-of-return basis. The IRS held that the portion of the facilities with pricing set by means of bilateral negotiations between the utility and nonjurisdictional customers does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not established or approved by a public utility commission and are not determined on a rate-of-return basis. Finally, the IRS ruled that the portion of the facilities allocated to wholesale customers in one of the utility’s regulatory jurisdictions, with pricing set by negotiation or the wholesale market index (or both) and approved by the commission, does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not set on a rate-of-return basis.

The IRS indicated in PLR 201619005 that it did not express or imply an opinion about (1) whether the contract to sell electricity constitutes a service contract or a lease, (2) whether the utility is the owner of the facility for federal income tax purposes, or (3) the classification of the property for purposes of depreciable recovery period.

The utility in PLR 201718017 requested guidance on whether the pricing arrangements for its solar generation facility indicate that the generation plant is not public utility property in the context of the scope of the deferred tax and ITC normalization requirements. The taxpayer in PLR 201718017 offers a voluntary community solar pilot program to its customers. Participating customers are not entitled to any of the electricity generated by the solar facility and continue to buy power from the utility at commission-approved retail rates. Participating customers pay an annual subscription fee (or a reduced annual subscription fee in the case of a multiyear commitment to the program) to the utility in exchange for a monthly incentive fee payable as a credit on their monthly bills and intended to compensate the participants for the energy output of the solar generation facility valued on the basis of avoided fuel costs achieved by operating the solar generation facility instead of other power plants.

The solar generation facility is not included in the utility’s rate base. The utility recovers the cost of its investment in the solar generation facility solely through subscription fees. The aggregate subscription fees are intended to cover the full projected annual revenue requirement of the solar generation facility, including return on and return of plant costs. The subscription fees are computed as the “levelized” projected annual revenue requirement over the economic life of the facility on a net present value basis. The annual revenue requirements, including the allowed return, would otherwise be higher at the beginning of the life of the depreciable plant than toward the end of the life of the plant. To the extent that an insufficient number of subscriptions are sold annually over the life of the solar generation
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facility, the economic risk is borne by the utility, not the participating or nonparticipating customers. Nonparticipating customers pay for power generated by the solar facility on the basis of the market price of fuel used by the utility to operate its nonsolar generation facilities (i.e., costs avoided by the utility by operating the solar generation facility instead of other generation facilities).

The IRS analyzed the pricing arrangements with respect to the solar generation facility under the normalization rules by applying the definition of “public utility property” as a three-factor test:

- [T]he property must be used predominantly in the trade or business of the furnishing or sale of . . . electrical energy.
- [T]he rates for such furnishing or sale must be established or approved by a State or political subdivision thereof, any agency or instrumentality of the United States, or by a public service or public utility commission or similar body of any State or political subdivision thereof.
- [T]he rates so established or approved must be determined on a rate-of-return basis.

The IRS held that the solar generation facility is not public utility property for normalization purposes because:

- None of the payments for electricity produced by the solar facility constitutes a payment for the furnishing or sale of electricity at a price that reflects cost-based, rate-of-return ratemaking (i.e., prices were set at a market rate on the basis of avoided fuel costs).
- The subscription fee is not for the furnishing or sale of electricity from the facility.

PLR 201722006 addresses whether the normalization requirements apply to prices set with respect to the output of a peaking facility operating as a wholesale power provider under the Federal Power Act with rates established through negotiation and by the wholesale market or both. The merchant generator is not subject to rate regulation by the public utility commission of the state in which the plant is located. However, legislation in that state intended to encourage the construction of peaking electric generation plants to benefit electricity consumers provides that owners of a peaking plant must be compensated at its cost of service plus a reasonable rate of return on their prudently incurred investment.

The owner of the merchant plant is not an electric distribution utility subject to statutory rate regulation by the state commission, but merchant generators in the state may agree contractually to submit to rate determinations. The predecessor owner of an interest in the peaking facility entered into a multiyear contract with a public service electric distribution company in the state. The distribution utility is subject to rate regulation by the state commission. Prices determined under the contract between the merchant generator and the distribution utility are established by the state commission in accordance with annual contested rate cases with the ROE reviewed periodically.

Some elements of this contractual arrangement are similar to those related to the determination of rates for the furnishing or sale of electrical energy established or approved by a state or political subdivision in accordance with the definition of “public utility property” under IRC Section 168(i)(10). However, the IRS agreed with the taxpayer by holding in PLR 201722006 that under the pricing arrangement, the generation plant is not public utility property subject to the deferred tax normalization requirements.

PLR 201825025 and PLR 201825026 are essentially identical rulings regarding whether a solar generation facility owned by a utility subject to regulation by two state public utility commissions and by FERC constitutes public utility property. The pricing for power in one of the state jurisdictions is in accordance with a program resulting from a statute aimed at facilitating renewable energy integration and is based on a form of market-based rates. The pricing for power generated by the same facility
subject to regulation by the other two jurisdictions is based on traditional cost-of-service, rate-of-return ratemaking. The IRS held that the portion of the plant subject to regulation by the commission utilizing market-based rates is not public utility property and that the portions of the same plant subject to regulation by the other two commissions are public utility property.

**Normalization Letter Ruling Regarding the Election of Out of Bonus Depreciation**

PLR 201718015 addresses the application of the deferred tax normalization requirements to a taxpayer's initial intention to elect out of bonus depreciation and its ultimate decision to deduct bonus depreciation in the context of annual formula rates subject to a true-up adjustment.

The taxpayer in PLR 201718015 intended to elect out of bonus depreciation for a particular tax year and forecasted its ADFIT and deferred tax expense for purposes of its projected revenue requirement filing in accordance with its intention. The taxpayer and its consolidated group made estimated tax payments, an extension payment, and intercompany tax-sharing payments in a manner consistent with the intention to not deduct bonus depreciation for this tax year.

A customer challenged certain inputs of the taxpayer's formula rates in 2017 and alleged that the taxpayer unreasonably and imprudently opted out of using bonus depreciation, thereby understating ADFIT amounts and unduly increasing transmission rates. The commission determined that the taxpayer did not demonstrate that its decision to opt out of using bonus depreciation was prudent and required the taxpayer to calculate its ADFIT for its true-up adjustment of the year at issue to simulate the effects of deducting bonus depreciation.

After analysis of the commission's decision, the taxpayer decided to deduct bonus depreciation for the tax year at issue and requested a rehearing regarding the commission's authority to negate the taxpayer's statutory right to elect out of bonus depreciation and to require the taxpayer to simulate the effects of deducting bonus depreciation on a retroactive basis in the setting of rates.

To comply with the commission's order, the taxpayer computed its ADFIT for its actual revenue requirement for the year at issue even though the ADFIT amounts reported in the taxpayer's regulatory financial statements for the year at issue reflected its intention to not deduct bonus depreciation.

The taxpayer deducted bonus depreciation on the tax return for the year at issue and ultimately received refunds of estimated taxes paid for such year and, by carrying back an NOL, taxes paid in a prior tax year.

The IRS ruled in PLR 201718015 that the taxpayer's reflection of the increase in ADFIT in the actual revenue requirement used to determine the true-up adjustment complied with the deferred tax normalization rules, including the consistency requirements, because the true-up adjustment was based on the actual tax liability for the year at issue. The IRS indicated that the ratemaking resulting from the computation of the actual revenue requirement did not constitute a simulation because it reflected the taxpayer's choice to claim bonus depreciation.

**Correction of Deferred Tax Accounting Errors**

In January 2016, the IRS, through its PLR process, addressed the correction of deferred tax accounting errors. Specifically, the utility in PLR 201603017 became aware of deferred tax errors embedded in its legacy accounting system while installing a “more robust” new accounting system. The previously unrecognized errors resulted in (1) a lower amount of deferred tax expense than would have been
calculated if the errors had not been present and (2) a lower DTL balance. The net effect of these errors was a lower revenue requirement.

The utility sets rates for a five-year period that are based initially on a traditional rate case and adjusted for subsequent years by the application of a formula. The utility identified the deferred tax accounting error during one of the years subject to adjustment by using the prescribed formula and believed that it was unable to have the error recognized and corrected by its commission during the five-year period. Instead, the utility calculated the amount by which the benefits of accelerated depreciation were being flowed through to ratepayers beginning in the year tested and created an entry on its regulatory books in this amount. In its next general rate case, the utility sought to amortize the amount of unfunded deferred tax expense that it had measured since its identification of the accounting error, but the commission staff proposed that computation of deferred tax in the new system should be prospective without any recovery of the regulatory asset that the utility had recorded.

The IRS ruled in PLR 201603017 that the utility's ratemaking and accounting procedures that resulted in the partial flow through of the tax benefits of accelerated depreciation were not inconsistent with the normalization requirements and hence not in violation of the normalization rules so long as the utility implemented corrective measures that were adequate under those rules. The IRS held that the proposal by the commission staff to use the new system solely to calculate deferred tax expense prospectively would not adequately correct the inadvertent violation of the normalization rules. However, the utility's proposal to amortize the regulatory asset and to use the new system to calculate deferred tax expense prospectively would constitute an adequate corrective measure under the normalization rules if adopted by the commission.

**Effect of Repairs-Related Change in Tax Method of Accounting**

The IRS addressed in PLR 201640005 the application of the deferred tax normalization requirements to a change in tax method of accounting under Rev. Proc. 2011-43 related to the unit of property for electric transmission and distribution plant in the determination of whether an expenditure with respect to such plant is a deductible repair or a capitalizable and depreciable improvement for federal income tax purposes.

The utility in PLR 201640005 used future test years to set rates for three-year periods. The utility changed its tax method of accounting after rates had been set for a three-year rate cycle on the basis of a forecasted repairs-related book/tax difference that was lower than the actual repairs-related book/tax difference under its new tax method of accounting. The utility employed the flow-through method of accounting for deferred taxes related to repairs-related book/tax differences arising under its historical tax method of accounting as well as its new tax method, including the Section 481(a) cumulative catch-up adjustment. The incremental repairs deductions were not incorporated into the rates in effect at the time of the change in the tax method of accounting; however, in accordance with flow-through accounting, they reduced regulatory tax expense, increased net income, and increased the tax-related regulatory asset.

During the rate proceeding for the next rate cycle, a consumer advocate raised a concern and proposed a ratemaking adjustment, asserting that the failure to incorporate the incremental tax benefits in the prior rate cycle will result in a detriment to ratepayers in future years. The consumer advocate estimated the future detriment as the sum of both of the following:

- The forecasted incremental tax expense for which ratepayers would be charged when the repair timing differences that flowed during the prior rate cycle reverse in the future.
• The absence of the ADFIT that would have existed had the repair accounting method election prescribed by Rev. Proc. 2011-43 not been made (i.e., the costs deducted as repair under the new method would have been capitalized and depreciated for tax purposes, thereby producing incremental ADFIT).

The final rate order included a rate base offset based on the “net present value of future excess costs to ratepayers resulting from Taxpayer’s proposed ratemaking treatment for the repair deduction as compared to the ratemaking tax treatment assumption in place at the time of the applicable repairs.”

The IRS ruled that the rate base offset related to the repair deductions was not calculated on the basis of any element of the depreciation deduction and thus did not violate the deferred tax normalization requirements.

**Application of the Deferred Tax Normalization Rules to Section 743(b) Adjustments of a Rate-Regulated Partnership**

The IRS addressed in PLR 201816005 the application of the deferred tax normalization requirements to transfers of interests in a rate-regulated partnership with an IRC Section 754 election in effect. PLR 201816005 relates to the operation of an electric transmission utility as a partnership that recovered deferred income tax expense in accordance with the policy of its regulator and reduced rate base by ADFIT related to its public utility property. Certain of the utilities owning the utility partnership were directed by their regulator, a different commission than the one regulating the partnership, to transfer their interests in the partnership to nonregulated affiliates. The transfers of the partnership interests were treated as “exchanges” for Section 743(b) purposes and, thus, the utility partnership made Section 743(b) basis adjustments to its assets for the benefit of the transferee partners (i.e., the nonregulated affiliates of the utilities that had been partnership members) at the time of the transfers. The transferor utilities (i.e., former partnership members) deferred the gains resulting from the transfers of the partnership interests to their nonregulated affiliates under Treas. Regs. Section 1.1502-13(c). In accordance with the matching rule of the consolidated return regulations, the deferred intercompany gains are recognized as the utility partnership allocates to the nonregulated transferee members depreciation and amortization deductions attributable to the Section 743(b) basis adjustments.

The public utility property remained within the regulated partnership at all times before, during, and after the intercompany transfers of membership interests by certain members. The regulated partnership did not record any journal entries on its regulated books of account related to the intercompany transfers by its members. The partnership represented that the Section 743(b) adjustments are not increases in the basis of the property on its regulated books and that the Section 743(b) adjustments and the depreciation of such adjustments do not change the partnership’s public utility property for ratemaking purposes and are not associated with the partnership’s cost-of-service ratemaking. Approval of the transaction by the partnership’s regulator was conditioned on representations of the partnership, including its commitment to hold customers harmless from any transaction-related costs and its representation that the transaction will not affect its regulatory accounts. As part of its ruling request, the partnership represented that:

• The members of the consolidated groups will treat the transaction in a manner consistent with Treas. Regs. Section 1.1502-13.

• The transfers of interests in the partnership do not result in a disparity between the members’ bases in their interests in the partnership and the partnership’s basis in its assets.

• The intercompany transfers did not result in a termination of the partnership under IRC Section 708(b)(1)(B).
The IRS held that a normalization violation will not occur if the partnership does not adjust existing ADFIT balances to account for the consequences of the Section 743(b) basis adjustment resulting from the partnership's restructuring transaction. The ruling was expressly conditioned on the partnership's representation that the restructuring transaction will not affect the partnership's public utility property for ratemaking purposes and is not associated with the partnership's cost-of-service ratemaking. The ruling noted that no opinion was requested, and no opinion was expressed or implied, concerning the application of any consolidated return regulation under IRC Section 1502 to the transfers of the partnership interests.

**Safe Harbor Guidance for Inadvertent Noncompliance With the Normalization Requirements**

Rev. Proc. 2017-47 provides relief for normalization practices or procedures that inadvertently or unintentionally failed to comply with the ITC or accelerated depreciation normalization requirements. Rev. Proc. 2017-47 does not limit or change the process by which a taxpayer may request a letter ruling or a referral for a technical advice memorandum that the taxpayer's proposed practice or procedure is consistent or inconsistent with the normalization rules, but it will allow taxpayers within the scope of the safe harbor for inadvertent normalization noncompliance to avoid the sanctions applicable to utilities violating the normalization requirements without obtaining their own PLRs.

The relief provided by Rev. Proc. 2017-47 is available to utilities within the scope of the guidance and is conditioned on their correcting the ratemaking practice or procedure as directed by the guidance. Specifically, the relief applies to utilities that:

- Own public utility property.
- Have inadvertently or unintentionally failed to follow a practice or procedure that is consistent with the normalization rules in one or more years.
- Upon recognizing their failure to comply with the normalization rules, change their inconsistent practice or procedure to a consistent practice or procedure at the next available opportunity in a manner that totally reverses the effect of the inconsistent practice or procedure, provided their regulator adopts or approves the change.
- Retain contemporaneous documentation that clearly demonstrates the effects of the inconsistent practice or procedure and the change to a consistent practice or procedure adopted or approved by their regulator.

Rev. Proc. 2017-47 also requires a tax return attachment and representation applicable to any tax year after the taxpayer has identified an inconsistent practice or procedure but in which the taxpayer has not changed to a consistent practice or procedure because the taxpayer has not yet reached the year that presents the taxpayer with its next available opportunity (to comply with the normalization rules). Rev. Proc. 2017-47 is effective for taxable years ending on or after December 31, 2016.

In General Legal Advice Memorandum 2018-001, the IRS clarified that the phrase “in a manner that totally reverses the effect of the Inconsistent Practice or Procedure... does not contemplate taking into account any differences between the Inconsistent Practice or Procedure prior to the change” (i.e., what may be considered retroactive ratemaking). Instead, the change from the inconsistent practice or procedure to a consistent practice or procedure need apply only prospectively.
Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU 2015-17 (as part of its simplification initiative aimed at reducing the cost and complexity of certain aspects of U.S. GAAP), which modifies ASC 740-10-45 and requires entities to present all deferred taxes as noncurrent assets or noncurrent liabilities on a classified balance sheet.

Classification of all deferred taxes as noncurrent eliminates the requirement to allocate a valuation allowance on a pro rata basis between gross current and noncurrent DTAs, which was an issue that FASB constituents had asked the Board to address as part of its simplification initiative. However, jurisdictional netting will still be required under the ASU.

Companies should continue their historical use of the various DTA and DTL accounts included in the Uniform System of Accounts in their FERC reporting because the U.S. GAAP deferred tax netting rules do not apply for FERC reporting purposes. The change in U.S. GAAP may result in a need to reword the description of the FERC-GAAP reporting differences disclosed in FERC financial statements.

The ASU is effective for PBEs for annual periods beginning after December 15, 2016, and interim periods therein. For all other entities, the ASU is effective for annual periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The amendments in the ASU may be applied either prospectively to all DTLs and DTAs or retrospectively to all periods presented.

For more information about the ASU, see Deloitte’s November 30, 2015, Heads Up.
Section 8 — Renewable Energy Considerations
Production Tax Credits, Investment Tax Credits, and Treasury Grants

Introduction

Entities calculate PTCs under IRC Section 45 by using stated rates (e.g., 2017 and 2018 wind production at 2.4 cents per kWh) multiplied by kWh generated during each of the first 10 years of operation. The American Taxpayer Relief Act of 2012 modified the rules for PTC eligibility by changing the termination dates for eligibility for the credit from placed-in-service deadlines to a “begun construction” standard. The Tax Increase Prevention Act of 2014, enacted in December 2014, extended PTC eligibility to qualified facilities, including wind generation plants, whose construction began before January 1, 2015. The Protecting Americans From Tax Hikes Act of 2015 (the “PATH Act”), enacted in December 2015, further extended the termination dates for PTC eligibility. The Bipartisan Budget Act of 2018 (the “BBA”), enacted in February 2018, extended the termination dates for most types of facilities eligible for PTCs so that construction of the plant must begin generally before January 1, 2018. The key PTC qualification dates for wind generation plants are based on the following phase-out schedule:

- Full PTC rate for plants with construction beginning before January 1, 2017.
- 80 percent of the PTC rate for plants with construction beginning after December 31, 2016, but before January 1, 2018.
- 60 percent of the PTC rate for plants with construction beginning after December 31, 2017, but before January 1, 2019.
- 40 percent of the PTC rate for plants with construction beginning after December 31, 2018, but before January 1, 2020.

The energy credit under IRC Section 48 is an ITC available for certain renewable energy facilities generally subject to termination dates based on when construction begins. Entities calculate ITCs by using stated rates (e.g., 30 percent for fuel cells and solar generation property, 10 percent for geothermal electric generation property) multiplied by the tax basis of the eligible property. The depreciable tax basis of the property is reduced by 50 percent of any ITC claimed, and the ITC is subject to recapture if the related property is sold or otherwise ceases to operate within five years of being placed in service. The BBA extended the termination dates for certain types of facilities eligible for ITCs and amended the eligibility standard for the credit from placed-in-service deadlines to a “begun construction” standard for certain types of facilities. The ITC qualification dates for solar generation plants that commenced construction in 2017 or later are based on the following phase-out schedule:

- 30 percent ITC for plants with construction beginning before January 1, 2020.
- 26 percent ITC for plants with construction beginning after December 31, 2019, but before January 1, 2021.
- 22 percent ITC for plants with construction beginning after December 31, 2020, but before January 1, 2022.
• 10 percent ITC for plants with construction beginning (1) after December 31, 2021, or (2) before January 1, 2022, but not placed in service before January 1, 2024.

The American Recovery and Reinvestment Act of 2009 (the “Recovery Act”) provides an irrevocable election under IRC Section 48(a)(5) that allows entities to claim a 30 percent ITC instead of a PTC for most PTC-eligible facilities (such as wind facilities as discussed above) placed in service after December 31, 2008, as long as no PTC has been claimed for such property. The taxpayer may claim the ITC with the federal income tax return for the taxable year the facility is placed in service. The PATH Act extended the credit termination dates for most PTC-eligible facilities for which an ITC is elected so that PTC-eligible facilities are generally eligible for PTCs or ITCs to the extent that construction begins before January 1, 2017. The BBA further extended the termination date to construction beginning before January 1, 2018. For PTC-eligible wind generation plants that elect ITC in lieu of PTC, the termination dates are based on the following phase-out schedule:

• 30 percent ITC for plants with construction beginning before January 1, 2017.
• 24 percent ITC for plants with construction beginning after December 31, 2016, but before January 1, 2018.
• 18 percent ITC for plants with construction beginning after December 31, 2017, but before January 1, 2019.
• 12 percent ITC for plants with construction beginning after December 31, 2018, but before January 1, 2020.

Section 1603 of the Recovery Act allows the Treasury secretary to provide a grant in lieu of an ITC (a “Section 1603 grant”) for renewable generation property, including public-utility property. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 extended certain provisions in Section 1603 of the Recovery Act by one year to allow the Treasury secretary to continue to provide a Section 1603 grant as long as construction began by December 31, 2011, and the facility is placed in service before the ITC placed-in-service date otherwise applicable under then-current tax law to such property (e.g., before December 31, 2012, for wind generation facilities; December 31, 2013, for other PTC-eligible property; and December 31, 2016, for solar generation facilities). The deadline for submitting new Section 1603 grant applications was October 1, 2012.

PTC and ITC in Lieu of PTC

Through a series of notices, the IRS has provided guidance regarding the Begun Construction guidance described above. The subsequent notices were issued as a result of extensions of the statutory termination dates and in response to taxpayers’ requests for clarification and relief.

In May 2013, the IRS issued Notice 2013-29, which “provides guidelines and a safe harbor to determine when construction has begun” on facilities that are eligible to receive an ITC or a PTC in accordance with the American Taxpayer Relief Act of 2012 (the construction of the facility must have begun before January 1, 2014 (subsequently extended by legislation enacted in 2014 and 2015)). Eligible facilities include wind facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal facilities, landfill gas facilities, trash facilities, hydropower facilities, and marine and hydrokinetic facilities (no changes were made to the requirements for solar ITCs). However, under Notice 2013-29, the facility
must be in a continuous state of construction on the basis of the relevant facts and circumstances. The following is a summary of significant provisions of Notice 2013-29:

- The notice states that “[c]onstruction of a qualified facility begins when physical work of a significant nature begins.” Physical work of a significant nature would include “[b]oth on-site and off-site work (performed either by the taxpayer or by another person under a binding written contract).” However, such work “does not include preliminary activities [such as] planning or designing, securing financing, exploring, researching, obtaining permits, licensing, conducting surveys, environmental and engineering studies, clearing a site, test drilling of a geothermal deposit, test drilling to determine soil condition, or excavation to change the contour of the land (as distinguished from excavation for footings and foundations).” As with the Section 1603 grant guidance, removal of existing turbines and towers should be excluded from the definition of preliminary activities.

- A taxpayer is in a safe harbor from the beginning-of-construction requirement if it is able to demonstrate that it (1) has incurred at least 5 percent of the project’s total estimated eligible costs before January 1, 2014, and (2) has made “continuous efforts to advance towards completion of the facility” in the absence of disruptions that are beyond the taxpayer’s control (e.g., severe weather conditions, licensing and permitting delays, inability to obtain specialized equipment). Notice 2013-29 further states:

  If the total cost of a facility that is a single project comprised of multiple facilities (as described in section 4.04(2) [of Notice 2013-29]) exceeds its anticipated total cost, so that the amount a taxpayer actually paid or incurred with respect to the facility before January 1, 2014, is less than five percent of the total cost of the facility at the time the facility is placed in service, the [safe harbor threshold] is not fully satisfied. However, [the safe harbor threshold] will be satisfied and the PTC or ITC may be claimed with respect to some, but not all, of the individual facilities (as described in section 4.04(1) [of Notice 2013-29]) comprising the single project, as long as the total aggregate cost of those individual facilities is not more than twenty times greater than the amount the taxpayer paid or incurred before January 1, 2014.

- In evaluating the 5 percent safe harbor provision, taxpayers may rely on suppliers' statements regarding costs that the supplier has paid or incurred on the taxpayer's behalf for property to be manufactured, constructed, or produced under a binding written contract. In determining when it has incurred costs, the supplier may consult the economic performance rules in IRC Section 461(h) (see Treas. Regs. Section 1.461-1(a)(1) and (2)). The supplier may use any reasonable method (the method’s reasonableness depends on the facts and circumstances) to allocate the costs it incurs among the units of property manufactured, constructed, or produced under a binding written contract for multiple units. If a subcontractor manufactures components for the supplier, the cost of those components is incurred only when the components are provided to the supplier (not when the subcontractor pays or incurs the costs). In the determination and allocation of costs, property that the supplier reasonably expects to receive from a subcontractor within three and a half months from the date of payment (supplier's payment to subcontractor) is considered to be provided by the payment date.

In September 2013, the IRS issued Notice 2013-60, which clarifies the rules on beginning construction discussed above. Specifically, Notice 2013-60 explains that a facility meets the continuous construction criterion (to satisfy the physical work test) or the continuous efforts criterion (to meet the safe harbor threshold) if the facility is placed into service before January 1, 2016. Notice 2013-60 also explicitly states that when a qualifying facility meets the physical work test or the safe harbor threshold, the taxpayer that owns the qualifying facility as of the in-service date is eligible for the credit, regardless of whether it owned the facility at the beginning of construction.

Further, in August 2014, the IRS issued Notice 2014-46, which clarifies the application of the physical work test, the effect of certain transfers, and the application of the safe harbor for facilities that have
“incurred less than five percent, but at least three percent, of the total cost of the facility before January 1, 2014.” Regarding the physical work test, Notice 2014-46 indicates that Notice 2013-29’s list of activities that constitute physical work is not all-inclusive and that any one of the activities in Notice 2013-29 Section 4.02 (e.g., “the beginning of the excavation for the foundation, the setting of anchor bolts into the ground, or the pouring of the concrete pads of the foundation”), 4.05(1) (e.g., “[p]hysical work on a custom-designed transformer that steps up the voltage of electricity produced at the facility to the voltage needed for transmission”), or 4.05(2) (e.g., “[r]oads that are integral to the facility are integral to the activity performed by the facility”) would constitute physical work of a significant nature. In addition, Notice 2014-46 explains that the purpose of the example in Section 4.04(3) of Notice 2013-29 was to demonstrate the “single project” concept, not to provide a “work or monetary or percentage threshold” that would meet the physical work test.

To qualify for the PTC or ITC, a taxpayer that begins construction does not need to be the same taxpayer that places the qualifying facility in service. Notice 2014-46 distinguishes between transfers of fully or partially developed facilities and transfers of “just tangible” property (including contractual rights to such property). Specifically, Section 4.01 of the notice states:

Thus, except as provided in section 4.03 of this notice, a fully or partially developed facility may be transferred without losing its qualification under the Physical Work Test or the Safe Harbor for purposes of the PTC or the ITC. For example, a taxpayer may acquire a facility (that consists of more than just tangible personal property) from an unrelated developer that had begun construction of the facility prior to January 1, 2014, and thereafter the taxpayer may complete the development of that facility and place it in service. The work performed or amount paid or incurred prior to January 1, 2014, by the unrelated transferor developer may be taken into account for purposes of determining whether the facility satisfies the Physical Work Test or Safe Harbor.

Notice 2014-46 also clarifies the relocation of equipment by a taxpayer. For instance, a taxpayer may begin constructing a facility in 2013 but subsequently transfer the equipment to another site. The taxpayer may take the costs paid or incurred before January 1, 2014, into account in determining whether the facility satisfies the physical work test or the safe harbor threshold.

In addition, Notice 2014-46 indicates that if a taxpayer incurred at least 3 percent, but less than 5 percent, of the total costs of the project before January 1, 2014, to meet the physical work test, the taxpayer can claim the tax credit related to the costs incurred. Taxpayers are advised to maintain a continuous program of construction (since the IRS will closely scrutinize taxpayers that claim that their facilities qualify for PTCs or ITCs under the provisions related to physical work of a significant nature). In addition, taxpayers should consider documenting events that are beyond their control as well as milestones, continuous status of execution, engineering progress reports, and any delays encountered. Further, significant contracts, such as turbine supply and engineering, procurement, construction (EPC) agreements, should include recordkeeping requirements to demonstrate progress.

In March 2015, IRS Notice 2015-25 extended the safe harbor for the continuous construction test and continuous efforts test to allow certain facilities, including wind generation plants, to be eligible for the credit if (1) construction of the facilities began before January 1, 2015, and (2) the facilities are placed in service before January 1, 2017. Specifically, Section 3 of the notice states:

Thus, if a taxpayer begins construction on a facility prior to January 1, 2015, and places the facility in service before January 1, 2017, the facility will be considered to satisfy the Continuous Construction Test (for purposes of satisfying the Physical Work Test) or the Continuous Efforts Test (for purposes of satisfying the Safe Harbor), regardless of the amount of physical work performed or the amount of costs paid or incurred with respect to the facility after December 31, 2014 and before January 1, 2017.

IRS Notice 2016-31, issued in May 2016, provides additional guidance on the Begun Construction standard for PTCs and ITCs in lieu of PTCs. In a manner consistent with the PATH Act’s multiyear
extension of the Begun Construction deadline, Notice 2016-31 extends the safe harbor for the continuous construction criterion and continuous efforts criterion to allow certain facilities to be considered to satisfy the applicable requirement if a taxpayer places a facility in service during a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began. Notice 2016-31 prohibits a taxpayer from relying on the physical work test and the safe harbor threshold in alternating calendar years to satisfy the Begun Construction requirement or the applicable continuity requirement.

Notice 2016-31 reiterates that multiple facilities that are operated as part of a single project (along with any property, such as a computer control system, that serves some or all such facilities) may be treated as a single facility under the Begun Construction requirement (the “Aggregation Rule”). Notice 2016-31 requires that the taxpayer make its Aggregation Rule determination under the Begun Construction requirement in the calendar year during which the last of the multiple facilities is placed in service.

In addition, Notice 2016-31 indicates that multiple facilities that are operated as part of a single project and treated as a single facility in the determination of whether construction of a facility has begun may subsequently be disaggregated and treated as multiple separate facilities in the evaluation of whether a facility satisfies the applicable continuity requirement (the “Disaggregation Rule”). Disaggregated facilities placed in service before the end of the four-year continuity safe harbor will be eligible for this safe harbor. The remaining disaggregated facilities may satisfy the applicable continuity requirement under a facts-and-circumstances determination. This provision provides additional flexibility to developers working on large projects with long construction schedules.

Further, Notice 2016-31 revises Notice 2013-29’s nonexclusive list of construction disruptions that will not be considered as indicating that a taxpayer has failed to remain in compliance with the applicable continuity requirement and gives examples of additional permissible disruptions. IRS Notice 2017-04, issued in January 2017, extends and modifies the dates for the continuity safe harbor, prohibits an entity from combining (alternating) use of the physical work test and the 5 percent safe harbor test in alternating calendar years to satisfy the beginning-of-construction requirement, and clarifies the application of the 5 percent safe harbor test to retrofitted facilities.

IRS Notice 2017-33, issued in May 2017, publishes the inflation adjustment factor and reference prices for calendar year 2017 for the renewable electricity production credit and the refined coal production credit under IRC Section 45. The notice specifies that the inflation adjustment factor for qualified energy resources and refined coal was 1.5792 and that the reference price for facilities producing electricity from wind was 4.55 cents per kWh. Further, the notice states that the PTC rate for 2017 generation was 2.4 cents per kWh on the sale of electricity produced from the qualified energy resources of wind, closed-loop biomass, geothermal energy, and solar energy and 1.2 cents per kWh on the sale of electricity produced from open-loop biomass facilities, small irrigation power facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic energy facilities.

**Accounting for Grant-Eligible ITCs and Section 1603 Grants**

A Section 1603 grant should be accounted for as a grant and not as a tax credit. Depending on certain attributes, ITCs claimed with respect to a facility that is eligible for a Section 1603 grant may be accounted for as either a tax credit or a grant. ITCs that are not eligible for conversion to Section 1603 grants (e.g., ITCs related to construction that began after 2011) would be subject to the accounting requirements of ASC 740-10.

There is no definitive guidance on balance sheet presentation for an ITC eligible for a Section 1603 grant. In practice, the related balances have been deferred on the balance sheet, either as a reduction to the book property basis or as a deferred credit (not as a deferred tax credit). Such accounting is consistent
with IAS 20. Some entities have applied IAS 20 in practice because there is no specific U.S. GAAP guidance on accounting for government grants. Under this approach, the benefit should be recognized over the book life of the property. When the property balance is reduced, the income statement credit should not be recorded as a reduction of income tax expense but as a reduction to depreciation and amortization. When a deferred credit is recorded, the income statement credit should not be recorded as an increase to revenues but should be reflected as an increase to other income or as a reduction of depreciation and amortization.

See Rate-Regulated Entities below for a discussion of the possible application of ASC 450 (rather than IAS 20) to a grant for a rate-regulated plant.

Section 1603 Grants on Property Owned by Partnerships and LLCs

Section 1603 grants received by both nontaxable and taxable partnerships and LLCs must be recognized in the separate financial statements of such entities in accounts other than income tax accounts, as described above.

Applicability to Pass-Through Entities

The accounting described above for grant-eligible ITCs and Section 1603 grants also applies to pass-through entities. In addition, because the benefits of the ITC accrue to the taxable members of a pass-through entity, to the extent that the grant-eligible ITC is accounted for as a grant, such taxable members should recognize deferred income taxes for any book/tax basis differences as required by the applicable accounting guidance.

Rate-Regulated Entities

The Recovery Act initially stipulated that rate-regulated entities must apply the ITC normalization rules to Section 1603 grants, meaning that the benefits of the grants could not be passed back to customers faster than a plant’s book depreciable life. However, in late 2011, the National Defense Authorization Act for Fiscal Year 2012 retroactively eliminated the normalization provisions associated with cash grants. Accordingly, a regulator can reduce rates for the grants faster than the life of the property without violating the normalization rules. The ITC normalization rules continue to apply to ratemaking and accounting for the energy credit under IRC Section 48 claimed with respect to public utility property.

In addition, when rate-regulated entities account for the grant proceeds as a reduction of plant or as a deferred credit, they should be aware that if the regulator flows back the deferred grant for rate purposes more rapidly than the deferred amount is recognized in income under U.S. GAAP, the excess rate reduction (a timing difference between U.S. GAAP and ratemaking) may not qualify as a regulatory asset.

Entities have historically accounted for government grants by analogizing to IAS 20. As noted in the section above, this method involves recording the grant proceeds as a reduction of plant or as a deferred credit. However, we are aware of one situation in which the SEC staff indicated that it would not object to a company’s establishment of an accounting policy under which the company would account for the cash grants by analogy to ASC 450 and, more specifically, to the guidance in ASC 450 on gain contingencies. In this specific case, the power plant that qualified for the Section 1603 grant was part of the company’s rate-regulated operations. Because the regulator would require that the benefits from the Section 1603 grant reduce customer rates, the Section 1603 grant qualifies under the gain contingency recognition rules of ASC 450 and the benefit would be recorded as a regulatory liability rather than as an income statement gain.
Accounting for PTCs

When an entity claims PTCs (instead of ITCs or Section 1603 grants), the PTCs claimed will continue to be recognized as a reduction of income tax expense in the year in which the eligible kWh generation occurs. Entities must assess any DTAs for PTC carryforwards to determine whether a valuation allowance is necessary.

Structuring Project Arrangements and the Resulting Accounting and Tax Implications

Many renewable energy businesses are unable to fully use renewable energy tax benefits, including PTCs, ITCs, and accelerated depreciation, as a result of the absence of taxable income. Because of start-up activities, current economic conditions, changing tax rules or circumstances (e.g., eligibility for bonus depreciation), or less than ideal resource generation (e.g., wind, solar), an entity that has a direct or indirect ownership in a renewable energy project (herein referred to as a “renewable energy entity”) may be unable to take advantage of all the renewable energy tax benefits available. To address this challenge, entities often look for ways to monetize the value of their tax benefits.

For example, renewable energy entities sometimes enter into partnerships, or other structured arrangements, with “green investors” or investors looking to reduce their tax liability. Such arrangements, which are often called “partnership flip structures” or “tax equity structures” (and are herein referred to as “structures”), give both the renewable energy businesses and investors opportunities to maximize benefits and returns on investments.

Motivation for Structures

The motivation for renewable energy entities to enter into structures is simple — the arrangements allow them to monetize renewable energy tax benefits that otherwise might be lost or for which recognition is delayed because of insufficient taxable income. By entering into structures and allocating renewable energy tax benefits to investors, these entities are able to generate cash flows immediately by receiving cash in exchange for the tax benefits.

The early years of a renewable energy project that is owned and operated directly or indirectly by a renewable energy entity often do not generate enough taxable income for an entity to take advantage of the tax benefits resulting from the investment. Modified accelerated cost recovery system (MACRS) depreciation, including bonus depreciation, and PTCs are examples of these tax benefits. Consequently, renewable energy entities are typically unable to use such tax benefits and are required to analyze the likelihood of using any of the deferred tax benefits in accordance with ASC 740-10-30-2.

For investors, participating in structures offers several benefits: (1) an attractive return on investment, (2) tax benefits that can be used to offset taxable income or income tax liabilities, and (3) the opportunity to market their company as being environmentally friendly.

Investors in structures are typically entities with available cash for investing opportunities and sufficient taxable income to monetize the tax benefits. Since the inception of structures, these investors have evolved from the typical investment banks and insurance companies to foreign investors — which have become more active in renewable energy structures in the United States by using these investments to enter the U.S. market — and other commercial entities that are interested in investing in renewable energy. Such investors have available cash for investing opportunities and ample taxable income to use the tax benefits.

Renewable energy entities have explored various funding options, but the most common approach is for an investor to invest cash upon inception of the arrangement. Investing in structures allows investors
to offset tax liabilities and receive an attractive after-tax return on their investment. In addition, such investors are often predisposed to marketing themselves as “green,” and by entering into structures, they are able to market themselves as being environmentally friendly and focusing on renewable energy alternatives.

**Features of Traditional Structures**

Structures contain certain features that allow investors to receive favorable tax treatment. A common arrangement is a tax partnership in which the renewable energy entity and the investor hold interests in a partnership that directly owns and operates a renewable energy project. Under such an arrangement, the investor purchases the partnership interest for cash and is allocated a majority of the tax benefits (e.g., PTCs, accelerated depreciation) and cash flows generated by the renewable energy project for some defined period. Typically, at the end of the period, the renewable energy entity has the option, but is not required, to repurchase all of the investor’s partnership interest at its fair value as of the option exercise date. The tax benefits and cash flows allocated to the investor typically flip down from 99 percent to 5 percent before the repurchase option period, which makes the repurchase less expensive than it would be in a sale-leaseback arrangement. Such an arrangement allows both the renewable energy entity and the investor to maximize the renewable energy tax benefits. The renewable energy entity monetizes tax credits and tax depreciation that it will be unable to use, while the investor receives tax benefits to offset its tax liability.

One variable of structures is the timing of the cash receipts from an investor. An investor typically would make a small up-front cash payment upon the formation of the partnership, followed by a substantial cash payment to the partnership to coincide with the commercial operation of the renewable energy project. The amount of cash is meant to capture the expected tax benefits that the investor will receive throughout the life of the structure.

The features of structures described above are consistent with those described in Rev. Proc. 2007-65 (herein referred to as “traditional structures”). Issued in November 2007, Rev. Proc. 2007-65 provides a safe harbor for partnership arrangements between a renewable energy entity and one or more investors with the project company owning and operating the renewable energy project by identifying the economic terms that must be present in structures, including the following:

- Throughout the life of the structure, the renewable energy business has at least a 1 percent interest in partnership income, gains, deductions, losses, and credits (including PTCs).
- Throughout the life of the structure, the investor has at least a 5 percent interest in partnership income and has gains equal to at least 5 percent of its largest such interest.
- The investor’s allocation of renewable energy tax benefits cannot be guaranteed.
- When the project is placed into service, the investor has at least a 20 percent unconditional investment in the partnership.
- At least 75 percent of the investor’s capital contributions are fixed and determinable.
- The partnership has to bear operational risk (e.g., wind availability), and no party can guarantee the availability of wind.
- The investor may not hold an option that allows it to force the renewable energy entity to purchase its partnership interest (i.e., a put option); however, five years after the placed-in-service date (determined in accordance with federal income tax rules), the renewable energy entity may have the ability (but may not be required) to repurchase the investor’s partnership interest at fair value (i.e., a call option).
• The renewable energy entity cannot lend to, or guarantee, the investor’s investment in the partnership.

As long as the safe harbor provisions in Rev. Proc. 2007-65 are met, the IRS will not challenge the validity of the partnership for federal income tax purposes or the allocation of renewable energy tax benefits.

Although the safe harbor treatment of allocations described in Rev. Proc. 2007-65 specifically applies only to wind partnerships with PTCs, the criteria of this revenue procedure are also often copied in structures for other types of renewable energy partnerships (e.g., solar and biomass) and for other types of tax credits (e.g., ITCs).

### Accounting and Reporting Considerations for Traditional Structures

As discussed above, renewable energy entities often establish a partnership and sell a portion of the partnership interest to an investor to monetize the tax benefits generated by the renewable energy project. The primary asset of such a partnership is the renewable energy project (e.g., a wind farm or solar project).

A renewable energy entity should evaluate the effect that the adoption of ASC 606 will have on the accounting for traditional structures. ASC 606 is effective for public entities for fiscal years beginning after December 15, 2017, including interim reporting periods therein. For all other entities, it is effective for fiscal years beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019.

In February 2017, the FASB issued ASU 2017-05, which clarifies the derecognition guidance on nonfinancial assets (including sales and partial sales of real estate or in-substance real estate, which are not considered a business under ASU 2017-01). The ASU states that the unit of account is defined as a distinct nonfinancial asset. An entity should therefore identify each distinct nonfinancial and in-substance nonfinancial asset in accordance with the guidance on identifying distinct performance obligations in ASC 606, allocate consideration to each distinct asset, and derecognize the asset if and when an investor obtains control of it. If the developer retains a controlling financial interest in the nonfinancial asset or in-substance nonfinancial asset, the developer should account for the transaction as an equity transaction in accordance with ASC 810 and should not recognize a gain or a loss on the derecognition of the nonfinancial assets. If the developer has not retained a controlling financial interest, it will derecognize the asset when it transfers control of the asset in a manner consistent with the principles of ASC 606. Further, the developer should measure any retained noncontrolling ownership interest (and resulting gain or loss to be recognized) at fair value in a manner consistent with the guidance on noncash consideration in ASC 606-20-32-21 through 32-24. The ASU eliminates ASC 360-20 as well as the initial-measurement guidance on nonmonetary transactions in ASC 845-10-30 to simplify the accounting treatment for partial sales and to remove inconsistencies between ASC 610-20 and the noncash consideration guidance in the new revenue standard.

In addition, a renewable energy entity should consider the guidance in ASC 815-15 to determine whether its call option to repurchase the investor’s partnership interest after a certain date at the then fair market value represents an embedded derivative in the partnership agreement that must be bifurcated.

The accounting and reporting considerations discussed above apply to renewable energy entities. An investor would need to determine whether a structure constitutes equity or a debt security. If the investor concludes that a structure constitutes equity with no readily determinable fair value, it would need to determine whether it exercises significant influence over the investee in accordance with ASC 323-10, in which case it would apply equity method accounting. If, however, an investor concludes
that a structure constitutes a debt security, it would classify and account for the structure in accordance with ASC 320-10.

Both renewable energy entities and investors need to evaluate structures under ASC 810 to determine whether the partnership or the renewable energy project entity is a VIE and, ultimately, which party is required to consolidate the entity.

**Variations on Traditional Structures**

The terms and forms of structures have continued to evolve as a result of such factors as current market conditions, the availability and types of investors, fast-approaching deadlines to qualify for renewable energy tax benefits, and pending legislation and regulations affecting the industry as a whole. Accordingly, variations on traditional structures have become more common over the past few years.

**Put Options and Withdrawal Rights**

Certain investors are subject to regulatory requirements under which they must demonstrate their ability to exit certain categories of investment (e.g., structures discussed herein) at a specified time (e.g., 10 years after the inception of the arrangement). One way for investors to demonstrate such ability is to hold a put option in the structures. The exercise price of the put option typically (1) is the lower of a fixed amount or the fair value of the investor's partnership interest as of the exercise date and (2) does not provide an economic incentive for the investor to exercise the option.

A variation on a put option in structures is the presence of withdrawal rights, which are based on traditional common law or state law and represent an investor's right to withdraw from a partnership. The features of the exercise price for withdrawal rights are similar to those for put options. Withdrawal rights, however, are different from put options in that (1) withdrawal rights are not based on a regulatory requirement and (2) the only recourse for investors holding withdrawal rights is to the project assets (i.e., renewable energy projects), not to other partners (i.e., other investors, renewable energy entities) or other third parties.

**Accounting Considerations**

An entity should analyze the existence of a put option (or withdrawal right) within a partnership agreement to determine whether the substance and economics of the arrangement are equity- or liability-like. In performing such an analysis, the entity should consider the guidance in ASC 480. In addition, renewable energy entities should apply ASC 815-15 to determine whether a put option (or withdrawal right) represents an embedded derivative in the partnership agreement that must be bifurcated.

**Tax Considerations**

Rev. Proc. 2007-65, in conjunction with Announcement 2009-69 (which amended certain provisions in Rev. Proc. 2007-65) is the primary guidance that the Treasury has issued to date on wind structures. As discussed above, put options are prohibited under the safe harbor provisions of Rev. Proc. 2007-65.

The industry has typically looked to relevant case law to determine whether the investor's interest in structures containing put options is more debt- or equity-like. Entities should consider consulting with their tax advisers before making such a determination.
Other Variations

In addition to put options and withdrawal rights, variations (not all-inclusive) in the features of traditional structures may include:

- Preset cash distribution ratios among the renewable energy entity and investors from the inception of the arrangement or upon the occurrence of an event specified in the partnership agreement.
- Predetermined date (as opposed to the achievement of a target internal rate of return on the investment in the partnership) that triggers the change in the allocation of tax benefits and cash distributions among the renewable energy entity and investors.
- Fixed ownership percentages among the members over the life of the partnership.
- A requirement for the partnership to distribute a fixed percentage of available cash (as defined in the partnership agreement) as preferred cash distribution to the investors before available cash is distributed to members of the partnership.

The accounting considerations for traditional structures (discussed above) also apply to arrangements containing variations on features of traditional structures.

Other Accounting Considerations

Depending on how both renewable energy entities and investors would account for the features of structures (described in Features of Traditional Structures and Variations on Traditional Structures above), it may be necessary to allocate income/loss (determined in accordance with U.S. GAAP) and cash distributions of the partnership to a renewable energy entity and investors at varying percentages at different times or upon the occurrence of certain events. Income/loss may be allocated in accordance with ASC 810-10 between the controlling and noncontrolling interest holders, or an equity method investor’s share of the partnership's income/loss may be recorded in accordance with ASC 323-10. While ASC 810-10 is silent on the method to use for such income/loss allocation, ASC 323-10 prescribes allocation methods for investors, as discussed below.

Under the traditional equity method prescribed by ASC 323-10, income/loss would be allocated on the basis of preset ownership percentages for simple equity structures. Applying the traditional equity method to structures is generally challenging because it does not adequately incorporate the structures’ complexities, including the varying allocations of income/loss and cash at different times or upon the occurrence of specified events.

When an investor receives allocations of income/loss that are disproportionate to its equity interest in the investee (such as that found in structures), it may not be appropriate to record equity method income/loss on the basis of the percentage of equity interest owned. Under ASC 970-323-35-17, such arrangements should be “analyzed to determine how an increase or decrease in net assets of the venture (determined in conformity with [U.S.] GAAP) will affect cash payments to the investor over the life of the venture and on its liquidation.” The application of these principles often results in the use of the hypothetical liquidation at book value (HLBV) method.

The HLBV method is a balance-sheet-oriented approach for determining the allocation of U.S. GAAP equity and income/loss. Under this method, U.S. GAAP income/loss is allocated to each investor on the basis of the change during the reporting period of the amount each investor is entitled to claim in a liquidation scenario, which effectively indicates how much better (or worse) off the investor is at the end of the period than at the beginning of the period.
Renewable energy entities and their investors commonly use the HLBV method when allocating U.S. GAAP equity and income/loss on the basis of the features of structures described in the partnership agreements. Because features in structures are generally dominated by the value of the tax benefits being monetized, application of the HLBV method to allocate U.S. GAAP equity and income/loss in structures often incorporates tax concepts. Further, the underlying mechanics of the HLBV method largely depend on the terms of the partnership agreement and any interpretations thereof, which may involve the use of judgment. Thus, entities should tailor the components and mechanics incorporated into the HLBV calculation to properly reflect the facts and circumstances of each structure.

Certain variations on features found in traditional structures may lend themselves to the application of the traditional equity method or a variation thereof (e.g., one that is based on a preset ratio of cash distributions among the members) with respect to allocation of income/loss of a partnership to a renewable energy entity and its investors. In the context of structures, a method for allocating a partnership's income/loss should reflect the economics and substance of the arrangements at inception and over the life of a structure. Although the accounting literature does not advocate a “one size fits all” approach, we believe that it is not appropriate to adjust the allocation method without a robust rationale supporting such a change (e.g., a change in the expected economics of the structure during its remaining life).

Deferred Tax Considerations

Renewable energy entities typically elect to be taxed as a pass-through entity for federal income tax purposes, in which case the federal income tax liabilities are passed through to the members of the partnership. In such circumstances, the tax-related activity would not be reflected in the financial statements of the renewable energy entity if it is a pass-through entity for tax purposes.

Investors in structures are often entities with significant federal income tax liabilities; therefore, the features in structures are designed in such a way that these investors would receive a majority of the tax benefits generated by the renewable energy project. Accordingly, temporary and permanent differences resulting from investments in structures are expected to arise, and investors need to consider the related income tax effects in accordance with ASC 740.

When an investor accounts for its interest in a structure under the equity method, there may be circumstances in which the balance of an investor's investment in an investee differs from the investor's claim on the book value of the investee. This difference is referred to as the investor basis difference. ASC 323-10-35-13 requires entities to account for this basis difference as if the investee were a consolidated subsidiary. That is, entities (investors) would need to determine the difference between the cost of their equity method investment and their share of the fair value of the investee's individual assets and liabilities by applying the acquisition method of accounting in accordance with ASC 805.

Moreover, because equity method investments are presented as a single consolidated amount in the financial statements in accordance with the equity method of accounting, the tax effects attributable to basis differences are not presented separately in the investor's financial statements as individual DTAs and DTLs; rather, such tax effects would become a component of this single consolidated amount (i.e., the single DTA or DTL is based on the book vs. tax basis of the investment) in the financial statements.

Accounting for Traditional Structures Under IFRS Standards

U.S. GAAP and IFRS Standards differ in their treatment of tax credits in traditional structures, such as PTCs. Under U.S. GAAP (ASC 740-10), investors (typically taxable entities for federal income tax
purposes) are required to record tax credits earned as a component of deferred or current federal income tax expense in their financial statements. As discussed above, renewable energy entities often elect to be taxed as pass-through entities for federal income tax purposes; therefore, their financial statements would generally not include such tax credits as a component of deferred or current federal income tax expense. In contrast, because the accounting for tax credits is outside the scope of IAS 12 and most entities have accounted for tax credits on the basis of their nature and substance under IFRS Standards, tax credits may be recorded outside of the tax accounts.

While there are differences between the accounting for traditional structures under U.S. GAAP and that under IFRS Standards, entities should consider all relevant facts and circumstances in determining the appropriate accounting under each framework.

**Renewable Energy**

**Start-Up Versus Development Costs and Timing of Capitalization**

Fundamental to renewable energy developers' business activities is the development of new renewable energy generation facilities (individually, a project). A typical project has three stages: start-up, development (ordinarily, construction phase to achieving commercial operation), and late-stage development (the post-commercial-operation stage). As further discussed below, certain milestones must be accomplished before an entity decides to construct a project.

Various costs are incurred during each development stage. The primary accounting consideration related to these costs is whether to record the incurred costs as expense or capital items and, if capital items, when capitalization of such costs should commence and cease. In making this determination, entities should look to the guidance in ASC 720-15, ASC 360-970, ASC 805-10, and ASC 835-20.

ASC 720-15 requires that start-up costs be expensed as incurred and broadly defines such costs as “those one-time activities related to any of the following:

- Opening a new facility
- Introducing a new product or service
- Conducting business in a new territory
- Conducting business with an entirely new class of customers . . . or beneficiary
- Initiating a new process in an existing facility
- Commencing some new operation.”

Business initiation costs are components of start-up costs — they are incurred in the normal course of starting a business or a project and should be expensed as incurred. Generally, business initiation costs consist of costs incurred for activities pertaining to bid preparation, internal analysis, legal research and early-stage engineering, maintaining a development office, and organizing new legal entities.

Development costs are costs incurred before acquisition or construction of a project is initiated but after the decision to initiate such a transaction has been made. In general, development costs are capitalizable as long as the costs are related to a specific project and management concludes that the project's construction and completion are probable. The probability conclusion should be based on the achievement of milestones or a combination of milestones and the entity's historical experience. These milestones may include the receipt of permits or approvals from governmental agencies or the execution of significant project agreements such as PPAs, construction loan agreements, or agreements
to acquire significant project components (e.g., turbine supply agreements). Examples of potentially capitalizable development costs include project acquisition fees; costs of obtaining permits and licenses; professional fees related to appraisals, environmental studies, and so forth; and internal costs related to negotiations for contracts specific to the project and necessary for an entity to construct the project or achieve its commercial operation.

Construction costs are necessary costs incurred to prepare an asset for its intended use. Virtually all costs incurred in a project’s construction phase are capitalizable. Capitalization should cease on the commercial operation date. Potentially capitalizable construction costs may include EPC contractor fees; interest paid to third parties; test power costs and the related income (for short periods); internal costs directly related to the project; property tax incurred during the construction period; bonuses paid to the development team; and, in certain circumstances, development fees.

Certain late-stage development activities are likely to continue to take place after a project achieves commercial operation and may last up to a couple of years after the post-commercial-operation stage begins. Costs associated with late-stage development generally are related to employee training to operate and maintain the project, equipment fine-tuning, and contract negotiation concerning project operation. These costs are generally not capitalizable.

The determination of whether a cost exhibits characteristics of a start-up cost rather than a development cost is based on the relevant facts and circumstances. Certain costs may appear to be related to a specific project but may not need to be incurred for an entity to construct the project or achieve its commercial operation. These costs should not be capitalized as part of project costs. Examples include, but are not limited to, power market studies, professional fees related to accounting and tax services, legal fees associated with the execution of a PPA, and allocation of administrative/corporate overhead.

Certain circumstances throughout the development stages may call into question whether any or all of the capitalized project costs are recoverable. ASC 360-10-35-21 gives examples of such circumstances. Entities should look to the guidance in ASC 360-10 in determining whether capitalized project costs are impaired and thus warrant an immediate write-off. To test for recoverability, an entity should compare future cash flows from the use and ultimate disposal of the project (i.e., cash inflows to be generated by the project less cash outflows necessary to obtain the inflows) with the carrying amount of the project (i.e., inception-to-date capitalized project costs plus estimated costs of completing construction and achieving commercial operation). Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the project’s carrying amount.

It is also important to understand how to account for revenues generated before commercial operations. For instance, once project construction is substantially complete, the related assets generally must be commissioned before commercial operations commence. As part of standard tests during the commissioning process, electricity will be generated. Once the tests are completed, the asset is shut down and certified and control is transferred from the manufacturer to the owner/operator upon the latter’s signature of acceptance. All revenues produced before the owner/operator's acceptance of the project assets are considered test revenue. Test revenue is treated as a reduction of construction work-in-process in accordance with ASC 970-10-20, which states that “[r]evenue-producing activities engaged in during the holding or development period . . . reduce the cost of developing the property for its intended use, as distinguished from activities designed to generate a profit or a return from the use of the property.”
Example

Upon the near-completion of a wind turbine project, the turbines must be commissioned before being placed into commercial operation. As part of standard tests that are performed during the commissioning process, each wind turbine will produce some amount of electricity. Once the testing is complete, the turbine is shut down, a turbine completion certificate (TCC) is issued by the manufacturer, and the manufacturer relinquishes control of the turbine and transfers it to the owner/operator upon the latter’s signature of acceptance.

All revenues produced by a particular wind turbine before the owner's official acceptance of the TCC are considered test revenue and accounted for as a reduction of construction work-in-process in accordance with ASC 970-10-20.

Further, entities should develop a capitalization policy in accordance with ASC 360, ASC 720, and ASC 835 and apply this policy consistently to all of their projects. A best practice for capitalization policies is to incorporate entity-specific considerations, including factors affecting management’s judgment about properly accounting for start-up and development costs. At a minimum, entities should consider incorporating the following into their capitalization policy:

- Milestones in each development stage to establish the event (or a combination of events) that triggers the commencement and cessation of capitalization.
- The types of costs that qualify as capitalized project costs.
- An event (or a combination of events) that triggers a review to determine whether capitalized costs are impaired.
Appendixes
Appendix A — Other Resources and Upcoming Events

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Events
Deloitte Renewable Energy Seminar
August 15–17, 2018 | Denver, Colorado
For more information, please contact: USRenewableEnergy@deloitte.com.

Deloitte Oil & Gas Conference
October 30, 2018 | Houston, Texas
For more information, please contact: OilandGasConference@deloitte.com.

Deloitte Power & Utilities Fall Seminar
November 27–28, 2018 | Chicago, Illinois
For more information, please contact: USEnergyFallSeminars@deloitte.com.

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Appendix B — Titles of Standards and Other Literature

The following are the titles of standards and other literature mentioned in this publication:

**FASB Accounting Standards Updates (ASUs)**


ASU 2018-01, *Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842*

ASU 2017-14, *Income Statement — Reporting Comprehensive Income (Topic 220), Revenue Recognition (Topic 605), and Revenue From Contracts With Customers (Topic 606): Amendments to SEC Paragraphs Pursuant to Staff Accounting Bulletin No. 116 and SEC Release No. 33-10403*

ASU 2017-13, *Revenue Recognition (Topic 605), Revenue From Contracts With Customers (Topic 606), Leases (Topic 840), and Leases (Topic 842): Amendments to SEC Paragraphs Pursuant to the Staff Announcement at the July 20, 2017 EITF Meeting and Recission of Prior SEC Staff Announcements and Observer Comments*

ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*

ASU 2017-11, *Earnings Per Share (Topic 260); Distinguishing Liabilities From Equity (Topic 480); Derivatives and Hedging (Topic 815): (Part I) Accounting for Certain Financial Instruments With Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests With a Scope Exception*

ASU 2017-10, *Service Concession Arrangements (Topic 853): Determining the Customer of the Operation Services*

ASU 2017-09, *Compensation — Stock Compensation (Topic 718): Scope of Modification Accounting*

ASU 2017-08, *Receivables — Nonrefundable Fees and Other Costs (Subtopic 310-20): Premium Amortization on Purchased Callable Debt Securities*

ASU 2017-07, *Compensation — Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*

ASU 2017-06, *Employee Benefit Plan Master Trust Reporting — a consensus of the FASB Emerging Issues Task Force*
ASU 2017-05, Other Income — Gains and Losses From the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets

ASU 2017-04, Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment

ASU 2017-03, Accounting Changes and Error Corrections (Topic 250) and Investments — Equity Method and Joint Ventures (Topic 323)

ASU 2017-02, Clarifying When a Not-for-Profit Entity That Is a General Partner or a Limited Partner Should Consolidate a For-Profit Limited Partnership or Similar Entity

ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business

ASU 2016-20, Technical Corrections and Improvements to Topic 606, Revenue From Contracts With Customers


ASU 2016-17, Consolidation (Topic 810): Interests Held Through Related Parties That Are Under Common Control

ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory


ASU 2016-14, Not-for-Profit Entities (Topic 958): Presentation of Financial Statements of Not-for-Profit Entities

ASU 2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments

ASU 2016-12, Revenue From Contracts With Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients

ASU 2016-11, Revenue Recognition (Topic 605) and Derivatives and Hedging (Topic 815): Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting (SEC Update)

ASU 2016-10, Revenue From Contracts With Customers (Topic 606): Identifying Performance Obligations and Licensing

ASU 2016-09, Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting

ASU 2016-08, Revenue From Contracts With Customers (Topic 606): Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)

ASU 2016-07, Investments — Equity Method and Joint Ventures (Topic 323): Simplifying the Transition to the Equity Method of Accounting

ASU 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments — a consensus of the FASB Emerging Issues Task Force


ASU 2016-04, Liabilities — Extinguishments of Liabilities (Subtopic 405-20): Recognition of Breakage for Certain Prepaid Stored-Value Products
Appendix B — Titles of Standards and Other Literature

ASU 2016-02, Leases (Topic 842)
ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments
ASU 2015-14, Revenue From Contracts With Customers (Topic 606): Deferral of the Effective Date
ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory
ASU 2015-11, Simplifying the Measurement of Inventory
ASU 2015-09, Financial Services — Insurance (Topic 944)
ASU 2015-04, Compensation — Retirement Benefits (Topic 715)
ASU 2015-02, Consolidation — Retirement Benefits (Topic 810): Amendments to the Consolidation Analysis
ASU 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity — a consensus of the FASB Emerging Issues Task Force
ASU 2014-15, Presentation of Financial Statements — Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern
ASU 2014-10, Development Stage Entities (Topic 915)
ASU 2014-09, Revenue From Contracts With Customers (Topic 606)
ASU 2014-05, Service Concession Arrangements (Topic 853)

**FASB Accounting Standards Codification (ASC) Topics**

ASC 210, Balance Sheet
ASC 230, Statement of Cash Flows
ASC 250, Accounting Changes and Error Corrections
ASC 260, Earnings Per Share
ASC 270, Interim Reporting
ASC 310, Receivables
ASC 320, Investments — Debt and Equity Securities
ASC 321, Investments — Equity Securities
ASC 323, Investments — Equity Method and Joint Ventures
ASC 325, Investments — Other
ASC 350, Intangibles — Goodwill and Other
ASC 360, Property, Plant, and Equipment
ASC 405, Liabilities
ASC 410, Asset Retirement and Environmental Obligations
ASC 450, Contingencies
ASC 470, Debt
ASC 480, Distinguishing Liabilities From Equity
ASC 505, Equity
ASC 605, Revenue Recognition
ASC 606, Revenue From Contracts With Customers
ASC 610, Other Income
ASC 715, Compensation — Retirement Benefits
ASC 718, Compensation — Stock Compensation
ASC 720, Other Expenses
ASC 740, Income Taxes
ASC 805, Business Combinations
ASC 810, Consolidation
ASC 815, Derivatives and Hedging
ASC 820, Fair Value Measurement
ASC 825, Financial Instruments
ASC 835, Interest
ASC 840, Leases
ASC 842, Leases
ASC 845, Nonmonetary Transactions
ASC 855, Subsequent Events
ASC 960, Plan Accounting — Defined Benefit Pension Plans
ASC 965, Plan Accounting — Health and Welfare Benefit Plans
ASC 970, Real Estate — General
ASC 980, Regulated Operations

**FASB Proposed Accounting Standards Updates**

Proposed ASU 2018-240, Collaborative Arrangements (Topic 808): Targeted Improvements


Proposed ASU 2018-220, Derivatives and Hedging (Topic 815): Inclusion of the Overnight Index Swap (OIS) Rate Based on the Secured Overnight Financing Rate (SOFR) as a Benchmark Interest Rate for Hedge Accounting Purposes
Appendix B — Titles of Standards and Other Literature

Proposed ASU 2018-200, Leases (Topic 842): Targeted Improvements

Proposed ASU 2017-320, Codification Improvements

Proposed ASU 2017-310, Technical Corrections and Improvements to Recently Issued Standards: Accounting Standards Update No. 2016-02, Leases (Topic 842)


Proposed ASU 2017-290, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842

Proposed ASU 2017-280, Consolidation (Topic 812): Reorganization

Proposed ASU 2017-270, Not-for-Profit Entities (Topic 958): Clarifying the Scope and Accounting Guidance for Contributions Received and Contributions Made


Proposed ASU 2017-220, Compensation — Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting

Proposed ASU 2017-210, Inventory (Topic 330): Changes to the Disclosure Requirements for Inventory

Proposed ASU 2017-200, Debt (Topic 470): Simplifying the Classification of Debt in a Classified Balance Sheet (Current Versus Noncurrent)

Proposed ASU 2016-330, Financial Services — Insurance (Topic 944): Targeted Improvements to the Accounting for Long-Duration Contracts


Proposed ASU 2015-340, Government Assistance (Topic 832): Disclosures by Business Entities About Government Assistance

Proposed ASU 2015-310, Notes to Financial Statements (Topic 235): Assessing Whether Disclosures Are Material

Other FASB Proposals

Invitation to Comment, Agenda Consultation

EITF Issues

12-H, “Accounting for Service Concession Arrangements”

92-7, “Accounting by Rate-Regulated Utilities for the Effects of Certain Alternative Revenue Programs”
SEC C&DI Topics
Exchange Act Rules
Exchange Act Form 8-K
FAST Act
Non-GAAP Financial Measures
Regulation Crowdfunding
Regulation S-K
Securities Act Forms
Securities Act Rules

SEC Final Rules
34-78716, Access to Data Obtained by Security-Based Swap Data Repositories
34-78167, Disclosure of Payments by Resource Extraction Issuers
34-78321, Regulation SBSR — Reporting and Dissemination of Security-Based Swap Information
34-78319, Amendments to the Commission’s Rules of Practice
34-67716, Conflict Minerals
33-10514, Inline XBRL Filing of Tagged Data
33-10513, Smaller Reporting Company Definition
33-10332, Inflation Adjustments and Other Technical Amendments Under Titles I and III of the JOBS Act
33-10322, Exhibit Hyperlinks and HTML Format
33-10238, Exemptions to Facilitate Intrastate and Regional Securities Offerings
33-9877, Pay Ratio Disclosure

SEC Proposed Rules
33-10425, FAST Act Modernization and Simplification of Regulation S-K

SEC Division of Corporation Finance Financial Reporting Manual
Topic 2, “Other Financial Statements Required”
Topic 3, “Pro Forma Financial Information”
Topic 10, “Emerging Growth Companies”
Topic 11, “Reporting Issues Related to Adoption of New Accounting Standards”

SEC Interpretive Guidance
33-10415, Commission Guidance on Pay Ratio Disclosure
33-10459, Commission Statement and Guidance on Public Company Cybersecurity Disclosures
SEC Regulation S-K
Item 402, “Executive Compensation”
Item 601, “Exhibits”

SEC Regulation S-X
Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
Rule 4-08, “General Notes to Financial Statements”
Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
Rule 3-11, “Financial Statements of an Inactive Registrant”
Rule 3-13, “Filing of Other Financial Statements in Certain Cases”
Rule 5-04, “What Schedules Are to Be Filed”

SEC SAB Topics
Topic 5.EE, “Income Tax Accounting Implications of the Tax Cuts and Jobs Act” (added by SAB 118)
Topic 8, “Retail Companies”
Topic 11.M, “Miscellaneous” (SAB 74)
Topic 13, “Revenue Recognition”
Topic 116, “Staff Accounting Bulletin No. 116”
Topic 117, “Staff Accounting Bulletin No. 117”

SEC Securities Act of 1933 General Rules and Regulations
Rule 147
Regulation A, Conditional Small Issues Exemption
Regulation D, Rules Governing the Limited Offer and Sale of Securities Without Registration Under the Securities Act of 1933

SEC Securities Exchange Act of 1934 Rule
Rule 13n-4, Duties and Core Principles of Security-Based Swap Data Repository

International Standards
IFRS 16, Leases
IFRS 15, Revenue From Contracts With Customers
IAS 36, Impairment of Assets
IAS 20, Accounting for Government Grants and Disclosure of Government Assistance
IAS 17, Leases
IAS 12, Income Taxes
## Appendix C — Abbreviations

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<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>A&amp;G</td>
<td>administrative and general</td>
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<tr>
<td>ACC</td>
<td>Arizona Corporation Commission</td>
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<tr>
<td>ADFIT</td>
<td>accumulated deferred federal income tax</td>
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<td>AFS</td>
<td>available for sale</td>
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<td>AFUDC</td>
<td>allowance for funds used during construction</td>
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<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
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<td>ALJ</td>
<td>administrative law judge</td>
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<td>AMI</td>
<td>advanced metering infrastructure</td>
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<tr>
<td>AO OCI</td>
<td>accumulated other comprehensive income</td>
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<td>A OO</td>
<td>asset owner and operator</td>
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<td>APS</td>
<td>Arizona Public Service Electric Company</td>
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<td>APSC</td>
<td>Arkansas Public Service Commission</td>
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<td>ARAM</td>
<td>average rate assumption method</td>
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<td>ARC</td>
<td>asset retirement cost</td>
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<td>ARO</td>
<td>asset retirement obligation</td>
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<td>ASC</td>
<td>FASB Accounting Standards Codification</td>
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<td>ASU</td>
<td>FASB Accounting Standards Update</td>
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<td>B&amp;E</td>
<td>blend and extend</td>
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<td>BBA</td>
<td>Bipartisan Budget Act of 2018</td>
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<td>BCF</td>
<td>beneficial conversion features</td>
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<tr>
<td>Bcf</td>
<td>billion cubic feet</td>
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<tr>
<td>Bcf/d</td>
<td>billion cubic feet per day</td>
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<td>BPS</td>
<td>bulk-power system</td>
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<td>C &amp; DI</td>
<td>SEC Compliance and Disclosure Interpretation</td>
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<td>CAISO</td>
<td>California Independent System Operator</td>
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<td>CAM</td>
<td>critical audit matters</td>
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<td>CAQ</td>
<td>Center for Audit Quality</td>
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<td>CCF</td>
<td>cash conversion features</td>
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<td>CCR</td>
<td>coal combustion residuals</td>
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<td>current expected credit loss</td>
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<td>CF-OCA</td>
<td>Division of Corporation Finance, Office of the Chief Accountant</td>
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<td>CIAC</td>
<td>contribution in aid of construction</td>
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<td>CIP</td>
<td>critical infrastructure protection</td>
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<td>CO₂</td>
<td>carbon dioxide</td>
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<td>CPP</td>
<td>Clean Power Plan</td>
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<td>CPUC</td>
<td>California Public Utilities Commission</td>
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<td>CSAPR</td>
<td>Cross-State Air Pollution Rule</td>
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<td>CTA</td>
<td>currency translation adjustment</td>
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<td>CWIP</td>
<td>construction work in progress</td>
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<td>DAA</td>
<td>FERC’s Office of Enforcement Division of Audits and Accounting</td>
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<td>DECON</td>
<td>Decontamination</td>
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<td>DOE</td>
<td>U.S. Department of Energy</td>
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<td>DPT</td>
<td>delivered price test</td>
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<td>DTA</td>
<td>deferred tax asset</td>
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<td>DTL</td>
<td>deferred tax liability</td>
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<td>e21</td>
<td>Minnesota 21st Century Energy System</td>
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<td>EDGAR</td>
<td>SEC’s Electronic Data Gathering, Analysis, and Retrieval system</td>
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<td>EDF</td>
<td>Électricité de France</td>
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<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>EEI</td>
<td>Edison Electric Institute</td>
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<td>EGC</td>
<td>emerging growth company</td>
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<td>E-ISAC</td>
<td>NERC’s Electricity Information Sharing and Analysis Center</td>
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<td>EITF</td>
<td>Emerging Issues Task Force</td>
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<td>EMCOS</td>
<td>Eastern Massachusetts Consumers-Owned Systems</td>
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<td>EPA</td>
<td>Environmental Protection Agency</td>
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<td>EPC</td>
<td>engineering, procurement, construction</td>
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<td>EPS</td>
<td>earnings per share</td>
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<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
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<td>FAQs</td>
<td>frequently asked questions</td>
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<td>FASB</td>
<td>Financial Accounting Standards Board</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>FES</td>
<td>FirstEnergy Solutions</td>
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<td>FinREC</td>
<td>AICPA’s Financial Reporting Executive Committee</td>
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<td>GAAP</td>
<td>generally accepted accounting principles</td>
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<td>GridEx</td>
<td>Grid Security Exercise</td>
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<tr>
<td>GW</td>
<td>gigawatt</td>
</tr>
<tr>
<td>GWh</td>
<td>gigawatt hour</td>
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<tr>
<td>HB</td>
<td>House Bill</td>
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<tr>
<td>HLBV</td>
<td>hypothetical liquidation at book value</td>
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<tr>
<td>HTML</td>
<td>HyperText Markup Language</td>
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<tr>
<td>IAS</td>
<td>International Accounting Standard</td>
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<td>IASB</td>
<td>International Accounting Standards Board</td>
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<tr>
<td>ICFR</td>
<td>internal control over financial reporting</td>
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<tr>
<td>IFRS</td>
<td>International Financial Reporting Standard</td>
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<tr>
<td>IP</td>
<td>intellectual property</td>
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<tr>
<td>IRC</td>
<td>Internal Revenue Code</td>
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<tr>
<td>IRS</td>
<td>Internal Revenue Service</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>ISO-NE</td>
<td>ISO New England Inc.</td>
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<td>ITC</td>
<td>investment tax credit</td>
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<tr>
<td>kWh</td>
<td>kilowatt hour</td>
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<tr>
<td>LLC</td>
<td>limited liability company</td>
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<td>LNG</td>
<td>liquefied natural gas</td>
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<tr>
<td>M&amp;A</td>
<td>mergers and acquisitions</td>
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<tr>
<td>MACRS</td>
<td>Modified accelerated cost recovery system</td>
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<td>MATS</td>
<td>Mercury and Air Toxics Standards</td>
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<td>MLP</td>
<td>master limited partnership</td>
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<tr>
<td>MMBtu</td>
<td>million Btu</td>
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<tr>
<td>MMBtu/h</td>
<td>million Btu per hour</td>
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<td>MTC</td>
<td>minimum tax credit</td>
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<tr>
<td>MW</td>
<td>megawatt</td>
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<tr>
<td>MWh</td>
<td>megawatt hour</td>
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<tr>
<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<tr>
<td>NCCIC</td>
<td>National Cybersecurity and Communications Integrations Center</td>
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<td>NCI</td>
<td>National Council of ISACs</td>
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<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<td>NETOs</td>
<td>New England Transmission Owners</td>
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<td>NFP</td>
<td>not-for-profit entity</td>
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<td>NOI</td>
<td>Notice of Inquiry</td>
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<td>NOL</td>
<td>net operating loss</td>
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<td>NOPR</td>
<td>FERC Notice of Proposed Rulemaking</td>
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<td>NOx</td>
<td>nitrogen oxides</td>
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<td>NPUC</td>
<td>Nevada Public Utility Commission</td>
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<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
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<tr>
<td>O&amp;M</td>
<td>operations and maintenance</td>
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<tr>
<td>OATT</td>
<td>Open Access Transmission Tariffs</td>
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<td>OCA</td>
<td>SEC’s Office of the Chief Accountant</td>
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<tr>
<td>OCI</td>
<td>other comprehensive income</td>
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</table>
Abbreviation | Description
--- | ---
OCIE | SEC's Office of Compliance Inspections and Examinations
OE | FERC Office of Enforcement
OIS | Overnight Index Swap
P&U | power and utilities
PBE | public business entity
PCAOB | Public Company Accounting Oversight Board
PG&E | Pacific Gas and Electric Co.
PJM | PJM Interconnection LLC
PLR | IRS private letter ruling
PPA | power purchase agreement
PP&E | property, plant, and equipment
PSC | Public Service Commission
PTC | production tax credit
PUCN | Public Utilities Commission of Nevada
RCC | readily convertible to cash
REC | renewable energy certificate
REV | Reforming the Energy Vision
ROE | return on equity
ROU | right of use
RRWG | revenue recognition working group
RTO | regional transmission organization
SAB | SEC Staff Accounting Bulletin
SAFSTOR | Safe Storage
SASP | stand-alone selling price
SB | Senate Bill
SBS | security-based swap
SCE&G | South Carolina Electric & Gas Co.
SEC | Securities and Exchange Commission
SIL | simultaneous transmission import limit
SO₂ | sulfur dioxide
SOFR | Secured Overnight Financing Rate
TCC | turbine completion certificate
Tcf | trillion cubic feet
TEP | Tucson Electric Power
TRG | transition resource group
TVA | Tennessee Valley Authority
UPSC | Utah Public Service Commission
VIE | variable interest entity
WEC | WEC Energy Group
XBRL | eXtensible Business Reporting Language

The following is a list of short references for the Acts mentioned in this publication:

Abbreviation | Act
--- | ---
Dodd-Frank Act | Dodd-Frank Wall Street Reform and Consumer Protection Act
FAST Act | Fixing America's Surface Transportation Act
JOBS Act | Jumpstart Our Business Startups Act
PATH Act | Protecting Americans From Tax Hikes Act of 2015
Securities Act | Securities Act of 1933
The Act | Tax Cuts and Jobs Act of 2017 (H.R.1)