

A photograph of an industrial facility, likely a refinery or chemical plant, featuring large pipes and structures. The scene is brightly lit, suggesting a sunny day. A red square graphic is positioned in the upper left quadrant of the image. The text is overlaid on a dark, semi-transparent rectangular area in the center-right.

**BAKER BOTTS ENERGY UPDATE:
2017 ROUNDUP –
CONSOLIDATION CONTINUES**

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BAKER BOTTS ENERGY UPDATE: 2017 ROUNDUP – CONSOLIDATION CONTINUES APACE

Contributors: Joyce Banks, James Barkley, Brooksany Barrowes, Emil Barth, Megan Berge, Jonathan Bobinger, William Bumpers, Joshua Davidson, Peter del Vecchio, Michael Didriksen, A.J. Ericksen, Jennifer Golinsky, Kyle Henne, Thomas Holmberg, Marcia Hook, Stephanie Jeane, Bill Lamb, Luckey McDowell, Steven Miles, Jon Nelsen, Jay Ryan, Carlos Solé, Mark Spivak, Andrea Stover, Andrew Stuyvenberg, Martin Toulouse, Susan Toumanian, Gregory Wagner, Elaine Walsh, Matthew West, Jason Wilcox, Baker Botts Tax Partners

TO: CLIENTS AND OTHER FRIENDS OF THE FIRM

Each year around this time we take the opportunity to review the transactions and other significant industry developments over the past year and offer our views on what they may mean for the coming year.

Mergers and acquisitions activity in the energy industry during 2017 was higher than at any time in the last decade. Deal volume for transactions in the United States was over \$213 billion, well above the \$141 billion recorded in 2016 and above the previous high-water mark of \$201 billion set in 2015.¹ Initial uncertainty about the potential for tax reform was overcome by optimism about the economy generally, which kept stock valuations high and interest rates lower than at least some had thought they might be at this point in the business cycle. Utility stock valuations did decline somewhat toward year end, but it remains to be seen what effect lower valuations may have on the level of transaction activity in 2018.

As usual, more than half the activity involved pipelines, midstream companies and MLPs, with \$118 billion of announced transactions, up from about \$76 billion the year before. Transactions among regulated electric utilities also increased, to \$36.5 billion from \$19.8 billion in 2016. The two largest transactions involving regulated electric companies were the acquisition of Oncor Electric Delivery Company by Sempra Energy and Dominion Energy's acquisition of SCANA Corporation, both of which likely would not have taken place but for the financial distress associated with the company or its parent company. Canadian acquirers remained active with Hydro One Limited agreeing to acquire Avista Corporation in another major transaction. Among LDCs, volume nearly doubled to \$8.6 billion from \$4.8 billion, although this was still well short of the \$18 billion in 2015, when transactions involving AGL Resources and Piedmont Natural Gas Company set a new high-water mark. Most of the 2017 volume in the LDC sector was AltaGas Ltd.'s acquisition of WGL Holdings and the sale of Elizabethtown Gas to South Jersey Industries by Southern Company Gas. As in 2016, the volume of transactions involving electric generation assets was well above average, although at \$32.5 billion, 2017 volume was slightly below the \$33.5 billion of 2016. Two major transactions announced by IPP companies were Calpine's going private transaction

¹ Source: S&P Global, SNL Energy, transactions with announced transaction values of \$100 million or more.

and the merger of Dynegy and Vistra Energy. Transaction volume for renewable generation assets also jumped in 2017, to \$13.1 billion from \$6.6 billion in 2016 and \$8.5 billion in 2015. Key transactions and trends that we see in each of these subsectors are discussed in more detail below.

Although not deal specific, other key developments during the year included the evolving legislative and regulatory reform under the Trump Administration. The Administration's efforts to significantly change regulations pertaining to the environment and related energy regulatory matters have only begun, but it is clear that they are likely to be significant. The potential implications of regulatory reform are discussed in more detail in many of the sections below.

The other area of major reform is of course federal income tax. The recently enacted tax reform act (the "Tax Reform Act"), informally known as the Tax Cuts and Jobs Act, was signed into law by President Trump on December 22, 2017. The Tax Reform Act made sweeping changes to the Internal Revenue Code of 1986, as amended (the "Code"), most of which took effect on January 1, 2018. We have included discussion of the effects of the Tax Reform Act in many of the sections below (see Regulated Utilities, Renewables, Master Limited Partnerships and YieldCos, Project Finance, and Bankruptcy Developments in the Energy Sector). We also have included a separate section discussing the overall impact of the Tax Reform Act on the energy sector.

The discussion below covers the following areas:

- [Regulated Utilities](#)
- [Independent Power Producers and Generation Assets](#)
- [Renewables](#)
- [Master Limited Partnerships and YieldCos](#)
- [Project Finance](#)
- [Bankruptcy Developments in the Energy Sector](#)
- [Environmental Regulation](#)
- [FERC](#)
- [Small Scale LNG](#)
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- [ERCOT](#)
- [Tax Reform Act](#)
- [Mexico](#)

REGULATED UTILITIES

As in past years, the market for regulated utilities remains robust with valuations quite high and deal terms very seller-favorable. The Canadians have remained active, announcing two major transactions during 2017. 2017 was also marked by two large transactions involving distressed companies, Energy Future Holdings and SCANA Corporation. Reverse break-up fees remain a staple of acquisition agreements. The charts attached to this memo show several of the key metrics for transactions involving regulated electric and gas companies since 2013.

With respect to specific transactions, 2017 began with two major transactions pending, Westar/Great Plains and NextEra's acquisition of Energy Future Holdings Corp. and Oncor Electric Delivery Company. Both transactions evolved in very different but interesting ways during the year. Kansas regulators rejected the proposed Westar/Great Plains merger, but after taking stock of the situation, the companies decided to restructure what had been an acquisition as a merger of equals. The NextEra/EFH/Oncor transaction also ran into regulatory troubles, but NextEra was not able to salvage the transaction. Next in line to sign up a deal for EFH/Oncor was Berkshire Hathaway Energy, but that deal too was terminated in the face of opposition from some creditors and a competing proposal from Sempra Energy. That transaction also is still pending, and is discussed in more detail below. Other new transactions announced in 2017 included the acquisition of WGL Holdings by AltaGas Ltd., followed later in the year by Hydro One Limited's acquisition of Avista, Southern Company Gas's sale of Elizabethtown and Elkton Gas properties to South Jersey Industries and Dominion Energy's acquisition of SCANA Corporation. Two major announced transactions among IPPs were Calpine's going private transaction and the Dynegy/Vistra combination. Another interesting transaction announced in 2017 was Eversource Energy's acquisition of Acquarion Water Company from a group of Macquarie funds, marking a relatively unusual acquisition of a water company by an electric utility.

WESTAR/GREAT PLAINS

Westar Energy, Inc. and Great Plains Energy, Inc. announced the first iteration of their proposed combination on May 31, 2016 in what would have been a \$12.2 billion acquisition of Westar by Great Plains. Under that agreement, Westar shareholders would have received \$60.00 per share of total consideration for each share, comprised of \$51.00 per share in cash and \$9.00 per share in Great Plains common stock. The transaction ran into regulatory difficulties from the start with the Missouri Public Service Commission opening proceedings to determine whether it had jurisdiction over the transaction and to investigate the potential impact of the transaction on Missouri ratepayers. Then, on December 16, 2016, the staff of the Kansas Corporation Commission ("KCC") recommended that the proposed merger be rejected for not being in the public interest. It was not clear at the time if the commission itself would adopt the Staff's recommendation; many utility mergers have overcome such staff recommendations and gone on to be approved. However, on April 19, 2017, the KCC issued an order adopting the staff recommendation and denying the companies' application for approval of the transaction. The essence of the Commission's objections to the transaction was that Great Plains was paying too high a price for Westar and would incur too much debt in connection with the transaction.

After evaluating the KCC's objections to the original transaction, the companies concluded that it still made sense to combine the companies and on July 10, 2017 announced a new transaction that they believed addressed the concerns of the KCC. The new transaction was structured as a merger of equals in

which Westar Energy shareholders will exchange each share of Westar Energy common stock for a share in the new holding company. Great Plains Energy shareholders will receive .5981 shares of common stock in the new holding company for each Great Plains Energy share. The transaction has a total equity value of approximately \$14 billion. It is structured to permit a tax-free exchange of shares. No transaction debt will be incurred. The exchange ratio reflects the agreed-upon ownership split between the two companies. Following completion of the merger, Westar Energy shareholders will own approximately 52.5 percent and Great Plains Energy shareholders will own approximately 47.5 percent of the combined company. The agreement provides that, upon closing, the new holding company expects to set its initial common dividend at a level which maintains the current dividend for Great Plains Energy shareholders. This will result in approximately a 15 percent dividend increase for Westar Energy shareholders.

Upon closing, Mark Ruelle, Westar's CEO, will become the non-executive chairman of the new company board. Terry Bassham, Great Plains' CEO, will serve as president and chief executive officer of the new company and will also serve as a member of the board of directors. Senior management roles will be shared by executives from both companies. The board of directors will consist of an equal number of directors nominated from each company, including Bassham and Ruelle. Operating headquarters will be in both Topeka, Kansas, and Kansas City, Missouri. Corporate headquarters will be in Kansas City, Missouri.

Shareholders of the two companies approved the transaction on November 21, 2017. Hart-Scott-Rodino clearance was received in December and applications are pending before the KCC, the Missouri Public Service Commission, the FERC and the Nuclear Regulatory Commission. The companies expect to close in the middle of 2018.

On January 29, 2018 the KCC staff filed testimony recommending that the transaction be approved, subject to conditions. The conditions include, among others, that KCP&L, Westar and its subsidiary Kansas Gas and Electric Co., would be subject to a five year rate case moratorium; fixed bill credits in years 2019 through 2022 of \$10.1 million for Westar and \$3.3 million for KCP&L's Kansas ratepayers, in addition to the \$50 million of upfront aggregate rate credits the companies had proposed to issue immediately upon completion of the transaction; and a most favored nations clause that would require the KCC to adopt any additional conditions imposed in the Missouri jurisdictional review of the deal if such conditions are more favorable than those adopted in the KCC proceeding.

EFH/NEXTERA/ONCOR/SEMPRA

At the start of 2017, Energy Future Holdings Corp. ("EFH") had been authorized by the bankruptcy court to sell its 80% ownership interest in Oncor Electric Delivery Company ("Oncor") to NextEra Energy. But, in April 2017, the PUCT denied approval, finding that the NextEra-Oncor transaction was not in the public interest because the transaction would expose Oncor to substantial financial risks without providing any tangible benefits to Texas ratepayers. The PUCT was particularly concerned that the transaction would leave debt at the EFH holding company level, remove the ring-fencing structure, and expose Oncor to additional financial risks associated with NextEra's highly leveraged capital structure and unregulated development activities. NextEra did not terminate its purchase agreement, however, and instead plotted a course to preserve its \$275 million termination fee.

Meanwhile, in July 2017 Berkshire Hathaway Energy announced that it had an agreement with EFH to purchase Oncor for \$9 billion. EFH filed a motion with the bankruptcy court to approve certain bid protections for Berkshire Hathaway—including a substantial breakup fee—but in August 2017, just days

before that agreement was scheduled to be approved by the bankruptcy court, EFH walked away from the deal in favor of a \$9.45 billion offer from Sempra Energy (“Sempra”). The proposed Sempra-Oncor transaction would, among other things, retain the ring-fencing structure and eliminate all debt at the EFH holding company level. It also has support from the PUCT staff and other parties in interest. The PUCT has scheduled a hearing on the Sempra-Oncor transaction for February 21, 2018. New proceedings to confirm a Sempra-backed chapter 11 plan for EFH will be scheduled only if the PUCT approves the Sempra-Oncor transaction.

In addition, after the PUCT denied approval of the NextEra-Oncor transaction, litigation broke out between EFH, NextEra, and Elliott Management (the largest creditor in the case) regarding whether EFH was obligated to pay NextEra a \$275 million termination fee. In an extraordinary decision, the bankruptcy court vacated its prior order approving the \$275 million termination fee. The bankruptcy court concluded that the parties (both EFH and NextEra) made incomplete and misleading statements with respect to whether the fee would be payable if the PUCT denied approval of the NextEra-Oncor transaction. NextEra has filed an appeal from the bankruptcy court’s decision, which the Third Circuit has agreed to consider direct from the bankruptcy court and on an expedited basis.

WGL HOLDINGS, INC./ALTAGAS LTD.

On January 25, 2017, WGL Holdings and AltaGas Ltd. unveiled a \$6.4 billion transaction in which AltaGas will acquire WGL holdings for \$88.25 per share in cash. The price represented a 27.9% premium to WGL’s share price on November 28, 2016, the last trading day prior to a Bloomberg article regarding potential takeover interest in WGL and approximately 26.2 times WGL’s then-expected 2017 earnings. WGL will maintain its utility headquarters in Washington, D.C. and WGL’s existing management will continue to manage WGL’s regulated utility business, while also assisting in the management of AltaGas’ U.S. regulated utility business. AltaGas also intends to relocate the headquarters of its U.S. power business to WGL’s service region. WGL shareholders approved the transaction on May 10, 2017. Consummation of the transaction is subject to certain closing conditions, including approvals of applications filed with the Public Service Commission of the District of Columbia and the Maryland Public Service Commission on April 24, 2017. The transaction has already received approval from the Virginia State Corporation Commission, the Committee on Foreign Investment in the United States, the Federal Regulatory Energy Commission and the Federal Trade Commission and U.S. Department of Justice. Closing is expected to occur in the second quarter of 2018.

EVERSOURCE/ACQUARION

On December 4, 2017 Eversource completed its acquisition of the Aquarion Water Company Energy (through Macquarie Utilities Inc) from Macquarie Group Limited in a transaction that was first announced on June 2, 2017 with total consideration of \$1.675 billion. The purchase price consisted of \$880 million in cash and \$795 million in assumed debt. Based on Aquarion Water’s 2016 results, the purchase price is 2.3 times book value and 4.2 times revenue. Eversource became the only U.S.-based electric utility to also own a water utility. As part of the closing process, the parties received approvals from the Connecticut Public Utilities Regulatory Authority, the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission and the Federal Trade Commission and the U.S. Department of Justice. The entities together serve nearly 4 million electric, natural gas and water customers combined in Connecticut, Massachusetts and New Hampshire.

AVISTA/HYDOONE

On July 19, 2017, Hydro One Limited (“Hydro One”) and Avista Corporation (“Avista”) announced a definitive merger agreement under which Hydro One will acquire Avista for \$53 per share. The total transaction consideration of \$5.3 billion consists of \$3.45 billion in cash to shareholders and \$1.86 billion in assumed debt. Together, the combined enterprise will serve more than two million retail and industrial customers and hold \$25.4 billion in assets throughout North America including Ontario, Washington, Oregon, Idaho, Montana and Alaska. Consummation of the transaction is subject to certain closing conditions, including approval from the Montana Public Utilities Commission, Idaho Public Utilities Commissions, PUC of Oregon, Washington Utilities and Transportation Commission, the Regulatory Commission of Alaska, the Federal Communications Commission, the Committee on Foreign Investment in the United States and the Federal Trade Commission. and U.S. Department of Justice. The parties have already received approval from Avista’s shareholders and the Federal Regulatory Energy Commission. Closing is expected to occur in the second half of 2018.

SOUTHERN COMPANY GAS/SJI INDUSTRIES

On October 16, 2017 Southern Company and Southern Company Gas announced that they had agreed to sell the assets of their Elizabethtown Gas and Elkton Gas operating divisions to South captures the Industries in in all-cash transaction with a value of \$1.7 billion. Southern's rationale for the transaction was that it would strengthen the balance sheets of Southern Company Gas and Southern Company by reducing existing financing requirements. The transaction is subject to approval by the New Jersey Board of Public Utilities and the Maryland Public Service Commission (with respect to the Elkton Gas sale) and Hart-Scott-Rodino clearance, and certain limited approvals by the FERC and the Federal Communications Commission.

Regulatory approvals are pending and the transaction is expected to close in the middle of 2018.

DOMINION ENERGY/SCANA

The most recent major transaction announced was Dominion Energy’s proposed acquisition of SCANA Corporation in a stock-for-stock merger in which SCANA shareholders would receive 0.6690 shares of Dominion Energy common stock for each share of SCANA common stock, the equivalent of \$55.35 per share, or about \$7.9 billion based on Dominion Energy's volume-weighted average stock price of the last 30 trading days ended Jan. 2, 2018. Including assumption of debt, the value of the transaction is approximately \$14.6 billion.

The agreement also calls for significant benefits to SCANA's South Carolina Electric & Gas Company subsidiary (SCE&G) electric customers to offset previous and future costs related to the withdrawn V.C. Summer Units 2 and 3 project. After the closing of the merger and subject to regulatory approvals, these benefits would include:

- A \$1.3 billion cash payment within 90 days upon completion of the merger to all customers, which the companies say is worth \$1,000 for the average residential electric customer.
- An estimated additional 5 percent rate reduction from current levels, which is equal to more than \$7 a month for a typical SCE&G residential customer. This benefit would be funded by a \$575 million refund of amounts previously collected from customers and savings of lower federal corporate taxes under recently enacted federal tax reform.

- The write-off of more than \$1.7 billion of existing V.C. Summer 2 and 3 capital and regulatory assets. According to the companies, this would allow for the elimination of all related customer costs over 20 years instead of over the previously proposed 50-60 years.
- Completion of the \$180 million purchase of natural-gas fired power station (Columbia Energy Center) at no cost to customers to fulfill generation needs.

In addition, Dominion Energy would provide funding for \$1 million a year in increased charitable contributions in SCANA's communities for at least five years, and SCANA employees would have employment protections until 2020.

The Merger Agreement contains unusually specific regulatory approval conditions. The parties are not required to close the transaction unless the South Carolina Public Service Commission approves the transaction and a series of regulatory undertakings as proposed by the companies without material modification. The specific regulatory conditions include the four set out above as well as a series or more specific provisions, many of which relate to recovery of costs for V.C. Summer, including (i) that approximately \$3.3 billion of invested capital for the terminated nuclear project shall be included in a regulatory asset and recovered through rates over a 20-year amortization and recovery and that a specified equity portion of that regulatory asset earn a return of 10.25% during the amortization period.

According to Dominion, the transaction would be accretive to Dominion Energy's earnings upon closing. The merger also would increase Dominion Energy's compounded annual earnings-per-share target growth rate through 2020 to 8 percent or higher.

The combination is subject to approval of SCANA's shareholders, Hart-Scott-Rodino clearance, and FERC and NRC approval. The companies hope to close the transaction in 2018.

Tax Reform Act – Impact on Normalization Rules for Regulated Utilities

Because the Tax Reform Act adopts a corporate tax rate of 21% (reduced from the prior maximum rate of 35%), many companies' accumulated deferred income tax ("ADIT") balances will be reduced. For regulated utilities making large capital investments and utilizing accelerated tax depreciation, the ADIT balances derive in large part from the differences between that accelerated tax depreciation, on the one hand, and the straight-line book depreciation that is required for rate making purposes, on the other hand. To encourage these capital investments, the Code requires the use of a normalized method of accounting, which effectively prevents regulators from flowing through the accelerated depreciation benefits to ratepayers too quickly.

Generally, in computing ADIT, the book/tax differences in depreciation are multiplied by the applicable tax rate. The tax rate reduction in the Tax Reform Act creates "excess ADIT" because the ADIT balance previously computed using the 35% rate will be reduced when the book/tax differences are multiplied by the new 21% rate.

To address normalization issues, the Tax Reform Act adopts a similar approach to that taken in the Tax Reform Act of 1986, which also substantially reduced the corporate tax rate. Namely, if excess ADIT is reduced more rapidly, or to a greater extent than, it would be reduced under the "average rate assumption method," the taxpayer will not be treated as using a normalized method of accounting. The Tax Reform Act further provides that normalization violations for any taxable year result in (1) the taxpayer's tax for that year being increased by the amount by which excess ADIT is reduced more rapidly

than permitted under a normalized method of accounting and (2) the taxpayer no longer being able to claim accelerated depreciation.

Shareholder Activism in the Energy/Utility Industry

2017 was a very busy year for activist shareholders. Like other industries, the energy industry saw its share of activist pressure to restructure and cut costs. Several IPPs and utilities, such as AES, Ameren, Dominion Resources, DTE Energy, Duke Energy, PNM Resources and Xcel Energy, were subject to activist inquiries on climate change. Recently ValueAct Capital took a substantial stake in AES, resulting in a board seat, and is pressing the company to continue its efforts to divest its coal assets, pay down debt, and invest more in clean energy such as solar and battery storage.

Others IPPs and utilities were subjected to more fundamental pressure to increase profitability. In January 2017, Elliott and Bluescape announced large positions in NRG Energy and were demanding financial and operational improvements to NRG's business. Elliott and Bluescape installed two directors in February. Soon thereafter NRG announced its plans to divest almost \$4 billion of assets, including its wind and solar portfolio.

This activist trend appears to be continuing through 2018. Elliott and Bluescape teamed up again, with other investors, recently to make a \$2.5 billion investment in FirstEnergy. The group will get two seats on the FirstEnergy board. FirstEnergy intends to use the investment to pay down its debt and pension fund obligations. It is unclear at this stage what exact changes they may make, but undoubtedly it will involve continuing FirstEnergy's path to a regulated wires business.

INDEPENDENT POWER PRODUCERS AND GENERATION ASSETS

IPP Activity

The unregulated side of the electric industry saw a dramatic uptick in M&A activity, with approximately \$36 billion in electric generation transactions, up from \$33.5 billion in 2016, and \$8.5 billion in 2015. Much of this value related to the Calpine/ECP transaction and the Dynegy/Vistra transaction. There were also numerous dispositions of renewables assets, including the notable controlling investment made by Brookfield in TerraForm Power.

CALPINE/ENERGY CAPITAL PARTNERS

In August 2017, Calpine Corporation entered into a definitive agreement under which Energy Capital Partners, along with a consortium of investors led by Access Industries and Canada Pension Plan Investment Board, will acquire Calpine for \$15.25 per share in cash, or \$5.6 billion. Calpine owns fleet of 80 power plants in operation or under construction represents approximately 26,000 megawatts of generation capacity. Calpine's stockholders approved the transaction in December 2017. The transaction is expected to close in the first quarter of 2018.

ENGIE/DYNEGY-ENERGY CAPITAL PARTNERS

On February 25, 2016, Dynegy and Energy Capital Partners formed a joint venture, Atlas Power, to buy Engie's 8.7 GW fossil fuel-fired generation portfolio for approximately \$3.3 billion or \$378/kW. In June, Dynegy announced that it was buying Energy Capital Partners out of the JV for approximately \$750 million and assuming additional debt to take 100% ownership in the Engie assets. Dynegy had expected to close the transaction by the end of 2016, however, FERC raised several concerns about the transaction's

potential impact on the capacity markets in ComEd in PJM and Southeast New England in its order dated December 22, 2016. On December 27, 2016, Dynegy filed with FERC a proposed mitigation plan that includes divesting generation and imposing capacity bidding limits. FERC approved the plan in early February and the transaction proceeded to closing on February 7, 2017.

DYNEGY/VISTRA

In October 2017, after a very busy year for both companies, Vistra Energy Inc. and Dynegy Inc. entered into a definitive agreement pursuant to which Dynegy will merge with and into Vistra in an all-stock deal. Vistra was formed in 2016 after TCEH, parent of TXU Energy and Luminant, emerged from bankruptcy in a tax free spinoff from Energy Future Holdings Corp. and later renamed Vistra Energy.

The combined company is expected to have a combined market capitalization of over \$10 billion and will own approximately 40 gigawatts of electric generation capacity. Of that capacity, more than 60% is natural gas-fueled, and 84% is in the ERCOT, PJM, and ISO-NE competitive power markets. The transaction is expected to close in the second quarter of 2018.

RENEWABLES

Renewables Development Activity

WIND

As of the end of the third quarter 2017, wind projects under construction or in advanced development totaled 29,634 MW of capacity, a 27% year-over-year increase as compared to 2016. According to the American Wind Energy Association (AWEA), through the end of the third quarter, utilities announced new plans to develop and own 3,040 MW of wind capacity in Q3 2017 for a cumulative total of 8,840 MW since the start of 2016, and project developers signed PPAs representing 1,337 MW in the third quarter and a cumulative total of 4,697 MW for the first three quarters of 2017. Corporate purchasers represented 62% of total project capacity contracted during the third quarter (823 MW), with JPMorgan Chase, Anheuser-Busch, Cummins and Kimberly-Clark all signing wind PPAs for the first time. Historically, non-utility customers have signed more than 6,460 MW of wind PPAs through the end of the third quarter 2017. Prospects for increased wind power procurement in 2018 look favorable with four requests for proposal (RFPs) released during the third quarter for up to 3,970 MW of wind-eligible capacity, including PacifiCorp's request for up to 1,270 MW of wind-specific capacity. Total installed wind capacity in the US to date as of the end of the third quarter 2017 stands at 84,944 MW, with more than 52,000 wind turbines operating in 41 states plus Guam and Puerto Rico. Upon completion of Dominion's 12MW Coastal Virginia Wind project currently in advanced development, Virginia will become the 42nd state with utility-scale wind capacity.

SOLAR

GTM Research and the Solar Energy Industries Association (SEIA) forecast that 11.8GW of new PV installations will come on-line in 2017, down 22% from a record-breaking 14GW in 2016. Activity in 2016 was due principally to the large number of projects brought to completion in a rush to meet what had been anticipated to be the end of solar ITCs, only to have the ITC extended for five years in late 2016. The downturn in 2017 utility PV installations has been softened somewhat as projects originally scheduled for 2016 completion were pushed out to 2017 in reaction to the long-term extension, with this spill-over

effect estimated to represent more than 50% of the 2017 utility PV forecast. As of Q3 2017, the US market showed 2,031 MW of installed solar PV capacity, a 51% decrease year-over-year from Q3 2016. Through the end of the first three quarters in 2017, PV solar represented 25% of all new electric generation capacity brought on-line in the US, ranking second only to natural gas. The residential solar sector declined quarter-over-quarter in Q3 2017, due to weakness in the California and major Northeast markets. By contrast, utility-scale installations grew 22% year-over-year, driven by demand resulting from impending policy deadlines in California and the Northeast. Voluntary utility procurement, that is procurement not driven by renewable portfolio standards, continued to be the primary driver of new utility PV procurement in 2017, accounting for 57% of new procurement through Q3 2017.

Installation costs increased across all segments in Q3 2017, due in large part to increases in module costs as a result of a global shortage of Tier 1 module supply and the overhang of the Section 201 *Suniva* case. In brief, U.S.-based crystalline-silicon solar PV manufacturers Suniva and SolarWorld Americas filed a petition to the US International Trade Commission (“USITC”) in May 2016 under Section 201 of the Trade Act of 1974, arguing that increased imports of solar cells and panels had caused serious injury to the domestic industry. On September 22, 2017, the USITC made a determination that such imports had caused a significant injury to the US producers, later setting forth a set of recommended tariffs sent to President Trump for final determination.² On January 22, 2018, the US Trade Representative recommended and the President approved the imposition of “global safeguard tariffs” over four years on imported solar cells and modules, established at 30% in Year 1, 25% in Year 2, 20% in Year 3 and 15% in Year 4. The decision excludes the first 2.5 GW of cells, but apparently not modules, which are imported annually from these additional tariffs (see *Regulatory Developments* below). According to a GTM Research forecast, the new tariffs are likely to result in a net reduction in US solar installations of about 11% or about a 7.6 GW reduction in forecasted solar capacity from 2018 through 2022 with utility-scale solar installations accounting for 65% of such reduction. GTM Research estimates the tariff to result in an average \$0.10 per watt increase in module costs in the first year reducing to \$0.04 per watt in the fourth year. The tariff is likely to be appealed to the World Trade Organization by US trading partners. Thin-film solar panel manufacturers, such as FirstSolar, are not subject to the new tariff. Free trade partners Canada, Mexico and South Korea are not exempt from the global safeguard tariff. The relatively high module tariff could incentivize manufacturers to open US domestic production facilities.

GTM Research’s base-case outlook, prior to the *Suniva* decision, had projected US solar to fall again in 2018 before rebounding in 2019, due in large part to positive trends in utility PV procurement, *i.e.*, voluntary procurement, PURPA, off-site corporate procurement and California-based community choice aggregators. However, GTM Research emphasized in its Q4 2017 report on the US solar market, that the foregoing base-case forecasts do not account for the USITC’s tariff recommendations. Another factor that is expected to affect GTM Research’s base-case outlook for US solar relates to the effects of the recent federal income tax reform. The legislation’s reduction in the top corporate tax rate from 35% to 21% is expected to reduce the “appetite” and, therefore, the availability of tax equity financing, making it more difficult for developers to monetize the federal ITC. In addition, the new Base Erosion Anti-Abuse Tax, called BEAT, could further tighten the tax equity market by making it harder for tax equity investors

² *Greentech Media, October 31, 2017, ITC Issues Recommended Remedies in Section 201 Solar Trade Case, available at <https://www.greentechmedia.com/articles/read/itc-solar-trade-case-recommendations#gs.cn2OzoQ>.*

subject to the new tax to know at the outset whether they will receive the full amount of the tax credit. The BEAT minimum tax amount is computed each year and is generally the excess of (a) a percentage (generally 10%) of the taxpayer's "modified taxable income" (generally, income computed without regard to certain "base erosion" payments made to foreign subsidiaries), over (b) the taxpayer's regular tax liability reduced by its tax credits, except for certain business tax credits, including up to 80% of the value of the PTC or the ITC. The market is still digesting and analyzing the full impact of both the solar safeguard tariffs and various aspects of the recent tax reform legislation.

STORAGE

2017 may be the year that energy storage has come into its own. The industry experienced several important milestones, including proving itself in two rapid response deployments resolving grid emergencies, significant increases in size and duration for utility-scale applications, acquisition of storage startups by major international conglomerates, and participation by nearly all major solar developers. Storage prices are dropping much faster than had been anticipated with battery pack costs below \$230 per kWh in 2016 as compared to \$1,000 per kWh in 2010. McKinsey reports that storage is already economical without subsidies, grants and other incentives in certain applications, for instance commercial customers seeking to reduce their peak consumption. In addition, storage is beginning to assume a broader footprint, moving from niche uses such as grid balancing to more conventional uses such as replacing generators for reliability, providing power-quality services and working in tandem with renewables to foster integration. In terms of economics, battery storage for utility applications is currently showing value in frequency regulation and is expected to achieve positive value with renewable energy technology firming and smoothing as well as deferring investments in transmission and distribution by 2020. For commercial and industrial users, batteries currently add value in helping customers to reduce demand charges and are expected to prove their worth in storage and solar self-consumption by 2020.

Storage was successfully deployed to help resolve peak power generation constraints in L.A and San Diego caused by the Aliso Canyon gas leak, the worst natural gas leak in US history discovered by SoCalGas employees in October 2015. In less than six months, Tesla, Greensmith Energy and AES Energy Storage successfully deployed 100MW of large-scale lithium-ion battery projects to resolve grid constraints. The battery installations were designed to store low-cost energy from an oversupply of solar power during the day and feed it back into the grid as energy use spikes in the evening preventing blackouts during the summer peak season. The success of the effort showed that storage could react to capacity constraints far more quickly than traditional power plants. Storage has been demonstrated to be a useful solution for future grid crises and has bolstered the case for using batteries to meet local capacity needs instead of relying on natural gas generation.

Solar-plus-batteries demonstrated their worth in two projects. In early 2017, AES contracted for a solar-plus-storage project in Kauai at \$0.11 per kWh. The facility combines 28MW of solar PV capacity with 20 MW of 5-hour duration batteries meeting 11% of Kauai's total electrical demand. In May 2017, Tucson Electric Power contracted with NextEra Energy Resources to build a solar-plus-storage project at a PPA price of less than \$0.045 per kWh. The TEP facility pairs a 100 MW solar PV generation unit with a 30 MW/120 MWh storage system. Batteries can be used to meet load growth that would otherwise require expensive cable upgrades. Arizona Public Service in another storage project coup contracted with AES to supply a 2 MW/8 MWh battery system for the Punkin Center project which helped it avoid wire upgrades for a remote desert town at half the upfront cost.

Large energy companies were engaged in several storage company acquisitions throughout 2017, including European utility and renewables developer Enel's acquisition of Demand Energy, a developer and operator of energy storage systems and software, in January; Finnish energy conglomerate Wartsila's acquisition of Greensmith Energy Management Systems, and the creation of Fluence, a new energy storage joint venture between AES and Siemens. These acquisitions continue a trend started in 2016 with the acquisition by Engie of a controlling stake in Green Charge and the acquisition by French energy giant Total of battery maker Saft. Although the impact of these 2017 acquisitions have not materialized, the combined companies each have expressed interest in international expansion, which industry observers expect may happen in 2018.

2018 may be the year when large solar developers turn solar-plus-storage from concept to execution. GTM Research reported in June 2017 that top solar developers have begun bidding hybrid solar-storage projects and projecting that the market may see such deployments in the next two or three years. In the meantime, residential solar installers have expanded their solar-storage offerings, led by SolarCity's merger with Tesla, Sunrun's marketing of its BrightBox solar-plus-storage package accounting for 10% of its direct sales in California, and Vivant's announced partnership with Mercedes-Benz Energy to deliver residential batteries.

No discussion of the 2017 year in storage is complete without mentioning Elon Musk's bet to deliver the world's largest battery project in South Australia in 100 days or it would be free. The 100 MW-129 MWh facility began testing during the American Thanksgiving holiday weekend and came online on December 1st. Like the Aliso Canyon project, the Tesla South Australia storage project demonstrated the ability of battery storage to meet urgent grid needs in record time.

2017 also saw increasing interest in domestic large grid-scale energy storage projects. ITC Holding Corp., a subsidiary of Fortis Inc., received a preliminary permit from the Federal Energy Regulatory Commission to study the development a 2000 MW closed-loop pumped storage project in Arizona that will facilitate integration of renewables and provide reliability services in the southwestern United States. Dominion Energy is also studying the potential feasibility of a pumped storage facility in Virginia. We anticipate that additional interest in grid-scale pumped storage will continue in 2018.

Regulatory Developments

On January 23, 2018, President Trump issued Proclamation 9693, "To Facilitate Positive Adjustment to Competition From Imports of Certain Crystalline Silicon Photovoltaic Cells (Whether or Not Partially or Fully Assembled Into Other Products) and for Other Purposes" (the "Proclamation"), which, effective February 7, 2018, imposes global safeguard tariffs on imported solar cells and modules. The Proclamation was in response to the U.S. International Trade Commission ("ITC") finding on September 22, 2017 that increased imports of certain crystalline silicon photovoltaic cells ("CSPCs") are a substantial cause of serious injury to domestic manufacturers.

Specifically, the Proclamation calls for safeguard tariffs on imports of CSPCs for the next four years, which includes a tariff of 30 percent in the first year, 25 percent in the second year, 20 percent in the third year, and 15 percent in the fourth year. These tariffs are intended to apply to CSPC imports worldwide (except from developing countries that are World Trade Organization ("WTO") members, under certain conditions). However, the first 2.5 gigawatts of imported solar cells will be exempt from the safeguard tariff in each of those four years.

ITC's determination was made in the context of a global safeguard investigation initiated on May 17, 2017, under Section 201 of the Trade Act of 1974 (the "Act") in response to a petition filed by Suniva, Inc., and supported by SolarWorld Americas, Inc. Section 201 authorizes the President to take action, in the form of tariffs, tariff-rate quotas, quantitative restrictions or other actions, in response to an ITC determination that increased imports are a substantial cause of serious injury to domestic producers.

Under the Act, if a majority of ITC Commissioners reach an affirmative determination of serious injury in a Section 201 investigation, the Commissioners voting in the affirmative must make a recommendation as to what action the President should take. Although the Commissioners unanimously made an injury determination in the CSPC proceeding, they could not agree on a single remedy to recommend to the President. However, most of the Commissioners favored an increase in duties with a carve-out for a specified quantity of imported cells, which the President ultimately favored.

It should be noted that the President's decision to impose global safeguard tariffs on imported CSPCs does not impact separate antidumping and countervailing duty measures currently imposed on Chinese solar products. In a January 22, 2018 press release on the President's decision, U.S. Trade Representative ("USTR") Robert Lighthizer noted that the USTR intends to engage in discussions among interested parties that could lead to a positive resolution of those measures.

Given that both the ITC and the President have broad discretion in exercising their authority under Section 201, judicial review of the President's decision is unlikely. However, on January 24, 2018, South Korea submitted to the WTO a request for consultations with the United States pursuant to WTO Agreement on Safeguards and General Agreement on Tariffs and Trade 1994, thereby initiating the process for challenging the safeguard measures at the WTO level. It is possible that other countries may also follow suit. Assuming that the challenge results in a full dispute, adjudication of the matter could take three years or more, during which time the global safeguard measures would remain in effect.

Instead, it is more likely that the President's decision will be challenged at the WTO, but such disputes may only be brought by governments and entail a rather lengthy process, during which time the global safeguard tariffs would remain in effect.

Tax Reform Act – Impact on Renewables

RENEWABLE TAX CREDITS UNCHANGED

The Tax Reform Act leaves unchanged the production tax credit (the "PTC") of Section 45 of the Code and the investment tax credit (the "ITC") of Section 48 of the Code. The House version of the Tax Reform Act had eliminated inflation indexing for the PTC and had eliminated the ITC for solar energy projects for which construction commences after 2027. The final version of the Tax Reform Act does not adopt these proposals.

Additionally, the House version of the Tax Reform Act would have codified the "continuous construction" requirement for determining when construction of a project commences. This requirement is currently established in IRS guidance, but such guidance also provides a safe harbor for projects placed in service within a certain time frame after construction commences. The House bill omitted, and thus would have invalidated, the safe harbor. The final version of the Tax Reform Act did not include this proposal, so taxpayers may continue to rely on the safe harbor.

Under current law, the PTC and ITC are phased out based on when construction begins. The PTC and ITC for wind facilities are scheduled to phase-down for projects commencing through 2019, after which the credits expire. The ITC for solar properties phases-down through 2021, bottoming out at 10% for projects that commence after 2021. During the drafting process of the Tax Reform Act, several members of Congress indicated interest in extending these credits, but no extensions were included in any version of the Tax Reform Act. Any extensions of renewable tax credits will need to be part of a future extender package. Finance Committee Chair Orrin Hatch has already introduced such an extender bill, S. 2256, the Tax Extender Act of 2017, which would extend the PTC and ITC and reinstate the ITC for fuel cells, geothermal heat pumps, fiber-optic solar panels, combined heat and power projects, and nuclear power plants. At least two Senate Finance Committee Democrats have expressed general support for these extenders, but the passage of an extender bill is uncertain.

REPEAL OF THE CORPORATE ALTERNATIVE MINIMUM TAX

The Tax Reform Act repeals the corporate Alternative Minimum Tax (the “AMT”), ensuring that renewable tax credits will continue to be valuable to corporate investors. The AMT imposed a minimum tax of 20% on certain corporations and restricted the use of the PTC to offset such tax. Repeal of the AMT ensures that the PTC will continue to be fully monetizable by most investors under the lower corporate tax rate (unless the taxpayer is subject to the BEAT provisions, as discussed below under Project Finance).

The Senate version of the Tax Reform Act had retained the AMT, raising alarm from the renewables sector. Under the Tax Reform Act’s lowered corporate tax rate of 21% (reduced from the previous maximum rate of 35%), the number of corporations subject to the AMT would have sharply increased, and the value of the PTC for such corporations would have been severely curtailed. The Tax Reform Act avoids this undesirable result by repealing the AMT.

PREPAID POWER PURCHASE AGREEMENTS

Prepaid power purchase agreements have often been used in renewable projects (notably, in rooftop solar projects). This is because, in part, they permit the electricity provider to include the advance payments in income over the entire period in which the electricity will be delivered. However, the Tax Reform Act will require these prepayments to be reported immediately as income (or, at best, partly in the year of the prepayment and partly in the following year, depending on the circumstances).

MASTER LIMITED PARTNERSHIPS (MLPS) AND YELDCOS

MLP Capital Markets in 2017

Overall MLP capital markets activity in 2017 was generally consistent with 2016 levels. However, the sector underperformed the broader market for the year. While the S&P 500 increased 19.4% in 2017, the Alerian MLP Index ended the year at (13.0)%, with a total return of (6.5)%, the second negative year out of the last three (compared to a 9.1% increase and total return of 18.3% in 2016). Among MLP equity securities, midstream MLPs fared better on a relative basis than publicly traded general partners of MLPs.

MLP equity capital markets activity remained relatively quiet during 2017; however, there was a strong uptick in IPO activity for the sector. Five MLPs went public raising \$2.4 billion of gross proceeds—Kimbell Royalty Partners, Hess Midstream Partners, Oasis Midstream Partners, BP Midstream Partners and Antero Midstream GP LP. By comparison, there were one MLP IPO raising gross proceeds of \$300 million in 2016,

nine for \$4.9 billion of gross proceeds in 2015 (all in the first half of the year) and 20 transactions for \$7.7 billion of gross proceeds in 2014.

During 2017, equity follow-on activity declined relative to 2016. In 2017, there were 21 follow-on transactions for \$5.9 billion of gross proceeds compared to 32 transactions for \$6.6 billion of gross proceeds in 2016. Bought deals and confidentially marketed offerings (CMPOs) remained popular in light of market volatility. Bought deals provide greater certainty to the issuer as the lowest possible price at which the units will be sold is guaranteed by the underwriter. CMPOs provide the issuer with the ability to put together a complete book of investors at an acceptable price before publicly announcing the offering, while selling freely tradeable units to the investors. Private placements of equity also continued to be relatively popular. In 2017, there were 12 private placements/block trades to third parties or affiliates for \$4.5 billion. PIPEs provide an opportunity to confidentially complete an offering, although the investors typically demand a greater discount than if they buy units in a public offering because the units are not freely tradeable until registered, although there is no underwriting discount in PIPEs.

Preferred unit transactions also remained popular in 2017, with 15 transactions. Preferred units, which can be targeted to private equity and affiliate investors or marketed to institutional investors or retail holders, can be used to lower an MLP's cost of capital as these units may have a lower yield and the distributions paid on the preferred equity do not increase incentive distributions to the general partner. These preferred units may also be convertible into common units. Convertible preferred units provide the holders with an annual PIK and/or cash dividend at an attractive yield and an option to convert into common units after 18-24 months. The issuer also has the option to force conversion of the units if the market price of the common units rebounds to a certain level.

In addition, MLPs continued to use at-the-market (ATM) equity programs to feed their ongoing capital needs. ATM programs allow MLPs to issue targeted amounts of common units in broker transactions from time to time.

Debt capital markets activity in the MLP sector increased year over year. MLPs engaged in 42 debt offerings raising proceeds of \$26.3 billion in 2017, compared to 35 transactions raising \$20.3 billion in 2016.

In 2017, over 80% of the MLPs in the Alerian MLP Index increased (21 of 37) or maintained (11 of 37) their distributions year over year through the third quarter (most MLPs have not yet announced their distributions in respect of the fourth quarter, which are paid in the first quarter of 2018). 2016 saw similar results, with 21 of 40 MLPs in the index growing their distributions and 14 MLPs holding their distributions steady. However, some of the larger names were among those to cut distributions, and so the cuts tend to generate the most headlines.

We are optimistic that the improved commodity price environment that has oil prices holding steady above \$60 per barrel, increases in midstream volumes handled, and a healthy U.S. economy will provide a tailwind for follow-on equity and high yield activity levels in the MLP sector. We expect that MLPs will continue to pursue organic investments in infrastructure, which will reduce some of the financing needs in the sector. We also believe the Tax Reform Act's removal of some uncertainty regarding the continued tax advantages of MLP income over C corporations will further benefit the sector (see below for further discussion of the Tax Reform Act). However, although there are several issuers in registration, we expect the MLP IPO market to remain relatively quiet in 2018.

MLP M&A in 2017

In 2017, M&A activity remained healthy, with increases in both transaction volume and values. In the sector, 96 transactions were announced with an aggregate disclosed value of approximately \$85.4 billion (compared to 78 transactions with a disclosed value of \$54.0 billion in 2016).

MLP consolidation continued in the midstream sector. MLP simplifications, take privates and general partner sales also continued as mature MLPs sought to lower their cost of capital and some sponsors sought to simplify their structures or came under market pressure. The two largest transactions in the sector were both simplifications—Williams Partners' \$11.4 billion acquisition of the incentive distribution rights held by its general partner and MPLX's \$10.1 billion acquisition of its general partner's economic interest, including incentive distribution rights. ONEOK's \$9.3 billion take private of ONEOK Partners was 2017's third largest transaction. Other notable transactions included MLPX's \$8.1 billion acquisition of refining logistics assets and fuels distribution services from its sponsor Marathon Petroleum.

Many midstream MLPs continued to grow their distributions through traditional drop-downs (i.e., an MLP's accretive acquisition of assets from its sponsor) and acquisitions of targeted assets from other MLPs and private companies. Multiples paid in drop downs were generally consistent with 2016 and remained below the historically high values seen in 2013. MLPs with a drop down story took extra steps to highlight their sponsors' inventories and support, though some sponsors have felt pressure to push down all of their suitable assets into their MLPs in one big transaction rather than a series of drop downs over time. MLPs also used more creative sources of financing drop downs, including issuing preferred equity as acquisition consideration.

We expect to see plenty of M&A activity in the sector, with continued buybacks and consolidation in 2018. Despite a wave of simplification transactions of incentive distribution rights in the last few years, there remain several MLPs with the potential to execute simplification transactions to reduce or eliminate the associated capital cost burden.

YieldCo Capital Markets in 2017

There were no YieldCo IPOs in 2017, and the last YieldCo IPO was in the third quarter of 2015. However, the YieldCo debt and equity capital markets became increasingly accessible, providing approximately \$3 billion in new capital. YieldCo share prices were highly volatile throughout much of 2017, even though share prices increased, on average, 15% year-over-year. Several factors influenced this volatility, the most significant being Brookfield Asset Management's acquisition of TerraForm Global and a majority interest in TerraForm Power (each of SunEdison's two YieldCos), Algonquin Power's acquisition of a sizeable minority stake in Atlantica Yield and the announcement of the potential sales of each of 8point3 Energy and NRG Yield. The bankruptcy of SunEdison, the filing of which occurred in the second quarter of 2016, likely continued to have a negative effect on the value of YieldCos. Going forward, despite the demand for U.S. renewable assets, the lack of transactions in the public markets and the current lack of retail investor appetite for YieldCos may continue to keep the YieldCo capital markets tight for the upcoming year.

YieldCo M&A in 2017

M&A by YieldCos slowed considerably in 2017, with only one acquisition announced (as compared to 12 in 2016) and two other previously announced transactions closed. M&A levels in 2018 will be dependent on several factors, notably YieldCos' access to additional capital, primarily through the equity capital

markets, the regularity of utility providers acquiring renewable energy projects directly from developers, which has become increasingly common, and the role that the new sponsors, Algonquin Power and Brookfield Asset Management, play in dropping down additional assets.

YieldCo Consolidation in 2017

More interesting than the acquisitions by YieldCos in 2017 was the acquisitions, or planned acquisitions, of the all or part of the YieldCos themselves. As noted above, Brookfield Asset Management, which already controls a YieldCo (Brookfield Renewable Energy Partners) acquired a 51% interest in TerraForm Power and all of TerraForm Global from SunEdison, and Algonquin Power acquired a 25% interest in Atlantica Yield from Abengoa. Additionally, in 2017, each of 8point3 Energy Partner's sponsors, First Solar and SunPower, and NRG Yield's sponsor, NRG Energy, have announced their intentions to sell their interests in their respective YieldCos. After these transactions, the YieldCo market could potentially be reduced to as few as five public companies.

Tax Reform Act - Impact on MLPs

MLP TAX RATE VS. CORPORATE TAX RATE

A significant benefit of MLPs over C corporations has been the lower effective tax rate that applies to MLP income. The Tax Reform Act preserves that benefit through 2025. The Tax Reform Act permanently reduces the corporate tax rate to a flat 21%, beginning in 2018. When combined with the maximum 20% tax rate on qualified dividends paid by a C corporation to an individual shareholder, the effective tax rate on income of a C corporation distributed to its shareholders will be 36.8% (or 39.8% after the 3.8% Medicare tax on dividends).

The Tax Reform Act reduces the maximum individual tax rate to 37%, beginning in 2018. In addition, the Tax Reform Act provides a deduction to individual MLP unitholders generally equal to 20% of the MLP's domestic income and 20% of any recapture income of an MLP unitholder on the sale of an MLP unit (without the wage-based limitation on the 20% deduction that generally applies to other pass-through entities). The combination of the reduced individual tax rate and the 20% deduction lowers the effective tax rate on income of an MLP to 29.6% (or 33.4% after the 3.8% Medicare tax).

Table of Effective Tax Rates Before and After the Tax Reform Act

TAX RATE	CORPORATE	SHAREHOLDER	EFFECTIVE C CORP	INDIVIDUAL	MLP	MLP BENEFIT BEFORE MEDICARE 3.8%	ADJUSTED FOR MEDICARE 3.8%
Pre-2018	35%	20%	48%	39.6%	39.6%	8.4%	7.1%
Tax Reform Act	21%	20%	36.8%	37%	29.6%	7.2%	6.6%

The reduced maximum individual 37% rate and the 20% deduction for MLP income, but not the reduced 21% rate on income of a C corporation, are scheduled to expire after 2025. Thus, after 2025, the effective tax rate on MLP income will be slightly higher than the effective tax rate on C corporation income (39.6% for MLPs and 36.8% for C corporations, in both cases before the 3.8% Medicare tax), unless the individual reduced rates and the 20% deduction are extended before then. Because many other favorable provisions of the Tax Reform Act sunset after 2025, it is possible that future legislation will extend the MLP effective tax rate benefit beyond 2025.

INTEREST DEDUCTION LIMITATION

The Tax Reform Act imposes a new limitation on interest expense deductions of large business taxpayers, including MLPs, beginning in 2018. The Tax Reform Act limits net interest expense deductions of an affected entity to 30% of its "adjusted taxable income." "Adjusted taxable income" is taxable income computed without regard to business interest expense, business interest income, the 20% deduction for pass-through entities, net operating losses, and for taxable years prior to 2022, depreciation, amortization, and depletion. For a more detailed discussion, please see Tax Reform Act – Interest Expense Deductions Generally Limited, below.

The limitation is calculated and applied separately for each entity, in a manner that is intended to avoid double-counting. For example, in calculating the limitation on an MLP's ability to deduct its own interest expense, the MLP would take into account net income allocated to it from a subsidiary partnership only if the subsidiary partnership's interest expense fell short of 30% of the subsidiary partnership's adjusted taxable income, and in proportion to that shortfall. Similarly, an MLP unitholder would take into account net income allocated to it from the MLP in calculating the limitation on the unitholder's interest expense only if the MLP's interest expense fell short of 30% of the MLP's adjusted taxable income, and in proportion to that shortfall.

Disallowed interest expense allocated to an MLP unitholder can be carried forward indefinitely, to a year in which the unitholder's share of the MLP's interest expense does not exceed 30% of the unitholder's share of the MLP's adjusted taxable income. The disallowed interest expense immediately reduces the unitholder's basis in its MLP interest, but any amounts that remain unused upon disposition of the interest are restored to basis immediately prior to disposition.

BONUS DEPRECIATION

Under the Tax Reform Act, the bonus depreciation percentage is generally increased to 100% (from its prior level of 50%) for property placed in service after September 27, 2017, and before 2023. After 2022, the bonus depreciation percentage is phased-down to 80% for property placed in service in 2023, 60% for property placed in service in 2024, 40% for property placed in service in 2025, and 20% for property placed in service in 2026.

The Tax Reform Act expands the availability of bonus depreciation to non-original use property, as long as it is the taxpayer's first use. The Tax Reform Act does not provide any express rules for how this expanded availability applies to purchasers of MLP units or other partnership interests. Bonus depreciation is not available for property of a regulated public utility.

TECHNICAL TERMINATIONS

The Tax Reform Act permanently repeals the partnership technical termination rule contained in Section 708(b)(1)(B) of the Code. This repeal allows an MLP or other partnership to continue—without resetting depreciation periods and without allowing or requiring new elections—even after the disposition by partners of more than half of the partnership’s outstanding capital and profits interests in a twelve-month period.

SALE OF FOREIGN PARTNER’S PARTNERSHIP INTEREST

The Tax Reform Act added Section 1446(f) to the Code, which provides that gain or loss realized by a foreign corporation or a foreign individual from the sale or exchange of an interest in a partnership engaged in a U.S. trade or business is treated as effectively connected with a U.S. trade or business to the extent that the sale of all the partnership assets would have produced effectively connected gain or loss. This provision applies to sales, exchanges, and dispositions occurring on or after November 27, 2017. This provision repeals the result in *Grecian Magnesite Mining v. Commissioner*, 149 T.C. No. 3 (2017), where the Tax Court held that a foreign partner was not subject to U.S. tax on sale of a partnership interest, rejecting the holding of Rev. Rul. 91-32 to the contrary.

Under Section 1446(f), the transferee of a partnership interest is required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person. The partnership is required to deduct and withhold from the transferee amounts that should have been withheld by the transferee. The withholding requirement is effective for sales, exchanges, and dispositions after December 31, 2017.

In Notice 2018-8, published on December 29, 2017, the IRS announced that Treasury and the IRS are temporarily suspending the application of Section 1446(f) to any disposition of an interest in a publicly traded partnership (within the meaning of Section 7704(b) of the Code) until regulations or other guidance have been issued under Section 1446(f) that address how to withhold, deposit, and report the tax withheld. Such guidance will be prospective and include transition rules to allow sufficient time for compliance. The IRS also indicated that it may provide guidance permitting brokers to handle the withholding of the 10% tax in cases where foreign partners sell MLP units through a broker, as is suggested in the explanation to the Tax Reform Act, but only after general guidance is provided and new withholding systems are developed.

PROJECT FINANCE

The aggregate volume of transactions consummated in the US project finance market increased somewhat in 2017, to \$42.5 billion from \$33.8 billion in the prior year.³ Similarly, the volume of transactions for the Americas as a whole increased to \$64.4 billion in 2017 from \$55.9 billion in 2016, with strong levels of activity in Canada and Latin America. Overall, credit markets were healthy throughout the year, supported in part by indications that commodity prices may begin to recover.

Liquidity remained strong in the commercial bank market for US project finance. The traditional Japanese and European banks continued to dominate the league tables, but a large number of institutions were active in the space, thereby creating generally favorable conditions for borrowers both with respect to

³ Source: Thomson Reuters Project Finance International league tables.

pricing and tenor. Fueled by significant investor demand and more limited supply, the term loan B market also offered attractive terms to project sponsors and owners during most of 2017, often for refinancing and acquisitions though assets with remaining construction risk can also be financed in the term loan B market.

Looking ahead to 2018, renewables are expected to constitute a significant source of activity in the US project finance market. A related and emerging asset class that has generated significant interest in the project finance community (though relatively modest amounts of actual debt financing at this point) is energy storage. As noted elsewhere in this memorandum, the battery storage industry has achieved significant milestones in 2017 and is expected to grow rapidly over the next few years. As the market continues to evolve, financing for battery storage projects, whether on a stand-alone basis or together with a solar or other generating asset, will require participants to become comfortable with the technology and regulatory risks and to ascertain the various revenue streams that can be generated by battery storage.

While market conditions in 2017 were favorable, the full impact of the tax reform on the financing of renewables remains to be seen. The Tax Reform Act permanently lowers the corporate rate to 21% (reduced from the prior maximum rate of 35%). A lower corporate tax rate renders the accelerated tax depreciation deductions associated with renewable energy projects less valuable.

In addition, the new Base Erosion Anti-Abuse Tax (the "BEAT") will limit or eventually eliminate the value of the PTC and ITC for certain multinational investors. The BEAT is a minimum tax intended to prevent "earnings stripping" by multinational corporations. The BEAT minimum tax amount is computed each year and is generally the excess of (a) a percentage (generally 10%) of the taxpayer's "modified taxable income" (generally, income computed without regard to certain "base erosion" payments made to foreign subsidiaries), over (b) the taxpayer's regular tax liability reduced by its tax credits, except for certain business tax credits, including up to 80% of the value of the PTC or the ITC. In effect, the Tax Reform Act allows the taxpayer to offset any tax owed under the BEAT by 80% of the value of the PTC and the ITC. The Tax Reform Act does not provide a carry-forward mechanism to allow unused tax credits to offset the BEAT in future taxable years.

Whether and to what extent a corporation will be subject to the BEAT will not be certain until the end of each taxable year because the determination turns on a complex set of factors unique to each taxpayer. Thus, the value of the PTC or ITC in any given year is also uncertain. Creating additional uncertainty, the BEAT provisions relating to renewable credits expire after 2025. After 2025, the renewable credits provide no offset to the BEAT, which will vastly decrease the value of the credits for many investors in the tax equity market.

This result is in some respects more favorable to investors than the Senate bill's original version of the BEAT, which did not include any adjustments for the PTC or ITC. But the final version may still negatively impact the tax equity market by reducing and eventually eliminating the value of the PTC and ITC for certain investors. Moreover, as compared to the Senate version, the final version of the Tax Reform Act expands the number of taxpayers that may be subject to the BEAT. How much the BEAT will affect corporate investors and the tax equity market overall is difficult to predict.

Another potential source of uncertainty for the loan market in 2018 and beyond, though not directly tied to project finance lending, relates to the opinion issued by the Government Accountability Office (the

“GAO”) in respect of the leveraged lending guidance. Adopted in 2013 by Office of the Comptroller of the Currency, the Federal Reserve Board and the FDIC, the leveraged lending guidance was designed to assist financial institutions by describing the regulators’ expectations for the sound risk management of leveraged lending activities. As such, the guidance had a significant impact on the leveraged loan market and banks’ underwriting standards generally. In October 2017, the GAO ruled that the leveraged lending guidance is a “rule” for purposes of the Congressional Review Act and therefore must be submitted to Congress for review. While the GAO ruling may lead the agencies to reopen the guidance for comment and review once all new agency heads are confirmed by Congress, the actual impact of such review process on bank underwriting criteria in the short term remains to be seen.

Finally, both lenders and borrowers are expected to pay close attention to developments relating to LIBOR in 2018. LIBOR has long been used as the benchmark or reference rate for floating rate loans and other instruments, including in project finance, but following allegations of collusion among market participants in the determination of LIBOR, efforts have been under way to find a replacement. In July 2017, the head of the UK Financial Conduct Authority, the agency responsible for overseeing LIBOR, indicated that the process for assessing LIBOR may not be enforced after 2021. It is too early to make any predictions with respect to the nature of any LIBOR replacement, but loan documentation for credit facilities set to mature after 2021 now routinely include specific provisions designed to facilitate a transition from LIBOR to whatever rate may gain market acceptance in the future.

BANKRUPTCY DEVELOPMENTS IN THE ENERGY SECTOR

Overall there were fewer energy sector bankruptcies in 2017 due to the recovery of commodities prices and the explosive rebound in debt markets (the amount of high-yield U.S. energy debt issued in 2017 was more than double the amount issued in 2016). Still, many companies could not be saved from bankruptcy in 2017, with a notable uptick in generation-related bankruptcies, including GenOn Energy, Westinghouse Electric, Homer City Generation, and ExGen Texas Power. Furthermore, although fewer in number than in 2016, there was an increase in size among the oil and gas companies and service providers that filed for bankruptcy in 2017, including Pacific Drilling, Tidewater, Seadrill, Memorial Production Partners, Vanguard Natural Resources, Bonanza Creek Energy, Rooster Energy, and Castex Energy Partners.

In contrast to previous years, many of these new filings entered bankruptcy without a prepackaged chapter 11 plan. And with respect to generation related cases, disputes with project owners were often at the heart of the case. For example, Westinghouse filed its bankruptcy case primarily to resolve up to \$8 billion in liabilities related to the construction of nuclear power plants in Georgia and South Carolina. Major points of dispute in the Westinghouse case include the amount of contingent liabilities owed to project owners and the provision of guarantees by Westinghouse’s parent, Toshiba, to project owners. Despite these disputes, in January 2018 Westinghouse announced that it had agreed to be acquired by Brookfield Business Partners for \$4.6 billion. A similar story played out in the GenOn case, where a prepetition dispute with the owner-lessors of certain sale-leaseback project subsidiaries spilled over into the bankruptcy court in the form of a ten-day trial to estimate the owner-lessors’ claims. GenOn prevailed at trial, which in turn facilitated the confirmation of GenOn’s chapter 11 plan.

Another trend that has continued in 2017 is the growing role of Houston as a venue for energy-related cases. Of the five largest energy-related cases in 2017, three were filed in Houston (Seadrill, GenOn, and Memorial Production Partners). We see this trend as likely to continue into 2018.

TAX REFORM ACT

CHANGES TO NOL RULES

Highly leveraged corporations commonly have significant NOLs, which can be of great value for tax planning purposes. The Tax Reform Act makes two changes to the use of NOLs by C corporations that may have a substantial impact on tax planning for highly leveraged corporations.

First, the Tax Reform Act changes the rules for carrying NOLs to other taxable years. Prior to the Tax Reform Act, with some exceptions, corporations could carry NOLs back for two years and forward for twenty years. Under the Tax Reform Act, NOLs arising in taxable years ending after December 31, 2017, generally cannot be carried back at all but can be carried forward indefinitely. Special rules apply to NOLs of a farming business or property and casualty insurance company.

The elimination of the NOL carryback period may be significant for many highly leveraged corporations. The ability to carry back NOLs was extremely valuable to some, allowing the corporations to receive immediate refunds of taxes paid in prior years. On the other hand, the extension of the carryforward period beyond twenty years may be of little benefit to a corporation that is struggling to survive.

Second, the Tax Reform Act imposes a new limit on NOL deductions. Prior to the Tax Reform Act, there was no general limit on the amount of NOLs that can be used to offset regular taxable income, although the amount of alternative minimum tax NOLs that can be used in a particular taxable year is generally limited to 90% of the alternative minimum taxable income for such year (subject to certain adjustments and exceptions). The Tax Reform Act limits the deduction for NOLs arising in any taxable year beginning after December 31, 2017, to 80% of taxable income in the carryforward year. The Tax Reform Act also eliminates the corporate alternative minimum tax.

This new NOL limitation potentially exposes highly leveraged corporations to increased tax liability in connection with any taxable restructuring transactions (at an effective tax rate of 4.2%, based on the corporate tax rate under the Tax Reform Act of 21%) and generally reduces the future usefulness of their NOLs.

LIMIT ON DEDUCTION FOR INTEREST EXPENSE

Prior to the Tax Reform Act, there was no general limit on the amount of taxable income that can be offset by interest deductions, although the deductibility of interest may be limited in certain specific situations. Under the Tax Reform Act, the amount of business interest expense that a taxpayer may deduct in any taxable year beginning after December 31, 2017, is generally limited to the sum of (i) the business interest income of the taxpayer for such year, (ii) 30% of the taxpayer's "adjusted taxable income" for such year, and (iii) the amount of the taxpayer's interest expense for such year on certain debt used to finance the acquisition of motor vehicles held for sale or lease. "Adjusted taxable income" for this purpose generally means the taxable income of the taxpayer computed without regard to (1) any item of income, gain, deduction, or loss which is not properly allocable to a trade or business, (2) any business interest expense or business interest income, (3) the amount of any NOL deduction, (4) the new 20% deduction for certain pass-through income, and (5) for taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

The amount of any interest deductions in excess of the limit may generally be carried forward indefinitely. Any interest deduction that is carried forward will generally be treated as a loss for purposes of Section 382 of the Code, which imposes limitations on the use of NOL carryforwards after certain ownership changes.

The limit on interest deductions under the Tax Reform Act does not apply to interest allocable to certain specified trades or businesses, including certain regulated utility businesses and certain electing real property trades or businesses. The limit also does not apply to certain low-revenue taxpayers. Special rules apply with respect to partnerships and S corporations and owners thereof. For additional discussion, please see Tax Reform Act – Interest Expense Deductions Generally Limited, below.

Interest expense can be an important source of deductions for highly leveraged corporations. Consequently, the interest limitation under the Tax Reform Act could have a significant impact on the tax liability of such corporations and should be considered when determining financing strategy. Furthermore, because the amount of the limit is based on adjusted taxable income, the impact of the limit will be exacerbated in the case of a highly leveraged corporation whose income is declining while its interest obligations are stable or increasing.

TREATMENT OF CAPITAL CONTRIBUTIONS

The House bill would have required a corporation to recognize income from its receipt of a capital contribution of money or property to the extent the fair market value of such capital contribution exceeded the fair market value of any stock issued by the corporation in exchange therefor. The House bill also would have repealed Section 108(e)(6) of the Code, under which a debtor corporation acquiring its indebtedness from a shareholder as a contribution to capital is treated as having satisfied the indebtedness with an amount of money equal to the shareholder's adjusted basis in the indebtedness. These changes proposed by the House bill, if enacted, could have significantly impacted a highly leveraged corporation's ability to restructure in a tax-efficient manner.

The Tax Reform Act did not adopt these capital contribution provisions from the House bill. The Tax Reform Act does amend Section 118 of the Code, which generally excludes contributions to capital from the income of a corporation, so that it will not apply to contributions by any governmental entity or civic group (other than any such contributions made by a shareholder as such), to contributions in aid of construction, or to contributions as a customer or potential customer. However, this provision of the Tax Reform Act is much more narrowly tailored than the capital contribution provisions of the House bill and does not raise the same general issues with respect to the restructuring of highly leveraged corporations as were raised by the capital contribution provisions of the House bill.

ENVIRONMENTAL REGULATION

Going into 2018, the power sector continues to face uncertainty regarding the future of major environmental regulations and policies that were implemented during the Obama Administration. The Trump Administration has taken significant steps to alter, repeal, or withdraw many of these regulations and policies, with the goal of significantly reducing EPA's regulatory impact on the economy, and on the power sector in particular.

President Trump issued several Executive Orders instructing EPA to review environmental regulations and suspend, revise, or replace those rules that excessively burden the economy or exceed EPA's statutory

authority. However, the process for undoing existing regulations is lengthy: it generally must follow the same notice-and-comment procedures required by the Administrative Procedure Act for issuing those regulations in the first place. Additionally, litigation inevitably follows every major EPA rulemaking. These legal challenges to EPA's regulatory and deregulatory actions interject uncertainty regarding regulatory requirements.

The Trump Administration has targeted a number of regulations and policies for repeal, modification, or replacement, including:

- **WOTUS Rule.** In June 2015, the EPA and the U.S. Army Corps of Engineers finalized a rule intended to clarify the meaning of the term "waters of the United States" or "WOTUS," which establishes the scope of regulated waters under the Clean Water Act. The rule has been challenged by numerous states and industrial groups and some environmental groups, and its effectiveness had been stayed by the Sixth Circuit pending resolution of the various litigations. On January 22, the Supreme Court issued an opinion regarding the appropriate venue for challenges to the WOTUS Rule that will vacate the stay of the rule. The rule will go into effect after the ruling becomes effective, unless and until the Agencies take final action on proposed rules that would (1) delay implementation of the rule or (2) rescind the WOTUS Rule entirely. Regardless of any interim action they may take, the Agencies have stated that they intend to propose a replacement for the WOTUS Rule in May 2018.
- **Climate Regulations for New Power Plants.** In October 2015, EPA finalized new source performance standards ("NSPS") for greenhouse gas ("GHG") emissions from new, modified, and reconstructed power plants under Section 111(b) of the Clean Air Act. The GHG NSPS are a legal prerequisite for the Clean Power Plan, which sets GHG emission standards for existing power plants under Section 111(d) of the Act. Numerous state and industry groups are challenging the rule, while other states, environmental and nonprofit groups, and some utilities have intervened on behalf of EPA to help defend the rule. Oral argument had been scheduled for April 2017 in the U.S. Court of Appeals for the D.C. Circuit; however, the case was held in abeyance when EPA initiated its review of the rule. EPA has not yet provided a timeline for action pursuant to its ongoing review of the GHG NSPS. Should the Trump Administration decide to overturn or withdraw the rule, or to let it remain in place but stop defending it in court, this could impact the future of both the GHG NSPS and the Clean Power Plan.
- **The Clean Power Plan.** In October 2015, EPA finalized performance standards for GHG emissions from existing power plants under Section 111(d) of the Clean Air Act. Commonly referred to as the Clean Power Plan, these standards were the centerpiece of the Obama Administration's climate policy. Numerous state and industry groups are challenging the rule, while other states, environmental and nonprofit groups, and some utilities have intervened on behalf of EPA to help defend the rule. The U.S. Supreme Court in February 2016 stayed the rule, pending resolution of these challenges. In April 2017, the U.S. Court of Appeals for the D.C. Circuit held the cases in abeyance, pending EPA's reconsideration of the rule. EPA proposed a rule in October 2017 that would repeal the Clean Power Plan, and in December 2017 it published an advance notice of proposed rulemaking to solicit input on a possible replacement rule, should the Clean Power Plan be repealed or overturned in court.
- **Regional Haze Rule.** In January 2017, EPA finalized revisions ("Revision Rule") to the Regional Haze Rule, a Clean Air Act program that aims to improve visibility, or visual air quality, in national parks and wilderness areas across the country. The Regional Haze Rule requires that states, in coordination with the federal government, develop and implement air quality protection plans every ten years to reduce

the pollution that causes visibility impairment. The Revision Rule is a double-edged sword as it provides a much needed extension of the deadline for states to submit implementation plans for the second planning period from 2018 to 2021, but also memorializes unlawful interpretations that greatly expand the scope of the visibility program requirements. The Revision Rule is currently in effect. In March 2017, several states, utility companies, environmental organizations, and the U.S. Chamber of Commerce filed petitions for review of the rule in the U.S. Court of Appeals for the District of Columbia Circuit. That litigation is ongoing. Additionally, industry groups filed petitions for reconsideration of the rule, which are still pending before EPA. On January 17, 2018, EPA confirmed by letter that it intends to “revisit” aspects of the Revision Rule, including the Reasonably Attributable Visibility Impairment and Federal Land Manager consultation provisions.

- **NSR Reform.** New Source Review (“NSR”) is a general term for EPA’s preconstruction permitting requirements under the Clean Air Act. New major stationary sources and major modifications at existing sources must obtain air quality permits before beginning construction. In light of recent federal court cases that have caused uncertainty in what sources must do to comply with NSR preconstruction requirements, EPA in December 2017 issued a memorandum announcing that it would review its NSR regulations, with a focus on making improvements and clarifications to the implementing regulations, providing greater technical support and oversight to the states that administer the NSR program, and evaluating EPA’s enforcement of its requirements. This is consistent with EPA’s efforts to streamline regulatory permitting requirements for manufacturing and other types of facilities. This memorandum also explained how EPA plans to approach the calculation of potential increases in emissions from new projects, and how it will exercise—or, in some cases, decline to exercise—its enforcement authority under the NSR program.
- **NEPA Reform.** The National Environmental Policy Act (“NEPA”) requires projects that need federal agency approval to first assess the project’s anticipated environmental impacts, and give the public the opportunity to comment on that project’s environmental impact. NEPA is administered jointly by any federal agency that participates in the permitting for a particular project, and each agency has its own NEPA implementing regulations. NEPA review at each agency has long been the cause of undue delay on proposed infrastructure projects, with additional delays added by environmental challenges to approved projects. As directed by President Trump’s Executive Order to review regulations that potentially burden the development of domestic energy sources, several environmentally focused agencies—including the Department of Energy, Department of Interior, Department of Commerce, and U.S. Forest Service—are reviewing their respective NEPA regulations, guidance documents, and policies, in an effort to streamline and expedite permitting. Those reviews are ongoing, and action is expected by each agency throughout 2018.

As expected, action by the Trump Administration on these and other regulatory requirements has been met by fierce opposition by the environmental community and certain states. The Trump Administration has been able to reverse Obama-era changes in existing environmental programs through rescission of administrative guidance and modification of enforcement practices. However, as discussed above, the most significant regulatory changes must go through a longer process, and it will likely take several years before the dust settles on the Trump Administration’s environmental regulatory reform efforts.

FERC

Introduction

From February 3 through August 10, 2017, the Federal Energy Regulatory Commission (FERC or Commission) lacked the three-Commissioner quorum necessary to conduct certain types of business, such as approving or rejecting significant projects and resolving contested proceedings. On August 8, Neil Chatterjee, most recently energy policy advisor to Senate Majority Leader Mitch McConnell, was sworn in, and on August 10 was elevated to Chairman. Also on August 10, Robert F. Powelson—formerly of the Pennsylvania Public Utility Commission and past president of the National Association of Regulatory Utility Commissioners—joined Chairman Chatterjee and remaining Commissioner Cheryl LaFleur in reconstituting the quorum lost on February 3, 2017. The Commission promptly began work on a substantial backlog of proceedings and issued its first orders on August 15. Monthly open Commission meetings resumed in September. Commissioner Richard Glick—previously general counsel to Democrats on the Senate Energy and Natural Resource Committee—was subsequently sworn in on November 29, 2017, and Kevin McIntyre—previously a partner at the law firm of Jones Day—was sworn in and designated as Chairman on December 7, 2017.

The discussion below summarizes significant regulatory and judicial developments affecting the energy industry over the past year.

CWA Section 401 and NEPA Litigation

FERC RULING ON STATE'S WAIVER OF AUTHORITY TO ISSUE A WATER QUALITY CERTIFICATION

On September 15, 2017, as reiterated in a denial of rehearing issued November 15, 2017, FERC issued an order finding that the New York State Department of Environmental Conservation ("NYSDEC") waived its authority to issue a water quality certification under Section 401 of the Clean Water Act ("CWA") for the Millennium Pipeline Company, L.L.C.'s ("Millennium") Valley Lateral Project by failing to act before the statutorily-imposed one-year deadline. NYSDEC has appealed the decision to the U.S. Court of Appeals for the 2nd Circuit, with oral argument scheduled for January 24, 2018.

On November 9, 2016, FERC issued a certificate to Millennium authorizing the project and requiring Millennium to, among other things, file documentation evidencing that NYSDEC had issued, or waived its authority to issue, a water quality certification. Pursuant to Section 401 of the CWA, federal agencies cannot issue a permit or a license for a project that will discharge into navigable waters until an applicant has secured a state water quality certification or such certification has been waived. Millennium had filed an application for a water quality certification with NYSDEC on November 23, 2015. In response to NYSDEC notices finding the application incomplete and requesting additional information, Millennium filed supplemental information with NYSDEC on August 16 and August 31, 2016.

In response to these delays, Millennium filed with FERC a "Request for Notice to Proceed with Construction" asserting that NYSDEC had waived its authority to issue a water quality certification by failing to timely act within one year of Millennium's November 23, 2015 filing. NYSDEC opposed Millennium's request asserting that the one-year review period provided by CWA Section 401 commenced when NYSDEC received a complete application (i.e., within one year of August 31, 2016, the date NYSDEC

received Millennium's last response to NYSDEC's request for additional information). NYSDEC denied Millennium's water quality certification on August 30, 2017.

FERC determined that the plain text of the CWA, which states that the Section 401 application review period shall not exceed one year "after the receipt of such request", indicates that the one-year state agency review period begins the day the agency receives a certification application. FERC also noted that, to the extent there is ambiguity in the statutory text, the legislative history supports FERC's finding and made clear that Congress established the one-year review period to "ensure that sheer inactivity by the State . . . will not frustrate the federal application." FERC also noted that its holding in this proceeding is consistent with its prior precedent interpreting the one-year review process for water quality certification applications filed for natural gas pipeline, liquefied natural gas terminal, and hydroelectric infrastructure. Consequently, FERC rejected NYSDEC's argument that a one-year state agency review period begins when a state agency determines a water quality certification is complete and ruled that NYSDEC had waived its certification authority.

The Millennium order evinces an effort by FERC to minimize the delays associated with permitting natural gas and hydroelectric infrastructure. If upheld by the 2nd Circuit, states will no longer be able to hold the development and licensing of energy infrastructure projects in limbo by requiring applicants to continually provide additional information in support of a water quality certification application. However, while the ruling is beneficial to Millennium, it could result in more states denying water quality certifications particularly when a state agency concludes that it does not have enough information in the record to make an informed decision. Still, even if state agencies are more inclined to deny water quality certifications or impose onerous conditions on applicants as a result of FERC's decision mandating a one-year review period from the date an application is filed, timely state action enables judicial review of the state's decision to occur on a faster timeline.

D.C. CIRCUIT VACATION OF FERC PIPELINE CERTIFICATE ORDERS FOR FAILURE TO CONSIDER DOWNSTREAM GREENHOUSE GAS EMISSIONS

On August 22, 2017, the United States Court of Appeals for the D.C. Circuit issued a 2-1 opinion vacating and remanding FERC's issuance of three Natural Gas Act ("NGA") Section 7 certificates. *Sierra Club v. Federal Energy Regulatory Commission*, 867 F.3d 1357 (D.C. Cir. 2017). The majority, over a forceful dissent by Judge Brown, held that FERC failed to consider the environmental effects of greenhouse gases ("GHGs") that would be emitted by power plants to be served by the pipelines. The case involved the Southeast Markets Pipelines Project ("Project"). The Project was constructed to supply gas to various proposed and existing power plants. FERC has no role in the siting or authorization of the power plants, which are instead permitted by the Florida Power Plant Siting Board under state law. FERC issued the certificates on February 2, 2016 and by the time of the Court's decision, portions of all three pipelines had been placed in service.

The D.C. Circuit found that the Environmental Impact Statement ("EIS") underlying FERC's certificate order was inadequate because it failed either to quantitatively estimate the downstream GHGs that would result from burning the natural gas that the pipelines will transport or explain with sufficient specificity why it could not do so.

Although the Court has recently held, in a set of cases addressing LNG exports discussed below, that neither the U.S. Department of Energy ("DOE") nor FERC, when approving construction of and export from

such facilities, is required to analyze the indirect effects on regions or specific localities of upstream sourcing of gas, it nevertheless held here that FERC does need to analyze the indirect environmental effects of downstream use of gas as power plant feedstock. The Court relied heavily on the fact that the Project's "entire purpose" is to transport natural gas to electric generating plants in Florida, and that the burning of the feedstock gas will release GHGs. As a result, the Court held the significance and incremental impact of these environmental effects were reasonably foreseeable and must be considered as part of FERC's review under the National Environmental Policy Act of 1969 ("NEPA"). The Court specifically instructed FERC to consider whether the inter-agency Social Cost of Carbon is a useful tool for evaluating GHG emissions under NEPA.

The Court distinguished this case from recent cases in which it held that FERC is not required to consider the downstream effects of LNG projects permitted under Section 3 of the NGA on the basis that under Section 3, FERC is "forbidden to rely on the effects of gas exports as a justification for denying" approval. In contrast, Section 7 certification requires FERC to broadly consider public convenience and necessity, including a balancing of public benefits against adverse effects. Thus, the Court reasoned, under Section 7, FERC could deny a pipeline's request for certification based on harm to the environment, making FERC's approval the "legally relevant cause" of both the direct and indirect environmental effects of pipelines it approves.

Judge Brown dissented, arguing that the case is indistinguishable from others in which the D.C. Circuit and Supreme Court have found that when an indirect environmental effect is contingent on issuance of a license from another agency, the original agency is not required to address that effect. The dissent noted that the majority's opinion "completely omits any discussion" of the "dispositive" role Florida state agencies play in approving the construction and expansion of power plants. Taking into account the state approvals required to site and operate the power plants, the dissent reasoned that FERC's certificate orders cannot be the cause of any environmental effects of burning the natural gas and, as a result, FERC should not be required to analyze those effects.

Natural gas pipelines may face a new burden, in terms of uncertainty, expense, and delay, in developing new pipeline infrastructure to serve power plants. Although this new burden can, to an extent, be addressed through FERC's existing environmental review process, the decision nonetheless opens another avenue for costly follow-on litigation challenging FERC's analysis. The electric industry may feel similar effects, as the decision places additional pressures on the ability to obtain supply for new natural gas-fired generating facilities.

D.C. CIRCUIT DECISIONS REJECTING CHALLENGES TO DOE AUTHORIZATION OF LNG EXPORTS

In addition to FERC proceedings, the D.C. Circuit weighed in on a number of permits to export LNG issued by the DOE. On August 15, 2017, the D.C. Circuit issued an opinion rejecting Sierra Club's challenge to DOE's authorization for LNG exports from the Freeport terminal in Brazoria County, Texas. *Sierra Club v. Department of Energy*, 867 F.3d 189 (D.C. Cir. 2017). The court clarified the extent to which agencies are expected to analyze indirect environmental effects of LNG exports.

The D.C. Circuit upheld DOE's determination not to analyze the potential effects of increased gas production at a local or regional level. The court found that DOE acknowledged the potential for locally significant impacts but reasonably avoided undue speculation as to the impacts in any particular location

or region, a task that would not have provided meaningful information. The court also accepted DOE's assertion that the connection between higher natural gas prices and potential impacts from increased reliance on coal is too speculative to measure, and it rejected Sierra Club's greenhouse gas claims as "flyspecking," which would require a broad and highly uncertain analysis to resolve. Finally, the court dispensed with Sierra Club's public-interest claim by noting that the only issue Sierra Club raised was that DOE allegedly failed to thoroughly consider environmental impacts, an issue the court had already resolved in DOE's favor.

Following this decision, on November 1, 2017, the D.C. Circuit issued another decision rejecting the Sierra Club's challenges to DOE's authorizations of LNG exports from the proposed Sabine Pass, Dominion Cove Point, and Corpus Christi export terminals. *Sierra Club v. Department of Energy*, Case No. 16-1186 (Nov. 1, 2017) (Dominion Cove Point), *Sierra Club v. Department of Energy*, Case No. 16-1252 (Nov. 1, 2017) (Sabine Pass), and *Sierra Club v. Department of Energy*, Case No. 16-1253 (Nov. 1, 2017) (Corpus Christi). The D.C. Circuit's brief decision relied heavily on its August 15, 2017 decision, discussed above. In light of that decision, in the court's view, only three narrow issues required additional consideration.

First, the court found that DOE's reliance on Environmental Assessments and findings of no significant impact for the Dominion Cove Point and Sabine Pass export applications was appropriate. The court explained that its role in reviewing the agency's decision not to prepare an Environmental Impact Statement was limited to ensuring that DOE did not ignore "arguably significant consequences" of the major federal action. Second, the court concluded that DOE did not act arbitrarily or capriciously in deciding not to engage in a more localized analysis of where incremental natural gas production may occur to support LNG exports from Dominion Cove Point. Additional facts highlighted by Sierra Club did not "sufficiently pinpoint the location of additional production as to facilitate meaningful analysis, especially given the fungibility of natural gas and the existence of a national pipeline network." Finally, with respect to all three projects, the court found that DOE adequately addressed potential distributional impacts. Specifically, DOE acknowledged the potential for shifting income sources that may not prove beneficial to some segments of the economy, but ultimately found that the exports would benefit the economy as a whole and, absent stronger record evidence of negative distributional consequences, would not be inconsistent with the public interest under the NGA.

In consistently upholding DOE's environmental review process in response to concerns often raised by opponents of LNG export projects, the D.C. Circuit has provided additional certainty for LNG export applicants and resolved some concerns about delays for pending authorizations. Both developments are positive for the LNG export industry. The D.C. Circuit also made several observations in its opinions that are favorable to LNG export proponents. Among other points, the D.C. Circuit reaffirmed that the NGA contains a presumption in favor of export authorization to non-free trade agreement countries, and it reiterated the long-standing tenet that significant environmental impacts—even if they had been present in this case—would not necessarily have required a negative public interest determination, provided that other factors weighed more heavily in favor of granting the requested export authorization.

FERC ROE

On April, 14, 2017, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated and remanded orders issued by the Federal Energy Regulatory Commission (FERC) which had established a new, and lower, return on equity (ROE) for certain New England transmission owners (Transmission Owners). The D.C. Circuit's opinion clarifies that, prior to establishing a new ROE for

transmission owners under Section 206 of the Federal Power Act, FERC must *first* make an independent and separate determination that the existing rate is unjust and unreasonable.

In the underlying proceeding, and in other recent ROE cases, FERC argued that the burden of proof under Section 206 could be satisfied using a single ROE analysis. Specifically, FERC argued that if a new ROE established by FERC is below the existing ROE then, by definition, the existing ROE is unjust and unreasonable. The D.C. Circuit disagreed and held that “finding that an existing rate is unjust and unreasonable is the ‘condition precedent’ to the FERC’s exercise of its section 206 authority to change that rate.”

The D.C. Circuit’s opinion is significant because it clarifies that, under Section 206, FERC has the burden of making an explicit determination that a utility’s existing ROE is unlawful *before* it is authorized to set a new ROE. This burden cannot be met using a single ROE analysis, whereby FERC establishes a new ROE and then uses that ROE to find that the existing ROE is unjust and unreasonable. The D.C. Circuit noted that the two-step process required by Section 206 is a form of statutory protection for utilities. Without a showing that an existing rate is unlawful, FERC has no authority to impose a new rate.

The D.C. Circuit’s opinion also reinforces that the justification for any new ROE must be based on a sufficiently articulated relationship between the record evidence and the new ROE.

Enforcement

In 2017, FERC approved six settlements with enforcement targets. The largest of these was the end of the long-standing investigation of Barclays Bank for payments totaling \$135 million. FERC had initially assessed civil penalties of \$435 million against Barclays, \$15 million against an individual trader and \$1 million each against other Barclays traders. FERC alleged that Barclays and the traders engaged in a fraudulent scheme to manipulate physical electricity prices to benefit related financial swap positions. Barclays had elected to have FERC assess the penalties without an administrative hearing and pursue litigation in the District Court, as permitted by the Federal Power Act. The parties settled after the District Court of the Eastern District of California ruled that the defendants were entitled to discovery beyond the administrative record compiled by FERC during its investigation and that the defendants would be permitted to present defenses not previously raised during the FERC investigation.

FERC also approved settlements with GDF SUEZ Energy Marketing NA, Inc. (\$40,800,000 to PJM and \$41,000,000 to FERC) related to alleged manipulation of the PJM market to obtain improper lost opportunity cost credits; City Power Marketing, LLC and an individual (\$11,720,000) for alleged fraudulent transactions in the PJM market and making false or misleading statements to FERC Staff in the course of the investigation; American Transmission Company (\$205,000) related to alleged failures to obtain approval to acquire FERC-jurisdictional facilities and failures to file certain jurisdictional agreements; Westar Energy, Inc. (\$180,000) related to alleged submissions of inaccurate cost information to SPP; and Covanta Haverhill Associates L.P. (\$36,000) related to alleged failures to provide required data to ISO-NE.

Hydro Reform

On October 19, 2017, FERC issued a new “*Policy Statement on Establishing License Terms for Hydroelectric Projects*” (Policy Statement). Under its prior policy, FERC generally issued 30-year licenses for projects with minimal improvements, 40-year licenses for projects with moderate improvements, and 50-year licenses for projects with extensive improvements. The new policy provides for a 40-year default license term for all original and new hydroelectric projects located at non-federal dams, except:

- Where necessary to coordinate license terms of projects located in the same river basin;
- In accordance with an explicitly agreed upon and generally supported comprehensive settlement (provided the settlement term does not conflict with the coordination of license terms for projects located in the same river basin); and
- In connection with an applicant's request for a longer license term, supported by "significant measures" expected in the license or voluntarily undertaken in the prior license term (provided the longer term requested by the applicant is consistent with the coordination of license terms for projects located in the same river basin).

The Policy Statement does not directly address whether FERC will maintain its prior policy of generally providing 50-year terms for original licenses. However, certain examples of "significant measures" in the Policy Statement suggest that the activities required to construct a new hydroelectric project requiring an original license would warrant a license term beyond the 40-year default. Examples of "significant measures" identified in the Policy Statement include the construction of pumped storage facilities, fish passage facilities, fish hatcheries, substantial recreation facilities, dams, and powerhouses.

Separately, the Commission identified, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, a number of hydropower regulations and policies that may burden the development or use of domestically-produced hydropower. Changes to existing regulations and policies that may be implemented pursuant to FERC's regulatory review include eliminating the Integrated Licensing Process as the default licensing process; eliminating the requirement to prepare a draft license application or preliminary licensing proposal; and reducing certain procedural timelines associated with Integrated Licensing Process.

Resiliency NOPR

In January 2018, FERC terminated the proceeding it had initiated in late 2017 to address the Proposed Rule on Grid Reliability and Resilience Pricing (Pricing Rule) submitted to FERC by the Secretary of Energy.

The Pricing Rule, if adopted, would have directed ISOs and RTOs to ensure, through their FERC-approved tariffs, that "eligible grid reliability and resiliency resources" be "fully compensated for the benefits and services [they provide] including reliability, resiliency, and on-site fuel assurance . . . and a fair return on equity." To qualify as an eligible grid reliability and resiliency resource under the Pricing Rule, a generator had to have a 90-day fuel supply on-site to support operation during emergencies, extreme weather, or disasters and not be subject to cost-of-service rate regulation by any state or local authority, among other criteria.

In the January order, FERC noted the importance of grid resilience, but the Commissioners voted unanimously to terminate the pending proceeding on the Pricing Rule due to its failure to satisfy the "clear and fundamental legal requirements under section 206 of the [Federal Power Act]." Concurrent with terminating its consideration of the Pricing Rule, though, FERC initiated a new proceeding to evaluate resilience issues in RTOs/ISOs and to determine whether further action is warranted. Unlike the Pricing Rule, which focused on a resource's availability of secure on-site fuel, the new proceeding will encompass a broad range of topics impacting resilience. In this new proceeding, FERC expects to consider characteristics such as wholesale market design, transmission planning, mandatory reliability standards, emergency action plan development, inventory management, and routine system maintenance.

FERC established three specific goals for its new proceeding. First, the proceeding will seek a common definition of grid resilience. Second, FERC intends to develop an understanding of how each RTO/ISO assesses and addresses resilience in its footprint. To this end, the Commission has requested a broad range of information from the RTOs/ISOs regarding identification of threats to grid resilience, to be submitted in March 2018. Third, upon analysis of the information submitted by the RTOs/ISOs and interested third parties, FERC will evaluate whether further action regarding grid resilience is warranted. FERC has not identified a specific timeline for final action on grid resilience.

State Law and Policy Incentives

The past year saw new efforts by state governments to either advance or defend measures supportive of nuclear generation resources, which in many organized energy markets have experienced declines in financial viability arising from continued low natural gas prices and correspondingly low wholesale electricity prices. States have largely styled their programs as providing compensation for the environmental—or environmental and fuel-diversity—attributes of nuclear-generated electricity and compensate nuclear resources through a per-megawatt-hour credit. States have argued that these credits are similar to long-established renewable energy credit programs, although challengers have argued that certain programs' use of a projected market price in setting the value of the credits—as is currently done to reduce credit values from the so-called Social Cost of Carbon in New York and Illinois—renders these programs more analogous to the contracts-for-differences that the Supreme Court found in *Hughes v. Talen Energy Marketing, LLC* to intrude on FERC's authority under the Federal Power Act by impermissibly setting wholesale capacity rates. Developments in 2018 are likely to further define the permissible extent of state programs.

New York: New York was the first mover in 2016 when the Public Service Commission promulgated the Zero Emission Credit ("ZEC") program. The ZEC program formally took effect in April of 2017, and on July 25, the U.S. District Court for the Southern District of New York dismissed a series of legal challenges. The challengers—interest groups associated with, and entities active as, independent power producers—promptly appealed the decision to the U.S. Court of Appeals for the Second Circuit.

Illinois: Illinois's ZEC program, passed as legislation in December of 2016, became effective in June 2017. Like New York's program, it found vindication in federal court this summer, when the U.S. District Court for the Northern District of Illinois dismissed cases brought by retail customers and by independent power producers. The plaintiffs promptly appealed to the U.S. Court of the Appeals for the Seventh Circuit, and oral arguments in the consolidated case were held on January 3, 2018. The court subsequently ordered supplemental memoranda to address (1) whether to defer to FERC's primary jurisdiction; (2) whether Supreme Court precedent allows plaintiffs to succeed in pursuing an injunction if the ZEC law is found to be unconstitutional; and (3) whether Supreme Court antitrust precedent permits only participants in the wholesale electric markets to sue for relief.

Connecticut: On October 31, 2017, Connecticut created a state-sponsored zero-carbon solicitation and procurement program. The program requires the state Department of Energy and Environmental Protection and the Public Utilities Regulatory Authority to assess (1) the current economic conditions facing the nuclear generating facilities within ISO-New England; (2) the projected future economic conditions of the facilities; and (3) the potential impacts from early (prior to July 1, 2027) retirement of the facilities on (a) electric markets, fuel diversity, energy security and grid reliability; (b) Connecticut's greenhouse gas emissions; and (c) the state, regional and local economy. The study is due to the General

Assembly by February 1, 2018. If the study “demonstrate[s] that action is necessary,” then the Commissioner of Energy and Environmental Protection may issue one or more solicitations for zero-carbon energy sources, which may include nuclear stations within ISO-New England, hydropower resources, certain other renewable energy sources, and energy storage systems, up to a total of 12 million megawatt hours annually, which is equivalent to more than 70% of the electricity generated by Dominion Nuclear Connecticut, Inc.’s two-unit Millstone Power Station in 2016

New Jersey: Companion bills to create a Nuclear Security Diversity Program died prior to floor votes in both houses of the New Jersey legislature at the end of the 2016-2017 legislative session. A nearly identical measure has already been introduced, however, for the 2018-2019 session. The proposal would create nuclear diversity certificates (“NDCs”), analogous to ZECs, for each megawatt-hour of electricity produced by eligible nuclear power plants. To qualify for payments under the NDC program, a nuclear power facility must demonstrate either that it is cash-negative on an annual basis, or that it is not covering its costs, including its cost of capital. The facility must also certify that it would cease operation within three years, absent a material financial change. The value of NDCs would be determined based on funds raised by a per-kilowatt-hour charge on retail electric sales and the total quantity of qualifying nuclear-generated megawatt-hours. The new bill is currently before the Senate Budget and Appropriations Committee.

Ohio: In Ohio, legislators introduced the Ohio Clean Energy Jobs Act, which would add language to Ohio’s electricity statutes to expressly recognize environmental and fuel diversity benefits of nuclear power by establishing zero-emissions nuclear credits from zero-emissions nuclear resources. Electric distribution utilities with one or more zero-emissions nuclear resources within their certified territories would be required to purchase credits, and any electric distribution utilities in the same holding company system would be required to jointly participate. The legislation also provides criteria—based on environmental benefits to Ohio—that could conceivably allow out-of-state resources to qualify, and it provides caps for rate impacts. In features aimed more at preserving employment than securing environmental or fuel-diversity benefits, any utility with a corporate headquarters in Ohio must maintain its headquarters in the state during any period in which it receives credits, and zero-emissions nuclear resources would be required to maintain employment levels commensurate with those at similar facilities. The proposal is currently pending in the House Public Utilities Committee.

SMALL SCALE LNG

Small-scale liquid natural gas (“LNG”) projects drew closer attention from regulators and legislators in 2017. Recent efforts have focused on streamlining regulatory approval for those projects proposing to export less than 0.14 billion cubic feet per day (Bcf/d) (51.1 Bcf/year) of natural gas from the U.S. to countries with which the U.S. does not have a free trade agreement in place.

The Department of Energy has undertaken an effort to accelerate the authorization process for small-scale exports of natural gas and LNG. On September 1, 2017, the DOE published a notice of proposed rulemaking to revise its regulations by providing for expedited approval of certain applications to authorize the export of small quantities of natural gas, including LNG, to countries with which the U.S. has not entered into a free trade agreement. To take advantage of this process, the export applicant would need to show that its application is for “small-scale natural gas exports,” meaning (1) it proposes to export no more than 0.14 Bcf/d of natural gas, and (2) approval would not require DOE to prepare an

environmental impact statement or environmental assessment under the National Environmental Policy Act of 1969. The proposed amendments are pending final action by the agency.

Congress also took up the issue of small-scale LNG exports through proposed legislation which would essentially codify DOE's proposed rule, insulating the streamlined process for small-scale exports from future presidential administration's regulatory preferences. For example, H.R. 4606 - Ensuring Small Scale LNG Certainty and Access Act, H.R. 4370 - Small Scale LNG Access Act of 2017, and S. 1981 - Small Scale LNG Access Act of 2017 all provide that applications to export 0.14 Bcf/d or less of natural gas be deemed in the public interest and granted without modification or delay. Although none of these bills has moved beyond committee-level consideration, industry commenters have praised the effort to reduce the regulatory burden on smaller projects.

Even absent a streamlined process, to date DOE has issued export authorizations to eight "small-scale" exporters, including to Carib Energy (USA) LLC (0.04 Bcf/d), American Marketing LLC (0.008 Bcf/d), Emera CNG, LLC (0.008 Bcf/d), Floridian Natural Gas Storage Company, LLC (0.04 Bcf/d), Air Flow North American Corp. (0.002 Bcf/d), Flint Hills Resources, LP (0.01 Bcf/d), Carib Energy (USA), LLC (0.004 Bcf/d), and Eagle LNG Partners Jacksonville II LLC (0.01 Bcf/d). However, only one of these applications, Eagle LNG Partners Jacksonville II LLC, was approved in 2017. Development of future small-scale LNG projects may be accelerated if the regulatory changes proposed by the DOE and Congress are codified.

CFTC

Two new Commissioners joined the U.S. Commodity Futures Trading Commission ("CFTC") in 2017. The first, Brian D. Quintenz, a Republican, was sworn in on August 15, 2017 for the remainder of a five-year term expiring in April 2020. Before the CFTC, Commissioner Quintenz was Managing Principal and Chief Investment Officer of Saeculum Capital Management, a registered Commodity Pool Operator. Earlier in his career Commissioner Quintenz worked as an analyst for Hill-Townsend Capital LLC, a financial-sector focused hedge fund, and as a policy advisor to Congresswoman Deborah Pryce. The second new Commissioner, Rostin Behnam, a Democrat, was sworn in on September 6, 2017 for a term expiring in June 2021. Commissioner Behnam most recently served as senior counsel to Senator Debbie Stabenow, having previously practiced law in New York City and worked at the New Jersey Office of the Attorney General.

The CFTC made few changes or additions to its regulations implementing the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"). It has not yet acted on its December 2016 re-proposal to adopt position limits for certain futures, options and economically equivalent swaps, or on its December 2016 proposal to adopt capital requirements for swap dealers and major swap participants that are not subject to the capital rules of a prudential regulator such as the Federal Reserve or the Federal Deposit Insurance Corporation.

The CFTC did extend the sunset date of the de minimis threshold used to determine whether an entity entering into non-hedging swaps must be regulated as a swap dealer. That threshold has been set, since the adoption of the swap dealer regulations, at a gross notional amount of \$8 billion over the preceding 12-month period and was set to decrease to \$3 billion on December 31, 2018. That sunset date has now been extended to December 31, 2019 to allow the CFTC additional time to analyze the issue.

ERCOT/TEXAS

It was a busy year in the Electric Reliability Council of Texas (“ERCOT”) and at the Public Utility Commission of Texas (“PUCT”). The Commission continued dealing with various applications to acquire Oncor Electric, the largest transmission and distribution utility in Texas, as part of the bankruptcy proceedings for Energy Future Holdings (“EFH”). Resource adequacy once again became a topic of debate in ERCOT, having largely fallen off the radar for a few years. The PUCT also found itself dealing with the proposed move of Lubbock Power & Light into ERCOT from the Southwest Power Pool (“SPP”), jurisdictional implications for ERCOT of the opening Mexican power market, a new rule requiring utilities to file rate cases on a set schedule, changes to the handling of applications for transmission line licenses, and the anticipated effects on electricity rates of the Tax Cuts and Jobs Act of 2017. Amidst all of these issues, the PUCT saw the replacement of two of its three commissioners and the resignation of its Executive Director.

DISPOSITION OF ONCOR

As 2017 began, NextEra Energy Inc.’s (“NextEra”) application for approval of its proposed \$18.4 billion acquisition of Oncor Electric Delivery Co. (“Oncor”) was pending at the PUCT. NextEra’s bid was the second attempt to acquire Oncor as part of the bankruptcy of Oncor’s parent, Energy Future Holdings Corp. Hunt Consolidated Inc. had previously sought approval from the PUCT in 2016. The PUCT had approved that transaction, but had imposed conditions that Hunt’s investors had found too onerous, causing the deal to fall apart. That opened the door for the NextEra application.

In April 2017, the PUCT rejected NextEra’s application finding that it was not in the public interest, pointing in part to the lack of certain ring-fencing measures the commissioners believed were important to protect Oncor’s credit rating. In July 2017, Berkshire Hathaway Energy (“Berkshire”) won approval at the bankruptcy court to buy Oncor in an \$18.1 billion deal. That same month Elliott Management Corp. (“Elliott”) announced it was seeking approval at the bankruptcy court for a proposed \$18.5 billion deal to purchase Oncor.

Although Berkshire, the PUCT staff, and other stakeholders announced a settlement of issues for a PUCT approval, the deal ultimately fell through. In August, press reports indicated that Elliott had acquired enough EFH debt to block approval of the Berkshire transaction. That same month, Sempra Energy (“Sempra”) announced that it was proposing an \$18.8 billion bid, which the bankruptcy court approved. Sempra filed for PUCT approval in October 2017. In December 2017, a majority of the parties to the Sempra application proceeding at the PUCT announced a settlement; but two parties—Texas Legal Services Center, a low-income legal services group, and the Energy Freedom Coalition of America, a group that includes SolarCity, a wholly-owned subsidiary of Tesla—have refused to join the settlement, and the matter is set for a hearing in February 2018.

RESOURCE ADEQUACY

For several years, resource adequacy was almost the single issue in ERCOT. Sustained low reserve margin projections ignited a debate over whether ERCOT should abandon its energy only market structure and adopt some form of capacity market. Ultimately, projected reserve margins increased and, while some measures were taken such as the 2014 incorporation of an operating reserves demand curve (ORDC), the serious push for a capacity market receded.

The past year, however, has seen the announcement of a number of key generation retirements. Luminant announced the retirement of three coal plants—Monticello, Big Brown, and Sandow—that by themselves total over 4 GW of generating capacity. In December, ERCOT released its “Capacity, Demand, and Reserves report (the “CDR”). This latest CDR projects a 9.3 percent planning reserve margin for summer 2018. That number is projected to increase to 11.7 percent by summer 2019. The latest CDR represents a 7,200-megawatt (MW) decrease in projected overall generation capacity for summer 2018 compared to the same projection in May 2017. ERCOT will release its final “Seasonal Assessment of Resource Adequacy (SARA)” in March 2018. The SARA is a scenario-based seasonal forecast. The large retirements and the lower projected reserve margins have sparked some renewed calls for price reform of some sort.

In May, Professor William Hogan of Harvard and Susan Pope of FTI Consulting co-authored a report entitled, “Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT.”⁴ The report prompted the PUCT, on May 22nd, to open Project No. 47199, *Project to Assess Price-Formation Rules in ERCOT’s Energy-Only Market*. Several rounds of comments have been received in the new project and additional comments are due on January 19th in the related Project No. 41061, *Rulemaking Regarding Demand Response in the Electric Reliability Council of Texas (ERCOT) Market*.

In October, the PUCT directed ERCOT and the independent market monitor (“IMM”) to undertake a cost-benefit study of incorporating real-time co-optimization (“RTC”) and/or marginal losses into ERCOT’s wholesale market. ERCOT and the IMM have estimated that the requested study will be available near the end of the first quarter of 2018.⁵

MEXICAN POWER MARKET REFORM

As the Mexican power market has continued to open, the PUCT has grappled with how those reforms might affect the Texas power market and, in particular, the peculiar jurisdictional status of ERCOT. Recent proposals to interconnect the Mexican and U.S. grids in Arizona as well as proposals to connect the main Mexican grid to the grid in Baha California (which is already connected to the California grid), have raised the possibility that power could be transmitted from a U.S. state other than Texas, into Mexico, and then back into ERCOT. Such a transaction might be considered a transaction in interstate commerce that could subject ERCOT to FERC jurisdiction. The PUCT Chairman has expressed concern regarding such transactions⁶ and the PUCT is currently in discussions with FERC regarding how to address such potential transactions.

LUBBOCK POWER & LIGHT MOVE TO ERCOT

In September 2015, Lubbock Power and Light (“LPL”) announced its intention to integrated into the ERCOT market, and in the summer of 2016 the PUCT requested that ERCOT and SPP study the impacts of

⁴ William W. Hogan, Harvard University & Susan L. Pope, FTI Consulting, May 9, 2017, *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, available at https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

⁵ Public Utility Commission of Texas Report Regarding Electric Reliability Council of Texas, Inc.’s Proposed Plan for Conducting Benefits Analyses, December 7, 2017, available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47199_62_963678.PDF.

⁶ Public Utility Commission of Texas Memorandum Regarding Open Meeting of November 17, 2017, available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/46665_9_961791.PDF.

possible integration. In February 2017, ERCOT and SPP updated the PUCT on the process for developing the study scope. In June and July, SPP and ERCOT submitted analyses regarding the impacts of LPL's departure from SPP and integration into ERCOT.

On September 1, 2017, LPL filed an application for authority to connect a portion of its system with ERCOT. LPL suggests that there will be significant benefits to ERCOT from LPL's integration. LPL suggests that the proceeding must be resolved quickly in order to have the necessary facilities built to interconnect its load by May 2021 (when its power supply agreement expires). Separate future proceedings will determine what utilities will build the facilities and seek CCN approval. In rebuttal testimony, LPL has indicated that the portion of its load to be integrated into ERCOT should be transitioned into competition. The matter is set for hearing the week of January 15, 2018.

RESPONSE TO CORPORATE TAX RATE REDUCTION

As 2017 came to a close, Congress passed the Tax Cuts and Jobs Act (TCJA), which lowers the maximum corporate tax rate from 35% to 21%. Utility regulators around the country immediately began considering whether and how they can quickly reflect the lower corporate tax rate in the rates charged by the utilities they regulate. The PUCT is no exception. On January 11, 2018, Chairman Walker requested that the PUC Staff open a project in which information can be filed by Texas utilities related to the impact of the reduction in the corporate tax rate. Chairman Walker indicated her preference for a project of limited scope, in which financial information would be accumulated, but in which there would not be an opportunity for comment on whether and how the PUCT might address the lower tax rate. Chairman Walker indicated there would be an opportunity for such comments at a later date.

On January 12, 2018, PUCT Staff opened Project No. 47945, *Proceeding to Investigate and Address the Effects of the Tax Cuts and Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies*.⁷ The Staff have asked utilities to file, no later than January 18th, responses to 11 requests for information regarding their future tax liability. The Staff's request references a complaint filed on December 21, 2017, at the Kentucky Public Service Commission by the Kentucky Industrial Utility Consumers, Inc. requesting an order directing Kentucky utilities to establish a regulatory liability to track the difference between the tax expenses built into their rates and the new, lower tax rate.

PROPOSED NEW RATE CASE RULE

In August 2017, the PUC established a rulemaking, Project No. 47545, *Rulemaking Proceeding to Establish Filing Schedules for Investor-Owned Electric Utilities Operating Solely Inside ERCOT*. In the project, the PUCT has proposed the adoption of new 16 Tex. Admin. Code § 25.247, relating to rate case filing requirements. The proposed rule would establish a filing schedule for ERCOT electric utilities (below), although the rule contains off-ramps based on a utility's annual earnings monitoring report (EMR). The rule preserves the right of the Commission to call a utility in for a rate case at any time.

⁷ Public Utility Commission of Texas Memorandum Regarding Project No. 47945, December 12, 2017, available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/47945_2_966783.PDF.

TEXAS-NEW MEXICO POWER	August 31, 2018
AEP TEXAS	April 1, 2019
CENTERPOINT ENERGY HOUSTON ELECTRIC	July 1, 2019
WIND ENERGY TRANSMISSION TEXAS	October 1, 2019
CROSS TEXAS TRANSMISSION	February 3, 2020
SHARYLAND UTILITIES LP AND SHARYLAND DISTRIBUTION SERVICES LLC	July 1, 2020
LONE STAR TRANSMISSION	September 1, 2020
ELECTRIC TRANSMISSION TEXAS	February 1, 2021
ONCOR ELECTRIC DELIVERY COMPANY	October 1, 2021

Comments to the proposed rule were set to be accepted in December 2017 (initial comments) and January 2018 (reply comments), with the Proposal for Adoption anticipated for May 2018.

CCN "TERM LIMIT"

There is a current proposal 43519/47522 at the PUCT to change the Commission's standard preliminary order governing applications for a Certificate of Convenience and Necessity ("CCN"). The preliminary order establishes the issues to be addressed in CCN cases. The proposal would alter some of the issues to be considered and, most notably, would propose a time limit for the validity of a CCN. An initial proposal was issued by PUCT Staff in Project No. 43519.⁸ The current proposal, under consideration in Project No. 47522, *Revisions to Standard Preliminary Order for CCN Applications*, is for a 7-year time limit for an electric utility to construct its facilities before having to reapply for the CCN.

The impetus for this proposal stemmed from Oncor's successful application near the turn of the century for a CCN to build a transmission line. Oncor based the need for this transmission line on load-growth in a particular area, but the expected growth did not materialize. Eighteen years later, Oncor determined that load-growth in the area was now substantial enough to justify the transmission line for which it had received the CCN 18 years prior. When Oncor began construction of the transmission line, a number of landowners complained, arguing that the CCN should not be valid for an unlimited period of time. The

8 Delegation of Authority Generally to Commission Advising, Project No. 43519; Modification to Standard CCN Order of Referral and Preliminary Order; August 17, 2017 Open Meeting, Item 53.

Commission reluctantly held that the original CCN was not limited in time, but initiated a rulemaking to consider limits on future CCNs. The rulemaking is still under consideration and has not yet been adopted.

PUC PERSONNEL CHANGES

The Public Utility Commission of Texas (“PUC”) has had three significant staff changes since the beginning of 2017. Specifically, the PUC has two new Commissioners and has received the resignation of its Executive Director.

In September 2017, Governor Abbott appointed DeAnn T. Walker as the new Chairman of the PUCT after the previous Chairman, Donna Nelson, announced that she was stepping down. Before her appointment, Ms. Walker served as the Senior Policy Advisor to Governor Abbott on matters related to regulated industries. Her prior experience includes a nearly 20-year career at CenterPoint Energy as well as serving for nearly a decade as an assistant general counsel and later administrative law judge at the PUCT.

Arthur D’Andrea was appointed to the PUCT in November of 2017 for a six-year term. Mr. D’Andrea was appointed following the departure of Commissioner Ken Anderson whose six-year term had expired in August of 2017. Prior to his appointment, Mr. D’Andrea was an assistant general counsel for the Office of Governor Greg Abbott and previously served as an assistant solicitor general for the Office of the Attorney General of Texas.

Additionally, Brian Lloyd, the Executive Director of the PUC since the end of 2010, announced that he would resign from the agency, effective March 1, 2018. There has been no announcement about who will take his place, and there is no indication as to when that announcement will be made.

TAX REFORM ACT

The Tax Reform Act includes major changes to many areas of the Code impacting taxpayers who are engaged in the energy sector, most of which are effective January 1, 2018. This section gives a broad overview of the Tax Reform Act’s impact on the entire energy sector. How the Tax Reform Act will affect specific industries is discussed in multiple sections above (see Regulated Utilities, Renewables, Master Limited Partnerships and YieldCos, Project Finance, and Bankruptcy Developments in the Energy Sector).

Corporate Tax Rate Lowered

One major change is the reduction of the corporate income tax rate. The Tax Reform Act permanently reduces the corporate tax rate to a flat 21% beginning in 2018 (reduced from the prior maximum rate of 35%). When combined with the maximum 20% tax rate on qualified dividends paid by a C corporation to an individual shareholder, the effective tax rate on income of a C corporation distributed to its shareholders will be 36.8% (or 39.8% after the 3.8% Medicare tax on dividends).

UP TO 20% DEDUCTION FOR QUALIFIED BUSINESS INCOME OF PASS-THROUGH ENTITIES

Pass-through entities are also commonly used in the energy sector. Beginning in 2018, the Tax Reform Act provides for up to a 20% deduction for individuals for qualified business income earned through pass-through entities, such as partnerships and limited liability companies taxed as partnerships, S corporations, disregarded entities and trusts. This deduction (when combined with the reduction in individual income tax rates) theoretically would result in an effective maximum marginal tax rate of 29.6%

(plus unearned income Medicare tax, where applicable), for taxpayers entitled to the full 20% deduction. However, the deduction is subject to several limitations that are likely to materially limit the deduction for many taxpayers. These limitations include the following:

- Qualified business income does not include Code Section 707(c) guaranteed payments for services, amounts paid by S corporations that are treated as reasonable compensation of the taxpayer, or, to the extent provided in regulations, amounts paid or incurred for services by a partnership to a partner who is acting other than in his or her capacity as a partner.
- Qualified business income does not include income involving the performance of services (i) in the fields of, among others, health, law, accounting consulting, financial services, brokerage services, or any trade or business where the principal asset of such trade or business is the reputation or skill of one or more of its employees or owners, or (ii) consisting of investing or investment management, trading, or dealing in securities, partnership interests or commodities.
- Qualified business income includes (and, thus, the deduction is applicable to) only income that is effectively connected with the conduct of a trade or business within the United States.
- The deduction is limited to 100% of the taxpayer's combined qualified business income (e.g., if the taxpayer has losses from certain qualified businesses that, in the aggregate, exceed the income generated from other qualified businesses, the taxpayer's deduction would be \$0).
- The deduction is limited to the greater of (i) 50% of the W-2 wages paid with respect to the trade or business or (ii) the sum of 25% of the W-2 wages paid with respect to the trade or business and 2.5% of the unadjusted basis, immediately after acquisition, of all depreciable property used in the qualified trade or business.

This last limitation does not apply to income earned through publicly traded partnerships (discussed further above) or to taxpayers whose taxable income does not exceed \$315,000 (in the case of taxpayers filing a joint return) or \$157,500 otherwise.

This 20% deduction is scheduled to expire after 2025 under the Tax Reform Act, unless renewed before then.

INTEREST EXPENSE DEDUCTIONS GENERALLY LIMITED

Given the capital-intensive nature of the sector, changes to interest deductibility will impact financing costs for the sector. Subject to certain exceptions discussed below, beginning in 2018, the Tax Reform Act generally limits the annual deduction for business interest expense to an amount equal to 30% of the "adjusted taxable income" (as defined in the following paragraph), plus the business interest income, plus the floor plan financing interest (interest on debt secured by the inventory of auto dealers), if any, of the taxpayer for the taxable year. The amount of any business interest not allowed as a deduction for any taxable year may be carried forward indefinitely and utilized in future years, subject to this and other applicable interest deductibility limitations and to certain restrictions applicable to partnerships.

"Adjusted taxable income" generally means the taxable income of the taxpayer computed without regard to any item of income, gain, deduction, or loss which is not properly allocable to a trade or business and by adding back (1) any business interest expense or business interest income, (2) the 20% deduction for pass-through income, (3) the amount of any net operating loss deduction and (4) for taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

There are several exceptions to this new limitation on interest deductibility, including the following:

- At the taxpayer's election, the limitation does not apply to interest incurred by the taxpayer in any real property development, redevelopment, construction, reconstruction, acquisition, conversion, rental, operation, management, leasing, or brokerage trade or business;
- The limitation does not apply to interest incurred by taxpayers in the trade or business of the furnishing (which includes generation, transmission and/or distribution) or sale of (1) electrical energy, water, or sewage disposal services, (2) gas or steam through a local distribution system, or (3) transportation of gas or steam by pipeline, if the rates for such furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof, by any agency or instrumentality of the United States, by a public service or public utility commission or other similar body of any State or political subdivision thereof, or by the governing or ratemaking body of an electric cooperative; and
- The limitation does not apply to taxpayers whose annual gross receipts do not exceed \$25 million under the test set forth in Section 448(c) of the Code.

Special rules apply in the case of partnerships. The limitation on the deduction is determined at the partnership level, and any deduction available after applying such limitation is included in the partners' nonseparately stated taxable income or loss from the partnership. Any business interest that is not allowed as a deduction to the partnership for the taxable year is not carried forward by the partnership but, instead, is allocated to each partner as "excess business interest" in the same manner as nonseparately stated taxable income or loss of the partnership. The partner may deduct its share of the partnership's excess business interest in any future year but only against excess taxable income attributed to the partner by such partnership. The "excess taxable income" with respect to any partnership is the amount which bears the same ratio to the partnership's adjusted taxable income as (a) the excess of (i) 30% of the adjusted taxable income of the partnership, over (ii) the amount (if any) by which (x) the business interest expense, minus the floor plan financing interest, exceeds (y) the business interest income of the partnership bears to (b) 30% of the adjusted taxable income of the partnership. A partner's share of excess taxable income is determined in the same manner as nonseparately stated income and loss. Any disallowed interest expense allocated to a partner immediately reduces the partner's basis in its partnership interest, but any amounts that remain unused upon disposition of the interest are restored to basis immediately prior to disposition.

REPEAL OF THE CORPORATE ALTERNATIVE MINIMUM TAX

The repeal of the corporate AMT. The AMT imposed a minimum tax of 20% on certain corporations and restricted the use of the certain credits (for example, research and development credits and PTCs) to offset such tax. Repeal of the AMT ensures that these credits will continue to be fully monetizable by most investors under the lower corporate tax rate (unless the taxpayer is subject to the BEAT provisions, as discussed below).

REPEAL OF TECHNICAL TERMINATIONS OF PARTNERSHIPS

The Tax Reform Act permanently repeals the partnership technical termination rule contained in Section 708(b)(1)(B) of the Code. This repeal allows partnerships to continue—without resetting depreciation

periods and without allowing or requiring new elections—even after the disposition by partners of more than half of the partnership’s outstanding capital and profits interests in a twelve-month period.

NEW RESTRICTIONS ON NOL UTILIZATION

The Tax Reform Act generally limits the amount of net operating loss (NOL) that may be utilized in any taxable year to 80% of the taxpayer’s taxable income (determined without regard to the NOL deduction) with respect to losses arising in taxable years beginning after December 31, 2017. Carryovers to other years are adjusted to take account of this limitation, and may be carried forward indefinitely. The bill also generally repeals provisions allowing for the carryback of NOLs effective for losses arising in taxable years after December 31, 2017. For a more detailed discussion, see Bankruptcy Developments in the Energy Sector – Tax Reform Act, above.

Changes to Depreciation Rules

DEPRECIABLE LIVES FOR REAL PROPERTY MODIFIED

The Tax Reform Act requires any real property trade or business that elects to be excluded from the interest deductibility limitations described above to utilize the alternative depreciation system with respect to its depreciable real property. Under the alternative depreciation system, as modified by the Tax Reform Act, the recovery periods for nonresidential depreciable real property, residential depreciable real property and qualified improvements are 40 years, 30 years and 20 years, respectively.

The Tax Reform Act did not adopt the Senate proposal to reduce the MACRS depreciable lives on residential and nonresidential depreciable property.

IMMEDIATE EXPENSING OF QUALIFIED DEPRECIABLE PERSONAL PROPERTY

The Tax Reform Act extends and modifies the additional first-year depreciation deduction for qualified depreciable personal property by increasing the 50% allowance to 100% for property placed in service after September 27, 2017, and before 2023. After 2022, the bonus depreciation percentage is phased-down to 80% for property placed in service in 2023, 60% for property placed in service in 2024, 40% for property placed in service in 2025, and 20% for property placed in service in 2026. The bill removes the requirement in prior law that the original use of qualified property must commence with the taxpayer. Thus, immediate expensing applies to purchases of used as well as new items.

Qualified property does not include generation, transmission, distribution or transportation assets of a public utility.

Repeal of Section 199 Deduction

The deduction for domestic production activities under Section 199 of the Code is repealed for tax years beginning after December 31, 2017. The general reduction in the corporate tax rate is meant to encompass the key policy justifications that were the original motivations for the adoption of Section 199.

Changes to International Tax Provisions

The energy sector is international in scope, and the changes to the U.S. international tax system will have a profound impact on the energy industry.

TERRITORIAL CORPORATE TAX SYSTEM

The Tax Reform Act changes the taxation of domestic corporations from a worldwide tax system to a hybrid territorial tax system by establishing a limited participation exemption system. Such participation exemption will allow a domestic corporation to claim a 100% deduction for the foreign-source portion of a dividend (including deemed dividends arising under Section 1248 of the Code from the sale or exchange of stock) received by such domestic corporation from a "specified 10%-owned foreign corporation" in which such domestic corporation is a "United States shareholder." For this purpose, a "specified 10%-owned foreign corporation" is any foreign corporation (other than a passive foreign investment company (PFIC) that is not a controlled foreign corporation (CFC)) with respect to which any domestic corporation is a United States shareholder. As discussed below, the Tax Reform Act expands the prior definition of United States shareholder to include not only United States persons that own (directly or constructively) stock of the foreign corporation representing 10% of the combined voting power of a foreign corporation but also United States persons that own (directly or constructively) stock of the foreign corporation representing 10% of the value of the foreign corporation. The deduction is allowed only to a C corporation that is not a regulated investment company or a real estate investment trust.

A domestic corporation may claim the deduction only if the dividend is paid on a share of stock that the domestic corporation has held for 366 days or more during the 731-day period beginning on the date that is 365 days before the date on which the share becomes ex-dividend with respect to such dividend. The holding period requirement will be satisfied only if the specified 10%-owned foreign corporation is a specified 10%-owned foreign corporation at all times during this period and the domestic corporation is a United States Shareholder with respect to such foreign corporation at all times during such period.

The deduction is not available if the dividend received from the specified 10%-owned foreign corporation is a "hybrid dividend," which is generally defined as any dividend for which the specified 10%-owned foreign corporation received a deduction in a foreign country.

No credit or deduction is allowed for any foreign income taxes paid or accrued with respect to any portion of a dividend that qualifies for the deduction.

REPEAL OF ACTIVE TRADE OR BUSINESS EXCEPTION UNDER SECTION 367(A)

The Tax Reform Act provides that, if a U.S. person transfers to a foreign corporation property that is used in the active conduct of a foreign trade or business, then such foreign corporation shall not be treated as a corporation for purposes of determining the extent to which gain is recognized on such transfer. The Tax Reform Act thus repeals the active trade or business exception under Section 367(a) of the Code.

LOSS RECAPTURE ON TRANSFER OF A FOREIGN BRANCH TO A FOREIGN CORPORATION

Under the Tax Reform Act, if a domestic corporation transfers substantially all of the assets of a foreign branch to a specified 10%-owned foreign corporation with respect to which it is a United States shareholder after the transfer, then the domestic corporation must recapture, as U.S. source income, any net branch losses incurred after December 31, 2017, and before the transfer and with respect to which the domestic corporation was allowed a deduction.

DEEMED REPATRIATION OF DEFERRED FOREIGN EARNINGS OF 10%-OWNED FOREIGN CORPORATIONS

The Tax Reform Act amends Section 965 of the Code to require a United States shareholder (which for this purpose includes domestic corporations, partnerships, trusts, estates, and U.S. individuals that own 10% of the voting power) of CFCs and "other specified foreign corporations" to include in income, for the last taxable year of such foreign corporation beginning before January 1, 2018, such shareholder's pro rata share of the "deemed repatriation amount." Other specified foreign corporations are non-CFC, non-PFIC foreign corporations with a corporate United States shareholder (which for this purpose includes domestic corporations that own 10% of the voting power of such foreign corporation). The deemed repatriation amount is the greater of such foreign corporation's post-1986 deferred foreign income as of (i) November 2, 2017 or (ii) December 31, 2017 and that was not previously subject to U.S. tax (but excluding earnings and profits that were accumulated prior to the foreign corporation becoming a CFC or having a 10% U.S. shareholder). The deemed repatriation amount generally is unreduced by distributions made by the foreign corporation during the taxable year.

This deemed repatriation generally will be taxed at a 15.5% rate to the extent the underlying foreign earnings are attributable to the U.S. shareholder's cash position and an 8% rate for all other amounts. The "cash position" is defined to include cash, net accounts receivable, and the fair market value of similarly liquid assets.

The Tax Reform Act provides that a United States shareholder that is required to include an amount in income under Section 965 of the Code is allowed a credit for approximately 44.3% of the foreign income taxes paid that are attributable to the cash position portion of the inclusion and approximately 22.9% of the foreign income taxes paid that are attributable to the remainder of the inclusion.

The Tax Reform Act provides that, in the case of a corporation that becomes an expatriated entity (within the meaning of Section 7874(a)(2) of the Code) at any point within the 10-year period following the enactment of the Tax Reform Act, a United States shareholder of such corporation is subject to U.S. tax at a 35% rate (with no reduction for foreign tax credits) on the entire amount of the deemed repatriation with respect to such corporation.

CURRENT-YEAR TAXATION FOR GLOBAL INTANGIBLE LOW-TAXED INCOME (GILTI) FOR U.S. SHAREHOLDERS OF CFCs

The Tax Reform Act adds Section 951A to the Code, which requires a United States shareholder of a CFC to include in income, as a deemed dividend, the global intangible low-taxed income (GILTI) of the CFC. After factoring in a deduction that a domestic corporation will be entitled to claim with respect to such income inclusion, a domestic corporation will be subject to U.S. tax on GILTI at an effective rate of 10.5% (that is, 50% of the U.S. corporate tax rate of 21%).

GILTI is defined as the excess of the U.S. shareholder's net CFC tested income over a net deemed tangible income return. "Net CFC tested income" generally means a CFC's gross income, other than income that is subject to U.S. tax as effectively connected income, Subpart F income (including income that would be Subpart F income but for the application of certain exceptions), and foreign oil and gas extraction income, less allocable deductions. The "net deemed tangible income return" generally is an amount equal to the excess of (i) 10% of the aggregate of the United States shareholder's pro rata share of a CFC's qualified

business asset investment (generally, a quarterly average of the CFC's tax basis in depreciable property used in its trade or business) over (ii) the amount of interest expense taken into account to determine such U.S. shareholder's net CFC tested income.

Under the Tax Reform Act, a domestic corporation is entitled to a credit for 80% of its pro rata share of the foreign income taxes attributable to the income of the CFC that is taken into account in computing its net CFC tested income. The foreign tax credit limitation rules apply separately to such taxes, and any taxes that are deemed paid under these rules may not be carried back or forward to other tax years.

EFFECTIVE 13.125% TAX RATE ON FOREIGN-DERIVED INTANGIBLE INCOME OF A DOMESTIC CORPORATION

The Tax Reform Act adds Section 250 to the Code, which allows a domestic corporation to claim a deduction (for tax years from 2018 through 2025) for an amount equal to 37.5% of its foreign-derived intangible income (reduced to 21.875% for tax years beginning after December 31, 2025). Thus, a domestic corporation is subject to U.S. tax on foreign-derived intangible income at a rate of 13.125% through 2025.

In general, a domestic corporation's "foreign-derived intangible income" is calculated by applying a complex series of formulas and definitions that ultimately measure the extent to which the domestic corporation's income in excess of a 10% return on its U.S. depreciable assets (increased to 15.625% for tax years beginning after December 31, 2025) is attributable to (i) the sale of property to foreign persons for use outside the United States or (ii) the performance of services for foreign persons, or with respect to property located, outside the United States. Income of the domestic corporation is not taken into account for this purpose to the extent it is Subpart F income, GILTI, financial services income, a dividend received from a CFC in which the domestic corporation is a United States shareholder, domestic oil and gas extraction income, or foreign branch income. Special rules apply to transactions involving intermediaries and related parties.

OTHER CHANGES TO SUBPART F RULES

Expansion of Stock Attribution Rules for Determining CFC Status. The Tax Reform Act repeals Section 954(b)(4) of the Code, which provides that stock in a foreign corporation is not attributed "downward" from a foreign person to a related U.S. person for purposes of determining whether such U.S. person is a United States shareholder of such foreign corporation (and, thus, whether such foreign corporation is a CFC). This provision apparently is intended to render ineffective "de-control transactions" in which a foreign parent acquires a greater than 50% interest in a CFC of its U.S. subsidiary and, thus, causes the CFC to be a non-CFC. This provision is effective for the last taxable year of foreign corporations beginning before January 1, 2018, and each subsequent year of such foreign corporations and for the taxable years of United States shareholders in which or with which such taxable years of foreign corporations end.

Expansion of Definition of United States Shareholder. Prior to the Tax Reform Act, a United States shareholder was defined as any U.S. person that owns 10% of the voting stock in a foreign corporation. The Tax Reform Act expands this definition to also include any U.S. person that owns 10% of the value of the stock in a foreign corporation. This change accordingly expands the circumstances in which a foreign

corporation will be treated as a CFC (including in situations where a U.S. person owns “low vote” stock that represents at least 10% of the value of the foreign corporation).

Elimination of 30-Day Requirement for Subpart F Inclusions. Prior to the Tax Reform Act, a United States shareholder of a foreign corporation was required to include amounts in income under Subpart F for a particular tax year only if such foreign corporation has been a CFC for at least 30 consecutive days for such year. The Tax Reform Act eliminates this 30-day requirement.

Repeal of Treatment of Foreign Base Company Oil-Related Income as Subpart F Income. The Tax Reform Act repeals Section 954(g) of the Code, which includes foreign base company oil-related income as one of the categories of foreign base company income.

Repeal of Inclusion Based on Withdrawal of Previously Excluded Subpart F Income from Investment in Qualified Shipping Operations. The Tax Reform Act repeals Section 955 of the Code, which requires a United States shareholder of a CFC to include in income any previously excluded Subpart F income that such CFC withdraws from investment in certain qualified shipping operations.

Anti-Base Erosion Rules

EXPANSION OF THE DEFINITION OF INTANGIBLE PROPERTY FOR OUTBOUND TRANSFERS

The Tax Reform Act expands the definition of “intangible property” under Section 936(h)(3)(B) of the Code to include goodwill, going concern value, workforce in place and any other item the value or potential value of which is not attributable to tangible property or the services of an individual. This provision legislatively overturns several recent Tax Court cases holding that assets such as workforce in place and goodwill are beyond the scope of the statutory definition of “intangible property.” In addition, the Tax Reform Act removes the qualification that intangible property under Section 936(h)(3)(B) must have substantial value independent of the services of an individual. As a result, certain transfers of such assets by a U.S. person to a foreign corporation will be subject to Section 367(d) or 482 of the Code. The Tax Reform Act also requires Treasury to issue regulations that would, for purposes of applying the outbound transfer rules under Section 367(d), or the transfer pricing rules under Section 482, require the valuation of intangible properties on an aggregate basis or on the basis of realistic alternatives to such transfers, in each case, if Treasury determines that such a basis is the most reliable means of valuation. These provisions apply to transfers in taxable years beginning after December 31, 2017. However, the Tax Reform Act expressly provides that the changes to Section 936(h)(3)(B) are not to be construed as creating an inference as to the application of the prior version of the section.

CERTAIN RELATED PARTY AMOUNTS PAID OR ACCRUED IN HYBRID TRANSACTIONS OR WITH RESPECT TO HYBRID ENTITIES

The Tax Reform Act adds Section 267A to the Code, which disallows a deduction for interest or royalties paid or accrued to a related party pursuant to a “hybrid transaction” or by or to a “hybrid entity” if such amount is not included in the income of such party under the local tax laws of the country of which such related party is a resident or if such party is entitled to a deduction with respect to such payments under the local tax laws of such country. For purposes of this rule, a “hybrid transaction” is any transaction, series of transactions, or instrument one or more payments with respect to which are treated as interest or royalties for U.S. tax purposes but not so treated under the local tax laws of the country of which the

recipient is a resident. A “hybrid entity” is an entity that is treated as fiscally transparent under U.S. tax law but not so treated under the local tax laws of the country of which the recipient is a resident, or vice versa.

Changes to Foreign Tax Credit System

CHANGES TO INDIRECT FOREIGN TAX CREDIT RULES

The Tax Reform Act repeals Section 902 of the Code, which allowed a domestic corporation to claim an indirect foreign tax credit with respect to dividends it receives from a foreign corporation in which it owns 10% of the voting stock. The Tax Reform Act modifies Section 960 of the Code, which allows a domestic corporation to claim an indirect foreign tax credit with respect to Subpart F inclusions. Under the Tax Reform Act, the foreign tax credit is calculated based on current-year foreign taxes paid (rather than a cumulative foreign tax pool) with respect to the relevant item of Subpart F income. The Tax Reform Act also includes provisions addressing distributions of previously taxed income by a CFC to a domestic corporation (or by a lower-tier CFC to an upper-tier CFC).

SEPARATE FOREIGN TAX CREDIT LIMITATION BASKET FOR FOREIGN BRANCH INCOME

In general, under Section 904 of the Code, a taxpayer is permitted to claim a foreign tax credit in an amount equal to the U.S. tax imposed on such taxpayer’s foreign source income. This limitation applies separately to the taxpayer’s “general basket” and “passive basket” income. The Tax Reform Act adds as a new basket “foreign branch income,” which is defined as the business profits of a U.S. person that are attributable to one or more qualified business units in one or more foreign countries. However, foreign branch income does not include any income that is otherwise treated as passive basket income.

SOURCE OF INCOME FROM SALES OF INVENTORY PRODUCED BY THE TAXPAYER

Prior to the Tax Reform Act, the source of a taxpayer’s income from the sale or exchange of inventory property produced (in whole or in part) by the taxpayer in the United States and sold outside the United States (or vice versa) was generally sourced 50% to the place of production and 50% to the place of sale (based on title passage rule).

The Tax Reform Act modifies these rules and provides that the source of such income is determined solely based on the location of production with respect to such inventory property.

ELECTION TO INCREASE PERCENTAGE OF ODL RECAPTURE AS FOREIGN SOURCE INCOME

Prior to the Tax Reform Act, Section 904(g) of the Code allowed a taxpayer with an overall domestic loss (ODL) to recapture such ODL by recharacterizing U.S. source income earned in succeeding taxable years as foreign source to the extent of the lesser of the ODL or 50% of the taxpayer’s U.S. source income in such year.

The Tax Reform Act amends Section 904(g) of the Code to allow a taxpayer to elect a percentage between 50% and 100% with respect to ODLs that arose prior to January 1, 2018, in determining the amount of U.S. source income earned in a succeeding year that it may recharacterize as foreign source income.

This provision is effective for ODLs in existence prior to January 1, 2018, and the election may only be made during taxable years beginning after December 31, 2017, and before January 1, 2028.

THE BASE EROSION ANTI-ABUSE TAX (BEAT)

BEAT is a minimum tax on multinational corporations that have at least \$500 million of annual domestic gross receipts (averaged over a 3-year period) and a “base erosion percentage” of 3% or higher (2% or higher for certain banks and registered security dealers) for the taxable year. BEAT generally is the excess of

- 10% (5% for taxable years beginning during 2018) of the taxpayer’s modified taxable income (generally, its taxable income plus the base erosion tax benefit amount (including the base erosion percentage of an NOL deduction)) over
- an amount equal to the taxpayer’s regular tax liability reduced by certain credits, except for certain business tax credits, including up to 80% of the value of PTCs and ITCs.

For taxable years beginning after 2025, the 10% limit is increased to 12.5%, and certain credits are treated differently for purposes of determining a taxpayer’s regular tax liability. For example, after 2025, PTCs and ITCs will no longer offset any portion of the BEAT. For a more detailed discussion of the BEAT’s impact on the financing of renewables projects, see Project Finance, above.

A corporation’s “base erosion percentage” generally equals the aggregate amount of “base erosion tax benefits” of the corporation for the taxable year, divided by the aggregate amount of deductions allowable to the corporation for the taxable year. A “base erosion tax benefit” generally means (i) any deduction allowed with respect to a base erosion payment, (ii) in the case of a base erosion payment with respect to the purchase of depreciable property, any deduction allowed for depreciation (or amortization in lieu of depreciation) with respect to the property acquired with such payment, or (iii) any reduction in gross receipts with respect to a payment described above made to a related foreign corporation that became a surrogate foreign corporation after November 9, 2017, or made to a member of an expanded affiliated group that includes such surrogate foreign corporation. A “base erosion payment” generally is a deductible payment by the corporation to a foreign related party (subject to certain exceptions).

SHAREHOLDERS NOT ELIGIBLE FOR PREFERENTIAL TAX RATE ON DIVIDENDS FROM INVERTED COMPANIES

Certain dividends from “qualified foreign corporations” are subject to a reduced rate of tax. Such qualified foreign corporations include corporations incorporated in a U.S. possession and certain corporations that are eligible for benefits of an income tax treaty with the United States and is approved by Treasury as satisfactorily providing for an exchange of information.

The Tax Reform Act provides that dividends from a “surrogate foreign corporation” (as defined under Section 7874 of the Code), informally known as an inverted corporation, are not eligible for reduced tax rates unless such corporation is deemed to be a domestic corporation under Section 7874.

This provision is effective for dividends paid after December 22, 2017, and will apply only to dividends from foreign corporations that become surrogate foreign corporations after December 22, 2017.

SALE OF A PARTNERSHIP INTEREST BY A FOREIGN PERSON

Under the Tax Reform Act, gain or loss realized by a foreign corporation or a foreign individual from the sale or exchange of an interest in a partnership engaged in a U.S. trade or business is treated as effectively connected with a U.S. trade or business to the extent that the sale of all the partnership assets would have

produced effectively connected gain or loss. This provision applies to sales, exchanges, and dispositions occurring on or after November 27, 2017. This provision repeals the result in *Grecian Magnesite Mining v. Commissioner*, 149 T.C. No. 3 (2017), where the Tax Court held that a foreign partner was not subject to U.S. tax on sale of a partnership interest, rejecting the holding of Rev. Rul. 91-32 to the contrary.

The Tax Reform Act also amends Section 1446 of the Code to require the transferee of a partnership interest to withhold 10% of the amount realized on the sale or exchange of a partnership interest unless the transferor certifies that it is not a nonresident alien individual or foreign corporation. This provision is effective for transfers occurring after December 31, 2017. But see Master Limited Partnerships and YieldCos – Tax Reform Act - Impact on MLPs, above, for delayed effective dates for publicly traded partnerships.

REPEAL OF FAIR MARKET VALUE METHOD OF INTEREST EXPENSE APPORTIONMENT

Prior to the Tax Reform Act, members of a U.S. affiliated group may elect to allocate and apportion their interest expense among U.S. source income and foreign source income based on either the adjusted tax basis or fair market value of their assets. The Tax Reform Act now provides that interest expense must be allocated and apportioned based on the adjusted tax basis of their assets.

CONTRIBUTIONS TO CAPITAL NO LONGER TAX-FREE

The Tax Reform Act provides that Section 118 of the Code, which generally provides that a corporation is not taxed on property contributed to it, will not apply to contributions in aid of construction, to contributions as a customer or potential customer or to contributions by any governmental entity or civic group. Thus, for example, a contribution of land by a city to a developer corporation would be taxed to the corporation at the land's fair market value. The explanation to the bill further provides that "[t]he conferees intend that section 118, as modified, continue to apply only to corporations." This may be read to imply that a partnership (or any other type of entity other than a corporation) also would be taxed on such a contribution, as well as any contribution that might otherwise qualify for nonrecognition treatment under Section 118 if made to a corporation.

PROPOSED ENERGY TAX CHANGES THAT WERE NOT ENACTED

Several energy tax provisions that were proposed at one point to be amended were not amended in the final bill. The deduction for intangible drilling costs and depletion were not affected, but several tax credits were not extended. Credits for fuel cells, geothermal heat pumps, fiber-optic solar panels, combined heat and power projects, and nuclear power plants were not extended. The placed-in-service deadline for new nuclear plants was not waived, as had been proposed.

MEXICO

Mexico's newly liberalized power market continues to develop at a rapid pace. The country's Capacity Balancing Market, which provides market participants the ability to purchase and sell capacity on an annual basis, commenced operation in February 2017.

The last year also witnessed the continued proliferation of market manuals, operating guides, and other key documents by the Comisión Reguladora de Energía (CRE), Centro Nacional de Control de Energía (CENACE), and Secretariat of Energy (SENER). Of particular note, SENER published manuals governing imports and exports of power (Manual de Importaciones y Exportaciones), auctions for Financial

Transmission Rights (Manual de las Subastas de Derechos Financieros de Transmisión), and bilateral transactions (Manual de Transacciones Bilaterales y Registro de Contratos de Cobertura Eléctrica). These documents provide much-needed guidance for investors seeking to participate in the power market.

The Wholesale Electricity Market (Mercado Eléctrico Mayorista, or MEM) remains a cost-based, short-term energy market with a day-ahead and real-time market. CENACE makes publicly available the hourly Locational Marginal Prices for both the real-time and day-ahead markets. An hour-ahead market will be added during the second phase of the market, which is expected to commence operations in 2018.

In addition, SENER announced that it will, for the first time, solicit proposals for the development of a private, high-voltage direct current transmission line to connect the isolated system of Baja California to the National Interconnected System. SENER anticipates releasing the terms for bidders in January 2018, with registration of interested parties occurring in spring and early-summer of 2018. Bids will be due in July 2018 and the winning bid will be announced in September 2018. The line is expected to enter service in 2021.

Key Terms of Selected Utility Mergers and Acquisitions

January 1, 2013 – January 30, 2018

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
1/03/18 <i>(pending)</i>	Dominion Energy/ SCANA Corporation	\$15,550.17	\$7,690.17	Stock	38% (1 day)	16x	\$240M (3.1%)	\$280M (3.6%)	Dominion to determine post-closing management structure	SC, NC, GA, HSR, FERC, NRC, FCC	Competitive
10/16/17 <i>(pending)</i>	Southern Company Gas/South Jersey Industries	\$1,690	N/A	Cash	N/A	N/A	N/A	\$80M (4.7%)	SJI to determine post-closing management structure	NJ, MD, HSR, FERC, FCC	Competitive
7/19/17 <i>(pending)</i>	AVA/Hydro One Limited	\$5,311.59	\$3,445.73	Cash	24% (1 day)	28.2	\$103M (2.9%)	\$103M (0.8%)	AVA management to remain in place; headquarters to remain in Washington	WA, ID, OR, MT, AK, FERC, CFIUS, HSR, FCC	

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
7/9/17 (pending)	Westar/ Great Plains	\$26,503.46	\$13,845.31	Stock	No premium	NM	\$190M (2.5% /3.1%)	\$190M (3.1%)	Equal Board split; GXP CEO to be CEO; dual headquarters in Topeka, KS and Kansas City, MO	HSR, FERC, KS, MO, NRC and FCC	Bilateral
6/1/17 (12/4/2017)	Macquarie/ Eversource	\$1,675.00	\$880	Cash	N/A	N/A	N/A	N/A	Not specified.	CT, MA, NH, HSR	Competitive
1/25/17 (pending)	WGL Holdings/ AltaGas	\$6,324.34	\$4,520.08	Cash	27.9% (11/28/16 unaffected)	26.2x	\$136M (3.0%)	\$205M, \$182M or \$68M (4.5%, 4.0% & 1.5%)	Maintain headquarters in Washington, D.C.; WGL management to manage all AltaGas US operations	HSR, FERC, CFIUS, DC, MD and VA	Competitive

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
5/29/16 (terminated 7/9/17)	Westar/ Great Plains	\$12,193.75	\$8537.88	Cash	13.4% (1 day) 36.1% (3/9/16 unaffected)	25.0x	\$280M (3.28%)	\$380M (4.45%)	Maintain headquarters in Topeka, KS; one Westar director to be appointed to board of combined company	HSR, FERC, KS, NRC and FCC	Competitive
2/9/16 (1/1/17)	Empire District/ Algonquin	\$2,389.81	\$1,487.95	Cash	21.3% (1 day)	23.2x	\$53M (3.56%)	\$65M (4.37%)	Empire District management to head regional management team; no changes to management or employees at Empire	HSR, FERC, CFIUS, AR, KS, MO, OK and FCC	Competitive
2/9/16 (10/14/16)	ITC Holdings/ Fortis, Inc.	\$11,426.90	\$6,945.86	Cash/Stock	15.5% (1 day)	21.9x	\$245M (3.53%)	\$280M/\$245M (4.03%/3.53%)	Maintain headquarters in MI, no force reductions	HSR, FERC, CFIUS, IL, KS, MO, OK and WI	Competitive

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
2/1/16 (9/16/16)	Questar/ Dominion	\$5,982.94	\$4,396.74	Cash	23.2% (1 day prior)	19.1	\$99M (2.25%)	\$154M (3.5%)	One Questar representative to be appointed to each of Dominion and Dominion Midstream's boards; maintenance of headquarters in Salt Lake City	HSR, UT, WY, ID	Bilateral
10/26/15 (10/3/16)	Piedmont/ Duke	\$6,589.35	\$4,794.90	Cash	40% (1-day prior)	30.9x	\$125M (2.61%)	\$250M (5.21%)	One Piedmont representative will be added to Duke's Board of Directors; an existing member of Piedmont's management team will lead Duke's natural gas operations.	HSR, NC, FCC	Competitive

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
9/4/15 (7/1/16)	TECO/ Emera	\$10,422.48	\$6,481.18	Cash	48% (unaffected price as of 7/15/15)	24.7x	\$212.5M (3.28%)	\$326.9M (5.04%)	Tampa Electric and NM Gas to maintain existing headquarters in Tampa and Albuquerque	HSR, CFIUS, FERC, NM, FCC	Competitive
8/24/15 (7/1/16)	AGL/ Southern	\$12,001.74	\$7,924.74	Cash	36.3% (20-day VWAP)	21.8x	\$201M (2.54%)	N/A	AGL to maintain separate board and management team	HSR, CA, GA, IL, MD, NJ, VA, FCC	Bilateral
2/26/15 (12/16/15)	UIL/ Iberdrola (USA)	\$4,847.02	\$3,040.02	Stock/Cash	24.6% (est. 1-day prior)	21.6x	\$75M (2.47%)	N/A	UIL CEO to be CEO of combined entity; UIL CEO and 2 others to join Iberdrola (USA) board of directors	HSR, CFIUS, CT, MA, FCC	Bilateral

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
12/3/14 (terminated 7/16/16)	HEI/ NextEra	\$4,567.39	\$2,601.37	Stock	21% (est. 20-day VWAP)	15.9x	\$90M (3.46%)	\$90M (3.46%)	HEI to maintain local headquarters and be managed locally	HSR, FERC, HA, FCC	Bilateral
10/20/14 (4/13/16)	CLECO/ Macquarie/ BCIMC	\$4,703.54	\$3,365.13	Cash	14.7% (1-day prior) (strategic process had been previously disclosed)	20.3x	\$120M (3.57%)	\$180M (5.35%)	CLECO to maintain local headquarters and management; CLECO President to become CEO upon closing	HSR, CFIUS, FERC, LA	Competitive
6/23/14 (6/29/15)	Integrus/ WEC	\$9,114.57	\$5,684.47	Stock/Cash	17.3% (1 day prior)	19.5x	\$175M (3.08%)	\$175M (3.08%)	3 Integrus Directors to join WEC Board upon closing	HSR, FERC, WIA, IL, MI, MN, FCC	Bilateral
4/30/14 (3/23/16)	Pepco/ Exelon	\$12,605.43	\$6,912.43	Cash	19.6% (1 day prior); 29.5% (20-day VWAP)	22.4x	\$293M (4.24%)	\$180M (2.60%)	Maintenance of local and regional headquarters and management	HSR, FERC, DE, DC, MD, NJ, VA, FCC	Competitive

Date Announced (Closed)	Parties	Total Transaction Value (millions)	Equity Value (millions)	Consideration	Premium to Market Price (days prior to announcement)	P/E NTM	Break-Up Fee (% of Equity Value)	Reverse Break-Up Fee (% of Equity Value)	Management Structure/ Other Undertakings	Required Regulatory Approvals	Nature of Process
12/11/13 (8/15/14)	UNS/Fortis	\$4,343.11	\$2,502.68	Cash	30.1% (1 day prior)	18.4x	\$63.9M (2.55%)	N/A	UNS management team to remain in place, UNS headquarters to remain in Tucson and 4 current directors of UNS to remain on UNS Board of Directors following closing	HSR, CFIUS, FERC, AZ, FCC	Bilateral
5/29/13 (12/19/13)	NV/ Berkshire	\$10,688.83	\$5,664.63	Cash	20.3% (1 day prior)	18.0x	\$56.6M (1st 6 weeks) (1.0%)/\$16 9.7M (3.0%)	N/A	NV to continue to operate as a separate subsidiary and maintain local headquarters	HSR, FERC, NV, FCC	Bilateral

Risk Allocation RE Regulatory Approvals in Selected Utility Mergers and Acquisitions

January 1, 2013 – January 30, 2018

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
<i>SCANA/Dominion 1/03/18 (pending)</i>	SC, NC, GA, HSR, FERC, NRC, FCC	Specified SCPSC conditions must be obtained without material modification; other regulatory approvals must be obtained without any Burdensome Condition. Burdensome Condition based on Company and Buyer MAE	Reasonable best efforts	Reverse break-up fee payable if agreement is terminated and one or more regulatory orders contain a Burdensome Condition and the other conditions to closing have been satisfied
<i>Elizabethtown Gas/South Jersey Industries 10/16/17 (pending)</i>	NJ, MD, HSR, FERC, FCC	Conditions in regulatory orders shall not be reasonably be expected to have a material adverse effect on the Business taken as a whole.	Reasonably best efforts	"Hell or High Water" Payment of Reverse Break-up Fee (\$80M)

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
AVA/Hydro One Limited 7/19/17 (pending)	WA, ID, OR, MT, AK, FERC, CFIUS, HSR, FCC	Company MAE or Combined Company MAE (with Combined Company deemed to be only the size of the Company)	Reasonable best efforts generally. Take all steps necessary to remove impediments and obtain approval, including: <ul style="list-style-type: none"> • agreeing to divestitures • terminating or modifying existing relationships, ventures, contract rights or other arrangements • creating relationships, ventures or arrangements 	"Hell or High Water" Payment of Reverse Break-up Fee (\$103M), even if due to an order that would impose a Burdensome Condition. Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.
Westar/Great Plains 7/9/17 (pending)	HSR, FERC, KS, MO, NRC and FCC	Regulatory MAE based on a company the size of Westar for purposes of the closing conditions, but none for termination and the reverse break-up fee	Take all actions and do all things necessary. Reasonable best efforts to eliminate all impediments, including (subject to the condition precedent "gauge"): <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • agreeing to conduct limitations • taking any action required by a Governmental Entity 	"Hell or High Water" Payment of Reverse Break-up Fee (\$380M). Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
Macquarie/Eversource 6/1/17 (12/4/2017)	CT, MA, NH, HSR	All regulatory orders shall have been obtained; no requirement that orders not contain material adverse or burdensome conditions.	Reasonable best efforts	Provisions relating to reverse break-up fee redacted.
WGL/AltaGas 1/25/17 (pending)	HSR, FERC, CFIOUS, DC, MD and VA	Burdensome Condition based on Company MAE or Buyer MAE	Reasonable best efforts to consummate the transaction. Take any and all steps that may be required, including: <ul style="list-style-type: none"> • agreeing to divestitures • terminating or relinquishing or modifying any existing relationships, ventures or contractual rights of Buyer • creating new relationships, ventures, and contractual rights 	"Hell or High Water" Payment of Regulatory Termination Fee (\$68M), unless a Burdensome Condition is imposed. Payment of Parent Termination Fee (\$182M) if Buyer failed to comply with its covenants as regards seeking to obtain the required regulatory approvals. Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
Westar/Great Plains 5/29/16 (terminated 7/9/17)	HSR, FERC, KS, NRC and FCC	Regulatory MAE based on a company the size of Westar for purposes of the closing conditions, but none for termination and the reverse break-up fee	Take all actions and do all things necessary. Reasonable best efforts to eliminate all impediments, including (subject to the condition precedent "gauge"): <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • agreeing to conduct limitations • taking any action required by a Governmental Entity 	"Hell or High Water" Payment of Reverse Break-up Fee (\$380M). Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.
Empire District/Algonquin 2/9/16 (1/1/17)	HSR, FERC, CFIUS, AR, KS, MO, OK and FCC	Burdensome Condition is based on Combined Company MAE	Take all actions and do all things necessary. Reasonable best efforts to eliminate all impediments, including (subject to the condition precedent "gauge"): <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • agreeing to conduct limitations • taking any action required by a Governmental Entity 	"Hell or High Water" Payment of Reverse Break-up Fee (\$65M), even if due to an order that would impose a Burdensome Condition on Algonquin. Automatic six-month extension if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
ITC Holdings/Fortis 2/9/16 (10/14.16)	HSR, FERC, CFIUS, IL, KS, MO, OK and WI	None	<p>Proceed diligently and in good faith, and use best efforts.</p> <p>Take all actions and do all things necessary, including:</p> <ul style="list-style-type: none"> • taking any action and agreeing to any concession or condition requested or required by a Governmental Entity • agreeing to divestitures • terminating or restructuring existing relationships contracts or governance 	<p>"Hell or High Water" Payment of Reverse Break-up Fee (\$280M).</p> <p>Either Party may extend drop dead date by up to 6 months if all other Conditions Precedent have been satisfied or waived.</p>
Questar/Dominion 2/1/16 (9/16/16)	HSR, UT, WY, ID	Company MAE or Combined Company MAE (with Combined Company deemed to be only the size of the Company)	<p>Reasonable best efforts generally. Take all steps necessary to remove impediments and obtain approval, including:</p> <ul style="list-style-type: none"> • agreeing to divestitures • terminating or modifying existing relationships, ventures, contract rights or other arrangements • creating relationships, ventures or arrangements <p>Reasonable best efforts to defend through litigation, including appeals.</p>	<p>"Hell or High Water" Payment of Reverse Break-up Fee (\$154M), even if due to an order that would impose a Burdensome Condition on Dominion.</p> <p>Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived. Company may extend an additional 3 months if all conditions satisfied (including re receipt of approvals) but an injunction has been issued preventing Closing.</p>

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
<i>Piedmont/Duke</i> <i>10/26/15 (10/3/16)</i>	HSR, NC, FCC	Company MAE or Combined Company MAE (with Combined Company deemed to be only the size of the Company)	<p>Reasonable best efforts generally.</p> <p>Take all steps necessary to remove impediments and obtain approval, including:</p> <ul style="list-style-type: none"> • agreeing to divestitures • terminating or modifying existing relationships, ventures, contract rights or other arrangements • creating relationships, ventures or arrangements <p>Reasonable best efforts to defend through litigation, including appeals.</p>	<p>"Hell or High Water" Payment of Reverse Break-up Fee (\$250M), even if due to an order that would impose a Burdensome Condition on Duke.</p> <p>Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.</p>
<i>TECO/Emera</i> <i>9/4/15 (7/1/16)</i>	HSR, CFIUS, FERC, NM, FCC	None	<p>Take all actions and do all things necessary.</p> <p>Reasonable best efforts to eliminate all impediments, including (subject to the condition precedent "gauge"):</p> <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • agreeing to conduct limitations • taking any action required by a Governmental Entity 	<p>"Hell or High Water" Payment of Reverse Break-up Fee (\$326.9M).</p> <p>Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.</p>

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
AGL/Southern 8/24/15 (7/1/16)	HSR, CA, GA, IL, MD, NJ, VA, FCC	Combined Company MAE or a requirement to divest of a Company subsidiary or a Buyer subsidiary that constitutes more than 25% of the respective operations of the Company and its subsidiaries or Buyer and its subsidiaries	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • eliminate all impediments to obtaining approvals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	No liability if terminated due to failure to obtain approvals or imposition of a burdensome condition by approvals. Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.
UIL/Iberdrola (USA) 2/26/15 (12/16/15)	HSR, CFIUS, CT, MA, FCC	Company MAE (with Company deemed to be 150% of its size)	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	No liability if terminated due to failure to obtain approvals or imposition of a burdensome condition by approvals. Either Party may extend drop dead date by up to two successive 3 month periods if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
HEI/NextEra 12/3/14 (terminated - 7/16/16)	HSR, FERC, HA, FCC	Buyer MAE (with Buyer deemed to be the size of the Company) or Company MAE, in each case after giving effect to the related spin transaction	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	Payment of Reverse Break-up Fee (\$90M). Issuance of a regulatory approval that imposes a Burdensome Condition does not require payment of the Reverse Break-up Fee. Automatic six month extension if all other Conditions Precedent have been satisfied or waived.
CLECO/Macquarie/BCIMC 10/20/14 (4/13/16)	HSR, CFIUS, FERC, LA	Company MAE or Combined Company MAE, in each case with the Company deemed to be 50% of its size	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	Payment of Reverse Break-up Fee (\$180M), but only if terminated by Purchaser. Issuance of a regulatory approval that imposes a Burdensome Condition does not require payment of the Reverse Break-up Fee. Automatic six month extension if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
<i>Integrys/WEC</i> <i>6/23/14 (6/29/15)</i>	HSR, FERC, WIA, IL, MI, MN, FCC	Combined Company MAE (with Combined Company deemed to be only the size of the Company)	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • eliminate all impediments to obtaining approvals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	No liability if terminated due to failure to obtain approvals or imposition of a burdensome condition by approvals. Either Party may extend drop dead date by 6 months if all other Conditions Precedent have been satisfied or waived.
<i>Pepco/Exelon</i> <i>4/30/14 (3/24/16)</i>	HSR, FERC, DE, DC, MD, NJ, VA, FCC	Company MAE (with Company deemed to be 50% of its size and matters imposed on Buyer deemed to be imposed on the Company)	Reasonable best efforts to take all actions and do all things necessary, including defending through litigation.	"Hell or High Water" Payment of Reverse Break-up Fee (\$180M), even if due to an order that would impose a Burdensome Condition on Exelon. Fee is paid via redemption for \$0 of Preferred Stock purchased by Exelon at signing of Merger Agreement. Either Party may extend drop dead date by 3 months if all other Conditions Precedent have been satisfied or waived.

Transaction Announcement Date (Closing Date)	Required Regulatory Approvals	Regulatory Approvals Condition Precedent "Gauge"	Efforts Required	Effect of Failure to Obtain
UNS/Fortis 12/11/13 (8/15/14)	HSR, CFIUS, FERC, AZ, FCC	Company MAE or Combined Company MAE (with Combined Company deemed to be only the size of the Company)	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • eliminate all impediments to obtaining approvals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	No liability if terminated due to failure to obtain approvals or imposition of a burdensome condition by approvals. Automatic six month extension if all other Conditions Precedent have been satisfied or waived.
NV/Berkshire 5/29/13 (12/19/13)	HSR, FERC, NV, FCC	Company MAE or Combined Company MAE (with Combined Company deemed to be only the size of the Company)	Reasonable best efforts to take all actions and do all things necessary, including: <ul style="list-style-type: none"> • defending through litigation, including appeals • eliminate all impediments to obtaining approvals • agreeing to divestitures • taking any action required by a Governmental Entity • agreeing to conduct limitations 	No liability if terminated due to failure to obtain approvals or imposition of a burdensome condition by approvals. Either Party may extend drop dead date by 3 months if all other Conditions Precedent have been satisfied or waived.

Effect of Willful Breach in Selected Utility Mergers and Acquisitions

January 1, 2013 – January 30, 2018

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<p>SCANA/Dominion 1/03/18 (pending)</p>	<p>Break-up and reverse break-up fees payable in specified circumstances.</p>	<p>“Willful Breach” means, with respect to any breach or failure to perform any of the covenants or other agreements contained in this Agreement, a breach that is a consequence of an act or failure to act undertaken by the breaching party with actual knowledge that such party’s act or failure to act would result in or constitute a breach of this Agreement. For the avoidance of doubt, the failure of a party hereto to consummate the Closing when required pursuant to Section 1.02, or, on the Closing Date, cause the Effective Time to occur pursuant to Section 1.03, shall be a Willful Breach of this Agreement.</p>	<p>Break-up fees are exclusive remedy if paid.</p>

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<p><i>Elizabethtown Gas/South Jersey Industries</i> <i>10/16/17 (pending)</i></p>	<p>Break-up and reverse break-up fees payable in specified circumstances.</p>	<p>“<u>Willful Breach</u>” means a breach that is a consequence of a deliberate act or deliberate failure to act undertaken by the breaching Party with the knowledge that the taking of or failure to take, such act would, or would reasonably be expected to, cause or constitute a material breach of any covenants or agreements contained in this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the acquisition of the Purchased Assets, the assumption of the Assumed Obligations and the other transactions contemplated by this Agreement to be completed at the Closing (the “<u>Acquisition</u>”) after the applicable conditions to the Closing set forth in <u>VIII Article</u> have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Acquisition) shall constitute a Willful Breach of this Agreement by such Party.</p>	<p>In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Willful Breach occurs.</p>

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
AVA/Hydro One Limited 7/19/17 (pending)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Willful and material breach not defined	No damages remedy unless willful and material breach occurs. Break-up Fees are sole and exclusive remedy if paid
Westar/Great Plains 7/9/17 (pending)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	“Willful Breach” means a breach that is a consequence of a deliberate act or deliberate failure to act undertaken by the breaching Party with the Knowledge that the taking of, or failure to take, such act would, or would reasonably be expected to, cause or constitute a material breach of any covenants or agreements contained in this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the Merger and the other transactions contemplated hereby after the applicable conditions to the Closing set forth in Article VII have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Merger) shall constitute a Willful Breach of this Agreement.	No damages remedy unless an Willful Breach occurs In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy unless a Willful Breach occurs In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Willful Breach occurs If a Willful Breach occurs, the company can pursue damages, including lost premium to shareholders

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
Macquarie/Eversource 6/1/17 (12/4/2017)	Reverse break-up fee provision redacted.	"Willful Breach" of a Party means a material breach of any representation, warranty, covenant or other agreement set forth in this Agreement that is a consequence of an act or failure to act by such Party, with the actual knowledge of such Party at the taking of such act or failure to take such act would cause or constitute a material breach of this Agreement.	No termination of the agreement shall relieve any Party for any liability for Willful breach of the agreement.
WGL Holdings/AltaGas 1/25/17 (pending)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	"Willful and Material Breach" means a material breach that is a consequence of an action undertaken or failure to act by the breaching party with the actual knowledge that the taking of such action or such failure to act would constitute a breach of this Agreement. "Regulatory Failure Willful and Material Breach" means (a) a Willful and Material Breach by Parent of its obligations under Section 5.4 and (b) Parent acted in bad faith.	No damages remedy unless an Willful and Material Breach occurs or, in the case of the buyer's obligations to seek the regulatory approvals, a Regulatory Failure Willful and Material Breach occurs. In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy unless a Willful and Material Breach occurs In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Regulatory Failure Willful Breach occurs If a Willful and Material Breach occurs (or, in the case of buyer's covenants to obtain the regulatory approvals, a Regulatory Failure Willful and Material Breach occurs, the company can pursue damages

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<p>Westar/Great Plains 5/29/16 (terminated 7/9/17)</p>	<p>Break-up Fee payable in specified circumstances</p> <p>Reverse Break-up Fee payable in specified circumstances</p>	<p>“Willful Breach” means a breach that is a consequence of a deliberate act or deliberate failure to act undertaken by the breaching Party with the Knowledge that the taking of, or failure to take, such act would, or would reasonably be expected to, cause or constitute a material breach of any covenants or agreements contained in this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the Merger and the other transactions contemplated hereby after the applicable conditions to the Closing set forth in Article VII have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Merger) shall constitute a Willful Breach of this Agreement.</p>	<p>No damages remedy unless an Willful Breach occurs</p> <p>In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy unless a Willful Breach occurs</p> <p>In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Willful Breach occurs</p> <p>If a Willful Breach occurs, the company can pursue damages, including lost premium to shareholders</p>

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<p><i>Empire District/Algonquin 2/9/16 (1/1/17)</i></p>	<p>Break-up Fee payable in specified circumstances</p> <p>Reverse Break-up Fee payable in specified circumstances</p>	<p>“Willful Breach” means a breach that is a consequence of an act or omission undertaken by the breaching Party with the Knowledge that the taking of or the omission of taking such act would, or would reasonably be expected to, cause or constitute a material breach of this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the Merger and the other transactions contemplated hereby after the applicable conditions to the closing set forth in Article VII have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Merger) shall constitute a Willful Breach of this Agreement.</p>	<p>No damages remedy unless an Willful Breach occurs.</p> <p>In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy</p> <p>In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Willful Breach occurs</p> <p>If a Willful Breach occurs, the company can pursue damages, including lost premium to shareholders</p>

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<p><i>ITC Holdings/Fortis</i> <i>2/9/16 (10/14.16)</i></p>	<p>Break-up Fee payable in specified circumstances</p> <p>Reverse Break-up Fee payable in specified circumstances</p>	<p>“Willful Breach” means with respect to any breaches or failures to perform any of the covenants or other agreements contained in this Agreement, a material breach that is a consequence of an act or failure to act undertaken by the breaching Party with actual knowledge that such Party’s act or failure to act would, or would reasonably be expected to, result in or constitute a breach of this Agreement. For the avoidance of doubt, a Party’s failure to consummate the Closing when required pursuant to Section 1.2 shall be a Willful Breach of this Agreement.</p>	<p>No damages remedy unless an Willful Breach occurs.</p> <p>In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy</p> <p>In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy</p> <p>In cases where the Reverse Break-up Fee is not payable but a Willful Breach has occurred, damages may include lost premium to shareholders</p>
<p><i>Questar/Dominion</i> <i>2/1/16 (9/16/16)</i></p>	<p>Break-up Fee payable in specified circumstances</p> <p>Reverse Break-up Fee payable in specified circumstances</p>	<p>Willful and material breach not defined</p>	<p>No damages remedy unless willful and material breach occurs</p> <p>Break-up Fees are sole and exclusive remedy</p>

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
<i>Piedmont/Duke</i> <i>10/26/15 (10/3/16)</i>	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Willful and material breach not defined	No damages remedy unless willful and material breach occurs Break-up Fees are sole and exclusive remedy unless there is a willful and material breach
<i>TECO/Emera</i> <i>9/4/15 (7/1/16)</i>	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	<p>“Willful Breach” means a breach that is a consequence of an act or omission undertaken by the breaching Party with the Knowledge that the taking of or the omission of taking such act would, or would reasonably be expected to, cause or constitute a material breach of this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the Merger and the other transactions contemplated hereby after the applicable conditions to the Closing set forth in Article VII have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Merger) shall constitute a Willful Breach of this Agreement.</p>	No damages remedy unless an Willful Breach occurs. In cases where the Break-up Fee is payable, the Break-up Fee is sole remedy In cases where the Reverse Break-up Fee is payable, the Reverse Break-up Fee is sole remedy unless a Willful Breach occurs, in which case the company can pursue damages as well, including lost premium to shareholders.

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
AGL/Southern 8/24/15 (7/1/16)	Break-up Fee payable in specified circumstances No Reverse Break-up Fee	Intentional breach not defined. "Willful" breach will be deemed to have occurred if the Company took or failed to take action with knowledge that such action or inaction constituted a breach of such obligation	No damages remedy unless an intentional breach occurs. Break-up Fee is sole remedy unless a willful breach occurs and relates to (i) calling shareholders meeting/proxy or (ii) covenant not to solicit alternative transaction
UIL/Iberdrola (USA) 2/26/15 (12/16/15)	Break-up Fee payable in specified circumstances No Reverse Break-up Fee	Knowing and intentional breach not defined	No damages remedy unless knowing and intentional breach occurs, except for breach of representations, warranties and covenants If termination is due to breach (apparently without regard to whether knowing and intentional or not) of representations, warranties or covenants, Acquirer may collect Break-up Fee and also sue for damages
HEI/NextEra 12/3/14 (terminated - 7/16/16)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Willful breach not defined	No damages remedy unless willful breach occurs Break-up Fees are sole and exclusive remedy unless there is a willful breach

Transaction Announcement Date (Closing Date)	Applicable Break-Up Fees	Willful Breach Definition	Effect of Willful Breach on Available Remedies
CLECO/Macquarie/BCIMC 10/20/14 (4/13/16)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Knowing and intentional breach not defined	No damages remedy unless knowing and intentional breach occurs Acquirer's maximum liability cannot exceed the amount of the Reverse Break-up Fee
Integrys/WEC 6/23/14 (6/29/15)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Willful breach not defined	No damages remedy unless willful breach occurs Break-up Fees not explicitly stated to be sole remedies
Pepco/Exelon 4/30/14 (3/24/16)	Break-up Fee payable in specified circumstances Reverse Break-up Fee payable in specified circumstances	Willful and intentional material breach not defined	No damages remedy unless willful and intentional material breach occurs Break-up Fees are sole and exclusive remedy
UNS/Fortis 12/11/13 (8/15/14)	Break-up Fee payable in specified circumstances No Reverse Break-up Fee	Willful and material breach not defined	No damages remedy unless willful and material breach occurs Break-up Fee is a liquidated damage unless there is willful and material breach
NV/Berkshire 5/29/13 (12/19/13)	Break-up Fee payable in specified circumstances No Reverse Break-up Fee	Willful and material breach not defined	No damages remedy unless willful and material breach occurs Break-up Fee is a liquidated damage unless there is willful and material breach

Compensation and Benefit Matters in Selected Utility Mergers and Acquisitions

January 1, 2013 – January 30, 2018

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
SCANA/Dominion 1/03/18 (pending)	\$14,600	Fully vest Same as award agreement	Vest at target Same as award agreement	until 12/31/19 no less than	until 12/31/19 no less than	until 12/31/19 substantial comparable in the aggregate	until 12/31/19 as provided in disclosure schedule	until 12/31/19 protection from relocation by more than 50 miles
Elizabethtown Gas/South Jersey Industries 10/16/17 (pending)	\$1,700	N/A	N/A	Until end of full calendar year after closing; not less than	None.	Until end of full calendar year after closing no less favorable in the aggregate	Included in benefit protection	Assignment of worker's compensation and disability plans Full vesting of 401(k) account 2 years of continued retiree health

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
Avista/Hydro One 7/19/17 (pending)	\$5,300	If vesting date during year of closing, fully vest If vesting date following year of closing, converts to RSU of Parent Award agreement: full vest (unless assumed)	Vest at actual (if performance period ended); Vest at target (if performance period not ended) Award agreement: double trigger pro rata vesting at actual	3 years no less favorable in the aggregate	3 years no less favorable in the aggregate	3 years no less favorable in the aggregate	Assumption of plan	Implement executive retention program
Westar/Great Plains 7/9/17 (pending)	\$26,503	WR: Fully vest (payable in stock) Same as award agreement GXP: Convert to awards of Holdco	WR: Vest at greater of target or actual (payable in stock) Award agreement: vest at actual GXP: Convert to awards of Holdco	2 years no less favorable	2 years substantially comparable in the aggregate	2 years substantially comparable in the aggregate	2 years as provided in disclosure schedule Assumption of plan	2 years retiree welfare benefits no less favorable than retirees of Holdco

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
Macquarie/ Eversource 6/1/17 (12/4/2017)	\$1,675	N/A	N/A	No protection period. Obligated to provide total compensation package that is market-based and competitive	None.	No protection period. Obligated to maintain employee plans generally consistent with those maintained at signing	None.	None.
Westar/Great Plains 5/13/16 (terminated 7/9/17)	\$12,193	Fully vest Same as award agreement	Vest at greater of target or actual Award agreement: vest at actual	2 years no less favorable	2 years substantially comparable in the aggregate	2 years substantially comparable in the aggregate	2 years as provided in disclosure schedule Assumption of plan	2 years retiree welfare benefits no less favorable than retirees of Parent

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
Empire District/Algonquin 2/9/16 (1/1/17)	\$2,389	Vest pro-rata Same as award agreement	Vest at target Award agreement: vest pro-rata target	2 years no less favorable	2 years comparable opportunities	2 years substantially comparable in the aggregate	Assumption of plan	3 year protection from adverse plan amendments and 3 years treatment as similarly situated employee of parent
ITC Holdings/Fortis 2/9/16 (10/14/16)	\$11,426	Fully vest Award agreement: double trigger vest	Vest at greater of target or actual Award agreement: double trigger vest pro-rata actual	3 years no less favorable	3 years no less favorable	3 years substantially comparable in aggregate	Assumption of plan	3 year protection from relocation by more than 50 miles
Questar/Dominion 2/1/16 (9/16/16)	\$5,982	Fully vest Award agreement: double trigger vest	Vest at greater of target or actual Award agreement: double trigger vest actual	For the later of 1 year after closing or 12/31/17, no less favorable in the aggregate	For the later of 1 year after closing or 12/31/17, no less favorable in the aggregate	For the later of 1 year after closing or 12/31/17, no less favorable in the aggregate	No less favorable than Parent plans for the later of 1 year after closing or 12/31/17	Guarantee of no less than target annual bonus for any year ending prior to closing and in which closing occurs

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
<i>Piedmont/Duke</i> 10/26/15 (10/3/16)	\$6,589	Fully vest Same as award agreement	Vest at Target Same as award agreement	For the later of 1 year after closing or 12/31/17, no less favorable	For the later of 1 year after closing or 12/31/17, no less favorable	For the later of 1 year after closing or 12/31/17, no less favorable in the aggregate	For the later of 1 year after closing or 12/31/17, no less favorable	Guarantee of pro-rata target bonus for year of closing
<i>TECO/Emera</i> 9/4/15 (7/1/16)	\$10,422	Vest pro-rata target; unvested portion converts to cash and subject to time-vesting Award agreement: double trigger vest at target	Vest pro-rata; unvested portion converts to cash and subject to time-vesting Award agreement: double trigger vest	2 years no less favorable	2 years substantially comparable in the aggregate	2 years substantially comparable in the aggregate	No less than scheduled	3-5 year protection to be treated as similarly situated employees of parent

Transaction Announcement Date (Closing Date)	Total Transaction Value (millions)	Treatment of Timed-Vested Equity	Treatment of Performance Awards	Cash Compensation Protection	Bonus Protection	Benefit Protection	Severance Protection	Other
AGL/Southern 8/24/15 (7/1/16)	\$12,001	Fully vest Same as award agreement	Deemed earned at greater of 125% or actual; paid as scheduled subject to termination protection Award agreement: vest pro-rata target or actual (depending on when CIC occurs)	1 year no less favorable	1 year no less favorable in the aggregate	1 year no less favorable in the aggregate	N/A	Retention plan to be put in place prior to closing

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