UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Electric Transmission Incentives Policy Under	)	
Section 219 of the Federal Power Act	)	Docket No. RM20-10-000
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COMMENTS OF
AMERICAN MANUFACTURERS

July 1, 2020

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American Manufacturers respectfully submit these Comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") notice of proposed rulemaking proceeding regarding changes to the Commission's transmission incentives policy in the above-captioned docket.[1] American Manufacturers have joined together on these Comments to advocate for a transmission incentives policy that ensures just and reasonable rates for the benefit of consumers.

To evaluate the Commission's proposed transmission incentives policy changes, American Manufactures have engaged Mr. Michael P. Gorman, a consultant in the field of public utility regulation whose return on equity ("ROE") and capital formation recommendations have been adopted by the Commission in past proceedings, and Mr. Ali Al-Jabir, a consultant in the fields of wholesale power market structure, cost allocation and rate design. In support of these comments, American Manufacturers have included Mr. Gorman's affidavit ("Exhibit No. AMF-1") and

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[1] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, Notice of Proposed Rulemaking*, 170 FERC ¶ 61,204 (2020) ("Incentives NOPR"). *See also* Notice of Proposed Rulemaking, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power* Act, 85 Fed. Reg. 18,784 (Apr. 2, 2020); Notice Denying Extensions of Time, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket No. RM20-10-000 (May 15, 2020).

accompanying exhibits ("Exhibit Nos. AMF-2 through AMF-5") as Attachment A and Mr. Al-Jabir's affidavit ("Exhibit No. AMF-6") as Attachment B.

I. DESCRIPTION OF AMERICAN MANUFACTURERS

American Manufacturers are comprised of some of the largest companies in the United States. American Manufacturers own and operate facilities in regions where an independent system operator ("ISO") or regional transmission organization ("RTO") is present, and in regions where an ISO or RTO is not present. All American Manufacturers pay, either directly or through bundled retail rates, for the costs of the transmission system. All American Manufacturers depend on a robust and reliable transmission system. A list of the groups or companies that comprise the American Manufacturers is included in Appendix 1 to these Comments.

II. INTRODUCTION

As the Commission considers comments filed in response to the Incentives NOPR, American Manufacturers urge the Commission to bear in mind the substantial transmission cost increases borne by customers in many regions of the country in recent years. Most of the policy changes under consideration in the Incentives NOPR could contribute to further increases in transmission costs, while a few proposals could mitigate these expenses. As noted in their Motion for Extension of Time, American Manufacturers are dedicating limited resources during a time of unprecedented economic challenges to prepare these Comments as an indication of the level of their collective concern about increasing transmission costs, and to encourage the Commission to remain mindful of this concern as it evaluates the path forward for its transmission incentives policy. Maintaining transmission reliability, while adopting policies that ensure reasonable and reasonably allocated costs for consumers, must be a fundamental touchstone in evaluating and rendering a decision regarding modifications to the Commission's transmission incentives policy.

Failure to do so would not only fall short of the Commission's duty to protect customers against excessive rates but also its statutory mandate to develop a transmission incentives policy that ensures reliability as well as reduces the delivered cost of power to consumers.

The Commission should not equate American Manufacturers' concern about rising transmission costs with opposition to transmission investment in general. Prudently planned and constructive transmission facilities can increase supply options, reduce congestion-related costs, enable the integration of renewable resources that are necessary to satisfy corporate sustainability goals, and promote grid reliability. American Manufacturers support such beneficial transmission investment and Commission policies that promote it. In evaluating transmission incentives in this rulemaking proceeding, however, the potential increased cost burden on transmission customers must remain a principal consideration, particularly in light of recent, substantial transmission cost increases. The Commission's decision-making must also not occur in a vacuum. Rather, the Commission must consider other relevant changes, in particular, the ROE methodology changes recently announced in Opinion No. 569-A,[2] as well as the impact on customers' transmission service rates and the Commission's ability to ensure such rates are just and reasonable.

American Manufacturers' Comments focus on the key issues that are especially important to ensuring that the Commission's electric transmission incentives policy under section 219 of the Federal Power Act ("FPA") results in just and reasonable rates.

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[2] *Ass'n of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("Opinion No. 569-A").

III. COMMENTS

A. THE INCENTIVES NOPR PROVIDES INSUFFICIENT SUPPORT FOR THE PROPOSED REFORMS TO THE COMMISSION'S CURRENT TRANSMISSION INCENTIVES POLICY.

In recent years, the level of transmission investment has been robust, and this trajectory is expected to continue for the foreseeable future. Market evidence provides a substantial basis for the conclusion that there is no need for the Commission to enhance its transmission incentives policy to spur additional transmission investment. Notwithstanding, the Incentives NOPR posits two overarching bases for reforming the Commission's transmission incentives policy. While recognizing that transmission infrastructure development has remained generally robust,[3] the Incentives NOPR states that the "types of transmission projects that are needed, and the use of rate treatments to incent them, must evolve to reflect the changes in market fundamentals."[4] In addition, the Incentives NOPR states that changes are necessary to "more closely align with the statutory language of FPA section 219."[5] For the reasons discussed below, the Commission's existing transmission incentives policy remains largely appropriate, even in the current economic climate, and continues to realize the statutory objectives of FPA section 219. As such, the sweeping changes proposed in the Incentives NOPR, especially those that are poised to substantially increase the allowed ROEs for transmission owners, are wholly unnecessary. To the extent the Commission moves forward with revamping its transmission incentives policy, however, American Manufacturers recommend that the final rule incorporate their recommended changes and principles to ensure that the FPA's consumer protection mandate, including the just

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[3] Incentives NOPR at P 26.

[4] *Id*.

[5] *Id*. at P 24.

and reasonable rate requirement, is properly balanced against public utilities' interests in increased ROE-based revenues.

1. The Incentives NOPR fails to reconcile the proposed liberalization of the existing transmission incentives policy with the increased level of transmission investment and rapid growth in transmission charges in recent years.

The rate incentive provisions of FPA section 219 were enacted approximately 15 years ago following a "long decline in transmission investment."[6] In recent years, however, transmission investment has been robust, and this pace is expected to continue for the near future. For instance, FERC-jurisdictional ISOs and RTOs have approved tens of billions of dollars in new transmission investments over the period 2012-2017.[7] An examination of FERC Form 1 data for the period between 2010 and 2019 shows that the electric utility industry's transmission plant in service grew by 165 percent, nearly double the pace of overall electric utility plant in service.[8] Moreover, reports from individual transmission owners demonstrate that future plans for investment in transmission remain significant. By way of illustration:

- In its 1st Quarter 2020 Earnings Release Presentation, American Electric Power's ("AEP") 2020-2024 Capital Forecast includes \$7.6 billion in transmission.[9]

- FirstEnergy reported a transmission investment plan that includes annual investment levels between \$1.2 billion and \$1.45 billion on through 2023.[10]

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[6] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 117 FERC ¶ 61,345 at P 36 (2006) ("Order No. 679-A").

[7] Affidavit of Ali Al-Jabir on behalf of American Manufacturers, Exhibit No. AMF-6 at 11 ("Exh. No. AMF-6").

[8] Affidavit of Michael P. Gorman on behalf of American Manufacturers, Exhibit No. AMF-1 at 8-10 ("Exh. No. AMF-1").

[9] American Electric Power, 1st Quarter 2020 Earnings Release Presentation at 33 (May 6, 2020), *available at* https://www.aep.com/newsroom/resources/earnings/2020-05/1Q20EarningsReleasePresentation.pdf.

[10] FirstEnergy, Investor FactBook, 1Q2020 at 12 (April 23, 2020), *available at* https://investors.firstenergycorp.com/webcast-and-presentations.

The level of investment in transmission facilities provides strong evidence that transmission owners have access to capital on reasonable terms and that they are not foregoing transmission development opportunities due to a lack of more robust incentives.[11] At the same time, the nation's demand for power has remained relatively flat over the last 15 years.[12] In other words, current base ROEs have been demonstrated to be more than adequate to attract capital for transmission investment. This evidence strongly supports a conclusion that there is no need for the Commission to reform its incentives policy in order to stimulate transmission investment.

The increase in transmission investment in recent years has caused a corresponding rise in the transmission costs paid by customers in many regions of the country.

- According to a 2017 survey of transmission rates and charges in PJM Interconnection, L.L.C. ("PJM") sponsored by American Municipal Power, Inc. ("AMP"), the total annual revenue requirement for transmission enhancements increased by 294.5 percent from 2011 to 2017.[13] Additionally, 12 PJM transmission owners had a 20 percent or more increase in revenue requirement from 2009 to 2017.[14]

- In the last decade, PJM transmission costs increased from $4.22 to $10.39 per megawatt-hour, or 145 percent.[15] In the last five years, the costs increased from $7.69 to $10.39 per megawatt-hour, or 35 percent.[16]

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[11] *See generally* Exh. No. AMF-1 at 5-11.

[12] U.S. Energy Information Administration, Electricity Data Browser (2001-2019), *available at* https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=vvvvvvvvvvvvo&endsec=vg&linechart=ELEC.SALES.US-ALL.A&columnchart=ELEC.SALES.US-ALL.A&map=ELEC.SALES.US-ALL.A&freq=A&ctype=linechart&ltype=pin&maptype=0&rse=0&pin=.

[13] *See* Rose, Ken, Survey of PJM Transmission Rates and Charges, Transmission Study for American Municipal Power, Inc. at 14 (Sept. 21, 2010), *available at* https://www.amppartners.org/Assets/AMP_Rose_Transmission.pdf.

[14] *Id*.

[15] Q1 2020 Quarterly State of the Market Report for PJM: January through March at Table 1-10 (May 14, 2020), *available at* https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q1-som-pjm-sec1.pdf.

[16] *Id*.

- In the California Independent System Operator ("CAISO") region, total transmission charges increased from $2.8 billion to $3.1 billion, an 11% increase, in just four years.[17]

- In New England, total transmission costs increased from $2.0 billion to $2.2 billion between 2015-2020, an increase of 10% in just five years.[18]

- The U.S. Energy Information Administration's 2020 Energy Outlook projects that rising transmission and distribution costs will continue to offset declining generation costs through 2050.[19]

Transmission cost increases have imposed a significant burden on consumers across the nation, and the Commission should not add to this burden by making it unnecessarily easier for applicants to receive incentives, especially those that enhance returns on equity, that are not necessary to promote beneficial transmission development. In accordance with the FPA's consumer protection mandate, the Commission has a duty to ensure that its transmission incentives policy is not misused to boost value to shareholders by subjecting consumers to excessive rates.[20] In fact, as concerns incentives, the plain language of section 219 of the FPA directs the Commission to consider incentives as a means to an end – the end being reductions in the delivered cost of power.[21] This is especially true now as the nation's economy processes the impact of the current global health pandemic and American Manufacturers attempt to transition to operating under a "new normal" fraught with uncertainty about the future.

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[17] *See* CAISO, Five Year Summary of Comparable Statistics (2015=2019) at 1 (May 21, 2020), *available at* www.caiso.com/Documents/Five_Year_2015-2019_Financial_Summary.pdf.

[18] 2019 Annual Markets Report, Internal Market Monitor, ISO New England Inc. at Fig. 2.1 (June 6, 2020), *available at* https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf.

[19] U.S. Energy Information Administration, IA Annual Energy Outlook 2020 at 74 (Jan. 29. 2020), *available at* https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf.

[20] Exh. No. AMF-1 at 11-13 (discussing enhancement of shareholder value as a strong incentive to make infrastructure investment).

[21] 16 U.S.C. § 824s.

2. Market data do not support a finding that transmission incentives spur investment that would not otherwise occur.

According to the Incentives NOPR, "the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably."[22] Although changes certainly have occurred since the issuance of Order No. 679,[23] based on the information regarding transmission investment levels set forth in Section III.A.1, there was no decline in transmission investment after the Commission issued its 2012 Policy Statement,[24] which scaled back the award of incentive ROE adders. To the contrary, transmission investment increased significantly in the years following 2012 and continues to grow. This reality confirms that project-specific ROE adders did not (and do not and would not) play a major role in driving transmission investment.[25] And the Incentives NOPR does not demonstrate otherwise. The lack of empirical support for any correlation between incentives and investment undermines the fundamental premise underlying the Incentives NOPR that additional and more generous incentives are needed at this time.[26] Substantial evidence does not support and, in fact, runs contrary to the Commission's preliminary determination that significant changes to the Commission's existing policy on transmission incentives are necessary to promote investment in transmission infrastructure.

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[22] Incentives NOPR at P 25.

[23] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006) ("Order No. 679"), 'Order No. 679-A, 117 FERC ¶ 61,345,, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[24] *See Promoting Transmission Investment Though Pricing Reform*, Policy Statement, 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement").

[25] Exh. No. AMF-6 at P 3 ("There is insufficient evidence to conclude that additional administrative ROE incentives must be provided to incumbent utilities to include new transmission investment in the areas identified in the Incentives NOPR"); *id.* at PP 6-11.

[26] *Id*. at P 11 ("All of this evidence underscores the fact that there are no obstacles to transmission investment under the current regulatory paradigm that merit an increase in administratively-induced ROE incentives of the kind proposed in the Incentives NOPR.").

3. Rather than a wholesale change to transmission incentives policy, the Commission should consider improvements to regional transmission planning processes to stimulate desired types of transmission projects.

Although the data show robust investment in transmission, the Incentives NOPR seeks to ensure that the right type of transmission is being built and to make available incentives to encourage projects that might provide particular benefits or that reflect certain project characteristics. Inquiring whether the most beneficial and cost-effective transmission projects are being built is a reasonable question; however, such a question is more appropriately treated as a planning matter, rather than an issue of transmission incentives. Open and transparent planning processes under Order No. 890[27] and Order No. 1000[28] have identified, and should be further enhanced to identify, beneficial and cost-effective transmission – including interregional projects – and incentives should generally not be necessary to promote this infrastructure investment. To the extent beneficial transmission is not being built, there is no evidence that decisions not to build can be attributed to any shortcomings in the Commission's transmission incentives policy. Rather, such a development likely reflects a lack of need on a region-specific basis, problems with the transmission planning process, or the existence of other obstacles that cannot be addressed by simply enhancing transmission incentives.

According to Mr. Al-Jabir, "ROE incentives come at a significant cost to ratepayers that is unnecessary if there are alternative means of incentivizing new transmission construction to meet the FERC's policy goals."[29] Rather than modify its policies for awarding project-specific incentives, the Commission should assess whether, and if so why, open transmission planning

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[27] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 (2007) ("Order No. 890").

[28] *18 CFR Part 35 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order No. 1000").

[29] Exh. No. AMF-6 at P 12.

processes may not always produce the most beneficial and cost-effective projects, as contemplated by the Commission's rules and policies. The Commission should focus its resources on seeking to ensure that regional planning process rules are structured to fulfill the Commission's goals of identifying beneficial transmission projects or non-transmission alternatives. In short, "Competition, rather than administratively-induced incentives to incumbent utilities, is the most efficient means of incenting transmission investment and delivering value to the grid and to consumers at the lowest reasonable cost."[30]

American Manufacturers further recommend that the Commission prioritize harmonization of its transmission planning and incentives policies by conditioning the award of any incentives, including any RTO participation incentives, on projects being approved as part of the relevant regional transmission planning process. No incentives, especially any RTO participation incentives, should be permitted for any rate base that is added as a result of projects that are occurring outside of regional transmission planning processes, such as the projects that comprise "Other Projects" in MISO or "Supplemental Projects" in PJM.

Conversely, it would be *inappropriate* for the Commission to adopt changes to its transmission incentives policies to compensate for deficiencies in such processes. A properly functioning regional transmission planning process should already be identifying the more efficient or cost-effective projects to ensure reliability and reduce the cost of delivered power by reducing transmission congestion, consistent with the objective that Congress sought to achieve when enacting section 219 of the FPA. Incentives aimed at realizing benefits that should already

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[30] *Id*.

be the focus of the regional planning process are not only unreasonable and unnecessary but also inconsistent with Commission precedent.[31]

Finally, enhancing implementation of the Commission's obligation to encourage distributed energy resources ("DER"), such as cogeneration and waste heat recovery qualifying facilities ("QFs"), would reduce dependence on the transmission system by promoting a framework that would enable supply to be physically located closer to demand. Encouraging DER would also help address any perceived need for substantial amounts of new transmission investment. Moreover, continuing to encourage DER development would assist in promoting the Commission's policy objectives at a much lower cost. As discussed below, section 219 directs the Commission to develop incentive-based rate treatments that benefit consumers by ensuring reliability and *reducing* delivered power costs.

B. THE PROPOSED SHIFT FROM A NEXUS TEST TO A BENEFITS TEST DOES NOT COMPORT WITH FPA SECTION 219.

The Incentives NOPR includes a proposal to fundamentally change the framework for evaluating a project's eligibility for transmission incentives. Specifically, the Commission proposes to move from the current "nexus test" to a "benefits test".[32] Under the "nexus test" an applicant must demonstrate that a connection exists between the total package of incentives sought and the proposed investment, in light of the risks and challenges facing a transmission project developer that is seeking incentives.[33] By contrast, the benefits test would focus on a project's economic and reliability benefits to consumers – i.e., ensuring reliability and reducing delivered

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[31] *See New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001), *order on reh'g*, 98 FERC ¶ 61,249 (2002) (denying incentive for maintenance/construction pilot project that would "unjustly reward" the committee "for doing what it is supposed to do, i.e., to adequately maintain its facilities in a prudent, cost-effective manner.").

[32] Incentives NOPR at P 34.

[33] *Id*. at P 35.

power costs by lowering transmission congestion.[34] Under the new framework, the "applicant must demonstrate that the incentives it seeks meet a specified benefits-to-costs threshold for an economic benefits showing or provide a significant and demonstrable reliability enhancement for a reliability benefits showing," without requiring a showing that the incentives are needed to prompt the transmission investment.[35] As discussed below, a plain reading of FPA Section 219 requires a causal connection between the incentive sought and a public utility's investment decision. The proposed benefits test falls short of satisfying this requirement. Additionally, FPA Section 219 also requires that the transmission incentives policy result in material consumer benefits in the form of reliability and a reduction in the cost of delivered power, but the Incentives NOPR is silent on, and appears not even to consider, whether transmission incentives drive down delivered power costs.

FPA section 219(a) directs the Commission to "establish, by rule, *incentive-based* (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities *for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion*."[36] The Commission's proposal to depart from the nexus test is based on its finding that FPA section 219 does not require an applicant to demonstrate a connection between the total package of incentives sought and the proposed investment, nor that the Commission find the transmission project would otherwise not occur without the incentive.[37] According to the Incentives NOPR, replacing the nexus test with a

[34] *Id*. at P 36.

[35] *Id*. at P 37.

[36] 16 U.S.C. § 824s(a) (emphasis added).

[37] Incentives NOPR at P 35.

benefits test better realizes the "purpose and language of FPA section 219, which is to benefit consumers….".[38]

The Commission's new interpretation of FPA section 219(a) does not comport with the plain meaning of the statutory language. "Incentive" refers to "something that incites or has a tendency to incite to determination or action."[39] FPA section 219(a) explicitly directs the Commission to establish "*incentive*-based rate treatments."[40] The plain meaning of this phrase indicates that any ROE incentives must "incite…determination or action" by the public utilities receiving such incentives. FPA section 219(a) further states that the "incentive-based rate treatments" must be "for the purpose of benefitting consumers." FPA 219(a) establishes the need for a causal connection between the action or behavior to be motivated by the "incentive-based rate treatment" and the consequence of that behavior – *i.e.*, consumer benefits in the form of reliability, reductions to the cost of delivered power, and reduced transmission congestion. Thus, contrary to the Incentives NOPR's claim, the proposal to abandon the nexus test in favor of the benefits test does not better comport with the "purpose and language" of the FPA. In fact, the benefits test proposed in the Incentives NOPR does not recognize at all the FPA's causal connection requirement.

The Commission adopted the nexus test in order to ensure "incentives are not provided in circumstances where they do not materially affect investment decisions."[41] Incentives granted under FPA section 219 are not intended as a "bonus for good behavior."[42] In *CPUC v. FERC,* the

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[38] *Id.*

[39] *Merriam-Webster Dictionary, available at* https://www.merriam-webster.com/dictionary/incentive. *See also* Incentives NOPR, Glick Dissent at P 4 ("incentives must actually incentivize something").

[40] 16 U.S.C. § 824s(a) (emphasis added).

[41] Order No. 679-A at P 25; Order No. 679 at P 26.

[42] Order No. 679 at P 26 (internal quote omitted).

court noted that Order No. 679 incorporated FERC's "longstanding policy that rate incentives must be prospective and that there must be a connection between the incentive and the conduct meant to be induced."[43] Of particular importance here, the court stated, "[t]he requirement of a demonstrated, case-specific nexus tethers each authorized incentive rate increase to a determination that granting the incentive in a given case actually serves Congress's objective of benefitting consumers."[44] Thus, an incentive must be shown to influence the utility's decision to realize the goal the incentive seeks to promote. The nexus test requires an applicant to make this showing.

Furthermore, the plain language of FPA Section 219 directs the Commission to establish incentive-based rate treatments "for the purpose of benefitting consumers by ensuring reliability and *reducing the cost of delivered power by reducing transmission congestion*."[45] Although the Incentives NOPR asserts that the proposed changes to the Commission's transmission incentives policy is intended to "more closely align it with the statutory language of FPA section 219,"[46] American Manufacturers respectfully submit that the Incentives NOPR misses its own mark. Specifically, the Incentives NOPR is conspicuously silent on the issue of whether transmission incentives, in fact, reduce the cost of delivered power, as required under section 219 of the FPA. The Incentives NOPR does not point to any empirical analysis to assess the impact of transmission incentives on the cost of delivered power. Such an analysis is especially important given that the overall demand for power generally has remained flat since the first iteration of the Commission’s

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[43] *CPUC v. FERC*, 879 F.3d 966, 977 (9th Cit. 2018).

[44] *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127, 133 (D.C. Cir. 2019); *see also City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955) (stating that an incentive rate increase must be shown to be "in fact needed, and is no more than is needed, for the purpose.").

[45] 16 U.S.C. § 824s(a) (emphasis added).

[46] Incentives NOPR at P 2.

transmission incentives policy in 2005 and calls into question whether transmission incentives have realized, and if so, can continue to realize, the cost savings criterion of FPA section 219.[47] Absent such data to provide a foundation for the proposed changes outlined in the Incentives NOPR, the proposed changes are arbitrary and capricious and not the result of a reasoned decision-making process. As such, American Manufacturers urge the Commission to suspend this rulemaking process, perform the necessary analysis, and use the results to inform its decision-making process on whether and, if applicable, how to modify existing transmission incentives.

Finally, the nexus test aligns with the Commission's goal of promoting economic efficient investment in transmission infrastructure assets.[48] Changes to the existing transmission incentives policy that would provide "opportunity to earn above market rates of return"[49] would not represent the type of incentive that the FPA intends to offer. The Commission must avoid creating "significant economic incentives and financial incentives for TOs to maximize transmission investments to achieve this windfall opportunity"[50] Such a misguided focus could negatively influence the RTO/ISO planning process as well as electric utility companies' management of capital programs, financial integrity, and credit standing.[51]

American Manufacturers urge the Commission, consistent with its statutory responsibilities and consistent with appellate precedent, to maintain the nexus test for evaluating applications for transmission incentives. The Commission's existing approach for evaluating

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[47] *See* n.12 *supra*.

[48] Exh. No. AMF-1 at 5-6.

[49] *Id*. at 29.

[50] *Id*. at 29-30.

[51] *Id*.

applications for project-specific incentives is generally sound.[52] Neither the information regarding the level of transmission investment (as discussed above) nor the reasons offered in the Incentives NOPR support the fundamental changes to the Commission's existing framework for evaluating project-specific incentives. The 2012 Policy Statement appropriately reframed the nexus test to focus more directly on the requirements of Order No. 679, and established expectations that applicants will take all reasonable steps to mitigate risks of a project, including requesting risk-reducing incentives and considering project alternatives, before seeking an incentive ROE based on a project's risks and challenges.[53] Accordingly, the nexus test should be preserved.

C. APPLICATION OF THE BENEFITS TEST FOR ECONOMIC PROJECTS

The Incentives NOPR proposes to assess the economic benefits offered by an economically incentivized transmission project by measuring the degree to which such benefits exceed such project's costs.[54] A specified "benefit-to-cost" ratio would serve as the Commission's benchmark for determining an applicant's eligibility for rate incentives.[55] To the extent the Commission abandons the nexus test and adopts a benefits test in this proceeding, American Manufacturers recommend that the Commission incorporate the following modifications to the proposed benefits test.

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[52] Under the "nexus test," an applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219" and "that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project." The applicant must also show "that resulting rates are just and reasonable." *See* 18 C.F.R. § 35.35(d).

[53] *See* 2012 Policy Statement at P 16.

[54] Incentives NOPR at P 42.

[55] *Id.* at P 37.

1. The benefits test should incorporate basic consumer protection principles.

Any application for incentives under a "benefits test" that seeks an ROE adder should be required to include an answer to the following question: What will consumers receive in exchange for the money they are paying for the ROE adders? If the focus of the Commission's transmission incentives policy is consumer benefits, then a public utility seeking incentives must be able to answer this simple question. The response should be presented in plain language that can be understood by consumers without the need to engage an expert and, as discussed in more detail below, should include projections of the financial impact on customers' network integration transmission service ("NITS") and point-to-point transmission service ("PTP") rates so that all consumers can calculate the impact of the incentives proposal on their overall transmission service costs. Such information is also necessary to ensure that the public utility is not being awarded ROE incentives for benefits associated with a project that it already has an obligation to build.[56] In the absence of such a safeguard, transmission incentives could amount to a windfall to the transmission owner.

Next, given the long-term nature of transmission projects and the recovery of their associated costs, fundamental principles of fairness and equity dictate that there must be an effort to ensure that the groups of customers paying for the costs of the transmission incentives also realize the corresponding benefits over the useful life of a project. As Mr. Gorman explained, "[c]reating economic incentives that encourage electric utilities to accelerate capital investments can increase prices to customers immediately, while benefits may not be realized by customers for

[56] *See* Exh. No. AMF-6 at P 10 (explaining at RTO expansion planning processes "create an obligation on the part of member transmission owners to work in good faith to construct and put into service the projects that are approved in these expansion plans").

many years out into the future."[57] Consequently, to satisfy the benefits test, an applicant should be required to include a plan for matching benefits and costs over the useful life of the proposed project. To this end, American Manufacturers recommend that a public utility be required to present the expected impact of a project's costs and benefits on the utility's NITS and PTP rates during each year of the project's useful life or the duration of the requested incentive, whichever is longer. The consumer impact should be shown in a unit of measurement that allows customers to evaluate the proposed changes relative to their transmission service costs. This requirement would not only ensure matching of costs and benefits, but also facilitate consumer understanding of how the transmission incentives costs and benefits of the proposed project are expected to impact their transmission costs and service over the long-term, which is important for their own planning purposes.

Finally, consumers should be held harmless in the event an applicant's project fails to deliver the expected benefits. For example, financial incentives awarded under the benefits test should be conditioned upon the applicant demonstrating that the benefit-to-cost estimates have actually been realized. Such demonstrations could be made in the form of periodic compliance filings submitted to the Commission, subject to public notice and comment, or added as an exhibit or workpaper to annual formulate rate informational filings. Moreover, in the event the utility fails to produce the promised benefits, then customers should be reimbursed accordingly. Establishing accountability for expected benefits is essential to ensuring that consumers actually get the "bang for their buck," especially when the consumer dollars at stake are so high. Failure to hold public utilities receiving incentives premised on the materialization of consumer benefits accountable for their performance flies in the face of the FPA's consumer protection mandate. It also runs counter

[57] Exh. No. AMF-1 at 14.

to FPA section 219(a)'s directive that FERC establish *incentive-based* rate treatments.[58] Accordingly, any shift to a benefits test should be accompanied by an effective mechanism for measuring and verifying benefits as well as holding public utilities accountable and consumers harmless in the event such benefits are not realized.[59]

2. To the extent it is incorporated into the incentives framework, a standardized benefit-to-cost threshold should be formulated by an independent entity.

The NOPR provides transmission projects should offer substantially more net economic benefits than the average transmission project to be eligible for an incentive premised upon economic benefits.[60] Accordingly, the NOPR proposes to establish separate benefit-to-cost thresholds for economic incentives based on the cost of the transmission project, with $25 million as the distinction between small system modifications and significant transmission facility expansions.[61] For small transmission system modifications to be eligible for an ex-ante economic benefits ROE incentive, the NOPR proposes that the benefit-to-cost ratio must exceed the ratio for the 75th percentile of transmission projects studied, which was 33.91.[62] For significant transmission facility expansions, the NOPR proposes a benefit-to-cost ratio of 3.98 based on the ratio for the 75th percentile level of the transmission projects studied.[63]

The Commission's proposed benefit-to-cost ratios are based on the results of approximately 40 economic transmission projects selected by three different regional transmission processes

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[58] *See* Section III.B *supra*.

[59] *See, e.g.*, Exh. AMF-6 at P 16 (noting that the winning bidder in a competitive solicitation process for transmission solution "agreed to a penalty structure that imposed reductions to its project-specific ROE if it failed to meet the project in-service date specified in its agreement with MISO").

[60] Incentives NOPR at P 56.

[61] *Id*.

[62] *Id*. at P 58.

[63] *Id*. at P 57.

conducted by MISO, CAISO, and PJM.[64] The RTO/ISOs utilized various approaches to select transmission projects within their respective regions over a seven-year period.[65] None of those processes, however, was developed with the expectation that they would be used as part of a FERC process for determining a public utility's eligibility for transmission rate incentives. Further, due to differences in the processes, there are likely inconsistencies regarding the costs and benefits that are taken into consideration when determining a project's net benefits. To the extent the Commission seeks to rely upon "national benefit-to-cost ratios" as part of its transmission incentives policy, then FERC Staff, or a non-governmental independent entity or, alternatively, a task force of RTO/ISOs, should be tasked with developing standardized, national cost-to-benefit ratios. As part of a standardized cost-to-benefit ratio, the Commission should further direct that the cost of ROE incentives be reflected on the cost side of the ledger in order to ensure accuracy in the measuring of net benefits to consumers.

3. To be effective, a cost-to-benefit ratio must be based on quantifiable economic benefits that can be measured and verified based on publicly available information in order to ensure that public utilities remain accountable to their customers.

Under the benefit-to-cost threshold, the Commission proposes to measure benefits by looking at the "adjusted production cost, similar measures of congestion reduction, and certain other quantifiable benefits that are verifiable and not duplicative."[66] The Commission also proposes to establish a rebuttal presumption that RTO-derived economic benefits are included in the determination of an applicant's benefits.[67]

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[64] *Id*. at PP 57-58.

[65] *Id*. at P 57.

[66] *Id*. at P 50.

[67] *Id*.

Unlike costs, benefits arising from transmission projects are highly speculative and, therefore, more difficult to quantify. Nonetheless, to the extent the Commission is shifting its transmission incentives policies to focus on the expected benefits to consumers, then it must also establish a means to measure and verify that these benefits are realized. As stated previously, a measurement and verification process is central to holding a public utility accountable if it fails to deliver the benefits for which consumers have paid. Therefore, incentives awarded under any benefits test should be conditioned upon the applicant demonstrating that the benefits have been realized and, in the absence of such demonstration, be refunded to customers. To do anything less would fall short of the Commission's duty to ensure that customers are protected against excessive rates.

Additionally, American Manufacturers support the proposed use of RTO-adjusted production cost modeling as the source of economic benefits information. In fact, such modeling should be the only source relied upon for purposes of determining economic benefits. However, as the Commission acknowledged, ready access to such information may not be available.[68] Accordingly, the Commission should direct all RTOs to make production cost modeling information, as well as any information underlying the derivation of applicable benefit-to-cost ratios, accessible not only for public utilities and developers, but also to consumers and other interested stakeholders. Access to such information should be provided in a timely manner and in a format that is replicable by interested parties. Certain RTO/ISOs conduct processes that could

[68] *Id*. at P 52 ("Although some RTOs/ISOs appear to provide stakeholders access to the results of their adjusted production cost models, it is unclear whether all RTOs/ISOs provide public utilities with the results of their adjustment production cost models…as economic benefits measures, and the resulting benefit-to-cost ratios in a manner that would allow the developer to use these results to seek an ROE incentive for economic benefits.").

serve as a model, such as MISO's Market Efficiency Project process, which the Commission recently summarized as follows:

> Currently, to qualify as a Market Efficiency Project, a transmission project must cost at least $5 million and consist of facilities that have voltages of 345 kV or higher that constitute more than 50 percent of the combined project costs. Additionally, in order to be selected in the MTEP, a Market Efficiency Project must have a total regional benefit-to-cost ratio of at least 1.25-to-1, with benefits measured using an Adjusted Projection Cost Savings metric. If MISO selects a Market Efficiency Project in the MTEP, the project is then subject to the MISO's Competitive Developer Selection Process, under which qualified developers submit bids to construct the Market Efficiency Project. MISO designates the winning developer to construct the project and that developer, whether an incumbent or a non-incumbent, is then eligible to use the Market Efficiency Project regional cost allocation method.[69]

The foregoing measures would enable consumers and interested stakeholders to review important information, review and analyze the support for proposed transmission incentives, and meaningfully engage in the FERC proceeding, thereby ensuring a robust ROE framework. Notwithstanding, production cost models alone are insufficient to economically justify transmission investment and ensure that customers' interests are protected.[70]

4. American Manufacturers support the elimination of incentives available to Transcos.

American Manufacturers support the Commission's proposal to eliminate the incentives available to Transcos.[71] Section 219 of the FPA does not specifically addresses incentives to promote Transcos.[72] As the Commission also recognized, previous levels of investment by

[69] *Midcontinent Independent System Operator, Inc.*, 167 FERC ¶ 61,258 at P 3 (2019).

[70] Exh. No. AMF-1 at 34.

[71] Incentives NOPR at P 91.

[72] 16 U.S.C. § 824s.

Transcos are not sufficient to support continuation of the Transco incentive adder.[73] Further, the transmission industry has undergone material changes in circumstances since the Commission issued Order No. 679.[74] As Commissioner Glick recently explained:

> The electricity sector has changed dramatically in the intervening twelve years [since issuance of Order No. 679], not least because of subsequent Commission reforms, such as Order No. 1000, that have fundamentally altered the transmission landscape. It is certainly not clear that Transcos are superior to other public utilities that can and do invest in transmission facilities—including competitively developed transmission facilities—or that awarding Transcos a higher ROE actually leads to greater transmission investment.[75]

These fundamental changes, which the Commission also recognized,[76] coupled with the lack of evidence supporting an increased return for Transcos, support the Commission's proposal to remove from its regulations, incentives available to Transcos.

Further, Transcos face less risk than vertically integrated utilities or diversified utilities with affiliates serving multiple functions. Unlike generation assets, transmission assets and the service they provide, are largely insulated from competition. In addition, the prevalence of formula rates provides Transcos with the benefits of rate certainty and timely cost recovery supervised by a single regulator. Customers should not pay escalated rates that are not reflective of Transcos' risk. For these reasons, American Manufacturers support the proposal to eliminate the Transco-specific incentives.

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[73] Incentives NOPR at P 91 ("[W]e believe that the Transco business model has not enhanced the deployment of transmission infrastructure sufficiently to justify incentives based on this business model beyond those incentives available to all public utilities.").

[74] Order No. 679, 116 FERC ¶ 61,057, Order No. 679-A, 117 FERC ¶ 61,345, *order on reh'g*, 119 FERC ¶ 61,062.

[75] *GridLiance West Transco LLC*, 164 FERC ¶ 61,049, 61,295 (2018) (Comm'r Glick, concurring).

[76] *Incentives NOPR* at P 87.

5. The RTO/ISO participation adder should be eliminated.

The American Manufacturers oppose the Commission's proposal to increase the RTO participation adder ("RTO adder") from 50-basis-points to 100-basis-points and to apply the incentive to transmitting utilities that join and remain enrolled in an RTO/ISO regardless of the voluntariness of the entity's participation.[77] In fact, the Commission should consider eliminating the RTO adder. To the extent that the Commission elects to preserve the RTO adder, however, the American Manufacturers urge the Commission to cap the adder at 50-basis-points and limit its availability so that transmission owners who are obligated to remain in or join an RTO/ISO cannot take advantage of the incentive.[78] Finally, to the extent a utility is eligible for the RTO adder, it should be phased out over time.

As a preliminary matter, American Manufacturers question whether the RTO adder still serves the purpose of inducing a public utility to join, or retain its membership in, an RTO/ISO. Order No. 679-A describes the incentive adders as "an inducement for utilities to join, and remain in, Transmission Organizations."[79] Since Order No. 679's issuance, the organized wholesale markets administered by RTO/ISOs have evolved greatly. As a result of that evolution, the RTO/ISOs report significant efficiency and reliability gains. For example:

- MISO: For 2019, MISO reported that it delivered between $3.2 billion and $4 billion in benefits to its members.[80] For the period from 2009 through 2019, MISO's Value Proposition studies reported that MISO provided the region an estimated $26 billion in cumulative net benefits.[81]

[77] *Id*. at PP 97-99.

[78] Exh. No. AMF-1 at 26 ("It is not reasonable to ask customers to pay higher transmission prices to award a utility to do something it agreed to as part of a settlement, or is obligated to do as part of its state regulatory requirements.").

[79] Order No. 679-A at P 86.

[80] Midwest Indep, Sys. Operator, 2019 Value Proposition (2019), *available at* https://cdn.misoenergy.org/20200214%202019%20Value%20Proposition%20Presentation425712.pdf.

[81] *Id*. at 3.

- PJM: PJM has reported a comparable total annual value of $3.2 billion to $4 billion of which PJM attributed $600 million as related to energy production costs and $300 million related to reliability.[82]

The benefits of RTO/ISO participation, combined with many public utilities' now longstanding membership in an RTO/ISO, arguably have reduced or eliminated the financial motivation offered by the RTO adder alone.[83] The value generated by today's organized wholesale power markets executing their core missions appears to provide a greater inducement for joining and remaining in an RTO/ISO than does any ROE adder for RTO participation. Accordingly, American Manufacturers urge the Commission to eliminate the ROE adder for RTO participation.

Further, the current RTO adder of 50-basis points is already excessive and an increase to 100-basis points is objectionable for a number of reasons. First, the proposed increase to the RTO adder would result in a dramatic increase in transmission charges across the nation's RTO/ISOs, as shown in Table 1 below.[84]

TABLE 1

Revenue Impact 100 bpt ROE
($000)

RTO/ISO	Amount
CAISO	$125,092
MISO	$196,625
NEISO	$72,032
NYISO	$16,451
PJM	$282,308
SPP	$65,799
Total	$758,309

Source:
RRA Reports 2018-2020

[82] PJM Value Proposition (2019), *available at* https://www.pjm.com/-/media/about-pjm/pjm-value-proposition.ashx.

[83] *See* Section III.B *supra* (discussing the meaning of incentive-based regulations).

[84] Exh. No. AMF-1 at 26, Table 1, -27.

Next, the proposed increase arises against a backdrop of exponential increases in transmission rates in many RTO regions, driven by massive capital deployments in new rate base. The Incentives NOPR points to no tangible evidence that the transmission owners need higher ROEs, much less in the form of an ROE adder for RTO participation, in order to attract and deploy capital in transmission investment. The NOPR references only the RTO-calculated benefits of RTO participation, which, as expected, point to significant benefits of RTO participation.[85] The existence of RTO participation benefits, even if firmly substantiated, does not correlate in any meaningful way with the level of ROEs or the level of ROE adders, in particular. Under the Commission's theory, ROE adders of 300 basis points or more could be justified based on the level of RTO-related savings that the RTOs are claiming. And there is no evidence that transmission owners that are currently members of RTOs maintain their RTO membership based on ROE adders.

To the extent that the Commission continues to provide the ROE adder for RTO participation, the level should be capped at the current level of 50 basis points. Further, the RTO adder should not continue in perpetuity after a public utility has joined an RTO/ISO. The continued availability of an RTO adder long after a public utility has joined an RTO/ISO results in an unjustified windfall to the public utility at the expense of transmission customers. Lastly, the Commission should clarify that the RTO adder is a single-use incentive. In other words, if a public utility withdraws from an RTO/ISO or seeks to switch from its original RTO/ISO to another, the RTO adder should not be available.

The Commission should also consider reducing the size of the ROE incentive for RTO membership after a specified number of years from a public utility's membership start date and

[85] Incentives NOPR at P 97.

eliminating the incentive altogether after a public utility has remained a member for a certain number of years. American Manufacturers also recommend that the Commission initiate a process to phase out the RTO adder for public utilities that are currently members of an RTO/ISO. An RTO adder awarded to a public utility for joining an RTO/ISO should be allowed to remain in place at the initial level for a four-year period following the effective date of the public utility's membership start date, subject to reduction during the four-year period if warranted by a cap on the overall level of allowed ROE. At the conclusion of the four-year period, the RTO adder should begin to phase out over a subsequent one-year period, subject to a rebuttable presumption.

For existing members of an RTO/ISO that are currently receiving the 50-basis point RTO adder pursuant to Order No. 679, the Commission should initiate a process to phase out the RTO adder, subject to a rebuttable presumption. The RTO adder would be rebuttably presumed to decline by 12.5-basis points per year over a four-year period. To commence the phase-out process for existing RTO/ISO members, the Commission's issuance announcing this revision to the Commission's RTO/ISO adder policy should direct each recipient of the RTO adder to submit a filing to implement a phase out or demonstrate that can it overcome the rebuttable presumption and, thus, should not be subject to a phase out.

The phase out of the RTO adder for both new and existing RTO members could be subject to a rebuttable presumption. To overcome this rebuttable "phase down" presumption, the public utility would be required to show (and intervenors would have the opportunity to challenge) that unique factors warrant a deviation from the otherwise applicable adder "phase out" process. Such a showing could include evidence that the risks or financial constraints associated with the public utility's continued RTO participation are not adequately compensated if the adder is reduced or eliminated.

6. Incentives for transmission technologies must be subject to a cost-benefit test and limited to projects that public utilities are not otherwise required to build.

Under FPA section 219(b)(3), the Commission's incentive rules must encourage the deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of transmission facilities.[86] According to the Commission, experience to date indicates that incentives have not been effective in encouraging new technology deployment. To promote such deployment, the Commission is proposing regulations that offer rate treatments for technologies that, when deployed, would "enhance reliability, efficiency, capacity, and improve the operation of new or existing transmission facilities."[87] Specifically, the Commission's proposal includes: (1) a 100-basis-point ROE Transmission Technology Incentive on the cost of the specified transmission technology project[88]; and (2) a Deployment Incentive that confers specialized regulatory asset treatment of certain initial costs related to deploying technologies that are traditionally expensed in the year incurred.[89]

American Manufacturers agree that facilitating the development of transmission technologies that cost-effectively increase the capacity and efficiency of transmission technologies is a constructive and potentially beneficial objective. American Manufacturers support advancing this objective, particularly with respect to technologies offering significant cost savings compared to traditional transmission projects. Notwithstanding their worthwhile objective, any incentives aimed at encouraging such transmission technologies must pass a cost-benefit test. Moreover,

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[86] 16 U.S.C. § 824s(b)(3).

[87] Incentives NOPR at P 101.

[88] *Id*. at PP 103, 105.

[89] *Id*. at PP 103, 108.

such incentives should not be available for routine maintenance or industry standard technology. The Commission's proposed transmission technology incentives, however, will not be sufficient to promote the meaningful deployment of the desired technology. As discussed in Section III.A.3, the structure of the transmission planning process may include flaws that act as barriers to entry for such technology. Accordingly, in order to effectively promote deployment of transmission technology incentives, offering the proposed Deployment and Transmission Technology Incentive is not enough. The Commission must also target the removal of obstacles inherent in the transmission planning process.

7. A comprehensive transmission technology statement promotes transparency and accountability.

The Commission proposes that each applicant seeking the incentives for technology must submit a transmission technology statement that demonstrates that the technology, as applied in a particular transmission technology (or stand-alone transmission technology project), meets the criteria for eligible transmission technologies, the expected benefits and costs, and that the transmission technology project meets the economic benefits ROE incentive benefit-to-cost threshold proposed in the Incentives NOPR.[90]

As discussed elsewhere in these Comments, American Manufacturers firmly support measures, such as the proposed transmission technology statement, that require public utilities to disclose information underlying the costs ultimately borne by customers. To this end, to better assist customers in evaluating the impact of any incentive for a transmission technology project, American Manufacturers recommend that a transmission technology statement be required to present the expected impact of a project's costs and benefits on the utility's NITS rate during each

[90] *Id*. at P 111.

year of the useful life of the project or the duration of the requested incentive, whichever is longer. Public disclosure is fundamental to the Commission's ability to oversee the justness and reasonableness of a public utility's rates and customers' ability to challenge excessive rates. Equally important from customers' perspective is timely access to the information necessary to evaluate the costs and related impacts of a utility's proposals. Expanding the required content of the technology transmission statement as suggested here would give customers a meaningful opportunity to evaluate a proposal.

8. A cap on the "all-in" ROE must remain in place in order to protect consumers from excessive rates.

a. While a ceiling on "all-in" ROE is necessary for consumer protection, the Commission's proposed 250 basis point cap is arbitrary.

Under current policy, a utility's base ROE, including any ROE incentives, must remain within the zone of reasonableness that is used to establish a utility's allowed ROE.[91] The Commission proposes to allow ROE incentives to exceed a utility's zone of reasonableness when added to the base ROE; however, a cap of 250-basis points would apply to the total or "all-in" ROE incentives.[92] The Commission's view is that base ROE and transmission ROE incentives serve different functions and may be subject to different tests for evaluating just and reasonable rates.[93] Thus, the Commission states that ROE incentives are not required to be bound by the zone of reasonableness in order to be just and reasonable and not unduly discriminatory.

American Manufacturers strongly support capping the "all-in" ROE (i.e., base ROE, plus incentives) to ensure just and reasonable transmission rates. Establishing such a cap is critical to

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[91] *Id*. at P 76 (citing Order No. 679 at PP 2, 91-93).

[92] *Id*.

[93] *Id*. at P 78.

complying with the FPA's just and reasonable rate requirement. The Incentives NOPR, however, provides no rhyme or reason for the proposed 250-basis-point cap level. The NOPR similarly fails to state the Commission's rationale for "allow[ing] the ROE incentives to exceed the zone of reasonableness when added to the base ROE."[94] American Manufactures respectfully submit that the Commission's proposal is moving in the wrong direction.

While firmly supportive of imposing an upper limit on the total ROE, American Manufactures are concerned that the proposed 250-basis point cap is not only arbitrary but also excessive. According to Mr. Gorman, the "full maximum amount of the ROE incentives of 250 basis points represents an enormous premium to base ROE, of over 25%, and would provide TOs with returns well above that of expected market returns" and on par with "the expected returns of speculative, high risk, ventures."[95] At the same time, based on recent changes to the ROE methodology that have resulted in an expanded zone of reasonableness, American Manufacturers are concerned that retaining the upper bound of the zone of reasonableness as a ceiling may produce excessive total ROEs and, thus, no longer serves as a consumer safeguard. The Commission's apparent willingness to permit the "all-in" ROE to exceed the upper range of the zone of reasonableness only amplifies this concern.

To establish a ceiling on total ROE, American Manufacturers recommend that the Commission's approach begin with the results of the ROE methodology. Since the issuance of the Incentives NOPR, the Commission issued Opinion No. 569-A which sets forth the latest iteration of the ROE methodology. In brief, the newly revised ROE methodology establishes a composite zone of reasonableness using the Risk Premium, Discounted Cash Flow, and Capital Asset

[94] *Id*. at P 76.

[95] Exh. No. AMF-1 at 25.

Planning Model.[96] The zone of reasonableness is divided into thirds, representing ranges of presumptively just and reasonable ROEs for an electric utility company with a below-average, average, and above-average risk profile.[97] The base ROE is set at the appropriate measure of central tendency (i.e., midpoint or median) for the tertile corresponding to the utility's (or group of utilities') risk profile.

Rather than using the top end of the zone of reasonableness as a cap on the total allowed ROE, American Manufactures recommend using the upper end of the tertile corresponding to the utility's risk profile as a cap. Under the new ROE methodology, the tertiles represent the range of presumptively just and reasonable ROEs for a utility of comparable risk. As such, the upper end of that range represents a reasonable cap on the total ROE.

Establishing a total ROE cap cannot be completely divorced from the ROE methodology. The ROE methodology, while not perfect, is based on objective market data and is rooted in the consumer protection requirements of *Hope* and *Bluefield*.[98] Adopting a seemingly arbitrary one-size-fits all cap after the Commission has spent years refining the ROE methodology that is intended to identify the cost of equity for a utility would detract from the integrity and credibility of the ROE framework.

b. Any changes to the existing ROE caps should only apply prospectively.

The Commission invites comment on whether utilities should be permitted to seek removal of any zone-of-reasonable conditions placed on previously granted incentives and to replace those

[96] Opinion No. 569-A; Incentives NOPR at PP 45, 104. *See also* Incentives NOPR at P 141.

[97] Opinion No. 569-A at P 194.

[98] *FPC v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944). *Bluefield Water Works Co., v. Publ. Serv. Comm'n,* 262 U.S. 679 (1923).

restrictions with a hard cap on the incentives they have been granted.[99] American Manufacturers oppose retroactive changes to incentives that have already been granted, as doing so would contravene existing precedent and policy. In *CPUC v. FERC*, the court explained, "FERC has a longstanding policy that rate incentives must be *prospective* and that there must be a connection between the incentive and the conduct meant to be induced….The policy prohibits FERC from rewarding utilities for past conduct or for conduct which they are otherwise obligated to undertake."[100] Furthermore, a FERC policy statement previously recognized that "Consideration of past performance would violate the standard that incentive ratemaking must be prospective."[101] A retroactive change to incentives that have already been granted would not comport with the fundamental objective of incentive-based regulation, namely, motivating future conduct. Moreover, any conditions applicable to a utility's incentives were evaluated at the time of the request for such incentives and, presumably, deems necessary to ensure just and reasonable rates. Retroactive action to remove such conditions and allow incentives they have already been granted to increase up to an arbitrary would contravene basic ratemaking principles and contravene FERC precedent and policy.

9. American Manufacturers support public utility reporting obligations that facilitate transparency and accountability.

American Manufacturers support the Commission's proposal to modify the scope of public utilities' reporting obligation for Form 730 to mandate all public utilities receiving an incentive for any transmission project to submit information on Form 730.[102] In the face of escalating costs

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[99] Incentives NOPR at P 81.

[100] *CPUC*, 879 F.3d at 977 (emphasis added).

[101] *Incentive Ratemaking for Interstate Nat. Gas Pipelines, Oil Pipelines, & Elec. Utilities*, 61 FERC ¶ 61,168, 61,599 (1992).

[102] Incentives NOPR at P 122.

associated with transmission infrastructure investment and a lack of transparency regarding particular transmission project costs, American Manufacturers strongly support the expansion of reporting requirements associated with transmission investment by public utilities. In fact, American Manufacturers support expanding the Commission's proposal to include mandatory reporting of the RTO adder on Form 730.

Under expanded reporting requirements, public utilities should provide information about all transmission investment activity, including projects that fall outside of any regional transmission planning process, not only transmission projects that receive incentives, and certainly not only to incentive applications for an increased ROE. Providing additional information about each transmission project should enhance the Commission's ability to assess the status of transmission investment and, thus, ensure that the anticipated consumer benefits materialize. Furnishing information about annual transmission spending on a project-by-project basis would make such information more accessible to the Commission as well as interested parties, including consumers. Greater transparency also better positions the Commission and others to hold public utilities accountable for seeking to recover only prudently incurred costs through just and reasonable rates.[103]

With ultimate responsibility for transmission infrastructure investment costs, consumers are entitled to a reasonable level of detail about the transmission infrastructure for which they are being asked to pay. Finally, American Manufacturers support the elimination of the reporting threshold, particularly in the case where the transmission project has been awarded an incentive.

[103] *See* 18 C.F.R. § 35.35(g) (2020).

If a transmission project is significant enough to warrant incentives, the public utility should be required to provide reasonably detailed information about the transmission project.

IV. CONCLUSION

WHEREFORE, American Manufacturers respectfully request that the Commission consider these Comments as it determines whether and to what extent is will revise its transmission incentives policies.

Respectfully submitted,

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Counsel to the Industrial Energy Consumers of America and on behalf American Manufacturers

Dated: July 1, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 1st day of July 2020.

/s/ *Robert A. Weishaar, Jr.*

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ATTACHMENT A

Affidavit of Michael P. Gorman
On behalf of American Manufacturers

Exhibit No. AMF-1

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	Docket No. RM20-10-000

Affidavit of Michael P. Gorman

On behalf of

American Manufacturers

July 1, 2020

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Affidavit of Michael P. Gorman

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AFFIDAVIT AND EXHIBITS OF OF MICHAEL P. GORMAN

On Behalf Of

American Manufacturers

July 1, 2020

SUMMARY

In this Affidavit, I provide evidence supporting my conclusions on the following:

1. The Federal Energy Regulatory Commission's ("FERC" or "Commission") current incentive policy is based on a "nexus" between the incentives sought and making an investment that ensures reliability and/or reduces the cost of delivered power. Allowing an incentive return if necessary to encourage investment, was consistent with FERC's promotion of reliable and economically efficient transmission and generation of electricity. The FERC is considering changing its incentive policy to a benefits test, which ties incentive returns on equity ("ROE") to forecasted savings, and otherwise eliminates the nexus requirement for awarding an incentive.

   I recommend the FERC reject the benefits-based incentive and continue with its successful nexus incentive policy.

<u>I. Current "Nexus" Incentive Policy is Successful</u>

2. The current FERC policy, including its incentive policy, has encouraged significant investment in transmission infrastructure, and transmission owners ("TO") continue to plan for significant continued investment in transmission infrastructure.

3. FERC's current incentive policy has proven to incentivize economically efficient transmission investments. This includes increasing capital expenditure programs while at the same time managing the financial integrity and credit standing of the TO.

   The proposal to create economic incentives to increase capital expenditures, without managing the financial integrity or impact on rates to customers, can harm customers. Increasing transmission capital expenditure programs can create financial distress on companies, if this balanced approach to capital spending is not managed. Changing the incentive from encouraging economically efficient transmission investments to incenting maximizing capital investments to earn above market rates of return, can distort the economically efficient objective of scheduling prioritization of investments in transmission infrastructure.

4. Creating economic incentives to maximize capital investments that can earn an incentive return can unjustifiably increase prices to customers, with the expectation of benefits occurring many years into the future. This can create unjust impacts on transmission prices, that will not produce benefits for many years later, if at all.

5. Under current FERC protocols and incentive policy, TOs have been highly motivated to make significant investments in transmission assets while maintaining credit standing and access to capital. Capital market participants have responded by providing the industry with significant amounts of low-cost capital under reasonable terms and prices.

6. FERC regulatory policies have encouraged investments in transmission infrastructure, as ratemaking protocols and current incentive policy are regarded as favorable to investors. FERC's current policy minimizes the risk of investing in transmission assets by reducing cost recovery risk, while also mindful of the impact on customer transmission rates.

7. Utility companies generally, and now competitive transmission companies, are highly motivated to make infrastructure investments subject to FERC regulation. Making infrastructure investments allows these companies to grow their rate base, which in turn allows them to grow earnings and dividends, which enhances shareholder value. A fair and reasonable return has proven to induce significant incentive to invest in transmission plant.

II. Proposed Incentive Benefits Will Erode Customer Protections

8. The detriments of the proposed change in incentive policy from a nexus basis to a benefits basis will significantly distort the incentive of TOs and competitive market participants to pursue transmission investments that will quality for ROE incentives, rather than to develop transmission infrastructure in an economically efficient manner.

9. Creating incentives that encourage TOs and competitive transmission companies to maximize transmission investments that earn an above market rate of return will create economic and financial incentives to maximize investments, that can be awarded an above market return. The incentive to maximize transmission investment can have undue negative impact on transmission prices, and can economically incentivize a company to increase capital expenditure programs above that that can reasonably be managed while maintaining the financial integrity of the company. All of these factors can have negative impacts on transmission customers, and potentially erode service quality and reliability.

10. The FERC incentive policy will no longer have a nexus for incentive ROEs only when necessary to support the development of economically efficient capital programs. This includes managing capital programs in a manner that maximizes capital spend, but limited by ensuring the utility is able to also manage its financial integrity and credit standing. This balanced objective meets the economically efficient development objective because it allows the utilities to manage the size of a capital program while also managing financial integrity, cost of capital, access to capital, and support reasonable costs to customers.

    Changing the FERC incentive policy to encourage the maximum amount of capital expenditures to earn above market rates of return can break from the need for a balanced transmission infrastructure capital program that maximizes transmission investment while managing the financial integrity, credit standing and the reasonable rate standard for transmission customers.

III. Proposed Incentives Are Not Just and Reasonable

11. The proposed ROE incentives are excessive and will impair the development of just and reasonable transmission prices. ROE incentives for becoming a regional transmission organization ("RTO") or independent system operator ("ISO") member will increase authorized ROEs by over 10%, and align these ROEs to a level that is more reflective of a higher risk general market investment rather than a below market risk regulated transmission investment. The proposed changed incentives will provide TOs with a return in excess of the level of investment risk, and then unjustifiably increase prices to transmission customers.

    Further, the proposed maximum ROE incentive of 250 basis points will adjust the rate-setting ROE to a level of return that is more reflective of a speculative high-risk investment. Setting rates at a level that is not needed to incent transmission investments, and results in transmission prices being unjustifiably inflated to support an above market rate of return is not just and reasonable, and results in significant economic harm to customers.

IV. Benefits Test is Not Reliable

12. The Commission's proposed use of predominantly production cost studies to identify benefits to justify ROE adders does not reflect sound and balanced ratemaking principles. Production cost savings estimates are based on statistical models that produce "expected" savings in future periods based on an elaborate number of assumptions and projections of the delivery and generation of electric power to forecast loads over many years. The production costs savings are highly uncertain forecasts that do

not meet the known and measurable standard typically relied on for setting just and reasonable rates.

In contrast to the prospective fuel savings, the ROE incentive adder will be a certain known cost to transmission customers. As such, designing rates to include a significant ROE incentive cost, combined with the expectation of uncertain future delivered power costs savings unjustifiably will economically harm customers.

The proposal to provide an incentive ROE for certain types of reliability enhancement is equally unjustified. Utilities must justify the prudence of their proposed capital investments by showing that they are needed for reliability or to produce economic benefits to customers. Providing an incentive ROE above the level of investment risk necessary to undertake such investments distorts the economic incentive of TOs' capital investment programs, and results in unjust and inflated prices. Again, customers would be harmed from such a proposal.

<u>Affidavit of Michael P. Gorman</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this Affidavit.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A The American Manufacturers, as identified in the Comments.

Q WHAT IS THE PURPOSE OF YOUR AFFIDAVIT?

A I will respond to the Federal Energy Regulatory Commission's ("FERC" or "Commission") proposal to revise its existing regulations that were implemented under section 219 of the Federal Power Act ("FPA") related to changes in transmission development and planning.

I. NOPR BACKGROUND

Q WHAT CHANGES IS THE FERC CONSIDERING FOR TRANSMISSION INCENTIVES?

A FERC is considering departing from the nexus test framework of Order No. 679 where incentives were permitted only to the extent the transmission owner ("TO") demonstrated that the incentive sought is "necessary in order to make the desired investment." In this case, the Commission is proposing to depart from this "nexus" test, and instead develop incentives based on a "benefits" test.[1]

The Commission found that the current nexus incentive mechanism required TOs to demonstrate that the incentive sought is necessary in order to ensure that the investment will be made, and the desired investment is needed to ensure reliability or to reduce delivered cost of power.[2]

The benefits test is to be limited to economic benefits related to production cost savings or similar measures related to congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative.[3] The FERC anticipates relying on RTO/ISO economic dispatch savings studies as a relatively simple, transparent, and efficient analysis of economic benefits which it anticipates can be provided to stakeholders.[4] The Commission also notes that public utilities that are not in an RTO/ISO may face challenges with respect to the impact of their transmission investments on a planning region's existing processes for measuring the economic

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[1]Notice of Proposed Rulemaking, 170 FERC ¶ 61,204, March 20, 2020 ("NOPR") at ¶¶ 2-3.
[2]*Id*. at ¶ 15.
[3]*Id*. at ¶ 48.
[4]*Id*. at ¶ 44 and ¶ 52.

benefits and producing benefit-to-cost ratios. But it cites certain other options available to the non-RTO/ISO members to measure economic benefits including transactions between generators and loads in the region.[5]

The Commission also proposes a benefit-to-cost ratio threshold differentiated by the size of the transmission investment, with transmission investments of $25 million (adjusted for annual inflation) as the proposed dividing line between small system modifications and significant transmission facility expansions.[6] The Commission goes on to identify a cost-to-benefit ratio where the savings divided by the project costs produce a cost-to-benefit ratio or factor.[7] Based on historical cost-to-benefit ratio factors, the Commission prescribes a benchmark of 3.98x for significant transmission projects of at least $25 million, and 33.91x for small transmission projects.[8]

Q WHY IS THIS INCENTIVE CHANGE BEING CONSIDERED?

A The Commission states that it is considering making this change that was originally implemented in Order No. 679 and reviewed in transmission incentives and policy in a 2012 policy statement. FERC states that while it is encouraged by the investment in transmission infrastructure to date,[9] it observes that the industry has undergone a transformation, including the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. Those changes

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[5]*Id*. at ¶ 53.
[6]*Id*. at ¶ 56.
[7]Productive cost savings / project cost.
[8]NOPR at ¶¶ 57-58.
[9]*Id*. at ¶ 31.

include an evolution of resource mix, increases in new resources seeking transmission service, shifts in load patterns, impacts of implementation of the Commission's rulemaking on transmission planning and cost allocation as outlined in Order No. 1000. The Commission states additional reform may be necessary to continue to satisfy our obligations under FPA section 219 in this new transmission planning landscape.[10]

Q WHAT IS THE PURPOSE OF INCENTIVES?

A In Paragraph II.A.12 of the NOPR, the FERC states that the FPA directed it to promulgate a rule providing incentive-based rates for electric transmission for the purpose of "**benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion**."[11] It states that FPA section 219 provides some specific directives in the required rulemaking, including the following:

1. promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of facilities for the transmission of electric energy in interstate commerce, regardless of ownership of the facilities;

2. provide a return on equity ("ROE") that attracts new investment in transmission facilities, including related transmission technologies;

3. encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and

[10] *Id*.
[11] *Id*. at ¶ 12.

4. allow recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to FPA section 215, and all prudently incurred costs related to transmission infrastructure development pursuant to FPA section 216.[12]

II. CURRENT RISKS AND CHALLENGES (NEXUS) INCENTIVE POLICY IS REASONABLE AND PROVEN TO BE EFFECTIVE

Q SHOULD THE FERC CHANGE ITS INCENTIVE POLICY BASED ON RISKS AND CHALLENGES TO ECONOMIC BENEFITS?

A No. The FERC's current ratemaking policy, including its current "nexus" incentive test, has correlated with significant investments in transmission infrastructure designed to support improved reliability, reduce transmission congestion and to modernize transmission infrastructure. In contrast, the proposal to award incentives based on benefits would be at odds with the FERC's stated objective of promoting "economically efficient" development of transmission assets that benefit customers by ensuring reliability and reducing the costs of delivered power by reducing transmission congestion.[13]

While I agree with the Incentives NOPR that the utility infrastructure landscape is changing due to the advent of renewable technology, changing load characteristics of customers, and movements to more environmentally friendly generation and delivery of energy, the utility industry is highly motivated to respond to these new challenges where utility companies continue to plan and effectively manage construction projects, and capital markets continue to find the utility industry

[12] *Id*.
[13] *Id*. at ¶ 2 and ¶ 12.

a very safe, stable and attractive industry investment option. All of this occurring under the current FERC policies and practices including incentive-based ratemaking, that has resulted in the development of economic and efficient transmission delivery systems, especially when transmission development is being orchestrated by an ISO or RTO as part of an overall regional transmission plan. Providing unjustified ROE incentives will unnecessarily and administratively inflate prices, decrease potential benefits to customers, and put customers at true risk of paying higher prices for the expectation of savings that may or may not be realized.

Q WHY WILL THE CURRENT FERC POLICY CONTINUE TO ENCOURAGE ECONOMICALLY EFFICIENT TRANSMISSION ASSET DEVELOPMENT?

A The current FERC regulatory policy, including its incentive policy, has been proven to create strong incentives for TOs to make significant economically efficient investments in transmission infrastructure assets. I reach this conclusion based on the following:

1. My colleague, Ali Al-Jabir, outlines TOs' participation in RTO/ISO planning processes, and compliance with their obligation to make necessary transmission investments to meet the RTO/ISO improvements in infrastructure reliability, relief of transmission congestion, and improve the efficient operation of the wholesale transmission network. Mr. Al-Jabir also discusses TO members' investments in transmission infrastructure not required by RTO/ISO planning, and the introduction of competitive transmission plant investment that has attracted new non-utility companies to become members of RTO/ISO. These new transmission-owning companies have also proven to be highly motivated to make infrastructure investments, and have actually requested changes in FERC's rules and policies to allow them to an increased amount of transmission investments available for competitive development. All of this is a clear indication that RTO/ISO members are highly motivated and incented to invest in the development of the transmission infrastructure.

2. The electric utility industry generally, and specific transmission providers have planned very large capital programs for continued transmission investment. These transmission investments are supporting the utility companies' efforts to enhance shareholder value by growing earnings and dividends by making infrastructure investment. Energy companies are highly motivated to accomplish this shareholder value enhancement. Without infrastructure development and rate base growth, these utility companies will not accomplish the objective of enhancing shareholder value, and growing earnings and dividends. As such, infrastructure development is critical in enhancing shareholder value, and creates significant incentive for RTO/ISO members to make transmission infrastructure investments.

3. The current regulatory practices for utilities generally, and at the FERC specifically, have resulted in substantial increases in investments in utility electric plant in-service that has accommodated change in generation infrastructure, a significant investment in modernization and expansion of transmission infrastructure, and the modernization of distribution structures. No change to current incentives is justified.

4. The electric industry generally, and the major electric utility companies specifically, aggressively enhance shareholder value by making infrastructure investments to allow for growth in utilities' earnings and dividends but do so while managing the financial integrity and credit standing of the utilities. This managed approach to capital spending enhances shareholder value today, but preserves the utilities' access to external capital markets under reasonable terms and prices into the future.

5. Current policy where incentives are only allowed in the event of need has encouraged the efficient utilization of resources, and best achieves the FERC's stated goal of economically efficient investments in the transmission infrastructure which result in reasonable costs to customers.

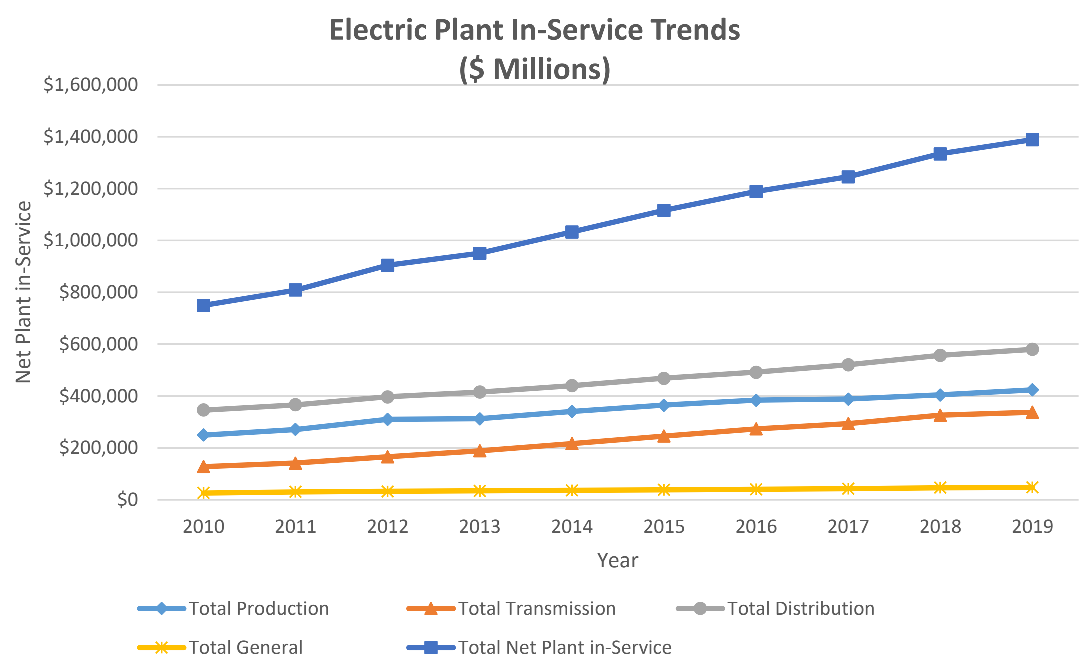
6. The current FERC incentives based on need and challenges also incent utility management to manage capital programs in a manner that maintains financial integrity and credit standing, and thus supports utilities' access to external capital markets under reasonable costs and terms. A FERC incentive policy that encourages these competing but balanced management objectives supports economically efficient transmission infrastructure development.

7. The investment community has made positive comments about the supportive regulatory treatment at FERC to encourage investments and maintain strong credit standing. A change to the FERC incentive policy is not necessary to support TO access to capital.

Q PLEASE DESCRIBE WHY YOU BELIEVE EVIDENCE CLEARLY ESTABLISHES THAT UTILITIES HAVE STRONG ECONOMIC INCENTIVE TO MAKE INFRASTRUCTURE INVESTMENTS.

A The utility industry has been making significant investments in transmission infrastructure for at least since 2010, a date preceding the current FERC incentive policy in 2012. The electric utility industry's plant in-service ("PIS") as recorded in FERC Form 1 data, has grown by approximately $750 billion in 2010 to over $1,390 billion in 2019. This is shown graphically in Figure 1 below.

FIGURE 1



Source:
Exhibit No. AMF-2

Of significance, while PIS has grown overall for electric utilities, transmission plant has realized the most significant increase in PIS. Transmission net PIS grew from $127.6 billion in 2010 to $337.4 billion in 2019. Overall, net PIS grew by 85% over this time period, but transmission plant grew by almost 165%, nearly twice as fast as the overall electric utility net PIS.

There are many reasons why net PIS has been growing so significantly for electric utilities over the last decade and why the cause of plant investments is not as relevant as the fact that electric utilities have made the investments, and have been able to do so by attracting significant amounts of external capital under reasonable terms and prices. Indeed, electric utilities' efforts to enhance shareholder value by growing their net PIS is expressed in their industry trade organizations and in investor reports by utilities to the investment public.

Q IS THERE EVIDENCE THAT THE ELECTRIC UTILITY INDUSTRY CONTINUES TO HAVE A STRONG INCENTIVE TO MAKE INFRASTRUCTURE INVESTMENTS?

A Yes. This investment allows utilities to grow their companies and enhance shareholder value. This perspective is noted by the current Edison Electric Institute ("EEI") president. In the EEI 2019 Financial Review of the electric utility industry, the current president made the following statements concerning the robust outlook of the industry:

> As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the sixth straight year in

> 2019, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set another record high of $124.1 billion in 2019.
>
> The EEI Index gained 25.8 percent in 2019, and our industry extended its long-term trend of widespread dividend increases. A total of 37 companies, or 93 percent of the industry, increased their dividend in 2019, matching the record-high percentage set in 2018. The industry's average dividend yield at the end of 2019 stood at 3.0 percent, while its dividend payout ratio was 64.1 percent for calendar year 2019. Among the primary U.S. business sectors, those results only trailed the energy sector. As of December 31, 2019, 39 of the 40 companies in the EEI Index were paying a common stock dividend.[14]

This statement by an industry trade organization is clear. Utilities grow their companies to appease their shareholders. Shareholders want increased stock value and increased dividend payments. Companies grow their earnings and ability to increase their dividends by making infrastructure investments.

The benefit of shareholders' value growth by making infrastructure investment is also evident in an executive financial presentation to investors. As shown on the attached Exhibit No. AMF-3, it is a common theme for utility executives to discuss value enhancement factors for shareholders. Utility executives outline the opportunities for enhancing shareholder value via increases in earnings and dividends that are largely fueled by making capital expenditure investment in growing rate base. These outlooks are expressed on my Exhibit No. AMF-3, where I highlight the utility executives' shareholder key enhancement value points made to the investment community.

[14] Edison Electric Institute: *2019 Financial Review: Annual Report of the U.S. Investor-Owned Electric Utility Industry*, at ¶ II.A.12, provided as Exhibit No. AMF-4, pages 1-88.

This shareholder value tied to infrastructure investments is also stated in a Standard & Poor's ("S&P") Market Intelligence report on the utility industry. There, reports to the investment community related to utility capital programs, and the related impact on earnings and dividend-paying ability of the utilities are stated as follows:

> Estimated capital expenditures for electric transmission and distribution (T&D) infrastructure for U.S. electric and multiutility holding companies in the RRA universe are projected to reach $53.6 billion in 2020 and to rise approximately 5% in 2021 to $56.4 billion. T&D spending in 2022-2023 is expected to remain robust at more than $50 billion in each year, before tapering to $35.5 billion in 2024. These conclusions flow from the June 8 Financial Focus report, "US energy utility capex undeterred by coronavirus to date, slated to reach $141B." By business category, T&D spending is forecast to comprise <u>more than half of overall utility capex between 2020 and 2022</u>, on par with levels observed in recent years and representing a <u>substantial contribution to utility earnings growth in the years ahead</u>. These investments also form an important component of many utilities' environmental, social and governance, or ESG, strategies, amid a broader utility sector transition toward decarbonization through electric grid modernization and renewable energy expansion. The increase in number of renewable generation sources, which are often great distances from load centers, will continue to drive new transmission line projects.[15]

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[15]S&P Global Market Intelligence: "Financial Focus: Utility electric T&D capex on upward trend; forecast nears $54B in 2020," June 15, 2020, emphasis added, provided as Exhibit No. AMF-4, pages 89-93.

Q AS THE ELECTRIC UTILITY INDUSTRY MANAGED THESE LARGE CAPITAL PROGRAMS, SHOULD CONSIDERATION BE GIVEN TO A BALANCED MANAGEABLE PROGRAM, RATHER THAN SIMPLY AN INCENTIVE TO TRY TO ENCOURAGE THE INDUSTRY TO INCREASE CAPITAL SPENDING UNCHECKED?

A Yes. Effectively, there are many reasons why a managed capital program is a key factor in meeting the FERC's economically efficient transmission infrastructure development objective. First, the industry must manage the level of capital spend at a level that allows it to effectively manage its financial integrity and credit standing. Increasing capital expenditure programs to a level that cannot be reasonably managed by the utilities can have a detrimental impact on their credit standing, access to capital, and if not managed effectively will negatively impact the cost of capital.

Second, prices to customers can be impacted by the timing of capital expenditures. Specifically, certain transmission investments may be expected to produce benefits to transmission customers, however those benefits may be realized at different points in time. Creating economic incentives that encourage electric utilities to accelerate capital investments can increase prices to customers immediately, while benefits may not be realized by customers for many years out into the future. In reality, accelerated development of transmission assets asked customers to pay higher prices now, for expected benefits that will be realized by future generations of customers. As such, imbalanced FERC incentives can create harm to customers by increasing transmission prices for increased development cost (rate base growth) and enhanced ROE, with the expectation of uncertain lower energy costs, and benefits where if those benefits are realized they are more likely passed on to future generations of customers. Again, this is not consistent with the objective of creating economically efficient transmission investment, and setting just and reasonable prices.

The FERC's current incentive policy of identifying transmission investments consistent with RTO/ISO planning, or encouraging incentives only when an incentive is necessary to create the priority development of transmission assets, balances these incentive mechanisms by prioritizing transmission development based RTO/ISO system improvement. The RTO/ISO development pace has supported the TOs' ability to responsibly grow capital spend and maintain financial integrity. This responsible pace of capital spending is consistent with the stated goal of efficient and economic development of infrastructure assets. FERC should not abandon its current successful approach.

Q EXPLAIN HOW TRANSMISSION INVESTMENT DEVELOPMENT HAS BEEN MANAGED IN A MANNER THAT SUPPORTS FINANCIAL INTEGRITY AND CREDIT RATINGS.

A The electric utility industry generally manages capital programs so as to have a reasonable balance of capital expenditures in a controlled manner that allows them to make large capital expenditures while managing investment risk and credit ratings. Changing the incentive policy to encourage TOs to further expand transmission investments may constrain utility credit ratings, erode credit quality, limit their access to external capital markets, and increase utility cost of external capital.

Utility companies have managed the level of capital expenditures to be a relatively stable portion of depreciation expense and cash flow from operations, as shown in Table 1 below.[16]

TABLE 1

Electric Utilities
Cap. Ex. and Cash Coverages
($ Millions)

Year	CapEx (1)	CapEx/ D&A (2)	CapEx/ OCF (3)
2019	$83,417	2.3x	0.6x
2015	$85,819	2.4x	1.0x
2010	$56,900	2.2x	0.9x

Sources:
[1]*S&P Global Market Intelligence*: "Utility Capital Expenditures Update", June 8, 2020, provided as Exhibit No. AMF-4, pages 94-98.
[2]*S&P Global Market Intelligence Financial Focus*: "Capital Expenditure Update", October 27, 2016, provided as Exhibit No. AMF-4, pages 99-107.

Notes:
[1]D&A = Depreciation and Amortization.
[2]OCF = Operating Cash Flow.

As shown in the table above, utilities have managed the size of capital expenditure programs as a proportion of internally generated cash, which is used in part to fund the capital programs. This practice manages the amount of external

[16]The data for Table 1 is provided as Exhibit No. AMF-4, pages 94-107, which are capital expenditure tracking reports published by Regulatory Research Associates ("RRA"), a subsidiary of S&P Global Market Intelligence. These RRA reports show that historically electric utilities have managed increased capital spending while maintaining the utilities' financial integrity.

capital needed to fund the program. This in turn manages construction risk and supports the utility's financial integrity, credit standing and access to external capital markets.

As such, as utilities' internally generated cash increases, with their embedded plant growing and rates increasing, utilities have systematically increased their level of capital spending. As shown in the table below, electric utilities' capital spending has increased from about $56.9 billion in 2010 up to approximately $83.4 billion in 2019. This is an approximate 50% increase. However, while the capital expenditures have been increasing, the table shows that the relative comparison of capital expenditures to depreciation and amortization recoveries in utility rates has remained relatively stable. The same kind of comparison is evident from a comparison of the capital expenditures to operating cash flow ("OCF") in the table. However, OCF has temporarily been reduced as a result of the Tax Cuts and Jobs Act of 2017.

The FERC's intent to create economically efficient incentives for utilities to manage their transmission infrastructure should continue to recognize the need to balance increasing capital expenditure programs with the utilities' need to maintain their financial integrity, credit rating and access to capital. Abandonment of the nexus test, combined with the potential for significant ROE adders, would work directly contrary to this objective.

Q DOES UTILITIES' MANAGEMENT OF LARGE CAPITAL PROGRAMS TO PRESERVE FINANCIAL INTEGRITY AND CREDIT STANDING ALSO NEED TO CONSIDER THE IMPACT ON TRANSMISSION RATES?

A Yes. In order to maintain credit standing, the transmission utilities must maintain as competitive a transmission rate as possible. To the extent transmission rates are increased to the point where they are no longer competitive, customers may seek alternative forms of energy, seek behind-the-meter generation, or move to locations where energy is more economical. Encouraging incentives that expand capital programs that do not maintain financial integrity, and unjustifiably increase transmission rates, will erode credit standing and is another factor that can result in the increase to cost of capital and transmission rates. This could have a devastating impact on TOs to the extent customers aggressively seek alternative means of managing energy costs.

Uncompetitive utility prices can have a negative impact on the utility's credit standing, and on the utilization of the transmission network. However, a more balanced approach where transmission rates are managed to a competitive level, in turn supports the utility's cash flow from operations to support capital investments and maintain financial integrity.

Again, there is a discipline to TOs' ability to responsibly and efficiently increase capital spending and it is not tied to only the awarded ROE. As the company increases its capital investment, and adjusts rates to reflect that increased capital investment, the company's depreciation expense and cash flow recovered through operations increase. This increase in cash flow then allows the utility to financially support a larger capital expenditure program, and support credit. This measured approach to managing a capital program that can be supported by the financial resources of the utility, allows the utility to increase capital expenditures while managing its credit rating. This is a critical aspect in allowing the utility to manage the capital expenditure program and maintain its access to capital under reasonable terms and prices. This responsible capital expenditure management is critical in ensuring that customers receive reasonably priced transmission service and high quality, reliable service.

Q HAVE CREDIT RATING AGENCIES NOTED THERE IS A CONCERN ABOUT RISKS ASSOCIATED WITH THE SIZE OF CAPITAL EXPENDITURE PROGRAMS FOR UTILITIES?

A Yes. Because capital programs can have a significant impact on the utilities' cash flows, credit rating agencies carefully monitor the level of capital expenditure programs currently being undertaken by the utilities. Credit rating agencies are also concerned about the impact on rates to the extent customers may have difficulty paying bills if growth in invested capital results in uncompetitive utility rate structures.

For example, S&P states the following concerning assessment of the size of a capital program, the impact on a utility's cash flows, and affordability of service is considered in the assessment of credit ratings:

> **2. Regulation and public policy support earnings and cash flow**
>
> We expect that regulators will continue to provide utilities with constructive frameworks that support credit quality. For most

> regulators, the requirement that utilities provide safe, reliable, and affordable utility services remains a priority. This regulatory perspective is balanced against an increasing awareness that the utility infrastructure in North America is aging, and that utilities may have to invest necessary capital to maintain and improve the infrastructure apparatus for electric, gas, and water systems. Such regulated infrastructure capital spending most often translates to low-risk rate base growth. In addition, regulatory support ensuring timely recovery of costs generally remains favorable for utilities' credit quality.[17]

Moody's also forms its credit outlook based on a combination of cash flow (Funds From Operations) coverage of capital expenditures, managing customers' rates, and receiving regulatory support of capital programs. Moody's notes that significant changes in any of these relevant factors could negatively impact utilities' credit standing. Moody's statements of the regulated electric and gas utility industry credit outlooks include the following:

> **2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics**
>
> - **FFO-to-debt ratios will hold steady in 2020 but at lower levels.**
> - **Customer rates remain steady despite elevated capital spending to grow rate base.**
> - **State regulators and legislators will remain supportive of utility credit quality.**
> - **What could change our outlook.** We would consider shifting our outlook to positive if regulation turns more credit-supportive or if the sector's consolidated FFO-to-debt ratio rises to around 18% on a sustainable basis. We would consider changing our outlook to negative if weakened cash flow causes the ratio to fall to around 14%. A more contentious regulatory environment or an increase in

[17] *S&P Global Ratings*: "Industry Top Trends 2019: North American Regulated Utilities," November 8, 2018, at 5, emphasis added, provided as Exhibit No. AMF-4, pages 108-118.

> leverage within the utility sector's capital structure could also change our outlook to negative.[18]

Finally, Fitch also makes comments concerning the impact of construction programs on the utility's financial capacity to manage the capital program, and consider the impact on rate affordability. Fitch states as follows:

> **Constructive Regulation Supports Recovery in Credit Metrics**
>
> **Fitch's Sector Outlook: Stable**
> Fitch Ratings' stable outlook embeds an expectation that sector <u>credit metrics will begin to stabilize in 2020</u>, driven by an increase in FFO after the record capex in 2019 and conclusion of a majority of tax reform-related refunds. Low commodity prices and interest rates, O&M cost savings, in part due to the ongoing transition to cleaner generation mix, and tax refunds are providing ample headroom to utilities to <u>seek recovery for capital investments without undue pressure on customer bills</u>.
>
> We expect utility <u>capex to remain elevated in 2020</u>. Much of this is driven by investments in <u>grid modernization</u> and resiliency, renewable generation, and natural gas pipeline replacement and safety, all of which are consistent with public policy goals and garner wide regulatory support.
>
> **Rating Outlook: Stable**
> With approximately 88% of ratings on Stable Outlook, we expect <u>limited rating movement in 2020</u>.[19]

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[18] *Moody's Investors Service Outlook*: "Regulated electric and gas utilities – US: 2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics," November 7, 2019, at 1, provided as Exhibit No. AMF-4, pages 119-135.

[19] *Fitch Ratings*: "Fitch Ratings 2020 Outlook: North American Utilities, Power & Gas," December 4, 2019, at 1, underlining emphasis added, provided as Exhibit No. AMF-4, pages 136-141.

Q HAVE CREDIT RATING AGENCIES NOTED WHETHER OR NOT CURRENT FERC REGULATORY POLICIES AND INCENTIVES SUPPORT FINANCIAL INTEGRITY AND CREDIT STANDING OF UTILITIES?

A Yes. FERC has consistently noted that transmission utilities regulated by FERC have a high probability of full cost recovery under the existing FERC rate-setting protocols. I have outlined some comments below related to only transmission companies operating before FERC.

Credit rating agencies have also noted the need to manage capital expenditure programs reasonably. Unjustifiably inflating capital programs to chase ROE incentives could have a negative impact on the TO's credit rating, and ability to access external capital markets.

S&P makes positive comments about FERC's regulatory treatment for ensuring cost recovery, and the supportive strong financial conditions of transmission affiliates. For example, S&P stated the following concerning companies that are predominantly transmission-only utility companies that are regulated by the FERC. These companies include American Transmission Company ("ATC") and International Transmission Company ("ITC") and its affiliate, Michigan Electric Transmission Company ("METC").

S&P commented about ATC:

> Formulaic, forward-looking rate-setting structure under the Federal Energy Regulatory Commission (FERC) supports American Transmission Co.'s (ATC's) effective management of regulatory risk.

* * *

> ***We expect American Transmission Co. (ATC) to effectively manage regulatory risk, supporting our assessment of its excellent business risk profile***. This reflects the company's essential transmission operations under a credit-supportive Federal Energy Regulatory Commission (FERC) regulatory framework.[20]

Similar comments about METC and ITC:

> Our assessment of ITC Midwest's business risk reflects our view of its fully rate-regulated and lower-risk transmission business operating within the FERC's highly supportive regulatory construct.
>
> * * *
>
> **Financial Risk: Modest**
>
> We assess ITC Midwest's financial risk profile against our most relaxed financial benchmark tables, compared to the typical corporate issuer, reflecting the company's low-risk transmission business and its effective management of regulatory risk under the FERC's supportive regulatory construct.[21]

S&P notes that transmission companies being rated against the more relaxed financial ratio benchmarks is an indication that their operating risk is very low, and allows them to more easily maintain financial coverage ratios that support strong credit standing. Indeed, S&P typically provides these lower risk metric rating categories to only companies that do not have direct commodity risk. Those typically include transmission companies regulated by FERC, and water utilities. As such, it is clear evidence that credit rating agencies believe that FERC regulated transmission companies are among the most low business risk of all utility companies.

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[20] *S&P Global Ratings RatingsDirect*: "American Transmission Co.," April 29, 2020, at 2, emphasis added, provided as Exhibit No. AMF-4, pages 142-149.

[21] *S&P Global Ratings RatingsDirect*: "Summary: ITC Midwest LLC," December 20, 2017, at 3-4, emphasis added, provided as Exhibit No. AMF-4, pages 150-157.

III. THE COSTS OF THE PROPOSED INCENTIVE CAN BE A SIGNIFICANT AND UNJUSTIFIED COST BURDEN ON TRANSMISSION CUSTOMERS

Q WHAT ARE THE POTENTIAL COSTS ON CUSTOMERS IF THE FERC IMPLEMENTS ITS INCREASED ROE ADDERS BASED ON ITS PROPOSED INCENTIVE TARGETS?

A The proposed ROE incentives will transform a base ROE into a return more in line with speculative enterprises and would produce a return that is not just and reasonable. This is particularly true in face of today's very low capital market costs. For example, in FERC Opinion Nos. 569 and 569-A, the Commission set base ROEs for MISO TOs at 9.88% and 10.02%, respectively. A 1 percentage point premium for joining an RTO/ISO would add over approximately a 10% premium to this earnings level. The proposal for such a significant increase in the base ROE will unjustifiably award TOs with a return that compensates for far greater risk than the TOs assume by making FERC regulated transmission investments. Further, the resulting ROEs of 10.88% and 11%, respectively, are nearing the estimated return on the market of 11.8% used in the CAPM analysis in reaching these base ROEs.[22] The full maximum amount of the ROE incentives of 250 basis points represents an enormous premium to the base ROE, of over 25%, and would provide TOs with returns well above that of expected market returns. This level of ROE is competitive with the expected returns of speculative, high risk, ventures. The resulting impact on transmission prices would produce unjust and unreasonable rates to transmission customers.

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[22]EL14-12-003, Initial Brief of the Commission Trial Staff, Attachment A, page 6; and EL15-45-000, Initial Brief of the Commission Trial Staff, Attachment A, page 6.

The direct impact on measurement of transmission revenue requirement is equally excessive based on these proposed ROE adders. The increase in total costs to customers that take transmission service can be significant. For example, simply looking at the transmission rate base for companies that participate in RTOs/ISOs, the potential increased cost to those customers of the various incentives is stated as follows:

One component of the proposed new incentive policy will provide all TOs that join an RTO/ISO a 100 basis point ROE adder. Currently, the RTO/ISO adder is 50 basis points, and only made available to TOs that voluntarily join the RTO/ISO. It is important to note that many TOs have joined RTOs/ISOs as a matter of regulatory commitments, or mergers and acquisitions, or based on changes in regulatory rules within state jurisdictions. It is not reasonable to ask customers to pay higher transmission prices to award a utility to do something it agreed to as part of a settlement, or is obligated to do as part of its state regulatory requirements.

Table 2 below, shows the increase in transmission prices for the various RTO regions based on a 100 basis point ROE adder.

TABLE 2

Revenue Impact 100 bpt ROE
($000)

RTO/ISO	Amount
CAISO	$125,092
MISO	$196,625
NEISO	$72,032
NYISO	$14,426
PJM	$282,308
SPP	$69,912
Total	$760,396

Source: Exhibit No. AMF-5

As shown in the table above, each of the various RTO/ISO regions' prices and revenue collections from customers will increase dramatically. On average, these increases in prices equate to an approximately $760 million increase in transmission rates. This annual cost will increase as RTO/ISO rate base or net plant grows over time.

Another aspect is to provide ROE incentive adders of 50 basis points to 100 basis points for certain economic benefit tests. There are material deficiencies in these economic benefit tests as discussed below. However, the potential increase in costs for transmission customers will depend on the assets qualifying for these incentives. Because a production cost study can be impacted by the inputs, and changes in factors underlying the outlook for changes in market conditions, the results can be very controversial. Under such circumstances, the costs to transmission customers would be dramatic. If TOs start adding to their current rate base, transmission assets that are qualifying for economic benefits, and these accumulate over time, eventually the transmission assets that qualify for a benefit could be a significant portion of the total transmission rate base.

Over time, if the maximum ROE incentive of 250 basis points is applied to a portion of a utility's rate base, then the cost outlined in Table 2 above would be increased by this additional adder cost. If initially the 250 basis points are applied to approximately 10% of the rate base, the annual cost in Table 2 above would be increased by another $150 million. As the incentive ROE grows up to a greater portion of rate base, up to all of rate base, the increase could be as much as two and a half times the estimate outlined in Table 2 above, or in excess of $2 billion per year. It is difficult to imagine just how expensive this could be, but largely depends on the level of maximum ROE incentive permitted to be included in the development of rates.

IV. UNJUSTIFIED FINANCIAL INCENTIVES CONFLICT WITH THE NOPR'S STATED GOAL OF ECONOMICALLY EFFICIENT INFRASTRUCTURE INVESTMENTS

Q DO YOU BELIEVE THAT THE PROPOSED CHANGE OF THE INCENTIVES TEST FROM BEING A NEXUS TEST TO BEING A BENEFITS TEST WILL ACHIEVE THE FERC'S OBJECTIVES?

A No. As stated above, the current FERC policy is to provide fair compensation with prudent and reasonable infrastructure investment that complies with the FERC's goal of economically efficient transmission systems. Incentives are only allowed when a demonstration of need exists, and that need is shown to be consistent with the public interest.

In significant contrast, allowing for a benefits test would change the dynamics of transmission investment on the part of TOs. TOs will have a financial and economic incentive to maximize transmission investments that are subject to an enhanced ROE. This can create more controversy in the system planning process, can create controversy in identifying whether or not there are any economic benefits associated with transmission investments, and whether or not the transmission investments are needed for improving reliability.

Under the FERC policy, TOs will be permitted to earn a well above market rate of return on transmission investments subject to an ROE incentive. This incentive can be up to 250 basis points, and will not be limited by the high-end of the zone of reasonableness established as appropriate for setting fair compensation for TOs. This opportunity to earn above market rates of return will create significant economic incentives and financial incentives for TOs to maximize transmission investments to achieve this windfall opportunity. The transmission planning will convert to a process that is searching for transmission investments that will earn an incentive ROE rather than purely look for investments that are needed for improvements to reliability and for relieving transmission constraints. TOs will be economically and financially incented to influence the RTO/ISO planning process to identify and prioritize transmission investments that qualify for incentive rates of return. This will complicate and potentially weaken the RTO/ISO planning process and skew the identification and assessment of whether new transmission investments truly will create economic benefits through fuel savings or are truly needed for system reliability benefits.

Equally as important, the TOs will likely have strong financial and economic incentives to invest in transmission plant that are provided well above market rates of return, that may no longer continue to plan and manage levels of capital investments so as to maintain large capital programs, while at the same time manage financial integrity and credit standing. Utilities may be more willing to expand capital programs above cash flow coverages and weaken credit, potentially impair access to external capital, or increase their cost of external capital.

The incentive to maximize transmission investments may also result in TOs hiring less qualified external contractors, or overloading existing internal engineering and technicians capable of economically and efficiently designing, planning and constructing transmission investments. In either case, the ability of the utility to manage an efficient and economic capital program can become impaired and the costs of the programs can suffer. Further, the reliability and life of the assets could also be detrimentally impacted. All of the impacts will negatively impact transmission customers.

Q IS THERE CONCERN THAT UTILITIES MAY NOT HAVE THE RESOURCES TO MANAGE A CONTINUED GROWTH IN CAPITAL EXPENDITURES?

A Yes. This is evident from certain concerns stated by certain executives that the aging of the technical work force of the utility is nearing retirement, and some utilities are having difficulty finding adequate engineering replacements. Several prominent transmission companies have stated concern about the risk of attracting and retaining a qualified work force.

Specifically, ITC Holdings Corp. ("ITC") outlines work force as components of risk related to its business. ITC states the following:

> **We contract with third parties to provide services for certain aspects of our business. If any of these agreements are terminated, we may face a <u>shortage of labor or replacement contractors</u> to provide the services formerly provided by these third parties.**
>
> We enter into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of our business, and we utilize the services of contractors to a significant extent. If any of these agreements or arrangements is terminated for any reason, <u>it could result in a shortage of a readily available workforce</u> to provide such services and we may face difficulty finding a qualified replacement workforce. In such a situation, if we are unable to find adequate replacements for contractors in a timely manner, it could have an adverse effect on our results of operations and the ability to carry on our business.[23]

Ameren Corporation also states concern about work force risk:

> **INDUSTRY ISSUES**
>
> * * *
>
> - the availability of a skilled work force, including retaining the <u>specialized skills</u> of those who are nearing retirement
>
> * * *
>
> **We are subject to employee work force factors that could adversely affect our operations.**
>
> Our businesses depend upon our <u>ability to employ and retain key officers and other skilled professional and technical employees. A significant portion of our work force is nearing retirement, including</u>

[23] ITC Holdings Corp.'s 2019 Form 10-K at 15-16, underlining emphasis added, provided as Exhibit No. AMF-4, pages 249-251.

> many employees with specialized skills, such as maintaining and servicing our electric and natural gas infrastructure and operating our energy centers. We are also party to collective bargaining agreements that collectively represent about 51% of Ameren's total employees. Any work stoppage experienced in connection with negotiations of collective bargaining agreements could adversely affect our operations.[24]

V. THE PROPOSED BENEFIT TEST WILL NOT PROTECT CUSTOMERS FROM EXCESSIVE ROE AWARDS

Q DID THE FERC OUTLINE THE OBJECTIVES IN DEVELOPING A BENEFITS TEST AS PART OF ITS INCENTIVE POLICY?

A Yes. The FERC stated it wanted to limit measurement of economic benefits to adjusted production costs or similar measures of congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative. FERC stated the analysis seeks to minimize total system costs by evaluating the security constrained unit commitment and economic dispatch of the system over a given time horizon.[25] FERC stated it expects that these economic dispatch runs will be based on the RTO/ISO analyses of the economic benefits of transmission projects.[26] While the Commission noted that these economic dispatch studies can be confidential, it is assuming that the stakeholders will have access to these economic dispatch results.[27]

[24]Ameren Corporation 2018 Form 10-K at 14, 16 and 25, underlining emphasis added, provided as Exhibit No. AMF-4, pages 252-257.
[25]NOPR at ¶ 48.
[26]*Id*. at ¶ 44.
[27]*Id*.

Q DOES FERC'S PROPOSAL FOR OUTLINING THE MEASUREMENT OF ECONOMIC BENEFITS IN SUPPORT OF SIGNIFICANT ROE INCENTIVE ADDERS PROVIDE ADEQUATE PROTECTION TO CUSTOMERS?

A No. The use of production cost studies for measuring benefits to justify ROE incentives is far from sufficient to ensure that customers' interests are protected. Production cost studies generally are statistically based methodologies that project over a long time horizon, in an effort to estimate the impacts on delivered energy cost that will be impacted by changes in load (growth and time of day shape), changes and reliability of production resources, changes in transmission constraints, changes in fuel costs, changes in environmental regulations, and additions and retirements of generating resources.

All of these highly uncertain variables are modeled under wide ranges of assumptions that are believed to capture the range of impacts on future energy costs. The production cost runs are really thousands of different scenarios that are assigned probability of occurrences to produce a statistical outlook of an "expected" production cost result. The fuel saving estimated from these long-term production cost planning tools does not produce a known and measurable energy savings that can be used to reliably offset a known ROE cost increase, and have any confidence that rates charged to transmission customers are just and reasonable.

These production cost model projections are useful in identifying the expected need for new transmission investments. If the prices for those transmission investment developments are based on prudent cost with fair compensation then the public benefits are supported by rational planning. As such, production cost models are beneficial tools in the economically efficient planning of transmission infrastructure. However, even on a resource planning perspective, a production cost model alone is not sufficient to economically justify transmission investments.

Q HAVE THERE BEEN ANY STUDIES THAT QUESTION THE USEFULNESS OF MEASURING TRANSMISSION INVESTMENT ECONOMIC BENEFITS USING ONLY PRODUCTION COST STUDIES?

A Yes. One such study was performed by The Brattle Group. The Brattle Group study questioned identifying prudent transmission investments only on the basis of a production cost study, concluding the following:

- Importance of Considering All Benefits
    - Not all proposed transmission projects can (or should) be justified economically
    - Transmission projects can provide a wide range of benefits—economic, public, and reliability—to a range of market participants and regions
    - Narrow or conservative evaluation of transmission benefits risks rejection of valuable projects
    - Transmission benefits in large part are a reduction in system-wide costs
    - Not considering the full economic benefits of transmission investments means not considering all costs and the potentially very-high-cost outcomes that market participants would face without these investments
    - Production cost simulations have become a standard tool to assess "economic benefits" of transmission, but only considers short-term dispatch-cost savings under very simplified system conditions (e.g., no transmission outages)

    - Simplified simulations reflect incomplete production cost savings, thus only a smaller portion of the overall economy-wide benefits

- Other Benefits considered by RTOs when performing transmission planning
    - Facilitation of the retirement of aging power plants
    - Encouraging fuel diversity
    - Improved reserve sharing
    - Increased voltage support
    - Enabling future markets
    - Storm hardening
    - Improving operating practices/maintenance schedules
    - Lowering reliability margins
    - Improving dynamic performance and grid stability during extreme events
    - Societal economic benefits
    - Mitigation of weather uncertainty
    - Mitigation of renewable generation uncertainty
    - Reduced cycling of baseload plants
    - Increased ability to hedge congestion costs
    - Increased competition and liquidity
    - Reduced air emissions
    - Avoided reliability projects
    - Avoided generation investment
- Long life of transmission assets requires comparison of long-term benefits and costs

- Either on a present value or levelized annual basis
- Over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets

- How benefits and costs accrue over time and across future scenarios will help optimize the timing of investments
- Near- and long-term uncertainties need to be addressed to develop robust plans and least-regret projects
- Long-term uncertainties
  - (industry structure, new technologies, fundamental policy changes, and shifts in fuel market fundamentals) can be addressed through scenario-based analyses
  - Near-term uncertainties within long-term scenarios (uncertainties in loads, fuel prices, transmission and generation outages) should be evaluated through sensitivity or "probabilistic" analyses[28]

Modifying the ratemaking incentives as proposed will create ROE adders that are tied specifically to the development of simplistic production cost model runs, which estimate potential fuel savings in the future. This will modify the prioritization of transmission investments for at least transmission providers, and may have undue influence on RTO/ISO planning studies in prioritizing transmission investments. This will essentially move away from economically efficient transmission infrastructure development, and move it toward maximizing shareholder value by choosing transmission projects that can earn and enhance ROE as opposed to creating greater system benefit. The proposed change is simply inappropriate and does not meet the FERC's stated goal of economically efficient transmission infrastructure development.

[28]The Brattle Group Presentation: "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," July 31, 2013, provided as Exhibit No. AMF-4, pages 258-282.

Q IF PRODUCTION COST STUDIES ARE NOT BY THEMSELVES ADEQUATE FOR TRANSMISSION SYSTEM PLANNING, SHOULD PRODUCTION COST STUDIES ALONE BE ADEQUATE FOR MEASURING ECONOMIC BENEFITS OF TRANSMISSION ASSETS?

A No. Production cost studies simply are not reliable enough to measure economic benefits associated with transmission investments that can justify an incentive ROE adder. Production cost studies are long-term studies that try to capture highly uncertain variables which can impact the need and drive economic investments in new infrastructure assets. It does produce expected values but it does not produce actual values. As a consequence, it is an appropriate tool for planning, but should not be the only tool utilized in identifying new infrastructure investments. A production cost study does not produce known and measurable cost savings and therefore should not be used to justify increased costs to customers to pay TOs ROE incentives. The net impact on customers is highly uncertain from the production cost study, but customers' rates certainly will go up by the inclusion of ROE adders.

Q DO THE PROPOSED INCENTIVES RELATED TO RELIABILITY INCENTIVES PROVIDE ADEQUATE PROTECTION TO CUSTOMERS?

A No. The proposed incentive policy will add a 50 basis point ROE incentive for transmission projects that provide significant and demonstrable reliability benefits.[29] This proposal is unreasonable for several reasons. First, transmission investment that can improve reliability is generally the standard which demonstrates that a

[29]NOPR at ¶ 65.

transmission investment is prudent and reasonable and should be undertaken. A fair and reasonable return for making transmission reliability investments is at the FERC's base ROE without any adders. The risk of such investment is low due to FERC's investor friendly cost recovery rate-setting protocols along with a fair and reasonable risk-adjusted base ROE. An above market rate of return is not justified for transmission companies undertaking the investment opportunities that align with the low-risk nature of making transmission infrastructure investments subject to minimal cost recovery risk uncertainty based on FERC current ratemaking policies.

It is clear from the FERC's standards that there are many ways to measure reliability, and therefore the awarded return on equity cannot be clearly distinguished from simply making a prudent investment decision, and an incentive ROE which is necessary to provide adequate incentive for the transmission infrastructure investment to actually be made. The proposal for an incentive ROE based on enhanced reliability is unjustified, unneeded, and should not be adopted.

Q DOES THIS CONCLUDE YOUR AFFIDAVIT?

A Yes.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas;

presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

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Acronyms and Abbreviations

ATC	American Transmission Company
BAI	Brubaker & Associates, Inc.
CFA	Chartered Financial Analyst
Commission	Federal Energy Regulatory Commission
DBA	Drazen-Brubaker & Associates, Inc.
EEI	Edison Electric Institute
FERC	Federal Energy Regulatory Commission
Form 730	Report of Transmission Investment Activity
FPA	Federal Power Act
ICC	Illinois Commerce Commission
ISO	Independent System Operator
ITC	International Transmission Company
NOPR	Notice of Proposed Rulemaking
OCF	Operating Cash Flow
PIS	Plant In-Service
RFP	Request for Proposals
ROE	Return on Equity
RRA	Regulatory Research Associates
RTO	Regional Transmission Organization
S&P	Standard & Poor's
Transcos	Transmission Companies
TO	Transmission Owner

Exhibit No. AMF-2

Federal Energy Regulatory Commission

Utility Net Plant in-Service
($000)

Line	Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Growth
	Gross Electric Plant in-Service											
1	Total Production	466,876	498,731	553,561	544,054	583,644	613,393	644,180	650,397	669,985	695,791	49%
2	Total Transmission	191,261	208,537	238,634	264,425	296,733	329,335	362,047	385,776	425,058	437,064	129%
3	Total Distribution	544,079	577,228	623,691	652,151	688,696	724,129	761,061	798,041	850,559	867,931	60%
4	Total General	45,851	48,813	53,132	56,078	59,473	61,884	65,239	68,577	74,006	78,271	71%
5	Total Plant in-Service	1,248,068	1,333,310	1,469,019	1,516,708	1,628,546	1,728,741	1,832,527	1,902,792	2,019,609	2,079,057	67%
	Accumulated Depreciation Reserve											
6	Total Production	217,411	227,526	243,760	231,840	243,396	248,851	260,438	262,404	265,867	272,195	
7	Total Transmission	63,687	67,310	72,854	75,638	80,112	83,822	89,138	92,097	98,857	99,635	
8	Total Distribution	198,088	211,214	227,003	236,920	249,071	256,033	269,316	277,602	293,474	288,297	
9	Total General	19,503	18,400	20,944	22,012	23,229	24,083	25,197	25,512	27,624	30,575	
10	Total Accumulated Depreciation	498,689	524,450	564,561	566,411	595,808	612,789	644,089	657,616	685,822	690,702	
	Net Plant in-Service											
11	Total Production	249,466	271,206	309,802	312,213	340,248	364,542	383,742	387,993	404,118	423,596	70%
12	Total Transmission	127,574	141,227	165,780	188,787	216,621	245,513	272,909	293,679	326,201	337,429	164%
13	Total Distribution	345,991	366,014	396,688	415,231	439,625	468,096	491,744	520,439	557,085	579,633	68%
14	Total General	26,349	30,413	32,188	34,066	36,244	37,801	40,042	43,065	46,382	47,696	81%
15	Total Net Plant in-Service	749,379	808,860	904,457	950,297	1,032,738	1,115,953	1,188,437	1,245,176	1,333,787	1,388,355	85%

Source:
S&P Global Market Intelligence, per FERC Form 1 filing

Federal Energy Regulatory Commission

Company Guidance

Line	Company	Company Guidance: Projected Growth			Credit Rating		Sources:
		Rate Base (1)	EPS (2)	DPS (3)	S&P (4)	Moody's (5)	
1	ALLETE	*Signific. Growth	6%	5%			ALLETE Investor Presentation at 6, 10, and 16 (Rate base), March 12, 2020.
2	Alliant Energy	*Increasing	7%	5%-7%			Alliant Investor Presentation at 2 and 7 (Rate base), February 21, 2020. Alliant Investor Presentation at 3 and 4, November 10-12, 2019.
3	Ameren Corp.	8.7%	6%-8%	4%	BBB+	Baa1	Ameren Investor Presentation at 5, 8, and 27, March 30 - April 1, 2020.
4	Amer. Elec. Power	7.9%	5% - 7%	3%			American Electric Power Investor Presentation at 7 and 13, March 3, 2020.
5	Avangrid, Inc.	9%	12%-14%, 8%-10% Adj	*Increase w/ EPS growth	BBB+	Baa1	Avangrid Investor Presentation at 7, 34, and 39, December 2019. Avangrid Investor Presentation at 22, February 26, 2020.
6	Avista Corp.	5% - 6%	9%-10%, 2020-22, 4%-6% after 2022	4.50%			Avista Investor Presentation at 5 and 7, March 3-4, 2020.
7	Black Hills	*Rate base growth greater than depreciation	3.5% EPS CAGR 10.1% Earnings CAGR	5.60%	BBB+	Baa2	Black Hills Investor Presentation at 15 and 25, February 7, 2020.
8	CenterPoint Energy	7.5%	5%-7%	1%-3%			CenterPoint Investor Presentation at 15 and 26, February 27, 2020.
9	CMS Energy Corp.	7%	6%-8%	6%-8%			CMS Energy Investor Presentation at 11, 16 and 21, February 2020.
10	Consol. Edison	5.4%	3% - 5%		BBB+	Baa1	Consol. Edison Investor Presentation at 13 and 38, March 2020.
11	Dominion Resources	6% y/y (2019)	5%+	2.50%	BBB+	Baa2	Dominion Investor Presentation at 4, 13 and 35, February 11, 2020.
12	DTE Energy		5%-7%	7%	BBB	Baa2	DTE Investor Presentation at 4, 5, and 18, February 5, 2020.
13	Duke Energy		4%-6%		BBB+	Baa1	Duke Investor Presentation at 3 and 14, February 13, 2020.
14	Edison Int'l (SCE)	7.5%	Expected to track Rate base growth				Edison International Investor Presentation at 6 and 9, February 27, 2020. Edison International Business Update at 4, October 30, 2019.
15	Entergy Corp.		5%-7%	*Expected to be in line with EPS	BBB+	Baa2	Entergy Investor Presentation at 13 and 15, February 13, 2020.
16	Eversource Energy	6.9%	5%-7%	5%-7%			Eversource Investor Presentation at 10, 11, 19 and 24, February 20, 2020.
17	Evergy, Inc.	3%-4%	5%-7%, associated with rate base growth of 2%-3%	*Expected to be in line with EPS	BBB+	Baa2	Evergy Investor Presentation at 6, March 2, 2020. Evergy Investor Presentation at 3 and 11, November 2019.
18	Exelon Corp.		3%				Exelon Investor Presentation at 18, February 11, 2020.
19	FirstEnergy Corp.		6%- 8% from 2018 through 2021, and 5% - 7% extending through 2023				First Energy Corp. Investor Presentation at 6, April 24, 2020.
20	Fortis Inc.			6%	n/a	A3	Fortis Investor Presentation at 5, April 30, 2020.
21	Hawaiian Elec.	4%	5.50%				Hawaiian Electric Investor Presentation at 23, May 5, 2020.
22	IDACORP, Inc.		<1%				IDACORP Investor Presentation at 9, April 30, 2020.

Federal Energy Regulatory Commission

Company Guidance

Line	Company	Company Guidance: Projected Growth: Rate Base (1)	EPS (2)	DPS (3)	Credit Rating: S&P (4)	Moody's (5)	Sources:
23	NorthWestern Corp		3%-5%				NorthWestern Corp Investor Presentation at 3, April 23, 2020.
24	OGE Energy		1%				OGE Energy Investor Presentation at 9, May 7, 2020.
25	Otter Tail Corp.		12%-15%		BBB	Baa2	Otter Tail Corp. Investor Presentation at 33, May 5, 2020.
26	Pinnacle West Capital	6%-7%	1%-4%		A-	A3	Pinnacle West Investor Presentation at 4 and 15, May 8, 2020.
27	PNM Resources		3%-5%		BBB	Baa3	PNM Resources Investor Presentation at 14, May 1, 2020.
28	Portland General		4%-6%		A	A1	Portland General Investor Presentation at 4, April 24, 2020.
29	PPL Corp.	5%-6%	5%-6%		A-	Baa2	PPL Corp. Investor Presentation at 5, May 8, 2020.
30	Public Serv. Enterprise		4%				Public Serv. Enterprise Investor Presentation at 8, May 4, 2020.
31	Sempra Energy		10%-11%				Sempra Energy Investor Presentation at 5, May 4, 2020.
32	Southern Co.		4%-6%				Southern Co. Investor Presentation at 10, April 30, 2020.
33	Xcel Energy Inc.		5%-7%				Xcel Energy Inc. Investor Presentation at 18, May 7, 2020.

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Edison Electric
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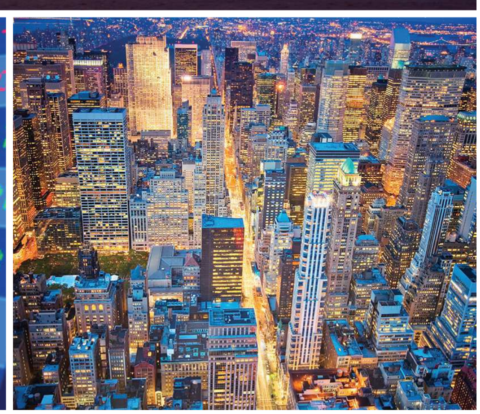
2019 Financial Review

Annual Report of the U.S. Investor-Owned Electric Utility Industry



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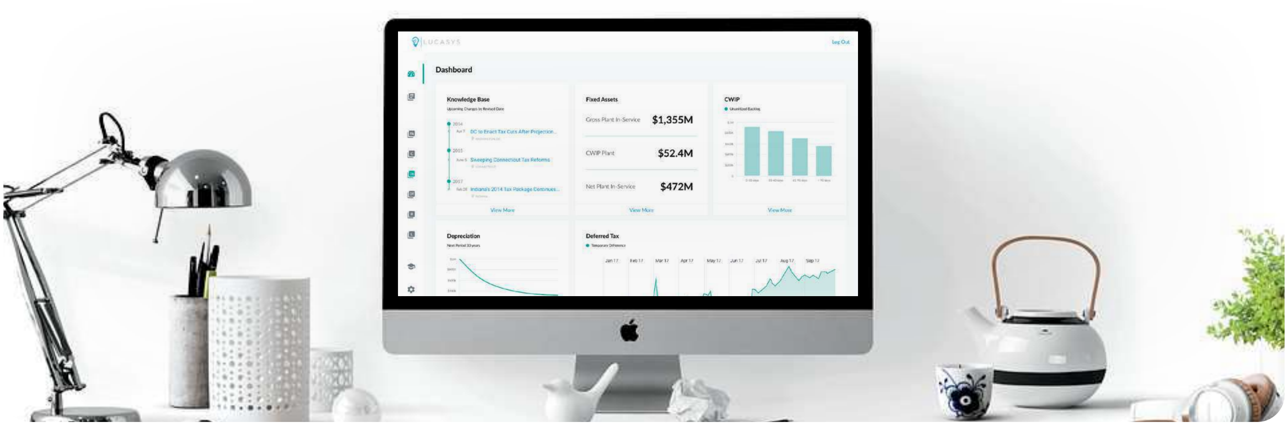

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2019
FINANCIAL REVIEW

ANNUAL REPORT OF THE U.S. INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2019 Financial Review is a comprehensive source for critical financial data covering 40 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on five additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms. These 45 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 76 for a list of these companies.

Contents

Highlights of 2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

FINANCIAL ($ Millions)	2019	2018r	% Change
Total Operating Revenues	364,895	364,383	0.1%
Utility Plant (Net)	1,244,443	1,147,970	8.4%
Total Capitalization	1,128,491	1,022,415	10.4%
Earnings Excluding Non-Recurring and Extraordinary Items	51,461	47,644	8.0%
Dividends Paid, Common Stock	27,938	25,726	8.6%

r = revised Note: Percent changes may reflect rounding.

Abbreviations and Acronyms

AFUDC	Allowance for Funds Used During Construction
BTU	British Thermal Unit
CFTC	Commodity Futures Trading Commission
CPI	Consumer Price Index
DOE	Department of Energy
DOJ	Department of Justice
DPS	Dividends per share
EEI	Edison Electric Institute
EIA	Energy Information Administration
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	Independent Transmission Company
kWh	Kilowatt-hour
M&A	Mergers & Acquisitions
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NOAA	National Oceanic & Atmospheric Administration
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
PSC	Public Service Commission
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
ROE	Return on Equity
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SO_2	Sulfur Dioxide
T&D	Transmission & Distribution

Company Categories

Two categories are used throughout this publication that group companies on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

Regulated: 80% or more of total assets are regulated.

Mostly Regulated: Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a “Diversified” category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a “Diversified” category.

President's Letter

2019 Financial Review

As I write this, the Edison Electric Institute's (EEI's) member companies—America's investor-owned electric companies—are addressing the unprecedented crisis caused by the COVID-19 pandemic with courage and commitment. We are determined to meet the new challenges that confront us, as we continue to deliver the safe, reliable, affordable, and clean energy our customers need and expect. Through our industry's efforts and dedication, we will play an instrumental role in our nation's recovery, and we will light the way forward to a brighter future.

At the same time, EEI's member companies continue to lead a profound transformation of America's energy. This long-term transformation already is delivering positive dividends for customers, communities, employees, and investors. Our dramatic reductions in carbon emissions; our broad deployment of renewables and of smarter energy infrastructure; the physical and cybersecurity protections we are implementing—these are three unmistakable examples of the enormous strides EEI's members have made just over the past decade.

We are proud that we stand on a strong foundation, and we look forward to our continued work together to deliver value to our customers, to our investors, and to all industry stakeholders. Our goal is to give our customers an energy future that is cleaner, smarter, stronger, and more secure than any they have known before.

Across the industry, there is strong evidence of our commitment to get as clean as we can, as fast as we can, while keeping customer reliability and affordability front and center as always. Over the past eight years, more than half of new electricity generation capacity was wind and solar. Today, nearly 40 percent of all U.S. power generation comes from carbon-free sources, including nuclear energy and hydropower and other renewables. Overall, emissions from the electric power sector are at their lowest level since 1987 and are down by a third (32.9 percent to be exact) compared to 2005 levels. Among EEI's member companies, emissions have been reduced even more and were 45 percent below 2005 levels as of year-end 2019.

Our industry long has been the nation's most capital-intensive industry, and, over the past decade, we have sustained a record-high level of capital expenditures. Since 2010, EEI's member companies have invested nearly $1 trillion to build smarter energy infrastructure and to integrate new generation.

EEI and our member companies also are working constantly to improve energy grid security, reliability, and resiliency, and we will continue to strengthen cyber and physical defenses and to elevate preparedness. Our strong industry-government partnership, coordinated through the CEO-led Electricity Subsector Coordinating Council, will continue to be critical to accomplishing our shared goal of protecting the energy grid against all threats.

We know that our stakeholders need a clear and consistent way to measure our progress on delivering the clean energy future. That is why EEI, working with our member companies and the investment community, created the first-of-its-kind, industry-wide environmental, social, governance, and sustainability (ESG/sustainability) reporting template. Launched in 2018, the template helps member companies provide investors, Wall Street analysts, and other key stakeholders with more consistent and uniform ESG/sustainability data and information. We expanded the template in 2019 to include a qualitative disclosure on cybersecurity governance and to formally integrate the American Gas Association's (AGA's) members.

Building on the work of the ESG/ sustainability template and recognizing the important role that natural gas has—and will continue to have—in our clean energy future, EEI and AGA now are focused on the Natural Gas Sustainability Initiative (NGSI). The NGSI is an overarching framework that enables the natural gas industry to measure, disclose, and recognize individual company and industry-wide progress and innovation on key sustainability metrics. The NGSI framework initially is focused on methane emissions and will incorporate additional ESG topics over time.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the sixth straight year in 2019, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set another record high of $124.1 billion in 2019.

The EEI Index gained 25.8 percent in 2019, and our industry extended its long-term trend of widespread dividend increases. A total of 37 companies, or 93 percent of the industry, increased their dividend in 2019, matching the record-high percentage set in 2018. The industry's average dividend yield at the end of 2019 stood at 3.0 percent, while its dividend payout ratio was 64.1 percent for calendar year 2019. Among the primary U.S. business sectors, those results only trailed the energy sector. As of December 31, 2019, 39 of the 40 companies in the EEI Index were paying a common stock dividend.

I know that the COVID-19 pandemic has impacted all Americans. I also know that EEI's member companies have a strong track record of coming together to help their customers and communities during times of need. We will be there every step of the way as our nation forges a path to recovery. And, we will build upon our long-term record of service, resilience, and success.

EEI and our member companies are demonstrating Power by Association, and we are committed to delivering a cleaner, smarter, stronger energy future.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn

President
Edison Electric Institute

Capital Markets

Stock Performance

The EEI Index trailed a surging stock market throughout 2019's final quarter, returning 0.4% versus the Dow Jones Industrial Average's 6.7%, the S&P 500 Index's 9.1% and the tech-heavy Nasdaq Composite's 12.2% gain. The market's multi-year rally resumed as growth fears ebbed with improving economic data, easing trade war tensions and another U.S. Federal Reserve rate cut — the third in 2019. Some market watchers also cited the Fed's aggressive intervention in the repo market late in the year as a trigger for liquidity-induced market gains. Otherwise, the 10-year Treasury yield pushed higher in Q4 after a year-long decline; this likely pressured utility shares relative to sectors that are more sensitive to economic conditions.

The EEI Index returned nearly 26% for full-year 2019, its strongest annual performance since 2014's 28.9%. But the broad market performance was even stronger. The Dow returned 25.3% for the year, the S&P 500 Index returned 31.5% and the Nasdaq climbed 35.2%. Beginning and ending dates powerfully shape relative return comparisons. The broad market's 15% fall in

2019 Index Comparison

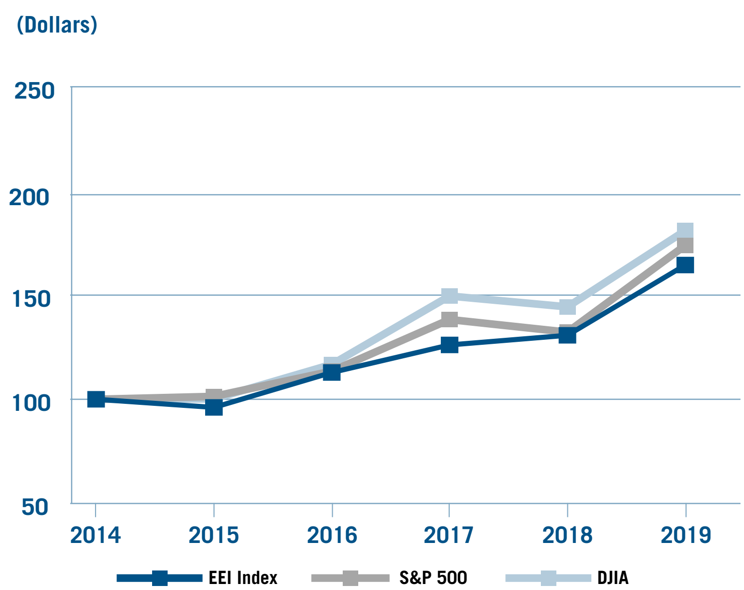
EEI Index	**25.8**
Dow Jones Industrials	25.3
S&P 500	31.5
Nasdaq Composite Index*	35.2

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/15–12/31/19

REFLECTS REINVESTED DIVIDENDS



All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2014.

Source: EEI Finance Department and S&P Global Market Intelligence.

2019 Returns By Quarter

Index	Q1	Q2	Q3	Q4
EEI Index	11.1	4.1	8.2	0.4
Dow Jones Industrial Average	11.8	3.2	1.8	6.7
S&P 500	13.7	4.3	1.7	9.1
Nasdaq Composite*	16.5	3.6	(0.1)	12.2
Category	**Q1**	**Q2**	**Q3**	**Q4**
All Companies	10.6	4.9	6.5	(0.4)
Regulated	10.6	5.9	6.5	(0.1)
Mostly Regulated	10.5	1.3	6.6	(1.2)

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

Sector Comparison 2019 Total Shareholder Return

Sector	Total Return %
Technology	47.5%
Industrials	32.8%
Financials	32.6%
Consumer Goods	28.7%
Telecommunications	27.9%
Consumer Services	26.9%
EEI Index	**25.8%**
Utilities	24.9%
Healthcare	21.3%
Basic Materials	19.8%
Oil & Gas	10.4%

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

Q4 2018 — when utility shares were flat — created a favorable 2019 starting point. Adding 2018's Q4 to 2019 results raises utility returns for the 15-month period well above those of the major averages.

Slow Growth but No Recession

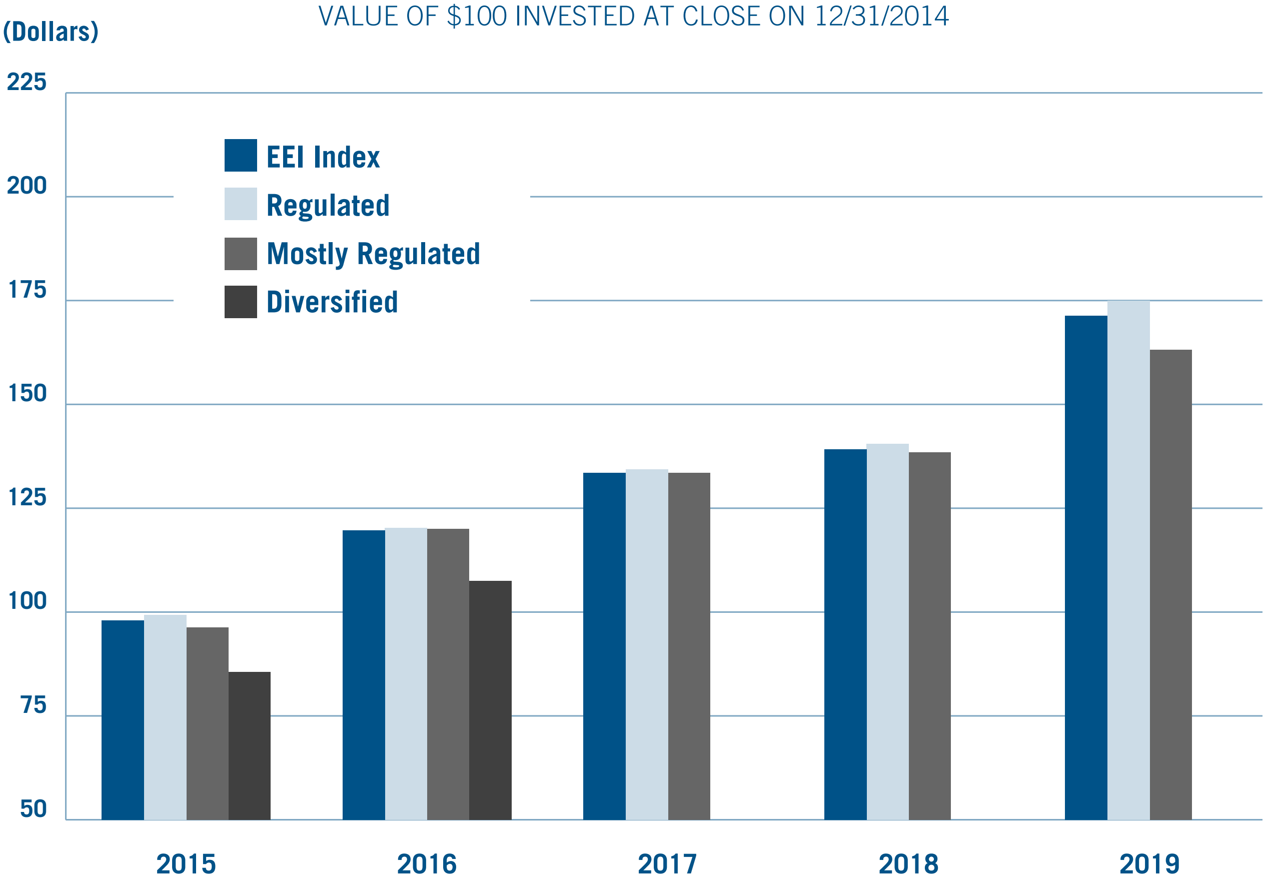
Utilities' short-term relative performance as a group typically results from shifting macroeconomic sentiment rather than changes in the industry's fundamental outlook. Indeed, Q4 2019 simply reversed Q3's pattern, when trade-war fears and worrisome economic data kept the broad averages flat while safe-haven utilities gained 8%.

U.S. real gross domestic product (GDP) growth slowed to a 2.0% rate in Q2 and 2.1% in Q3 from 3.1% in Q1. S&P 500 company profits (aggregate rather than per share) were about flat year-to-year in Q2 and Q3 with revenue up 4% each quarter, according to Zack's Investment Research data. Zack's pegs Q4 revenue up 3.5% and income down 2%. The Trump Administration's economic stimulus and tax cuts made 2018 corporate after-tax profits soar, somewhat distorting 2019's year-to-year comparison. And analysts expected revenue and profit growth to strengthen again in 2020. That bullish outlook contributed to Q4's market rally.

Falling interest rates through much of 2019 supported utilities' strong absolute return as well as the broad market's rise. The U.S. Federal Reserve cut short-term rates twice during Q3 citing continued low inflation and the spillover effect from slowing growth overseas, and again in late October. The Fed Funds target fell from a 2.25% to 2.50% range in early July to a 1.50% to 1.75% range after the October rate cut. The 10-year Treasury bond yield fell from a recent peak of 3.2% in late 2018 to 1.5% in early September before edging up to 1.9% as the year ended.

Comparative Category Total Annual Returns 2015–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2014



	2015	2016	2017	2018	2019
EEI Index Annual Return (%)	(2.05)	22.21	11.56	4.28	23.06
EEI Index Cumulative Return ($)	97.95	119.70	133.54	139.25	171.36
Regulated EEI Index Annual Return	(0.67)	21.16	11.66	4.55	24.56
Regulated EEI Index Cumulative Return	99.33	120.34	134.37	140.48	174.99
Mostly Regulated EEI Index Annual Return	(3.67)	24.57	11.32	3.62	17.87
Mostly Regulated EEI Index Cumulative Return	96.33	119.99	133.58	138.41	163.15
Diversified EEI Index Annual Return	(14.43)	25.59	–	–	–
Diversified EEI Index Cumulative Return	85.57	107.47	–	–	–

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2014.

Source: EEI Finance Dept., S&P Global Market Intelligence.

2019 Category Comparison

Category	Return (%)
EEI Index	**23.1**
Regulated	24.6
Mostly Regulated	17.9

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2019 Index Comparison table is cap-weighted.

Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

U.S. Electric Output Declines

The multi-year flattening in electric power demand persisted in 2019. Full-year demand fell 1.7% from 2018's level and annual nationwide generation is largely unchanged from its level in 2007. U.S. electric output declined 0.6% year-to-year in Q3 and 4.4% in Q2. Part of the shortfall in both quarters was weather-related. Cooling degree days fell 11.2% year-to-year nationwide in Q2 and 2.1% in Q3. Cooling degree days were off 4.9% for the year as a whole while heating degree days were flat. Analysts cited the impact of trade tariffs on U.S. industrial demand as well as years of energy efficiency initiatives nationwide as other reasons for the demand weakness.

Growth Outlook Remains Healthy

Despite the lackluster demand trend, there was little change in the industry's stable business fundamentals in 2019. Most stakeholders across the political spectrum support investments that advance renewable energy goals, decarbonization, reliability, job creation and the enlarged tax base that comes with it. Utility investment programs include new renewables generation, new gas-fired generation, transmission and distribution modernization and expansion, smart-grid deployment, and reliability-related network hardening among other projects.

Analysts seem to view state regulatory relations as generally fair, balancing the interests of ratepayers, utilities and other stakeholders. Some utilities have successfully advocated for changes to rate design — such as forward test years, rate mechanisms and adjustment clauses — that allow timely recovery of costs associated with big-ticket capital investment programs and offer some protection from lethargic demand.

The prospect of electric vehicle (EV) adoption gained some analytical traction in 2019 as a potential longer-term source of demand growth that also supports decarbonization when powered by emission-free generation. While technological evolution is notoriously difficult to accurately predict, some estimates suggested widespread EV adoption could boost load by 1% annually over the next few decades.

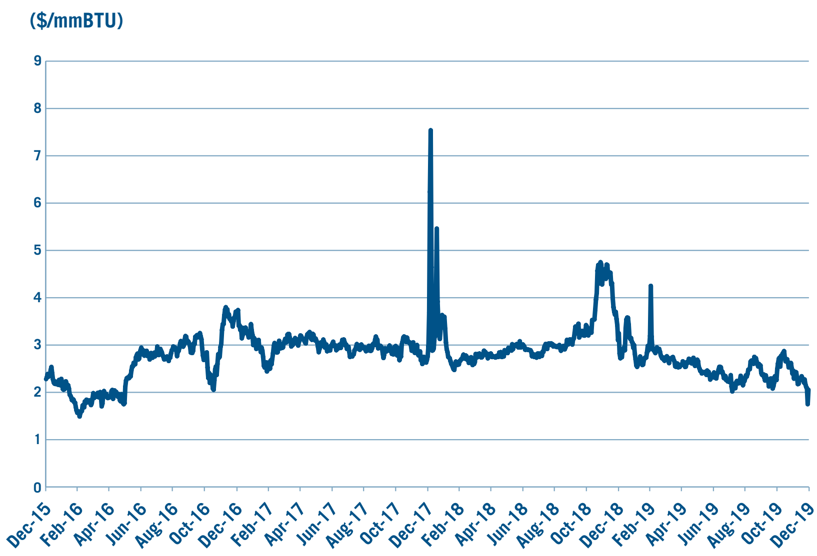
Favorable Cost Trends

Another favorable trend for regulated utilities is low fuel costs. Coal prices have declined steadily since 2011, natural gas prices have changed little in recent years and the growing amounts of wind and solar generation added to the grid have zero fuel cost. The low level of interest rates is also beneficial. Since regulated utilities pass fuel and interest expense through to customers (and fuel can account for 40% or more of the customer's bill), cost stability in these key areas helps keep bill inflation down and makes it easier to gain regulatory approval for large investment programs. Despite years of capex growth, the average nationwide cost of electricity for residential customers has risen from $0.1151/kilowatt hour (kWh) in 2009 to $0.1289/kWh in 2018, which was unchanged from 2017 and only marginally higher than 2014's $0.1252, according to EIA data.

Top EEI Index Gainers

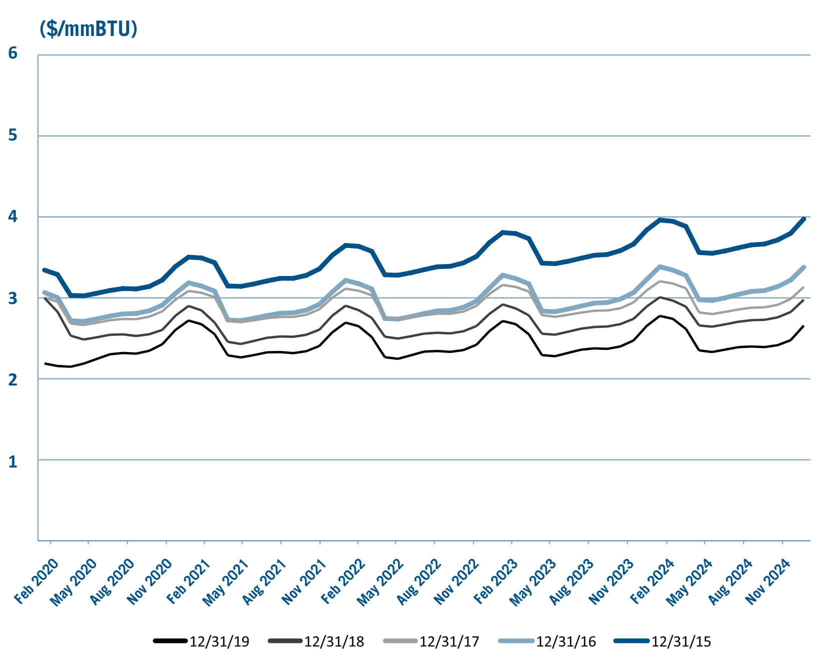
Several utilities gained 30% to 40% in 2019, in some cases rebounding from previous weakness. Southern Company gained 51.3% as investor gained confidence in the outlook for completion and commercial operation of its new Vogtle nuclear units and it completed a Georgia rate case near year-end. Entergy (+44.0%) gained on its reduced exposure to wholesale operations and transition back to a regulated utility with several regulatory outcomes that support its investment plans. FirstEnergy (+33.9%) exited its formerly large competitive generation operations and is focused on earnings growth from regulated transmission and distribution investments. Sempra (+43.9%) has also divested non-core assets and is focused on high-growth U.S. re-

Natural Gas Spot Prices - Henry Hub
12/31/15 through 12/31/19



Source: S&P Global Market Intelligence.

NYMEX Natural Gas Futures
February 2020 through December 2024



Source: S&P Global Market Intelligence.

EEI Index Top 10 Performers
Twelve-month period ending 12/31/2019

Company	Total Return %	Category
Southern Company	51.3	R
Entergy Corporation	44.0	R
Sempra Energy	43.9	R
NextEra Energy, Inc.	42.6	MR
El Paso Electric Company	38.6	R
Edison International	37.6	R
WEC Energy Group, Inc.	36.8	R
Eversource Energy	34.4	R
MGE Energy, Inc.	33.9	R
FirstEnergy Corp.	33.9	R

Note: Return figures include capital gains and dividends.

Source: EEI Finance Department.

Market Capitalization at December 31, 2019 (in $MM)

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Ticker	Market Cap.	% of Total	Company Name	Ticker	Market Cap.	% of Total
NextEra Energy, Inc.	NEE	116,697	12.89%	CenterPoint Energy, Inc.	CNP	13,696	1.51%
Dominion Energy, Inc.	D	67,333	7.44%	Alliant Energy Corporation	LNT	13,084	1.45%
Southern Company	SO	66,758	7.38%	NiSource Inc.	NI	10,415	1.15%
Duke Energy Corporation	DUK	66,492	7.35%	Pinnacle West Capital Corporation	PNW	10,114	1.12%
American Electric Power Company, Inc.	AEP	46,673	5.16%	OGE Energy Corp.	OGE	8,903	0.98%
Exelon Corporation	EXC	44,359	4.90%	MDU Resources Group, Inc.	MDU	5,922	0.65%
Sempra Energy	SRE	42,014	4.64%	PG&E Corporation	PCG	5,750	0.64%
Xcel Energy Inc.	XEL	32,951	3.64%	IDACORP, Inc.	IDA	5,393	0.60%
Consolidated Edison, Inc.	ED	30,054	3.32%	Hawaiian Electric Industries, Inc.	HE	5,106	0.56%
Public Service Enterprise Group Inc.	PEG	29,761	3.29%	Portland General Electric Company	POR	4,986	0.55%
WEC Energy Group, Inc.	WEC	29,089	3.21%	Black Hills Corporation	BKH	4,789	0.53%
Eversource Energy	ES	27,566	3.05%	ALLETE, Inc.	ALE	4,196	0.46%
Edison International	EIX	26,167	2.89%	PNM Resources, Inc.	PNM	4,057	0.45%
FirstEnergy Corp.	FE	26,147	2.89%	NorthWestern Corporation	NWE	3,615	0.40%
PPL Corporation	PPL	25,915	2.86%	Avista Corporation	AVA	3,187	0.35%
Entergy Corporation	ETR	23,832	2.63%	El Paso Electric Company	EE	2,757	0.30%
DTE Energy Company	DTE	23,766	2.63%	MGE Energy, Inc.	MGEE	2,733	0.30%
Ameren Corporation	AEE	18,885	2.09%	Otter Tail Corporation	OTTR	2,037	0.23%
CMS Energy Corporation	CMS	17,784	1.97%	Unitil Corporation	UTL	921	0.10%
AVANGRID, Inc.	AGR	15,834	1.75%				
Evergy, Inc.	EVRG	15,270	1.69%		Total Industry	905,009	100%

Source: EEI Finance Department and S&P Global Market Intelligence.

gions; in addition, it was impacted less than other California utilities by the devastating wildfires in 2017 and 2018. NextEra (+42.6%) continues to produce strong earnings and dividend growth from its large renewables portfolio and regulated electric/gas pipeline operations in the southeastern U.S.

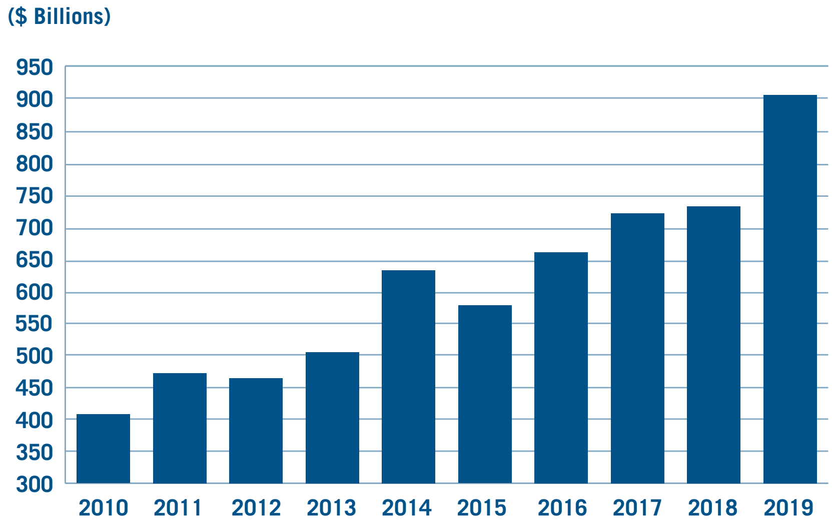
Elevated Valuations

At year-end, Wall Street analysts generally viewed utility stock valuations as high when measured by price/earnings (PE) ratios relative to the S&P 500 and to history. One reason for high PEs is the very low level of interest rates both in the U.S. and overseas. The U.S. 10-year Treasury yield was about 6% in the late 1990s, more than triple today's level, while bond markets in Europe and Japan sport widespread negative yields that drive global investors into relatively safe positive-yielding investments like utilities. Another reason is the strong fundamentals that underpin prospects for total returns in excess of 8% (5% from earnings growth and 3% from the dividend). While PEs seem high, utilities may offer enough value to lift multiples higher still if global economic growth turns down and interest rates fall to new lows.

Other Risks

A sharp rise in interest rates is widely seen as the biggest macro threat facing utility investors. Although that has been said for years and interest rates just seem to fall. Inflation held near 2% throughout 2018 even as the economy roared and didn't move in 2019 either. The main risk to the very long-lived eco-

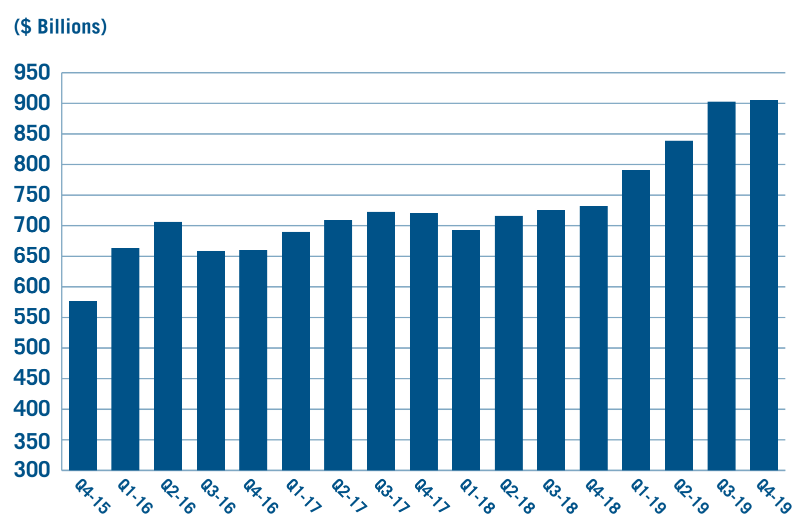
EEI Index Market Capitalization 2010–2019



Note: Results are as of December 31 of each year.

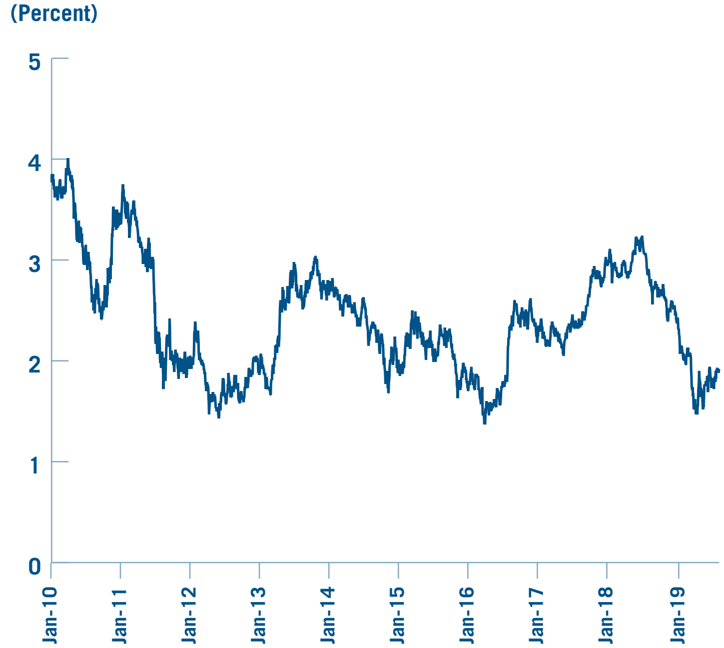
Source: EEI Finance Department and S&P Global Market Intelligence.

EEI Index Market Capitalization
December 31, 2015–December 31, 2019



Source: EEI Finance Department and S&P Global Market Intelligence.

10-Year Treasury Yield
1/1/10 through 12/31/19



Source: U.S. Federal Reserve.

nomic expansion seems to be weakness rather than red-hot growth.

A second, less discussed risk is pushback on rate increases needed to fund capex programs. Stable fuel costs and low interest rates have kept bill pressures muted. Industry analysts expect that trend will continue. But if the economy enters recession and consumer incomes fall, managing regulatory risk and financing needed capex through customer rates may become more challenging than it has been in recent years.

Dividends

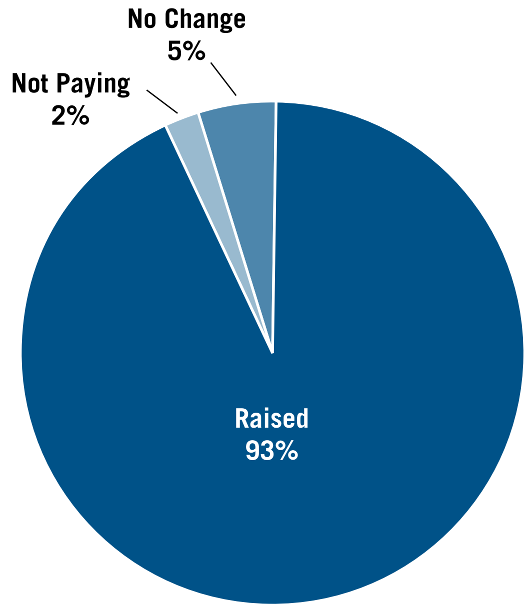
The investor-owned electric utility industry continued its long-term trend of widespread dividend increases in 2019. A total of 37 companies increased or reinstated their dividend compared to 39 in 2018, 38 in 2017, 40 in 2016 and 36 to 40 companies annually from 2012 through 2015.

The percentage of companies that raised or reinstated their dividend in 2019 was 93%, matching 2018's record high. This exceeded 2017's 88% and the previous record of 91% in 2016, the next two highest historical results. These followed results of 85% in 2015 and a range of 73% to 79% back to 2012. Only 27 of the 65 utilities tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates. The record high of 93% in both 2018 and 2019 is based on data beginning in 1988. (Note: M&A activity reduced the number of publicly traded utilities tracked by EEI from 65 in 2003 to 40 at year-end 2019).

As shown in the Dividend Patterns table, 39 of the 40 publicly traded utilities in the EEI Index were paying a common stock dividend as of December 31, 2019. Each company is limited to one action per year in the table. For example, if a company raised its dividend twice during a year, that counts as one in the Raised column. Companies generally use the same quarter each year for dividend changes, with the first being the most common for electric utilities.

2019 Dividend Patterns

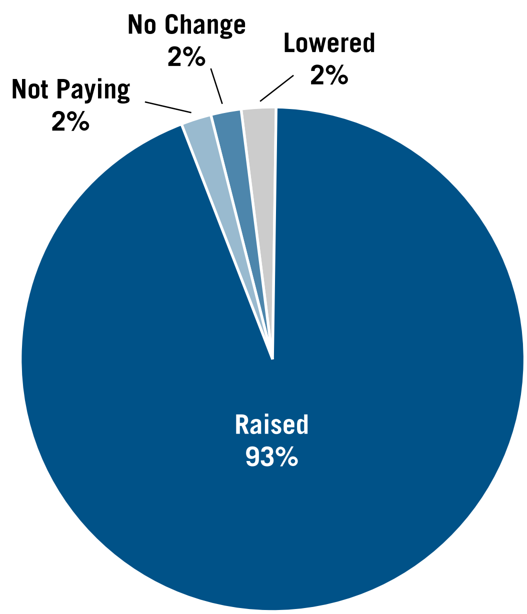
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2018 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

2019 Increases Average 5.1%

The average dividend increase in 2019 was 5.1%, with a range of 0.6% to 12.6% and a median increase of 4.9%. NextEra (+12.6% in Q1), Dominion (+9.9% in Q1), Sempra (+8.1% in Q1) and DTE (+7.1% in Q4) posted the largest percentage increases.

NextEra Energy, headquartered in Juno Beach, Florida, raised its quarterly dividend from $1.11 to $1.25 per share in Q1. The increase is consistent with its plan, announced in 2018, to target 12% to 14% annual growth in dividends per share through at least 2020, off a 2017 base. NextEra recorded the industry's second-highest percentage increase in 2018 (+13.0%) and the largest percentage increases in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

Dominion Energy, based in Richmond, Virginia, increased its quarterly dividend from $0.835 to

Dividend Patterns 1995–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Raised	No Change	Lowered	Omitted*	Reinstated	Not Paying	Total	Dividend Payout Ratio
1995	52	40	3	–	–	3	98	75.3%
1996	48	44	2	1	1	2	98	70.7%
1997	40	45	6	2	–	3	96	84.2%
1998	40	37	7	–	–	5	89	82.1%
1999	29	45	4	–	3	2	83	74.9%
2000	26	39	3	1	–	2	71	63.9%**
2001	21	40	3	2	–	3	69	64.1%
2002	26	27	6	3	–	3	65	67.5%
2003	26	24	7	2	1	5	65	63.7%
2004	35	22	1	–	–	7	65	67.9%
2005	34	22	1	1	2	5	65	66.5%
2006	41	17	–	–	–	6	64	63.5%
2007	40	15	–	–	3	3	61	62.1%
2008	36	20	1	–	1	1	59	66.8%
2009	31	23	3	–	–	1	58	69.6%
2010	34	22	–	–	–	1	57	62.0%
2011	31	22	–	1	1	–	55	62.8%
2012	36	14	–	–	1	–	51	64.2%
2013	36	12	1	–	–	–	49	61.5%
2014	38	9	1	–	–	–	48	60.4%
2015	39	7	–	–	–	–	46	67.0%
2016	40	4	–	–	–	–	44	62.9%
2017	38	4	–	1	–	–	43	64.0%
2018	39	1	1	–	–	1	42	63.9%
2019	37	2	–	–	–	1	40	62.6%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Average of the Increased Dividend Actions ***	8.2%	6.8%	7.2%	5.3%	5.7%	5.8%	5.6%	5.6%	5.7%	5.1%
Average of the Declining Dividend Actions ***	NA	(100.0%)	NA	(41.0%)	(34.5%)	NA	NA	NA	(79.8%)	NA

* Omitted in current year. This number is not included in the Not Paying column.

** * Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend.

*** Excludes companies that omitted or reinstated dividends.

2019 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2019 and earnings and dividends through 12/31/2019 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department

$0.9175 per share in Q1. As a result, 2019 marked the 16th consecutive year in which Dominion increased its dividend.

Sempra Energy, based in San Diego, California, announced in Q1 a quarterly increase from $0.895 to $0.9675 per share; 2019 was the ninth consecutive year that Sempra increased its dividend, which has grown by more than 47 percent since 2014.

DTE Energy, headquartered in Detroit, Michigan, raised its quarterly dividend from $0.945 to $1.0125 per share during Q4. DTE has issued a cash dividend for more than 100 years.

The industry's average and median increases have been relatively consistent in recent years. The average increase was 5.7% in 2018 and 5.6% in both 2017 and 2016. The median was 5.5% in 2018 and 2017 and 5.1% in 2016.

Sector Comparison Dividend Payout Ratio

For 12-month period ending 12/31/19

Sector	Payout Ratio (%)
EEI Index Companies*	**64.1%**
Energy	80.0%
Utilities	63.6%
Consumer Staples	55.9%
Materials	42.1%
Industrial	36.1%
Consumer Discretionary	32.7%
Technology	29.9%
Health Care	28.6%
Financial	28.0%

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

Assumptions:

1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2019E dividends and earnings per share (estimates as of 12/31/2019).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 64.1% for the twelve months ended December 31, 2019, trailing only the Energy sector's 80.0% among U.S. business sectors. The industry's payout ratio was 62.6% when measured as an un-weighted average of individual company ratios; 64.1% represents an aggregate figure. From 2000 through 2019, the industry's annual payout ratio ranged from 60.4% to 69.6%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.
3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 3.0% on December 31, 2019, trailing only the Energy sector's 3.8% and the broader Utilities sector's 3.1%. The year-end yield was 3.4% in each of the three previous years. In 2019, the industry's strong dividend activity was more than offset by stock price gains, resulting in the lower average yield. The market cap-weighted EEI Index increased by 25.8% in 2019.

Sector Comparison, Dividend Yield
As of December 31, 2019

Sector	Dividend Yield (%)
EEI Index Companies	**3.0%**
Energy	3.8%
Utilities	3.1%
Consumer Staples	2.6%
Financial	2.0%
Materials	2.0%
Industrial	1.9%
Health Care	1.6%
Consumer Discretionary	1.4%
Technology	1.3%

Assumptions:
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2019); S&P sector yields based on 2019E cash dividends (estimates as of 12/31/2019).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

We calculate the industry's aggregate dividend yield using an unweighted average of the yields of EEI Index companies paying a dividend. The strong yields prevalent among most electric utilities have helped support their share prices over the past decade, particularly given the period's historically low interest rates. The Tax Cuts and Jobs Act, signed into law in December 2017, maintained preexisting tax rates for dividends and capital gains. This is crucial to avoid a capital raising disadvantage for high-dividend companies.

Business Category Comparison

The Regulated category's dividend payout ratio was 62.1% for the 12 months ended December 31, 2019 compared to 64.1% for the Mostly Regulated category. The Regulated group produced the highest annual payout ratio in 2017, 2015, 2011, 2010 and in each year from 2003 through 2008. It was exceeded by the Mostly Regulated group in 2018, 2016, 2014, 2013, 2012 and 2009; weaker earnings from competitive power likely contributed to the higher payout ratio for the Mostly Regulated group in those years.

The Regulated and Mostly Regulated groups' average dividend yields were 3.0% and 3.1%, respectively, on December 31, 2019. Both had a 3.4% average dividend yield at year-ends 2018 and 2017. The yields for the Regulated and Mostly Regulated categories were 3.4% and 3.5%, respectively, on December 31, 2016.

Category Comparison, Dividend Payout Ratio

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EEI Index	**62.0**	**62.8**	**64.2**	**61.5**	**60.4**	**67.0**	**62.9**	**64.0**	**63.9**	**62.6**
Regulated	64.1	63.4	62.1	60.5	59.4	68.7	61.1	68.7	60.1	62.1
Mostly Regulated	60.7	63.1	69.7	64.7	63.8	62.6	68.0	53.3	72.8	64.1
Diversified	49.7	54.7	53.4	44.7	56.4	64.9	64.6	–	–	–

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department

Category Comparison, Dividend Yield
As of December 31, 2019

Category	Dividend Yield
EEI Index	**3.0%**
Regulated	3.0%
Mostly Regulated	3.1%

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Source: S&P Global Market Intelligence, company reports and EEI Finance Department

Dividend Summary
As of December 31, 2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Company Name	Stock	Company Category	Annualized Dividends	Payout Ratio	Yield (%)	Last Action	To	From	Date Announced
ALLETE, Inc.	ALE	MR	$2.35	75.0%	2.9%	Raised	$2.35	$2.24	2019 Q1
Alliant Energy Corporation	LNT	R	$1.42	59.5%	2.6%	Raised	$1.42	$1.34	2019 Q1
Ameren Corporation	AEE	R	$1.98	56.6%	2.6%	Raised	$1.98	$1.90	2019 Q4
American Electric Power Company, Inc.	AEP	R	$2.80	65.0%	3.0%	Raised	$2.80	$2.68	2019 Q4
AVANGRID, Inc.	AGR	MR	$1.76	102.1%	3.4%	Raised	$1.76	$1.73	2018 Q3
Avista Corporation	AVA	R	$1.55	90.6%	3.2%	Raised	$1.55	$1.49	2019 Q1
Black Hills Corporation	BKH	R	$2.14	53.5%	2.7%	Raised	$2.14	$2.02	2019 Q4
CenterPoint Energy, Inc.	CNP	MR	$1.15	56.3%	4.2%	Raised	$1.15	$1.11	2018 Q4
CMS Energy Corporation	CMS	R	$1.53	63.9%	2.4%	Raised	$1.53	$1.43	2019 Q1
Consolidated Edison, Inc.	ED	R	$2.96	64.2%	3.3%	Raised	$2.96	$2.86	2019 Q1
Dominion Energy, Inc.	D	R	$3.67	73.0%	4.4%	Raised	$3.67	$3.34	2019 Q1
DTE Energy Company	DTE	MR	$4.05	58.3%	3.1%	Raised	$4.05	$3.78	2019 Q4
Duke Energy Corporation	DUK	R	$3.78	74.7%	4.1%	Raised	$3.78	$3.71	2019 Q3
Edison International	EIX	R	$2.55	40.6%	3.4%	Raised	$2.55	$2.45	2019 Q4
El Paso Electric Company	EE	R	$1.54	45.7%	2.3%	Raised	$1.54	$1.44	2019 Q2
Entergy Corporation	ETR	R	$3.72	46.0%	3.1%	Raised	$3.72	$3.64	2019 Q4
Evergy, Inc.	EVRG	R	$2.02	64.5%	3.1%	Raised	$2.02	$1.90	2019 Q4
Eversource Energy	ES	R	$2.14	57.4%	2.5%	Raised	$2.14	$2.02	2019 Q1
Exelon Corporation	EXC	MR	$1.45	44.4%	3.2%	Raised	$1.45	$1.38	2019 Q1
FirstEnergy Corp.	FE	R	$1.56	90.0%	3.2%	Raised	$1.56	$1.52	2019 Q4
Hawaiian Electric Industries, Inc.	HE	MR	$1.28	66.7%	2.7%	Raised	$1.28	$1.24	2019 Q1
IDACORP, Inc.	IDA	R	$2.68	55.6%	2.5%	Raised	$2.68	$2.52	2019 Q4
MDU Resources Group, Inc.	MDU	MR	$0.83	47.8%	2.8%	Raised	$0.83	$0.81	2019 Q4
MGE Energy, Inc.	MGEE	R	$1.41	55.1%	1.8%	Raised	$1.41	$1.35	2019 Q3
NextEra Energy, Inc.	NEE	MR	$5.00	81.0%	2.1%	Raised	$5.00	$4.44	2019 Q1
NiSource Inc.	NI	R	$0.80	37.4%	2.9%	Raised	$0.80	$0.78	2019 Q1
NorthWestern Corporation	NWE	R	$2.30	57.0%	3.2%	Raised	$2.30	$2.20	2019 Q1
OGE Energy Corp.	OGE	R	$1.55	69.0%	3.5%	Raised	$1.55	$1.46	2019 Q3
Otter Tail Corporation	OTTR	R	$1.40	64.2%	2.7%	Raised	$1.40	$1.34	2019 Q1
PG&E Corporation	PCG	R	$-	0.0%	0.0%	Lowered	$-	$2.12	2017 Q4
Pinnacle West Capital Corporation	PNW	R	$3.13	59.1%	3.5%	Raised	$3.13	$2.95	2019 Q4
PNM Resources, Inc.	PNM	R	$1.23	38.0%	2.4%	Raised	$1.23	$1.16	2019 Q4
Portland General Electric Company	POR	R	$1.54	62.6%	2.8%	Raised	$1.54	$1.45	2019 Q2
PPL Corporation	PPL	R	$1.65	68.3%	4.6%	Raised	$1.65	$1.64	2019 Q1
Public Service Enterprise Group Incorporated	PEG	MR	$1.88	45.3%	3.2%	Raised	$1.88	$1.80	2019 Q1
Sempra Energy	SRE	R	$3.87	50.2%	2.6%	Raised	$3.87	$3.58	2019 Q1
Southern Company	SO	R	$2.48	106.6%	3.9%	Raised	$2.48	$2.40	2019 Q2
Unitil Corporation	UTL	R	$1.48	71.8%	2.4%	Raised	$1.48	$1.46	2019 Q1
WEC Energy Group, Inc.	WEC	R	$2.36	65.6%	2.6%	Raised	$2.36	$2.21	2019 Q1
Xcel Energy Inc.	XEL	R	$1.62	57.7%	2.6%	Raised	$1.62	$1.52	2019 Q1
Industry Average				**62.6%**	**3.0%**				

NOTES

Business Segmentation: Assets as of 12/31/2018

R = Regulated: 80% or more of total assets are regulated. **MR = Mostly Regulated:** Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2019.

Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2019 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2019. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.

"NM" applies to companies with negative earnings or payout ratios greater than 200%.

Dividend Yield: Annualized Dividends Per Share at 12/31/2019 divided by stock price at market close on 12/31/2019.

By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

Credit Ratings

The industry's average credit rating remained at BBB+ for a sixth straight year in 2019, although five parent-level downgrades versus one upgrade produced a slight weakening in holding-company credit quality after years of steady gains.

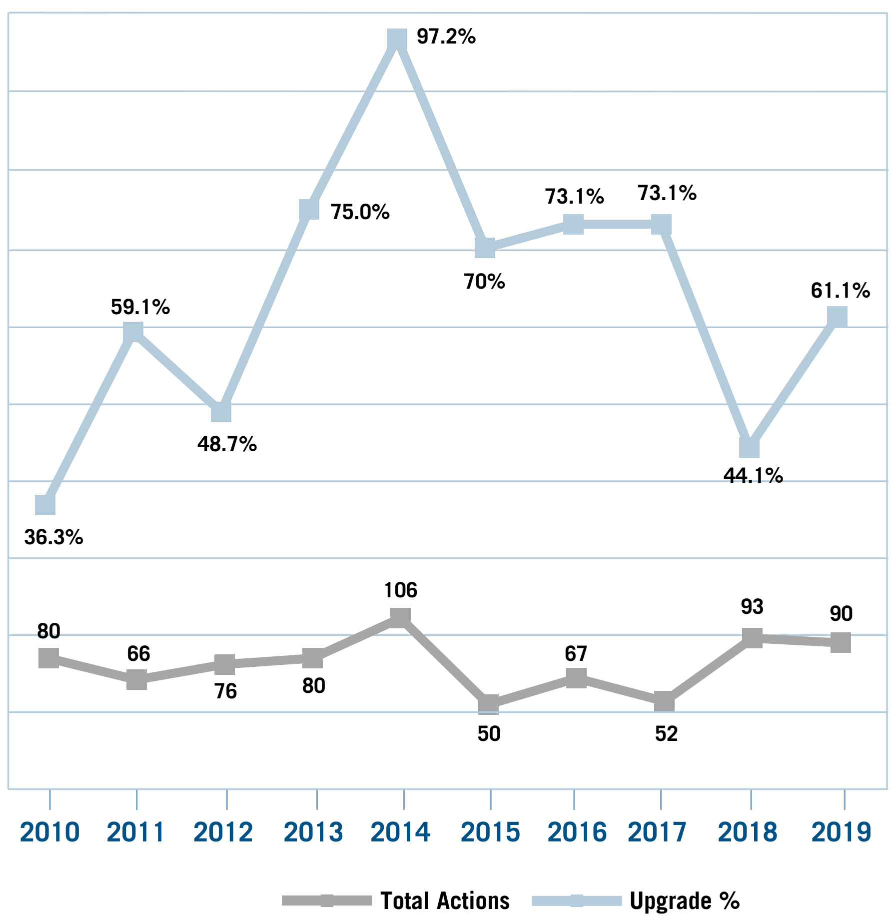
There were 90 total actions across all holding companies and underlying subsidiaries, above the 72 average of the previous ten years. Upgrades were 61.1% of the total. The five-year period 2013 through 2017 produced the five-highest upgrade percentages in our historical data. Over the past ten years, upgrades outnumbered downgrades in seven years with an annual average upgrade percentage of 64.4%.

EEI captures upgrades and downgrades at both the parent and subsidiary levels. Multiple actions within a parent holding company are included in the upgrade/downgrade totals. However, the industry's average credit rating and outlook are based on the unweighted average of all Standard & Poor's (S&P) parent holding company ratings and outlooks.

On December 31, 2019, 79.5% of holding company ratings outlooks were "stable" and 2.3% were

Direction of Rating Actions

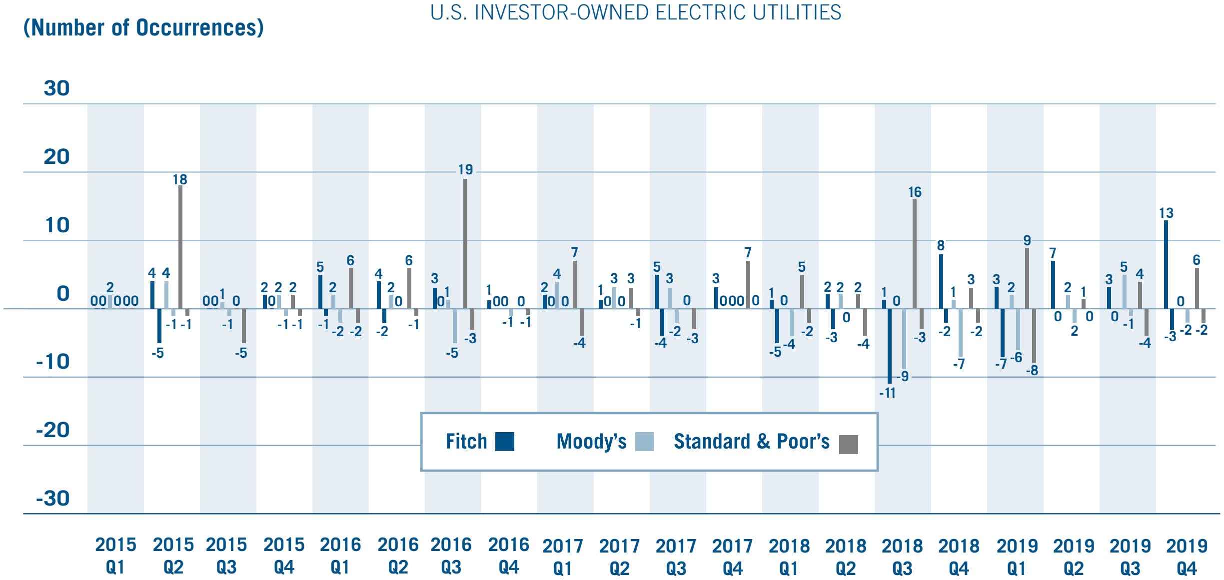
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2015 Q1–2019 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Credit Rating Agency Upgrades and Downgrades 2015 Q1–2019 Q4

	2015		2016		2017		2018		2019	
	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades	Total Upgrades	Total Downgrades
Fitch										
Q1	0	0	5	(1)	2	0	1	(5)	3	(7)
Q2	4	(5)	4	(2)	1	0	2	(3)	7	0
Q3	0	0	3	0	5	(4)	1	(11)	3	0
Q4	2	0	1	0	3	0	8	(2)	13	(3)
Total	**6**	**(5)**	**13**	**(3)**	**11**	**(4)**	**12**	**(21)**	**26**	**(10)**
Moody's										
Q1	2	0	2	(2)	4	0	0	(4)	2	(6)
Q2	4	(1)	2	0	3	0	2	0	2	(2)
Q3	1	(1)	1	(5)	3	(2)	0	(9)	5	(1)
Q4	2	(1)	0	(1)	0	0	1	(7)	0	(2)
Total	**9**	**(3)**	**5**	**(8)**	**10**	**(2)**	**3**	**(20)**	**9**	**(11)**
S&P										
Q1	0	0	6	(2)	7	(4)	5	(2)	9	(8)
Q2	18	(1)	6	(1)	3	(1)	2	(4)	1	0
Q3	0	(5)	19	(3)	0	(3)	16	(3)	4	(4)
Q4	2	(1)	0	(1)	7	0	3	(2)	6	(2)
Total	**20**	**(7)**	**31**	**(7)**	**17**	**(8)**	**26**	**(11)**	**20**	**(14)**

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

"positive" or "watch-positive". Only 18.2% were "negative" or "watch-negative", down from 23.4% at year-end 2018.

Credit Actions at Parent Level

Total ratings actions at the parent holding company level in 2019 included one upgrade and five downgrades compared to six upgrades and two downgrades in 2018. Over the past ten years, aggregate parent-level credit quality has experienced a steady strengthening, having declined in only two calendar years (2019 and 2012). Our universe of 45 U.S. parent company electric utilities at December 31, 2019 included 40 publicly-traded utilities and five that are either a subsidiary of an independent power producer, a subsidiary of a foreign-owned company, or that have been acquired by an investment firm.

CenterPoint Energy

On February 1, S&P downgraded CenterPoint Energy, citing its recently completed merger with Vectren, lowering the combined company CenterPoint's rating to BBB+ from A-. S&P said Vectren's construction business increased the risk profile of CenterPoint's non-utility operations; in particular, the acquisition debt would increase leverage and weaken financial measures over the next several years. S&P also lowered the ratings of subsidiaries CenterPoint Energy Houston Electric and CenterPoint Energy Resources to BBB+ from A-. Likewise, S&P downgraded Vectren and its subsidiaries Vectren Utility Holdings, Indiana Gas, and Southern Indiana Gas and Electric to BB+ from A- to align the ratings of Vectren and its subsidiaries with CenterPoint's group credit profile.

DPL Inc.

On November 26, S&P downgraded DPL Inc. and subsidiary Dayton Power and Light (DP&L) to BB from BBB-, a two-notch decrease, after Ohio regulators ordered DP&L to terminate its distribution modernization rider. The Public Utilities Commission of Ohio's (PUCO) decision was in response to a June 19 decision by the Supreme Court of Ohio that found PUCO's approval of an annual distribution charge by FirstEnergy's Ohio utilities was "unlawful and unreasonable" and must be removed for their electric security plans.

Eversource Energy

On July 25, S&P lowered Eversource Energy's rating to A- from A+, a two-notch decrease, due to the company's decision to pursue growth through riskier contracted renewable assets. The action followed a win in New York's offshore wind solicitation by Sunrise Wind, Eversource's 880-MW offshore wind venture with Danish power company Orsted. S&P views contracted offshore wind as considerably riskier than the rest of Eversource's low-risk transmission and distribution portfolio. Even with the downgrade, Eversource remains among the top-rated parent companies in the industry at A-; only Berkshire Energy Holdings had a higher A rating at year-end 2019. S&P also lowered the ratings of subsidiaries Yankee Gas Services, NSTAR Gas, and Aquarian by two notches, to A- from A+, while subsidiaries NSTAR Electric, Connecticut Power & Light and Public Service Co. of New Hampshire received one-notch downgrades, to A from A+.

Exelon

On March 1, S&P upgraded Exelon's issuer credit rating to BBB+ from BBB, citing the successful execution of its utility-focused growth strategy. S&P noted that Exelon has reduced its business risk by implementing zero-emission credits (ZECs) in New York and Illinois and said it expects Exelon will implement ZECs in New Jersey later in 2019. S&P also cited the continuous growth of Exelon's lower-risk regulated businesses, relative to other segments, as a reason for the upgrade. S&P expects Exelon's utility operations and ZECs will consistently account for about 75% of its consolidated EBITDA. S&P also upgraded subsidiaries Exelon Generation, Commonwealth Edison and PECO Energy to BBB+ from BBB; Pepco Holdings, Atlantic City Electric, Delmarva Power & Light and Potomac Electric Power to A- from BBB+; and Baltimore Gas and Electric to A from A-.

PG&E

In January 2019, S&P lowered the issuer credit rating for PG&E Corporation and subsidiary Pacific Gas and Electric in three actions related to the devastating California wildfires in 2017 and 2018. On January 7, S&P cited an eroding political and regulatory environment in its downgrade to B from BBB-. On January 14, the ratings were lowered to CC from B after PG&E

announced plans to seek Chapter 11 bankruptcy protection related to billions of dollars of potential liabilities. On January 29, S&P lowered ratings for PG&E and Pacific Gas and Electric to D from CC when PG&E made its voluntary Chapter 11 bankruptcy filing.

Other California Utilities

On January 21, S&P downgraded Edison International and its subsidiary Southern California Edison (along with Sempra Energy subsidiary San Diego Gas & Electric), stating the companies remain at high risk from catastrophic wildfires due to climate change and lack sufficient regulatory protection because of California's common law application of the legal doctrine of inverse condemnation. Edison International and Southern California Edison's ratings were lowered to BBB from BBB+, while San Diego Gas & Electric's rating was downgraded to BBB+ from A-.

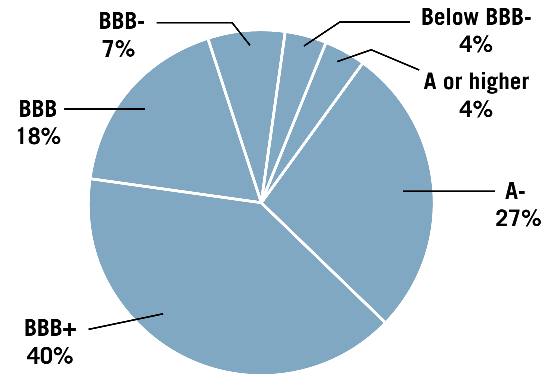
FirstEnergy

Although FirstEnergy's parent-level rating with S&P remained at BBB throughout the year, 23 total actions (all upgrades) at the operating utility level were the industry's most, by far, for any single holding company.

On March 21, Moody's upgraded subsidiaries American Transmission Systems and Mid-Atlantic Interstate Transmission to A3 from Baa1, citing robust capital investment programs supported by the Federal Energy Regulatory Commission (FERC) regulatory framework. On July 23, Moody's upgraded subsidiaries Ohio Edison and Pennsylvania Power to A3 from Baa1, Toledo Edison to Baa1 from Baa3, and Cleveland Electric Illuminating to Baa2 from Baa3, stating that FirstEnergy's Ohio utilities benefit from a constructive regulatory environment for rate base growth over the next several years. On April 18, Fitch upgraded FirstEnergy subsidiaries Monongahela Power, Allegheny Generating, Potomac Edison and Jersey Central Power & Light to BBB from BBB- stating that First Energy's core utility and transmission operations benefit from relatively low business risk and predictable earnings and cash flows. On November 8, Fitch upgraded parent company FirstEnergy to BBB from BBB-, along with upgrades for 12 of its subsidiaries; these included its Ohio, Pennsylvania and New Jersey operating utility distribution subsidiaries and FirstEnergy Transmission, along with its operating transmission utility subsidiaries.

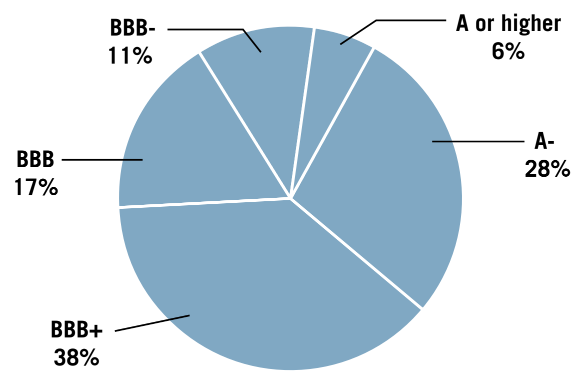
Bond Ratings December 31, 2019
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



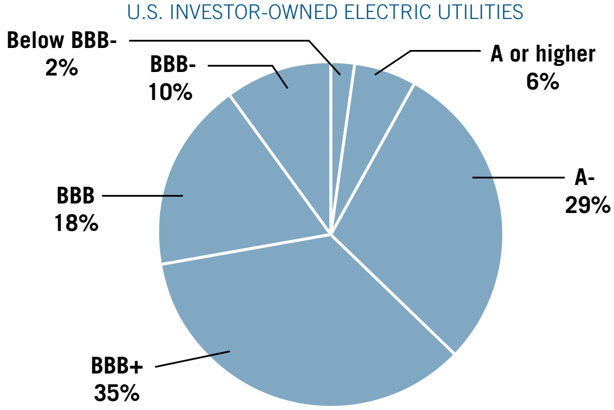
Bond Ratings December 31, 2018
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



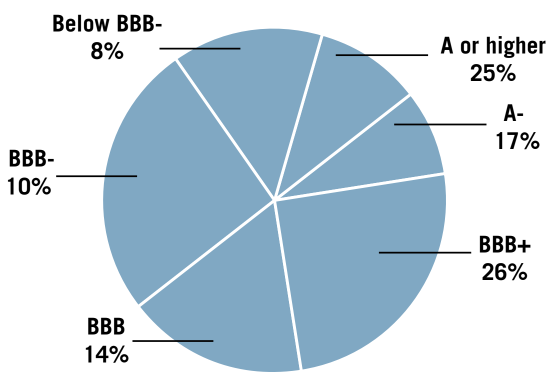
Bond Ratings December 31, 2017
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Bond Ratings December 31, 2001
as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Upgrades Outnumber Downgrades

The industry's 55 upgrades outnumbered its 35 downgrades in 2019. The 61.1% upgrade percentage is up from 45.3% in 2018, the only year since 2013 that upgrades did not outnumber downgrades. The five-year period 2013 through 2017 produced the five-highest upgrade percentages in our historical data.

Over the past ten years, upgrades outnumbered downgrades in seven years, with an annual average upgrade percentage of 64.4%. In 2019, FirstEnergy (23 upgrades) and Exelon (14 upgrades) accounted for 37, or two-thirds, of the industry's upgrades; these were spread across the three ratings agencies and throughout all four quarters.

A comparison of activity by all three ratings agencies is shown in the Rating Agency Activity table, with the following breakdown in 2019:

- Fitch (26 upgrades, 10 downgrades)
- Moody's (9 upgrades, 11 downgrades)
- Standard & Poor's (20 upgrades, 14 downgrades)

Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Total Ratings Changes	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Fitch	24	25	26	23	14	11	16	15	33	36
Moody's	20	11	20	17	85	12	13	12	23	20
Standard & Poor's	36	30	30	40	7	27	38	25	37	34
Total	**80**	**66**	**76**	**80**	**106**	**50**	**67**	**52**	**93**	**90**

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

Primary reasons for upgrades were favorable regulatory/rate activity, increased regulated focus across business models, and improved financial metrics. Primary reasons for downgrades were the California wildfire crisis, M&A activity, unfavorable regulatory/rate activity, and decreased percentage of regulated operations.

Ratings by Company Category

The table S&P Utility Credit Rating Distribution by Company Category presents the distribution of credit ratings over time by company category (Regulated, Mostly Regulated and Diversified) for the investor-owned electric utilities. The Diversified category was eliminated in 2017 due to its dwindling number of companies. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. At December 31, 2019, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	2015		2016		2017		2018		2019	
	#	%	#	%	#	%	#	%	#	%
Regulated										
A or higher	1	3%	2	6%	2	6%	1	3%	1	3%
A-	8	22%	10	28%	12	34%	11	32%	11	31%
BBB+	12	33%	13	36%	10	29%	11	32%	11	31%
BBB	12	33%	8	22%	7	20%	7	21%	8	23%
BBB-	1	3%	3	8%	4	11%	4	12%	2	6%
Below BBB-	2	6%	0	0%	0	0%	0	0%	2	6%
Total	36	100%	36	100%	35	100%	34	100%	35	100%
Mostly Regulated										
A or higher	1	8%	1	8%	1	7%	2	15%	1	10%
A-	5	38%	2	17%	2	14%	2	15%	1	10%
BBB+	5	38%	7	58%	7	50%	7	54%	7	70%
BBB	1	8%	0	0%	2	14%	1	8%	0	0%
BBB-	1	8%	1	8%	1	7%	1	8%	1	10%
Below BBB-0	0	0%	1	8%	1	7%	0	0%	0	0%
Total	13	100%	12	100%	14	100%	13	100%	10	100%
Diversified **removed this category after 2016*										
A or higher	0	0%	0	0%						
A-	0	0%	0	0%						
BBB+	1	50%	0	0%						
BBB	0	0%	1	50%						
BBB-	1	50%	1	50%						
Below BBB-	0	0%	0	0%						
Total	2	100%	2	100%						

Note: Totals may not equal 100.0% due to rounding.
Refer to page v for category descriptions.
Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Moody's	Standard & Poor's	Fitch
Investment Grade	Aaa	AAA	AAA
	Aa1	AA+	AA+
	Aa2	AA	AA
	Aa3	AA-	AA-
	A1	A+	A+
	A2	A	A
	A3	A-	A-
	Baa1	BBB+	BBB+
	Baa2	BBB	BBB
	Baa3	BBB-	BBB-

	Moody's	Standard & Poor's	Fitch
Speculative Grade	Ba1	BB+	BB+
	Ba2	BB	BB
	Ba3	BB-	BB-
	B1	B+	B+
	B2	B	B
	B3	B-	B-
	Caa1	CCC+	CCC+
	Caa2	CCC	CCC
	Caa3	CCC-	CCC-
	Ca	CC	CC
	C	C	C

	Moody's	Standard & Poor's	Fitch
Default	C	D	D

Source: Fitch Ratings, Moody's, and Standard & Poor's.

Business Strategies

Business Segmentation

The industry's regulated business segments — regulated electric and natural gas distribution — grew their combined assets by $112.7 billion, or 8.2%, in 2019, extending a multi-year trend and driving a $132.0 billion, or 8.1%, increase in total industry assets. Regulated assets remained at about 81.7% of the industry total, essentially matching their share at year-end 2018. The Regulated Electric segment's share of total industry assets edged down from 69.0% at year-end 2018 to 68.7% at year-end 2019, despite rising $89.3 billion, or 7.7%, in absolute terms as the industry's three other primary business segments experienced even higher percentage growth. Competitive Energy assets rose by $16.8 billion, or 9.5%, driven largely by growth in merchant renewable generation while the industry's natural gas operations also saw strong asset growth. A record-high $124.1 billion of capital expenditures and generally constructive regulatory relations supported the growth in regulated assets — both electric and natural gas-related.

The Regulated Electric business segment's revenue fell by $1.3 billion, or 0.5%, as power demand was almost 2% lower in 2019 than in 2018. Competitive Energy revenue declined by $2.8 billion, or 5.1%. Natural Gas Distribution was the only primary business segment with higher revenue, growing by $2.0 billion, or 4.4%. As a result, total industry revenue was nearly unchanged versus 2018, falling by $1.1 billion, or 0.3%. The Natural Gas Distribution segment has led the industry in revenue growth over the last four years, partly a result of several major gas acquisitions that closed during 2016.

2019 Revenue by Segment

Regulated Electric revenue decreased slightly in 2019, falling by $1.3 billion, or 0.5%, to $253.5 billion from $254.8 billion in 2018. The segment's share of total industry revenue was unchanged at 67.5%, remaining well above its level near the beginning of the industry's migration back to a regulated focus (its share was 51.9% in 2005).

Natural Gas Distribution revenue rose by $2.0 billion, or 4.4%, to $47.4 billion from $45.3 billion in 2018. This followed annual increases of 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016, gains due in part to the completion in 2016 of four large acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — increased by $685 million, or 0.2%, to $300.9 billion in 2019. The industry's focus on regulated operations has driven a steady growth in these two business segments' share of industry revenue. Regulated revenue in total accounted for 80.1% of industry revenue in 2019, up from 79.5% in 2018 and well above 2005's 65.3% share.

Eliminations and reconciling items were added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2019 and 2018*.

2019 Assets by Segment

Regulated Electric assets increased by $89.3 billion, or 7.7%, during 2019. However, the segment's share of total industry assets declined to 68.7% at year-end from 69.0% at year-end 2018 as the industry's other primary business segments experienced even higher percentage growth. Competitive Energy assets increased by $16.8 billion, or 9.5%. Natural Gas Distribution assets showed the highest percentage growth among the industry's three largest segments for the fourth consecutive year, gaining $23.3 billion, or 11.0%. Natural Gas Pipeline assets experienced an increase of $5.0 billion, or 19.3%.

Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2019	2018r	Difference	% Change
Regulated Electric	253,505	254,836	(1,331)	-0.5%
Competitive Energy	51,400	54,154	(2,754)	-5.1%
Natural Gas Distribution	47,356	45,340	2,016	4.4%
Natural Gas Pipeline	5,292	5,415	(123)	-2.3%
Other	18,174	17,692	482	2.7%
Discontinued Operations	—	—	—	0.0%
Eliminations/Reconciling Items	(10,832)	(11,463)	631	-5.5%
Total Revenues	**364,895**	**365,975**	**(1,079)**	**-0.3%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2019	12/31/2018r	Difference	% Change
Regulated Electric	1,244,310	1,155,008	89,302	7.7%
Competitive Energy	194,521	177,719	16,803	9.5%
Natural Gas Distribution	235,592	212,243	23,349	11.0%
Natural Gas Pipeline	30,999	25,986	5,012	19.3%
Other	106,755	103,717	3,038	2.9%
Discontinued Operations	3,960	3	3,957	NM
Eliminations/Reconciling Items	(59,200)	(49,706)	(9,494)	19.1%
Total Assets	**1,756,936**	**1,624,969**	**131,967**	**8.1%**

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Total regulated assets (Regulated Electric and Natural Gas Distribution) grew by $112.7 billion, or 8.2%, in 2019, maintaining the same share of total industry assets as last year, at just under 81.7%. This aggregate measure has risen steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth and widespread divestitures of non-core businesses over the 17-year period. Two-thirds of companies (30 of 45) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2019.

Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial customers. Regulated Electric revenues were slightly lower in 2019, falling by $1.3 billion, or 0.5%. Twenty-four companies, or 53% of the industry, had lower Regulated Electric revenue versus the prior year. Regulated Electric revenue was unchanged in 2018, grew 0.8% in 2017 and declined slightly in 2016 (-0.1%) and in 2015 (-2.6%).

Annual electric output decreased by 1.7% in 2019 and has risen in only six of the last 12 years. Previously, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percent demand growth. Energy efficiency initiatives, demand-side management programs and the off-shoring of formerly U.S.-based manufacturing and heavy industry continue to constrain growth in electricity demand.

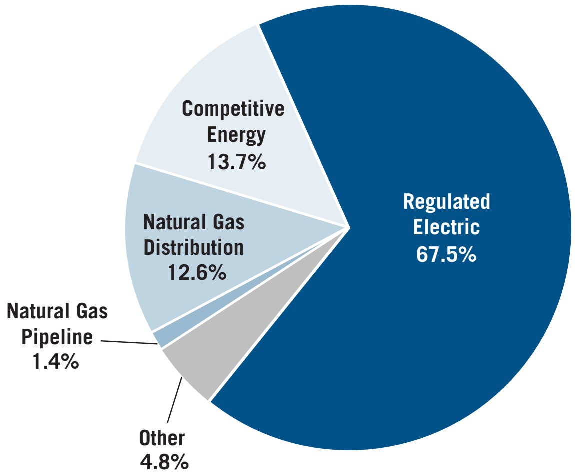
Regulated Electric assets increased by $89.3 billion, or 7.7%, in 2019, showing the largest asset growth in dollar terms of all business segments. A record-high $124.1 billion of capital expenditures in 2019 and generally constructive regulatory relations supported the increase in regulated assets. The 2019 capital expenditures represent the eighth consecutive annual record high, with this expansion well represented across the four primary business segments. Asset growth is also evident in the industry's property, plant and equipment in service, which rose 7.3% from year-end 2018 and 26.4% over the level at year-end 2015. Such strong growth in assets reflects the magnitude of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure and other capital projects in recent years.

Competitive Energy

Competitive Energy assets increased by $16.8 billion, or 9.5%, to $194.5 billion in 2019 from $177.7 billion in 2018 due largely to new renewable generation. However, weaker pricing drove the segment's revenue down by $2.8 billion, or 5.1%, from $54.2 billion in 2018 to $51.4 billion in 2019, its lowest annual total in data going back to 2000. Despite the segment's 2019 asset growth, its total assets remain below their overall level of about a decade ago; the segment's year-end

Revenue Breakdown 2019

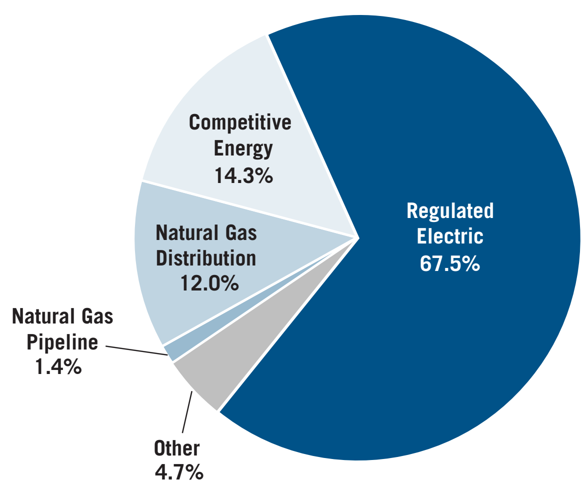
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Revenue Breakdown 2018r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

2007 assets were $206.0 billion and its annual revenue peaked at $113.2 billion in 2008. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically regional power pools, large industrial customers and electric utilities seeking to supplement generation capacity. Competitive Energy also includes the trading and marketing of natural gas. Of the 21 companies that maintain Competitive Energy operations, 15 (71%) grew these assets during 2019 and 57% had revenue gains from this segment.

NextEra Energy (NEE), a world leader in renewable generation, produced the largest Competitive Energy segment asset growth among all companies, increasing its NextEra Energy Resources assets (which includes its wholesale power generation and energy-related services business) by $7.0 billion, or 15.7%. The NEE parent also grew Regulated Electric segment assets by $9.5 billion, or 17.8%, which balanced NEE's overall asset growth of $14.0 billion, or 13.5%, in 2019. The growth in NEE's Regulated Electric segment was due to the acquisition of regulated utility Gulf Power from Southern Company in January 2019 and growth at FPL, NEE's primary rate-regulated utility.

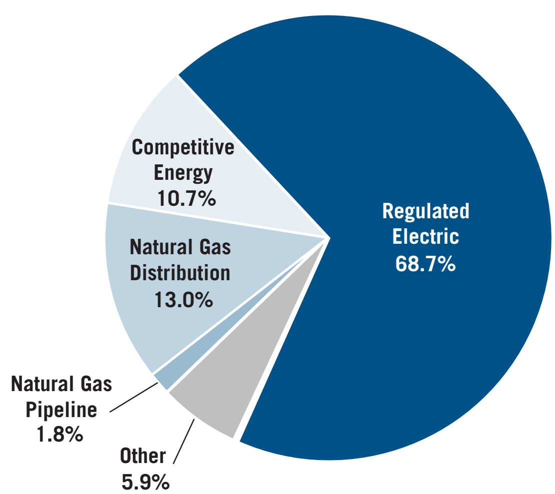
AVANGRID had the second-highest asset growth in the Competitive Energy segment, growing its renewables business by $2.5 billion, or 23.0%, in 2019. This business line includes mainly wind energy generation and related renewable energy trading activities.

Another notable expansion of Competitive Energy assets occurred at Cleco, which added Cleco Cajun as a new business segment with assets of $1.0 billion at year-end 2019. Cleco Cajun owns eight generating assets with a rated capacity of 3,555 MW and supplies wholesale power and capacity in Arkansas, Louisiana and Texas.

The largest decrease in Competitive Energy assets came from Sempra Energy, at $2.3 billion, an approximate 50% decline. Sempra completed the sale of its U.S. renewables business in 2019. As of year-end 2019, it had also announced the sale of its Sempra South American Utilities business, completing that divestiture in April 2020. Both sales support Sempra's focus on growth opportunities at its California and Texas utilities.

Asset Breakdown
As of December 31, 2019

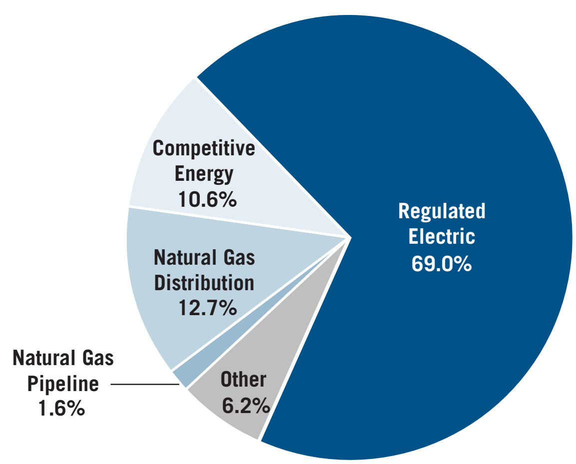
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Asset Breakdown
As of December 31, 2018r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department and company annual reports.

Natural Gas

Natural Gas Distribution revenue rose by $2.0 billion, or 4.4%, the only primary business segment with revenue growth in 2019. This followed revenue growth of 3.0% in 2018, 7.6% in 2017 and 8.9% in 2016. The large gas acquisitions that were completed in 2016 — Southern Company's purchase of AGL Resources, Dominion's purchase of Questar, Duke Energy's acquisition of Piedmont Natural Gas and Black Hills' acquisition of SourceGas Holdings — set a foundation for the segment's revenue growth in 2016, 2017, 2018 and 2019. Total gas distribution revenue for these four acquiring companies increased more than six-fold over the last four years, rising to $8.50 billion in 2019 from $1.26 billion in 2015. Overall, 19 of the 27 companies (70%) that report gas distribution revenue showed a year-to-year increase in 2019. This followed increases at 86% and 93%, respectively, of reporting companies in 2018 and 2017.

Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers. Added together, the Natural Gas Distribution and Natural Gas Pipeline segments increased assets by $28.4 billion, or 11.9%, in 2019 and produced revenue of $52.6 billion, up from $50.8 billion in 2018. In percentage terms, the contribution to total industry revenue from these two natural gas activities increased to 14.0% in 2019 from 13.4% in 2018.

Elimination of the Natural Gas and Oil Exploration & Production Business Segment

The Natural Gas and Oil Exploration & Production business segment has steadily declined in size over the past decade. No companies had revenue there in 2019, and only one still carries a small asset amount for the segment. Therefore, we have eliminated this segment from our reporting and shifted its small remaining asset amount to the Other segment.

2019 Year-End List of Companies by Category

Early each calendar year, EEI updates our list of investor-owned electric utility holding companies organized by business category. The list is based on previous year-end business segmentation data presented in 10-Ks and supplemented by discussions with parent companies. Our categories are as follows: Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated). As of January 1, 2017, the Diversified category, which represented companies whose regulated assets were less than 50% of total assets, was eliminated due to its dwindling number of members.

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends. During the previous decade, for example, fluctuating natural gas and power prices impacted revenue so greatly that a company's strategic approach to business segmentation was distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and indicates the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

There was minimal movement between categories in 2019. The Regulated category decreased from 37 to 35 companies as a result of one addition and three deletions, two of which were merger-related. CenterPoint Energy was added as its regulated asset percentage rose above 80% while Vectren was removed due to its acquisition by CenterPoint. SCANA was removed due to its acquisition by Dominion Energy, and Sempra Energy migrated to the Mostly Regulated category as its regulated asset percentage fell below 80%. Sempra's exit from its Sempra South American Utilities business, which had been part of the Regulated Electric segment, outweighed the sale of its U.S. renewables business, which was classified as Competitive Energy, thus driving the overall lower regulated percentage.

The Mostly Regulated category remained at ten companies based on the addition of Sempra Energy and the loss of CenterPoint Energy.

The total number of parent companies in the EEI universe fell from 47 at year-end 2018 to 45 at year-end

List of Companies by Category at December 31, 2019

Regulated (35)

Alliant Energy Corporation	Edison International	PG&E Corporation
Ameren Corporation	El Paso Electric Company	Pinnacle West Capital Corporation
American Electric Power Company, Inc.	Entergy Corporation	PNM Resources, Inc.
Avista Corporation	Evergy, Inc.	Portland General Electric Company
Black Hills Corporation	Eversource Energy	PPL Corporation
CenterPoint Energy, Inc.	FirstEnergy Corp.	*Puget Energy, Inc.**
*Cleco Corporation**	IDACORP, Inc.	Southern Company
CMS Energy Corporation	*IPALCO Enterprises, Inc.**	Unitil Corporation
Consolidated Edison, Inc.	NiSource Inc.	WEC Energy Group, Inc.
Dominion Energy, Inc.	NorthWestern Corporation	Xcel Energy Inc.
*DPL Inc.**	MGE Energy, Inc.	
Duke Energy Corporation	OGE Energy Corp.	
	Otter Tail Corporation	

Mostly Regulated (10)

ALLETE, Inc.	Exelon Corporation	NextEra Energy, Inc.
AVANGRID, Inc.	Hawaiian Electric Industries, Inc.	Public Service Enterprise Group Incorporated
*Berkshire Hathaway Energy**	MDU Resources Group, Inc.	Sempra Energy
DTE Energy Company		

Note:* Non-publicly traded companies.

2019, a result of the CenterPoint/Vectren and Dominion/SCANA mergers. In January 2019, Dominion Energy completed its merger with SCANA and in February CenterPoint Energy completed its merger with Vectren. At year-end 2019, the EEI universe included 35 Regulated and 10 Mostly Regulated utility holding companies. (*see List of Companies by Category at December 31, 2019*).

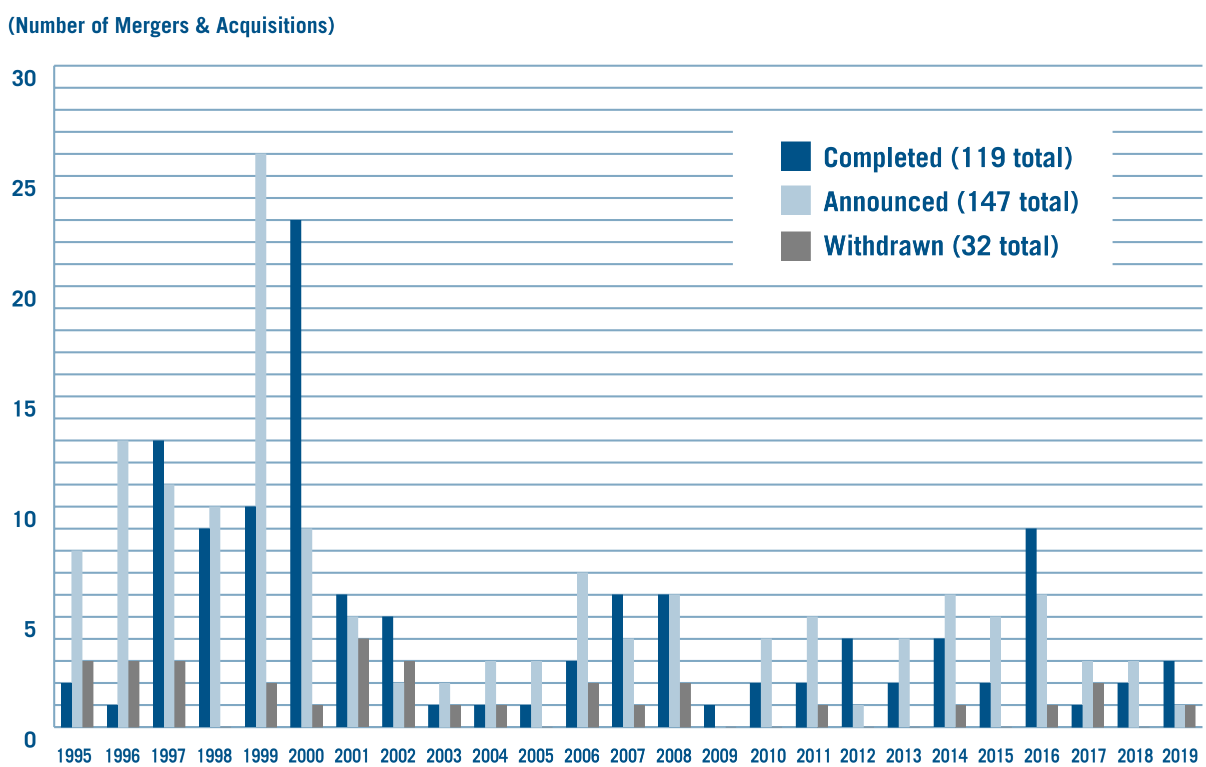
Mergers and Acquisitions

M&A activity — when defined as mergers or acquisitions of whole operating companies with a regulated service territory — produced only two announced transactions in 2019: the proposed sale of Emera Maine to Canadian utility ENMAX and a J.P. Morgan-advised infrastructure fund's bid for El Paso Electric. Note that the charts and tables in this section are based on changes that affect the U.S. Investor-Owned Electric Utilities, as defined on the cover page of this document, and therefore only one announcement (El Paso Electric) is included in those figures. The previous six years — 2013 through 2018 — saw 27 mergers proposed and 20 completed. Utilities spent 2019 in a consolidation phase and successfully closed five of the mergers announced in 2018, so it is not surprising that 2019 was the quietest year for announced deals since 2012, when only one merger was announced.

M&A is now being constrained by the industry's steady consolidation. There were 40 investor-owned utilities at year-end 2019, down from 58 ten years earlier and more than 70 at the turn of the century. And the competitive power side of the business has largely completed its wave of divestitures and restructurings. Analysts commentary also suggested the need for M&A to achieve the earnings growth investors demand is perhaps lower than it was several years ago. Most utilities are now focused on internal growth through regulated capex programs. And the price demanded by targets rose in 2019 as utility price-earnings (PE) multiples climbed higher. A 20% buyout premium added to PEs in the high teens and low twenties can make deal arithmetic difficult for many buyers. But high PEs are produced in part by very low interest rates and those continued to drive financial buyers to look hard at regulated as-

Status of Mergers & Acquisitions 1995–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: EEI Finance Department.

sets as a way of generating income. A third announced deal in 2019 saw a Canadian pension plan bid for renewable power producer Pattern Energy, based in San Francisco, CA, while other Canadian pension investors boosted their stake in Puget Sound in one of the year's completed deals.

State regulators blocked one deal in 2019, Avista and Canadian utility Hydro One's plan to merge, the seventh withdrawn deal of the past eight years. The large number of completed deals in recent years shows mergers can get done if they can show ratepayer benefits, respect the acquired utility's local presence and offer investment programs that support clean energy and economic development. But many of those completed deals weren't easy to close and analysts noted that deal politics is always a potential headwind to any proposed utility M&A.

Status of Announced Mergers & Acquisitions
1995–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Year	Completed	Announced	Withdrawn
1995	2	8	3
1996	1	13	3
1997	13	11	3
1998	9	10	–
1999	10	26	2
2000	23	9	1
2001	6	5	4
2002	5	2	3
2003	1	2	1
2004	1	3	1
2005	1	3	–
2006	3	7	2
2007	6	4	1
2008	6	6	2
2009	1	–	–
2010	2	4	–
2011	2	5	1
2012	4	1	–
2013	2	4	–
2014	4	6	1
2015	2	5	–
2016	9	6	1
2017	1	3	2
2018	2	3	–
2019	3	1	1
Totals	**119**	**147**	**32**

Source: EEI Finance Department.

Announced Transactions

Canadian utility ENMAX Seeks to Buy Emera Maine

On March 25, two Canadian utilities — Calgary-based ENMAX and Nova Scotia's Emera — announced a plan for ENMAX to buy Emera Maine, Emera's regulated electric transmission and distribution subsidiary in Maine, for $959 million USD or $1,286 million Canadian (CAD). Including assumed debt, the deal would have an aggregate enterprise value of $1.3 billion USD ($1.8 billion CAD) on closing. ENMAX, with $5.6 billion CAD in assets and revenue of $2.4 billion CAD, provides electricity, natural gas, renewable energy and other services to approximately 670,000 residential and commercial customers across Alberta, Canada. The company is wholly owned by the City of Calgary, Alberta. Nova Scotia-based Emera serves 2.5 million customers in Canada, the U.S. and the Caribbean with more than $32 billion CAD in assets and approximately $6.5 billion in revenue. Its U.S. subsidiaries include Tampa Electric, TECO People's Gas and New Mexico Gas in addition to Emera Maine, which provides transmission and distribution services to 154,000 residential, commercial and industrial customers in Maine.

Emera said the proposed sale supports its three-year plan to raise $2.1 billion CAD in equity proceeds, reduce corporate debt, optimize its asset portfolio and fund its $6.5 billion CAD regulated capex program. In March 2019, Emera sold its 1,100 MW New England gas generation portfolio, composed of three gas-fired electricity generating facilities, to Revere Power, an affiliate of The Carlyle Group, for $590 million USD ($792 million CAD). ENMAX said the proposed purchase supports its plan to grow through expansion of its regulated utility business in North America and would add approximately $900 million CAD in regulated rate base assets to ENMAX's portfolio, a 50% increase. ENMAX would derive 70% of future cash flow from regulated and non-commodity sources. ENMAX said the purchase would be funded with debt and immediately accretive to earnings and cash flow.

While the deal is relatively small by industry standards, it showcases the political and regulatory challenges often attendant with utility M&A. According to news reports, local politicians and stakeholders in Calgary criticized the planned $1.8 billion expenditure and assumption of new debt by a city-owned entity when city budgets are being cut and local commercial property prices are in steep decline. Others questioned why a city-owned utility should expand far outside its local jurisdiction and suggested the city should instead raise funds through a sale of the utility to private ownership, which could better accommodate any growth ambitions. In early October, S&P cut ENMAX's issuer credit rating to 'BBB' from 'BBB+' and placed the company on CreditWatch Negative, in part as a result of the acquisition's proposed debt financing.

In Maine, local politicians and stakeholders worried about potential rate hikes and job cuts. The Maine Public Utility Commission said it was concerned that debt service costs might force cuts to operating budgets and about the potential influence Calgary's city government could have over Emera Maine's management. In June, Maine passed a law subjecting utility M&A to a net benefit standard for approval rather than simply no net harm. Maine regulators rejected the deal in early March 2020, but gave it their blessing a few weeks later when ENMAX agreed to a negotiated settlement that offers direct benefits to Emera Maine customers; these include holding customer distribution rates at current levels until October 2021, implementing customer service quality and reliability performance standards, offering customer rate credits, and increasing levels of community investment. The deal closed successfully on March 24.

Infrastructure Fund to Buy El Paso Electric

Financial buyers made an appearance in 2019 M&A action in the form of a buyout offer for west Texas and southern New Mexico regulated utility El Paso Electric. On June 3, the utility announced it had agreed to be purchased by Infrastructure Investments Fund (IIF), an infrastructure fund advised by J.P. Morgan Investment Management, for $68.25 per share, a cash deal valued at $4.3 billion including debt. The purchase price was a 17% premium to El Paso's closing price before the announcement, representing a PE multiple of nearly 29 times 12-month earnings through March 31. El Paso said IIF's renewable energy expertise makes it an ideal partner to help the Texas utility navigate a rapidly changing industry that requires significant long-term investments in renewable energy and sustainability. New Mexico has said it wants its power carbon-free by 2045. El Paso Electric said the agreement would leave it independently operated with headquarters in El Paso and commitments that its management and workforce would remain in place. The announcement said EPE and IIF would offer $21 million in rate credits over 36 months and invest $100 million over 20 years in a community economic sustainability fund for El Paso's service area. IIF, which calls itself a long-term owner of utilities, said El Paso would be its flagship investment in the U.S. Analysts cited the strong customer growth and need for investment in El Paso's service territory as points of attraction for IIF.

El Paso Electric provides generation, transmission and distribution service to approximately 428,000 retail and wholesale customers across the Rio Grande Valley in west Texas and southern New Mexico. IIF's 19 portfolio companies are located primarily in the United States, Western Europe and Australia, and include 11 energy, utility and electric generation companies. IIF also has significant experience developing renewable energy sources, with $3 billion in renewable power generation assets that collectively provide 3.4 GW of renewable capacity.

The companies hope to close the deal, which requires approval from state regulators in Texas and New Mexico, along with the FERC, and in the first half of 2020. Texas state regulators approved the deal in January 2020.

Merger Impacts 1995–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Date	No. of Utilities	Change
12/31/95	98	–
12/31/96	98	–
12/31/97	91	(7.14%)
12/31/98	86	(5.49%)
12/31/99	83	(8.79%)
12/31/00	71	(14.46%)
12/31/01	69	(2.82%)
12/31/02	65	(5.80%)
12/31/03	65	–
12/31/04	65	–
12/31/05	65	–
12/31/06	64	(1.54%)
12/31/07	61	(4.69%)
12/31/08	59	(3.28%)
12/31/09	58	(1.69%)
12/31/10	56	(3.45%)
12/31/11	55	(1.79%)
12/31/12	51	(7.27%)
12/31/13	49	(3.92%)
12/31/14	48	(2.04%)
12/31/15	47	(2.08%)
12/31/16	44	(6.38%)
12/31/17	43	(2.27%)
12/31/18	42	(2.33%)
12/31/19	40	(4.76%)

Number of Companies Declined by 59% since Dec.'95

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

Mergers & Acquisitions Announcements Updated through December 31, 2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Ann'cd	Buyer	Seller/Acquired/Merged	Status	New Company	Completed Date	Months to complete	Bus.	Terms	Est. Trans Value ($MM)
6/3/19	JP Morgan Investment Management	El Paso Electric	PN					JPMorgan pays $68.25/share in cash for each share of El Paso Electric Co. common stock	4,285.7
5/21/2018	NextEra Energy, Inc.	Gulf Power Company	C		1/1/2019	7	EE	NEE to pay $4.35 billion in cash to acquire Gulf Power Company from Southern Company	4,350.0
4/23/2018	CenterPoint Energy	Vectren Corporation	C		2/1/2019	10	EG	CNP pays $72.00/share in cash for each share of Vectren common stock	6,000.0
1/3/2018	Dominion Energy, Inc.	SCANA Corporation	C		1/1/2019	12	EE	$6.7B debt + $7.9 stock (per share value of $55.35, roughly 31% premium)	14,600.0
8/21/2017	Sempra Energy	Oncor Electric Delivery Company	C		3/8/2018	6	EE	$9.5B cash	9,450.0
7/19/2017	Hydro One Limited	Avista Corporation	W		1/23/2019			$5.3B cash (per share value of $53.00, roughly 24% premium)	5,300.0
7/7/2017	Berkshire Hathaway Energy	Oncor Electric Delivery Company	W		8/21/2017			$9.0B cash	9,000.0
9/28/2016	DTE Energy	Appalachia Gathering System / Stonewall Gas Gathering	C		10/20/2016	1	EG	Undisclosed	1,300.0
7/29/2016	NextEra Energy	Oncor Electric Delivery Company	W		10/31/2017			$9.5B debt + additional cash and common stock	11,178.0
5/31/2016	Great Plains Energy	Westar Resources	C	Evergy, Inc.	6/5/2018	24	EE	$3.6B debt + $8.6 stock and cash (per share value of $60.00)	12,200.0
2/9/2016	Fortis Inc.	ITC Holdings Corp.	C		10/14/2016	8	EE	$4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium)	11,300.0
2/9/2016	Algonquin Power & Utilities	Empire District Electric Company	C		1/1/2017	11	EE	$1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium)	2,400.0
2/1/2016	Dominion Resources	Questar Corporation	C		9/16/2016	8	EG	$1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium)	4,400.0
10/26/2015	Duke Energy	Piedmont Natural Gas	C		10/3/2016	12	EG	$3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium)	4,900.0
9/4/2015	Emera	TECO Energy, Inc.	C		7/1/2016	10	EE	$6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium)	10,400.0
8/24/2015	Southern Company	AGL Resources	C		7/1/2016	10	EG	$4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium)	12,060.4
7/12/2015	Black Hills Corporation	SourceGas Holdings	C		2/12/2016	10	GG	$760M debt + $1.13B cash	1,890.0
2/25/2015	Iberdrola USA	UIL	C	AVANGRID, Inc.	12/16/2015	10	EE	$1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash)	4,756.0
12/3/2014	NextEra Energy	Hawaiian Electric	W		7/18/2016			NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares)	3,963.0
10/20/2014	Macquarie-led Consortium	Cleco	C		4/13/2016	18	EE	$3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt	4,700.0
6/23/2014	Winsconsin Energy	Integrys	C	WEC Energy Group, Inc.	6/30/2015	12	EE	WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58)	9,100.0
5/1/2014	Berkshire Hathaway Energy	AltaLink (Canadian)	C		12/1/2014	7	ET	BHE to acquire AL for $3.2B cash + $2.7B debt	5,927.0
4/30/2014	Exelon	Pepco	C		3/23/2016	24	EE	EXC to acquire POM for $6.8B in cash ($27.25 per POM share)	12,337.0
3/3/2014	UIL Holdings	Philadelphia Gas Works	W		12/4/2014			UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash	1,860.0
12/12/2013	Fortis Inc.	UNS Energy	C		8/15/2014	8	EE	Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt	4,578.1
11/4/2013	Avista	Alaska Energy & Resources Company	C		7/1/2014	8	EE	AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt	169.5
5/29/2013	MidAmerican Energy Holdings Co.	NV Energy	C	Berkshire Hathaway Energy	12/19/2013	7	EE	MidAmerican pays $23.75 / share + assume $4.8 billion debt	10,494.3
5/25/2013	TECO Energy, Inc.	New Mexico Gas Intermediate, Inc.	C		9/2/2014		EE	TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC	950.0
2/20/2012	Fortis Inc.	CH Energy Group	C		6/27/2013	16	EE	Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt.	1,609.7
5/27/2011	Fortis Inc.	Central Vermont Public Service Corp	W		7/11/2011		EE	Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt.	701.6
1/8/2011	Duke Energy	Progress Energy	C		7/3/2012	18	EE	0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt.	32,000.0
7/11/2011	Gaz Metro LP	Central Vermont Public Service Corp	C		6/27/2012	12	GE	Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt.	704.2

10/16/2010	Northeast Utilities	NSTAR	C		4/10/2012	18	EE	1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt	7,566.7
4/28/2011	Exelon Corp.	Constellation Energy Group Inc.	C		3/12/2012	11	EE	CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt	10,623.2
4/19/2011	AES Corporation	DPL Inc.	C		11/28/2011	7	EE	AES pays 30.00/share cash & assumes approx $1.1 billion of net debt	4,613.2
4/28/2010	PPL Corp.	E.ON U.S.	C		11/1/2010	6	EE	$6.83 billion cash + $764.0 million in assumed debt	7,625.0
3/12/2010	Emera Inc	Maine & Maritimes	C		12/21/2010	9	EE	$76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits	117.4
2/10/2010	FirstEnergy	Allegheny Energy	C		2/25/2011	12	EE	$4.3 billion in equity + $4.7 billion in assumed debt	9,273.2
9/17/2008	Berkshire Hathaway	Constellation Energy Group Inc.	W		12/17/2008		PE	$4.7 bill cash + $4.4 bill net debt and adjustments	9,152.5
7/25/2008	Sempra Energy	EnergySouth Inc.	C		10/1/2008	3	EG	$499 million cash + 283 million debt	771.9
7/1/2008	MDU Resources Group, Inc.	Intermountain Gas Co.	C		10/1/2008	3	EG	$245 million cash + $82 million debt	327.0
6/25/2008	Duke Energy	Catamount Energy Corp.	C		9/15/2008	3	EP	$240 million cash + $80 million assumed debt	320.0
2/15/2008	Unitil Corp.	Northen Utilities / Granite State Gas Transmission	C		12/1/2008	10	EG	$160 million cash	160.0
1/12/2008	PNM Resources, Inc.	Cap Rock Holding Corp.	W		7/22/2008		EE	$202.5 million	202.5
10/26/2007	Macquarie Consortium	Puget Energy	C		2/6/2009	16	EE	$3.5 billion cash + $3.02 billion net debt	6,520.2
6/25/2007	Iberdrola S.A.	Energy East Corp.	C		9/16/2008	15	EE	$4.5 billion cash + $4.1 billion net debt	8,600.0
2/26/2007	KKR & Texas Pacific Group	TXU Corp.[1]	C	Energy Future Holdings Corp.	10/10/2007	8	PE	$31.8 billion cash + $12.1 billion net debt	43,882.0
2/7/2007	Black Hills Corp. / Great Plains Energy Inc.[2]	Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.)	C		7/14/2008	17	EG	$940 million cash +working capital and other adjustments	940.0
7/8/2006	MDU Resources Group, Inc.	Cascade Natural Gas Corporation	C		7/2/2007	12	EG	$305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents)	465.8
7/8/2006	WPS Resources Corporation	Peoples Energy Corporation	C	Integrys Energy Group	2/21/2007	7	EG	$2.47 billion	2,472.4
7/5/2006	Macquarie Consortium	Duquesne Light Holdings	C		5/31/2007	10	EE	$1.59 billion cash + $1.09 billion total debt	2,674.4
6/22/2006	Gaz Metro LP	Green Mountain Power Corp.	C		4/12/2007	10	EE	$187 million in cash + ($100.8 debt - $9.1mm in cash equivalents)	279.5
5/11/2006	ITC Holdings Corp	Michigan Electric Transmission Co.	C		10/10/2006	5	EE	$485.6mm cash + $70mm common stock + $311mm assumed debt	866.6
4/25/2006	Babcock and Brown Infrastructure	NorthWestern Corp.	W		7/24/2007		EE	$2.2 billion cash	2,200.0
2/27/2006	National Grid	KeySpan Corp.	C		8/24/2007	18	EE	$7.4 billion cash + $4.5 billion long-term debt	11,877.5
12/19/2005	FPL Group Inc.	Constellation Energy Inc.	W		10/25/2006		EE	$11.3 billion equity + $4.1 billion net debt and pension liabilities	15,311.5
5/24/2005	MidAmerican Energy Holdings Co.	Pacificorp	C		3/21/2006	10	EE	$5.1 billion cash + $4.3 billion in net debt and preferred stock	9,300.0
5/9/2005	Duke Energy Corp.	Cinergy Corp.	C		4/3/2006	11	EE	$9.1 billion equity + $5.5 billion net debt and pension liabilities	14,600.0
12/20/2004	Exelon Corp.	Public Service Enterprise Group	W		9/14/2006		EE	$12.3 billion in equity + $13.4 billion in net debt and pension liabilities	25,700.0
7/25/2004	PNM Resources	TNP Enterprises	C		6/6/2005	12	EE	$189 million in stock and cash and $835 million in debt	1,024.0
2/3/2004	Ameren Corp	Illinois Power[3]	C		10/1/2004	8	EE	$1.9 billion in debt, pref stock, & other liab + $400 million in cash	2,300.0
11/24/2003	Saguaro Utility Group L.P.	UniSource Energy	W		12/30/2004		PE	$850 million cash + $2 billion in debt	2,850.0
11/3/2003	Exelon Corp.	Illinois Power	W		11/22/2003		EE	$275 million cash + $1.8 billion in debt + $150 million promissory note	2,225.0
4/30/2002	Aquila Inc	Cogentrix Energy Inc	W		8/2/2002		EIPP	$415 million cash + $1.125 billion in assumed debt	1,540.0
4/29/2002	Ameren Corp	CILCORP[4]	C		1/31/2003	9	EE	$541 million cash + $781 in assumed debt + $41 million in pref stock	1,400.0
10/8/2001	Northwest Natural Gas	Portland General	W		5/16/2002		GE	$1.55 billion cash + $250mm in stock	1,800.0
9/20/2001	Duke Energy	Westcoast Energy	C		3/14/2002	6	EG	Equity + cash valued at $27.90 per Westcoast share	8,500.0
9/10/2001	Dominion Resources	Louis Dreyfus Natural Gas	C		11/1/2001	2	EG	$890mm cash + $900mm stock +$505mm debt	2,295.0
2/20/2001	Energy East	RGS Energy	C		6/28/2002	16	EE	$1.4 bill. cash & equity + $1.0 bill. net debt	2,400.0
2/12/2001	PEPCO	Conectiv	C		8/1/2002	18	EE	$2.2 bill cash & equity + $2.8 bill. net debt	5,000.0
11/9/2000	PNM	Western Resources[5]	W		1/8/2002		EE	Stock transfer	4,442.0
10/2/2000	NorthWestern	Montana Power[6]	C		2/15/2002	16	EE	$1.1 billion in cash	1,100.0
9/5/2000	National Grid Group	Niagara Mohawk	C		1/31/2002	16	EE	$19 per share	8,900.0
8/8/2000	FirstEnergy	GPU Inc.	C		11/7/2001	15	EE	$35.60 per share	12,000.0
7/31/2000	FPL Group	Entergy	W		4/2/2001		EE	1/1 - FPL, 0.585/1 - ETR	27,000.0
7/17/2000	AES Corporation	IPALCO	C		3/27/2001	8	IPPE	$25 per share	3,040.0
6/30/2000	NS Power	Bangor Hydro	C	Emera	10/10/2001	16	EE	$26.50 per share	206.0

[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007.
TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

[3] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[4] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[5] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[6] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

Source: EEI Finance Department, S&P Global Market Intelligence.

C = Completed	E = Electric
W = Withdrawn	G = Gas
PN = Pending	O = Oil
	IPP = Independent Power Producer
	P = Privatized

Withdrawn Transaction

Avista and Hydro One Terminate Merger Plans

While technically a 2019 withdrawn deal, the events that caused the merger to be abandoned largely occurred during 2018. On January 23, 2019, Washington State utility Avista and Canadian utility Hydro One jointly terminated their plan for Hydro One to acquire Avista. The deal, announced on July 19, 2017, called for Hydro One to pay $53 in cash per common share, a 24% premium to Avista's closing price the previous day. Hydro One said the acquisition offered geographic and regulatory diversification while adding complementary and growing natural gas distribution operations as well as exposure to regulated and predominantly clean generation. Avista said combining with Hydro One would enable it to define and control its future in a consolidating industry through greater scale and financial flexibility. Avista planned to maintain its management team, employees, Spokane headquarters and its own board of directors and said no workforce reductions would result from the merger. However, both Washington and Idaho state regulators vetoed the merger in late 2018 citing concern about the province of Ontario's political influence over Hydro One. Ontario owns 47% of the Canadian utility. In July 2018, the newly elected premier of Ontario forced changes to Hydro One's senior management and board of directors. In December 2018, the Washington commission found that the proposed deal was not in the public interest since decisions affecting Hydro One's business operations and financial integrity were subject to overrule by Canadian politicians. Idaho denied the merger on January 3, 2019.

Completed Transactions

Five deals announced in 2018 were completed in 2019.

NextEra Acquires Gulf Power

On January 1, 2019 NextEra completed its acquisition of Gulf Power. On May 21, 2018 NextEra Energy and Southern Company announced that NextEra would purchase Gulf Power, Florida City Gas and Southern Company's interest in two natural gas generating plants in Florida in transactions valued at $6.475 billion, including the assumption of approximately $1.4 billion of Gulf Power debt. NextEra said the acquisition complements its existing operations in Florida and that it would employ its long-term strategy of advancing affordable, reliable and clean energy through smart infrastructure investments at both acquired utilities. Analysts noted Gulf Power's generation fleet is mostly coal-fired, potentially offering NextEra the chance to grow regulated rate-base through conversion to gas and renewable generation along with energy storage. Southern said it would use the proceeds to pay down debt and strengthen its balance sheet. NextEra announced the completion of the Florida Gas acquisition on July 30, 2018.

Dominion Buys SCANA

Dominion Energy closed its acquisition of SCANA (2018's biggest announced deal) on January 2, 2019. On January 3, 2018, Virginia's Dominion Energy and South Carolina-based SCANA said they hope to merge in a stock-for-stock transaction that represented an approximate 31 percent premium for SCANA shareholders, who would own 13 percent of the combined company.

Dominion called the merger a strategic combination and termed SCANA a natural fit, noting Dominion's presence in the Carolinas — through its Dominion Energy Carolina Gas Transmission, electric utility Dominion Energy North Carolina, and Atlantic Coast Pipeline operations — complements those of SCANA's South Carolina regulated electric and gas subsidiary SCE&G and North Carolina gas utility PSNC Energy. Dominion said the deal supports new expansion opportunities in the southeast U.S. and can boost its earnings growth rate through 2020 to eight percent or higher.

The companies said a key benefit for SCANA is Dominion's ability — given its larger size and financial strength — to fully resolve the July 2017 decision to cease construction of two new nuclear units at the V.C. Summer Nuclear Station in Jenkinsville, South Carolina. SCANA was part owner of the project, which it deemed prohibitively expensive to complete following the bankruptcy of the nuclear plants' contractor (Westinghouse) and a venture partner's move to abandon the project. SCANA said a merger with Dominion Energy would strengthen the company and enable it to focus on core operations.

CenterPoint Acquires Vectren

CenterPoint completed its acquisition of Vectren on February 1, approximately nine months after the April 23, 2018 announcement. The companies said the deal was motivated by opportunities for synergistic growth in their natural gas utility businesses rather than cost-saving synergies. Both companies are targeting growth through regulated gas infrastructure in their service territories. CenterPoint is reducing its exposure to the midstream energy business while Vectren has said it wants to transition its generation away from coal to reduce emissions and adapt to changing customer preferences and regulations. The companies said the merger would leverage best practices for service, reliability and deployment of new technologies across a larger U.S. footprint. At the time of announcement, CenterPoint had natural gas operations in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas that served more than 3.4 million customers. The company also delivered electricity to more than 2.4 million customers in the greater Houston area. CenterPoint Energy's competitive natural gas sales and services business served more than 100,000 customers in 33 states. Evansville, Indiana-based Vectren provided natural gas to more than 1 million customers in Indiana and Ohio, and electricity to 145,000 customers in Indiana. The combined company retained the CenterPoint Energy name and Houston corporate headquarters.

Canadian Pensions Buy Macquarie's Puget Sound Stake

On April 29, 2019, global infrastructure investor Macquarie closed the sale of its stake in Puget Energy to a group of Canadian pension funds. In August 2018, Puget Sound Energy (PSE) announced that long-time private equity investor Macquarie Infrastructure Partners would sell its 44% position in the company to a group of Canadian pension funds, including two who raised their ownership stake in the Washington state utility. Alberta Investment Management Corporation (AIMCo) and the British Columbia Investment Management Corporation (BCI) increased positions they've held since 2009 by six percent and four percent to 13.6 percent and 20.9 percent, respectively. Two new investors, OMERS (the defined benefit pension plan for municipal employees in Ontario, Canada) and Dutch pension fund manager PGGM will have 23.9 percent and 10 percent positions. The Canada Pension Plan Investment Board (CPPIB), an investor since 2009, continues its 31.6 percent position. The Macquarie infrastructure funds, which invested in PSE in 2009, are reaching the end of their terms and the sale was widely expected. Puget Sound Energy provides regulated electric service to 1.1 million customers and natural gas distribution services to about 790,000 customers in the Puget Sound region of Washington state.

BCI called the Puget equity stake a strong fit with the long-term investment objectives of its pension plan clients. OMERS said owning Puget aligns with its principles as a patient, long-term investor in high-quality infrastructure assets. Dutch investor PGGM said the purchase is consistent with its policy of investing long-term pension capital in companies actively involved in the transition to a low-carbon energy future. Analysts noted that pension funds have a very long-term investment horizon and don't require an exit strategy to accommodate the ten-year life cycle common in private equity funds. Canadian pensions have been active buyers of contracted power and renewable assets in recent years in the U.S. and globally.

Sempra/Oncor Buys InfraREIT

In a complex deal announced October 18, 2018, Sempra and its 80% owned Texas-based regulated transmission and distribution utility Oncor said they agreed to acquire New York Stock Exchange publicly traded InfraREIT for $1.275 billion or $21 per share. InfraREIT, structured as a real estate investment trust (REIT), owns and leases rate-regulated electricity delivery infrastructure assets to Sharyland Utilities, a Texas-based regulated electric utility. Sempra said it will also acquire a 50 percent limited-partnership interest in a holding company that will own Sharyland Utilities for approximately $98 million. Sempra/Oncor said the transaction enlarges its regulated utility platform in the growing Texas market, calling InfraREIT's assets highly desirable beneficiaries of Texas' strong economic growth, attractive demographic trends and increased demand for electric transmission. In summer 2018, Sempra said it would sell its entire portfolio of U.S. wind and solar assets as part of a portfolio optimization initiative to focus the company's strategy on earnings growth from regulated assets. Sempra said it would use the proceeds to fund its share of the InfraREIT purchase. The companies completed the deal on May 16, 2019.

Deal Talk: Santee Cooper and JEA

The scarcity of announced deals during the year focused more attention than usual on potential but not actual deals. News reports and analysis centered on two large government-owned utilities as buyout candidates — South Carolina's Santee Cooper and Florida's northeast regional utility JEA, based in and owned by the city of Jacksonville. Both narratives showcase familiar themes coloring utility M&A in recent years.

South Carolina's state-owned electric and water utility Santee Cooper was created during the 1930s New Deal as a rural electrification and public works project. It has been in the news since 2017 as a potential sale candidate after abandoning the V.C. Summers nuclear expansion project in July of that year, which was planned to come online in 2016-2017 and left the utility with 45% of the project's roughly $10 billion in debt. In late 2018, the state hired a consulting firm to evaluate buyout proposals. News reports in 2019 said Santee Cooper received four offers ranging from $7.9 billion to $9.2 billion, including bids by neighboring investor-owned utilities Duke and NextEra, although with no details about the handling of Santee Cooper's debt. The state said bidders will need to outline plans for rates and capital investment for 20 years and any plans for job cuts over five years. The state's governor and legislature are also considering a plan for another neighboring investor-owned utility, Dominion Energy, to run Santee Cooper while the state retains ownership (New Jersey-based, investor-owned utility Public Service Enterprise Groups operates New York State-owned Long Island Power Authority's transmission system under a long-term contract). A third possibility is continued state ownership with a reform plane executed by current Santee Cooper management. The state's legislators are expected to choose a path forward in 2020.

News surrounding JEA's potential for privatization also began in 2017, when a consultant hired to explore the company's options valued the utility in a range of $7.5 billion to $11 billion. But the utility reportedly ended privatization talks in May of 2018 following opposition to privatization from Jacksonville's mayor. JEA executives reawakened the concept in May 2019 with warnings the utility could face a cash gap of $2 billion by 2030, requiring severe staffing cuts and 40% to 50% rate hikes if there is no significant change to its business approach. In late July 2019, JEA's board authorized management to again solicit interest in new ownership structures. News reports said the board and management team leaders were concerned JEA's status as a government-owned utility severely limits its ability to make investments that respond to the technological disruptions impacting the industry, such as growth in renewable generation, increasing use of rooftop solar power, the need for grid modernization, smart-grid deployment and operating and maintenance cost reduction. JEA reportedly opened solicitation in August with the requirement that buyout offers exceed $3 billion and offer at least $400 million in customer benefits. Investor-owned utilities Duke, NextEra and Emera reportedly were among nine bidders that also included water utilities and global infrastructure investors. But political differences with the City of Jacksonville again surfaced, with the city's mayor, city councilors and other stakeholders objecting that JEA favored privatization over other potential ownership structures. In February 2020, JEAs board rescinded its July directive, terminated the JEA CEO who oversaw the process and board members suggested that any decision on JEAs future would be up to the mayor and Jacksonville city administration.

Utility M&A, even in the best circumstances, must carefully respect the standards imposed by state commissions and the sensibilities of wary stakeholders, whose opposition can scuttle the best-formed plans. The Santee Cooper and JEA stories suggest privatizing a government-owned utility may require even more political skill and the sensitivity to clearly and plainly spell out the advantages of any proposed deal to all concerned parties.

Construction

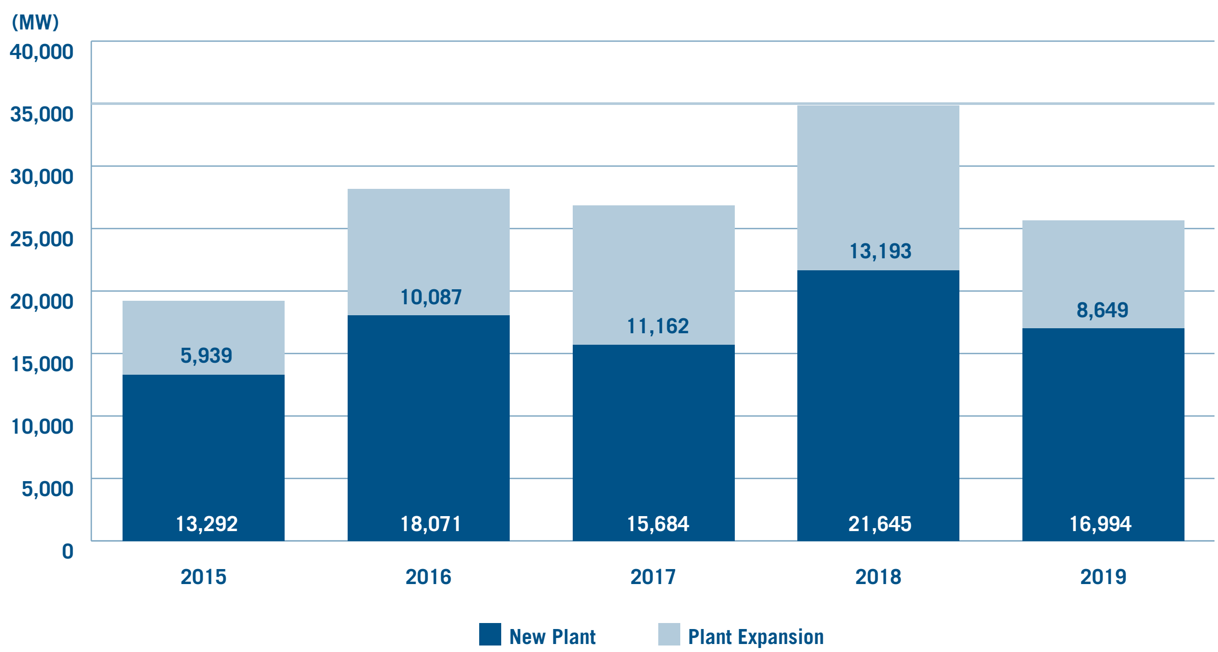
The electric utility industry brought 25,643 MW of new capacity online in 2019, a 25% decrease from the 34,838 MW total of 2018, which was the largest since 2012's 31,503 MW. Capacity added by new plants fell 21% versus last year while capacity from plant expansions declined 34%. Wind power led new capacity additions and accounted for 9,441 MW or 37% of the total. Natural gas was second at 9,301 MW, or 36%, while solar generation contributed 6,188 MW or 24%.

The nation's aggressive build-out of renewable energy is evident in wind and solar energy's 60% share of 2019's new capacity and the 18% growth in each fuel's total capacity added versus their total in 2018. The year-to-year decline in total new capacity was driven primarily by natural gas. Gas capacity installed in 2019 was down 54% after a record year in 2018 that resulted from new gas plants in the PJM region. Approximately 78% of 2019's new gas capacity is combined-cycle while 17% is combustion turbine.

New plants accounted for 3,696 MW, or 40%, of the total new gas capacity online in 2019 while 4,260 MW or 46%, resulted from expansions at existing facilities and 14% were re-rates. A re-rate at Alabama's Brown's Ferry nuclear plant, a Tennessee Valley Authority (TVA) facility, added 155 MW of new nuclear capacity.

Investor-owned utilities that brought the most renewable capacity online, either as new plants or expansions at existing facilities, were NextEra Energy (681MW solar and 1,293 MW wind), Berkshire Hathaway Energy (741 MW, nearly all wind power), Xcel Energy (12 MW solar and 640 MW wind), Duke Energy (247 MW solar and 202 MW wind), WEC Energy (300 MW of wind) and TECO Energy (259 MW of solar). NextEra also

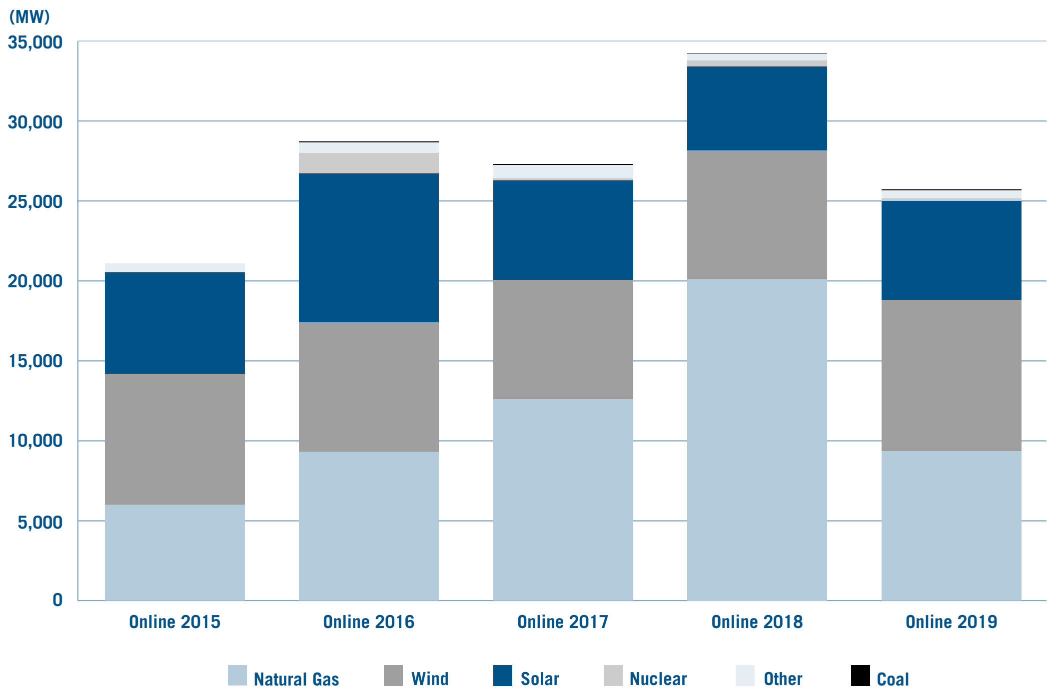
New Capacity Online 2015–2019



Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

New Capacity Online by Fuel Type 2015–2019



Fuel Type	2015	2016	2017	2018	2019
Coal	3	45	45	10	62
Natural Gas	5,971	9,282	12,530	20,033	9,301
Wind	8,179	8,045	7,456	8,031	9,441
Solar	6,316	9,287	6,222	5,246	6,188
Nuclear	0	1,291	102	350	155
Other	556	672	861	456	496
Total	**21,025**	**28,622**	**27,216**	**34,126**	**25,643**

Note: Includes all new capacity placed on the grid by investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

led natural gas additions, with 2,451 MW of new combined-cycle capacity. Entergy was next, at 914 MW, also combined-cycle. Pinnacle West added 809 MW of combustion turbine capacity and PSEG added 592 MW of new combined-cycle power.

New Capacity Online by Region

The Texas Reliability Entity (TRE) saw the biggest year-to-year growth in capacity additions, at 80% over 2018's level, boosted by 4,101 MW of new wind capacity, 3,524 MW of gas and 768 MW of solar. Hawaii (HCC) saw 38% growth from 2018's level, driven by 180 MW of new solar capacity. The Reliability First Corporation (RFC) saw the largest decline in added capacity, down 67% from 2018's total, as gas capacity added there dropped from 10,431 MW in 2018 to 2,552 MW in 2019. Capacity added in the Southwest Power Pool (SPP) region was down 45% versus 2018, largely because new wind additions declined to 954 MW in 2019 from 1,856 MW in 2018. The Northeast Power Coordinating Council (NPCC) region also saw new capacity additions fall, dropping 42% versus 2018's total, mostly because of a decline in new natural gas-powered capacity from 2,535 MW in 2018 to 1,122 MW in 2019. Note that the Florida Reliability Coordinating Council (FRCC) region was incorporated into the SERC region in 2019.

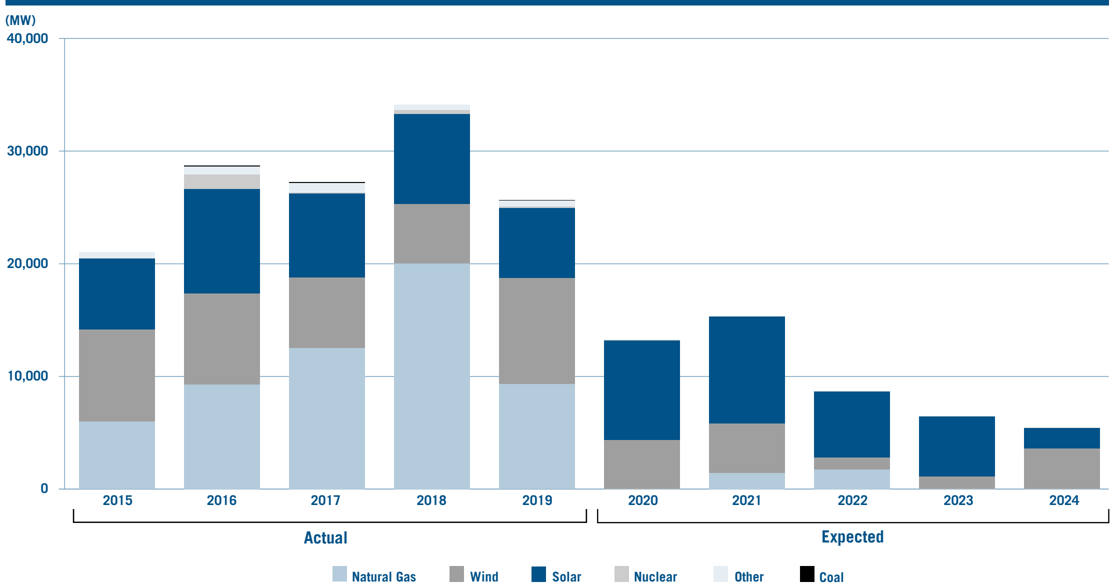
New Capacity Online by Region (MW) 2019

Region	Online 2016	Online 2017	Online 2018	Online 2019
ASCC	156	111	1	25
FRCC	1,815	2,408	2,532	See SERC
HCC	34	48	136	187
MRO	2,473	1,998	3,116	3,257
NPCC	868	529	2,948	1,704
RFC	3,927	5,358	10,606	3,475
SERC	4,763	3,720	6,428	6,966
SPP	3,702	3,411	1,947	1,072
TRE	2,958	6,522	2,882	5,189
WECC	7,926	3,111	3,530	3,768
Total	**28,622**	**27,216**	**34,126**	**25,643**

Note: Data includes new plants and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

Actual and Expected Capacity Additions 2015–2024



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coal	3	45	45	10	62	—	—	—	—	—
Natural Gas	5,971	9,282	12,530	20,033	9,301	—	1,435	1,749	—	—
Wind	8,179	8,045	6,222	5,246	9,441	4,366	4,366	1,027	1,098	3,580
Solar	6,316	9,287	7,456	8,031	6,188	8,821	9,501	5,876	5,363	1,850
Nuclear	0	1,291	102	350	155	20	—	—	—	—
Other	556	(734)	861	456	496	66	15	20	6	14
Total	**21,025**	**27,216**	**27,216**	**34,126**	**25,643**	**13,272**	**15,317**	**8,672**	**6,468**	**5,444**
	Actual					Expected				

Notes: Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date through 2024. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. 2015-2019 is actual plants brought online. 2020-2024 data is from announced projects as of March 2020.
Source: Velocity Suite, ABB Enterprise Software EEI Finance Department

Announced New Capacity by Region and Fuel Type in 2019 (MW)

Fuel Type	Electric Reliability Council of Texas	Hawaiian Coordinating Council	Midwest Reliability Organization	Northeast Power Coordinating Council	Reliability First	SERC Reliability Corp	Southeast Power Pool Inc.	Western Electricity Coordinating Council	Total
Coal						10			10
Natural Gas	1,897		49	65	1,107	1,333	8	304	4,762
Nuclear						20			20
Wind	1,267		2,461	4,641	1,739	350	3,789	1,934	16,181
Solar	2,007	283	1,156	7,342	4,469	7,651	590	7,911	31,411
Hydro	10		2	13	14	57		15	110
Other			4	31	15	59		45	154
Total	**5,182**	**283**	**3,671**	**12,091**	**7,345**	**9,480**	**4,387**	**10,209**	**52,648**

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates in 2019 for years 2020–2025. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

Announcements by Region and Fuel Type

Announced new capacity totaled 52,688 MW in 2019, down 22% from 2018's 68,003 MW. Renewable generation accounted for more than 90% of 2019's announcements, with solar contributing 60%, wind 31% and natural gas 9% of the total. Only 10 MW of new coal capacity was announced, and this was due to rerates and fuel conversions.

Solar power once again accounted for all of Hawaii's announced new capacity. The Northeast Power Coordinating Council (NPCC) produced the highest total announced new capacity in 2019, at 12,091 MW, nearly all renewable with approximately 61% of the total solar and 38% wind. Last year, the Western Electricity Coordinating Council (WECC) region dominated announcements, with 16,045 MW, also largely solar and wind generation. In 2019, WECC took second place with 10,209 MW of announced capacity, 77% of which was solar power.

Announced natural gas capacity was 55% lower in 2019 versus 2018, in part because 2018 was a record year. About 20 MW of nuclear capacity was announced, all due to repowers/rerates in Alabama, Michigan, North Carolina and Pennsylvania.

Stage of Announced Capacity Additions (MW) 2020–2024

Fuel	Proposed	Feasibility	Application Pending	Permitted	Site Prep	Under Construction	Testing	Total
Coal	—	—	—	—	—	—	—	0
Natural Gas	13,289	713	14,658	16,438	8	11,060	3,615	59,780
Nuclear	—	1,900	—	—	—	2,200	—	4,100
Wind	54,780	1,745	20,673	10,80	543	16,447	390	105,382
Solar	69,067	247	24,554	11,41	223	10,578	49	116,583
Other	4,175	10,691	1,183	2,146	—	334	13	18,542
Total	**141,310**	**15,296**	**61,068**	**40,807**	**773**	**40,619**	**4,514**	**304,387**

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date up to 2024.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

Expected Capacity Additions

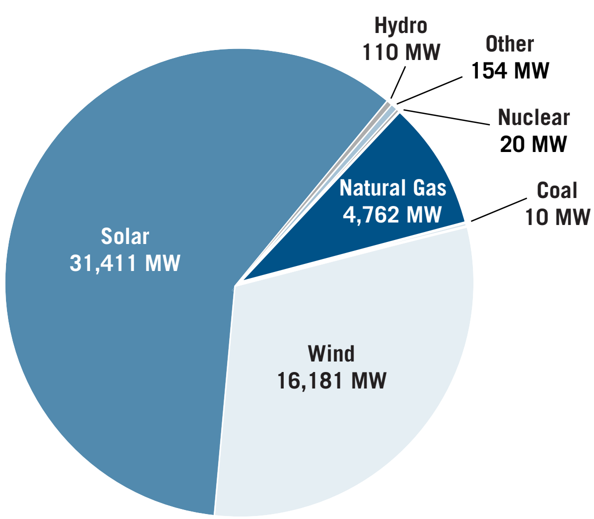
Based on projections at year-end 2019, capacity additions expected to come online through 2024 totaled 49,172 MW, with the bulk of that (28,589 MW) scheduled for 2020 or 2021. Solar accounts for 64% of the 49 GW total and most of that, at 18,322 MW, is also set to come online in 2020 or 2021. The amount of projected natural gas capacity is notably lower than in recent years, accounting for only 6% of total projected capacity additions through 2024.

No new natural gas capacity is set to come online in 2020 and only 1,435 MW is expected in 2021, with only slightly more, at 1,749 MW, in 2022. A projected 20 MW of nuclear capacity in 2020 results from a rerate at FPL's Turkey Point facility. In NPCC, 6,320 MW of offshore wind was announced with plans to come online by 2024 or 2025.

A total of 304,387 MW of new capacity were in various stages of planning at year-end 2019. Slightly less than half of this, at 46%, was in the proposal stage. Of that 46%, 88% is either wind or solar generation and only 9% is natural gas. Out of the grand total 304 GW, 38% is solar and 35% is wind. Natural gas accounts for just under 20% of the 304 GW at all stages of planning, 28% of the total that is in the permitted stage and just under 19% of the total under construction.

2019 New Capacity Announcements by Fuel Type

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates in 2019 for years 2020-2025. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding.

Source: Velocity Suite, ABB Enterprise Software; EEI Finance Department, March 2020

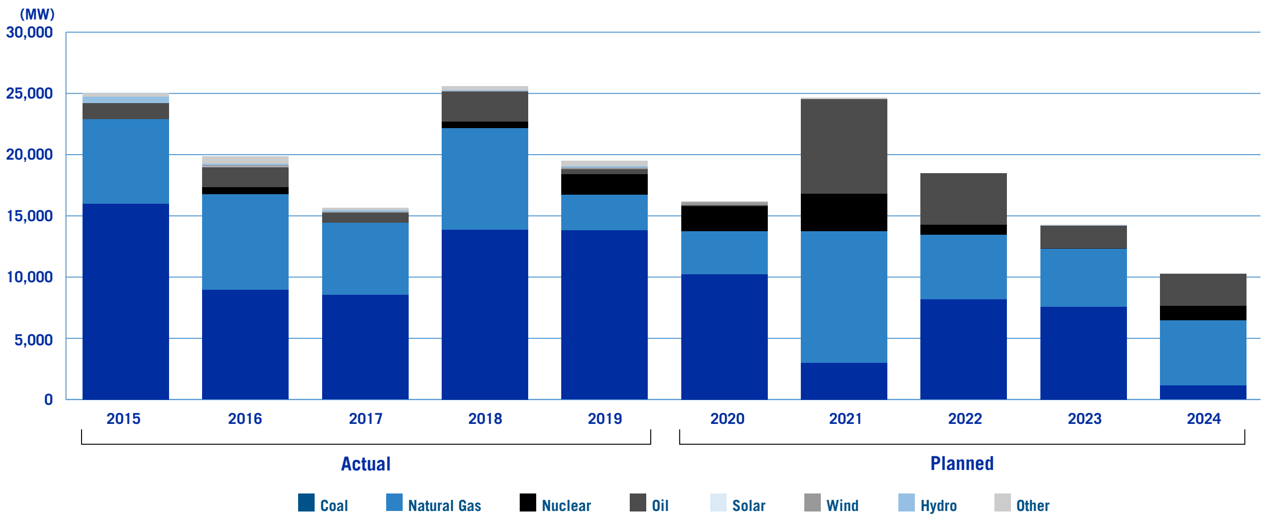
Retirements

At year-end 2019, 84 GW of capacity was scheduled to retire at some point from 2020 through 2024. While annual coal retirements taper off from their near-14 MW level in 2018 and 2019, they still dominate at 36% of total planned retirements through 2024, followed by gas at 35% and fuel oil at 20%. Gas retirements are expected to peak in 2021 at 10,715 MW, the fuel's highest annual level during the 2015-2024 period.

Wind and solar retirements remain minimal given their recent buildout; no solar is slated for retirement while wind retirements, at a mere 0.3% of the total, result from two plants that started operation in 2008 and 2011 in Texas and Illinois, respectively. Hydro retirements are also minimal, at only 0.1% of the total, and are largely associated with the Logan hydroelectric plant in Utah and the Cornell plant in Wisconsin.

Heating oil capacity retirements are expected to total 7,708 MW in 2021, the highest level reached by this fuel during the 2015-2024 period, following little retirement activity in 2019 and 2020. Annual oil capacity retirements are expected to run between roughly 2,000 MW and 4,000 MW from 2022 through 2024.

Actual and Planned Retirements 2015–2024



	Actual					Planned					
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Coal	16,002	8,946	8,529	13,876	13,797	10,236	2,996	8,160	7,567	1,129	30,086
Gas	6,883	7,811	5,887	8,270	2,936	3,502	10,715	5,276	4,746	5,352	29,590
Nuclear	—	577	—	550	1,641	2,031	3,097	823	—	1,159	7,111
Oil	1,311	1,652	854	2,424	444	86	7,708	4,206	1,866	2,621	16,486
Solar	14	35	—	1	—	—	—	—	—	—	—
Wind	359	8	60	80	88	249	—	—	—	—	249
Hydro	147	127	125	54	142	1	6	—	37	6	50
Other	303	619	204	352	462	93	139	37	76	—	344
Total	**25,019**	**19,854**	**15,658**	**25,606**	**19,508**	**16,200**	**24,660**	**18,500**	**14,292**	**10,266**	**83,917**

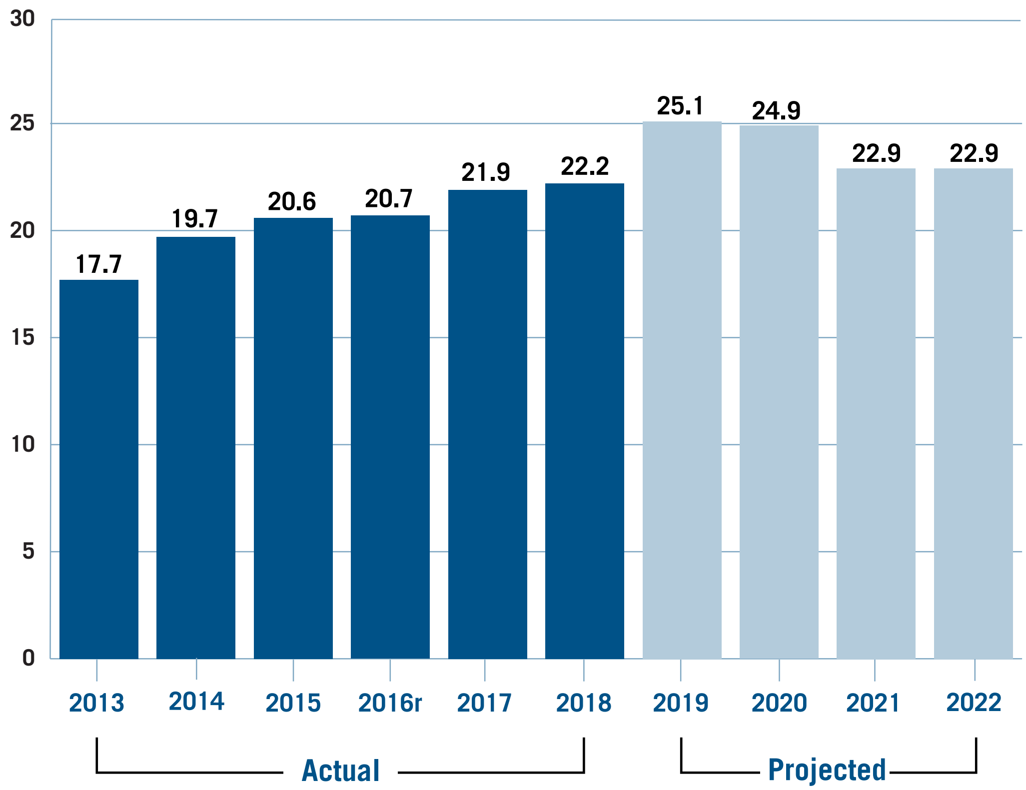
Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, wood, and energy storage. Totals may reflect rounding. 2015-2019 is actual plants retired. 2020-2024 data is from announced retirements as of March 2020.
Source: ABB Inc., The Velocity Suite; EEI Finance Department, March 2020

Transmission

According to EEI's 2019 Transmission Capital Investment Survey, investor-owned electric utilities and stand-alone transmission companies invested $22.2 billion in transmission assets in 2018, a 1.4% increase versus the $21.9 billion invested in 2017. The increase reflects the industry's efforts to meet changing customer expectations while providing low-cost, reliable service. EEI members continue to invest in the transmission system in order to provide access to clean energy; to increase the reliability, security and resiliency of the energy grid; and to reduce congestion so that lower-priced resources can meet customer needs now and in the future.

Actual & Projected Transmission Investment* 2013–2022

($ Billions)



r = revised

*Investment of investor-owned electric companies and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Budget & Forecast Survey supplemented with data obtained from company 10-k reports and investor presentations.

Source: EEI Business Analytics.

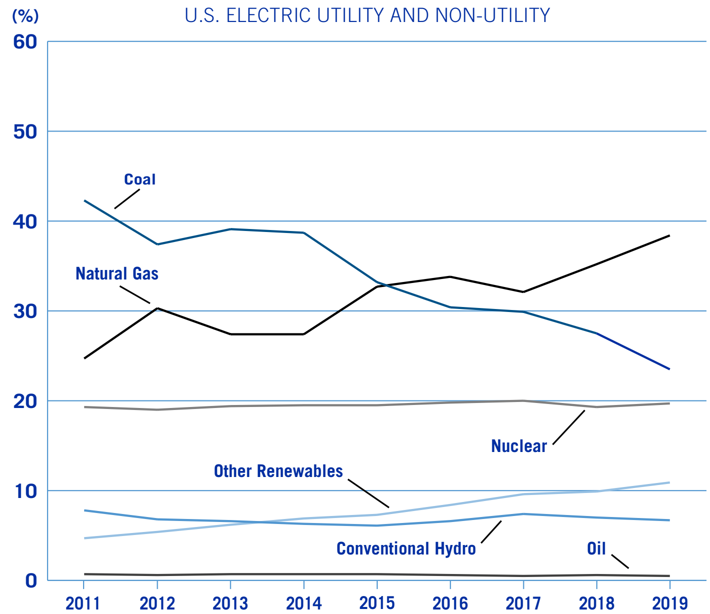
Updated November 2019.

Fuel Sources

Three primary trends that have impacted fuel use over the last decade persisted in 2019: natural gas prices drifted further down from already very low levels, renewable generation capacity continued to grow, and electricity demand remained lethargic, dropping 1.4% from its 2018 level partly due to milder weather in 2019.

Natural gas maintained its position, established in 2016, as the nation's primary generation fuel. Its share of total generation increased 3.2 percentage points, to 38.4% in 2019 from 35.2% in 2018. Coal's share fell 4.0 percentage points, to 23.5%, extending a relatively steady long-term decline since the late 1990s. In 1998, coal plants produced over half the nation's electricity. Nuclear generation continued its stable long-term contribution,

Fuel Sources as a Percentage of Total Electric Generation 2011–2019



U.S. Electric Utility: Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA), March 2020.

Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

	2018	2019
Coal	27.5%	23.5%
Gas	35.2%	38.4%
Nuclear	19.3%	19.7%
Oil	0.6%	0.5%
Hydro	7.0%	6.7%
Renewables	9.9%	10.9%
Biomass	1.5%	1.4%
Geothermal	0.4%	0.4%
Solar	1.8%	1.8%
Wind	6.5%	7.3%
Other fuels	0.5%	0.5%
Total	100%	100%

Note: Totals may not equal 100% due to rounding.

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Source: U.S. Department of Energy, Energy Information Administration (EIA). March 2020.

accounting for 19.7% of the nation's power in 2019, up marginally from its 19.3% share in 2018. Nuclear power has supplied between 19% to 20% of the nation's electricity for two decades. Hydro's share of generation edged down to 6.7% in 2019 from the record-high 7.0% in 2018 caused by high precipitation levels that year. Other renewables — wind, solar, geothermal and biomass — saw their collective share continue to rise. Together, they accounted for 10.9% of total generation in 2019 up from 9.9% in 2018.

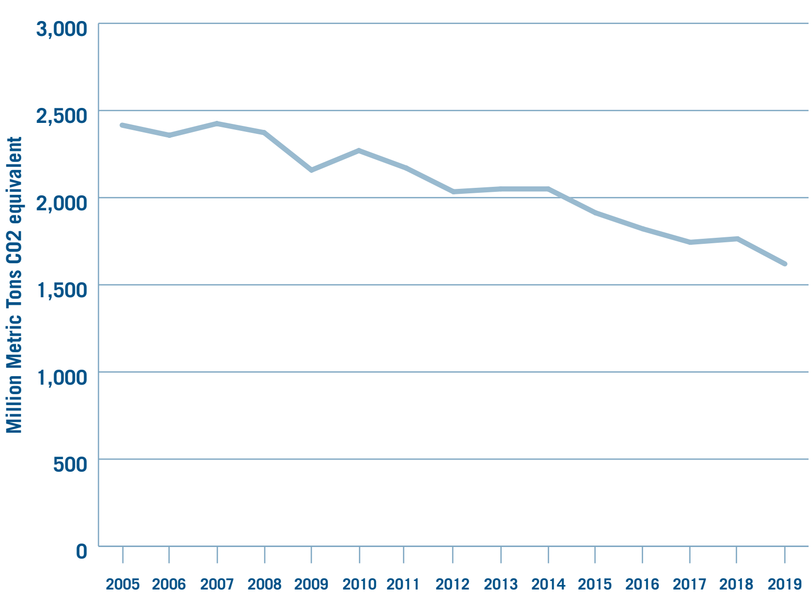
The nation's fuel mix has changed markedly over the past decade and EEI member companies have been leaders in implementing this change. As a result, the power sector has reduced its carbon emissions significantly and renewable generation has achieved strong, ongoing growth. Approximately 40% of the nation's electricity now comes from carbon-free sources (including nuclear energy, hydropower and other renewables).

Zero-carbon generation produced 37.2% of the nation's electric power in 2019. The electric power industry's 2019 carbon dioxide emissions were down 8% from 2018's total, 33% below the level in 2005 and at their lowest point over the past three decades (since 1987). Other benchmarks of progress include:

- EEI member companies' 2019 carbon emissions were approximately 45% below 2005 levels (Source: 2019 EPA, CEMS data; 2020 ABB Energy Velocity).
- 40 EEI members that account for approximately 90% of EEI-member generation have set near- and long-term greenhouse gas (GHG) reduction goals, with many aiming for reductions of 80% or more by 2050.
- Almost half of those goals include a net-zero by 2050 or earlier target date.

Roughly two-thirds of the emissions reductions achieved to date are a result of switching from coal to natural gas generation; since 2005, coal use has been cut by more than half. This shift has allowed EEI member companies to take advantage of the lower cost, around-the-clock reliability and easier dispatchability of natural gas to achieve deeper and faster emissions reductions. At the same time, EEI's member companies have aggressively increased their deployment and use of renewables. The amount of energy they have generated from non-hydro renewable sources has risen four-fold since 2005.

U.S. Power Sector Carbon Dioxide Emissions (2005-2019)



Source: U.S. Energy Information Administration, Monthly Energy Review, March 2020.

Electric Companies with 100 Percent Net Zero Emissions Goals

EEI Member	Climate/Carbon Goal
AVANGRID	100% carbon neutral by 2035
Avista	100% clean electricity by 2045
CMS Energy	Net-zero CO2 emissions by 2050
DTE Energy	Net-zero carbon emissions by 2050*
Dominion Energy	Net-zero CO2 and methane emissions by 2050
Duke Energy	Attain net-zero CO2 emissions by 2050
Eversource Energy	Carbon neutral by 2030
Green Mountain Power	100% carbon-free electricity by 2025, 100% renewable energy by 2030
Hawaiian Electric	100% renewable energy by 2045
Idaho Power	Provide 100% clean energy by 2045
Madison Gas & Electric	Net-zero carbon electricity by 2050
National Grid	Net zero emissions by 2050
Pinnacle West (APS)	100% carbon-free electricity by 2050
PNM Resources	100% carbon-free electricity by 2040
PSEG	Net-zero carbon emissions by 2050*
Puget Sound Energy	100% clean electricity by 2045
Southern California Edison	Carbon neutrality by 2045
Southern Company	Low- to no-carbon operations by 2050
Xcel Energy	Carbon-free electricity by 2050

Source: EEI, March 2020

Coal

Coal fueled 23.5% of U.S. generation in 2019, down four percentage points from its 27.5% share in 2018. Coal's once-dominant position as the nation's primary generation fuel has been eroded by the abundant supply of low-cost natural gas from the shale revolution, low wholesale market prices for natural gas and stricter environmental regulations. As a result of fuel switching and retirements, New York will have no coal-fired generation once the 686 MW Somerset plant is retired in the first half of 2020. Connecticut's 385 MW Bridgeport station coal-fired plant is scheduled for retirement in 2021; this will leave New England with only four operational coal-fired power plants — the 439 MW Merrimack and 138 MW Schiller plants in New Hampshire and Maine's 85 MW Rumford Cogeneration plant and 56 MW S.D. Warren Westbrook plant.

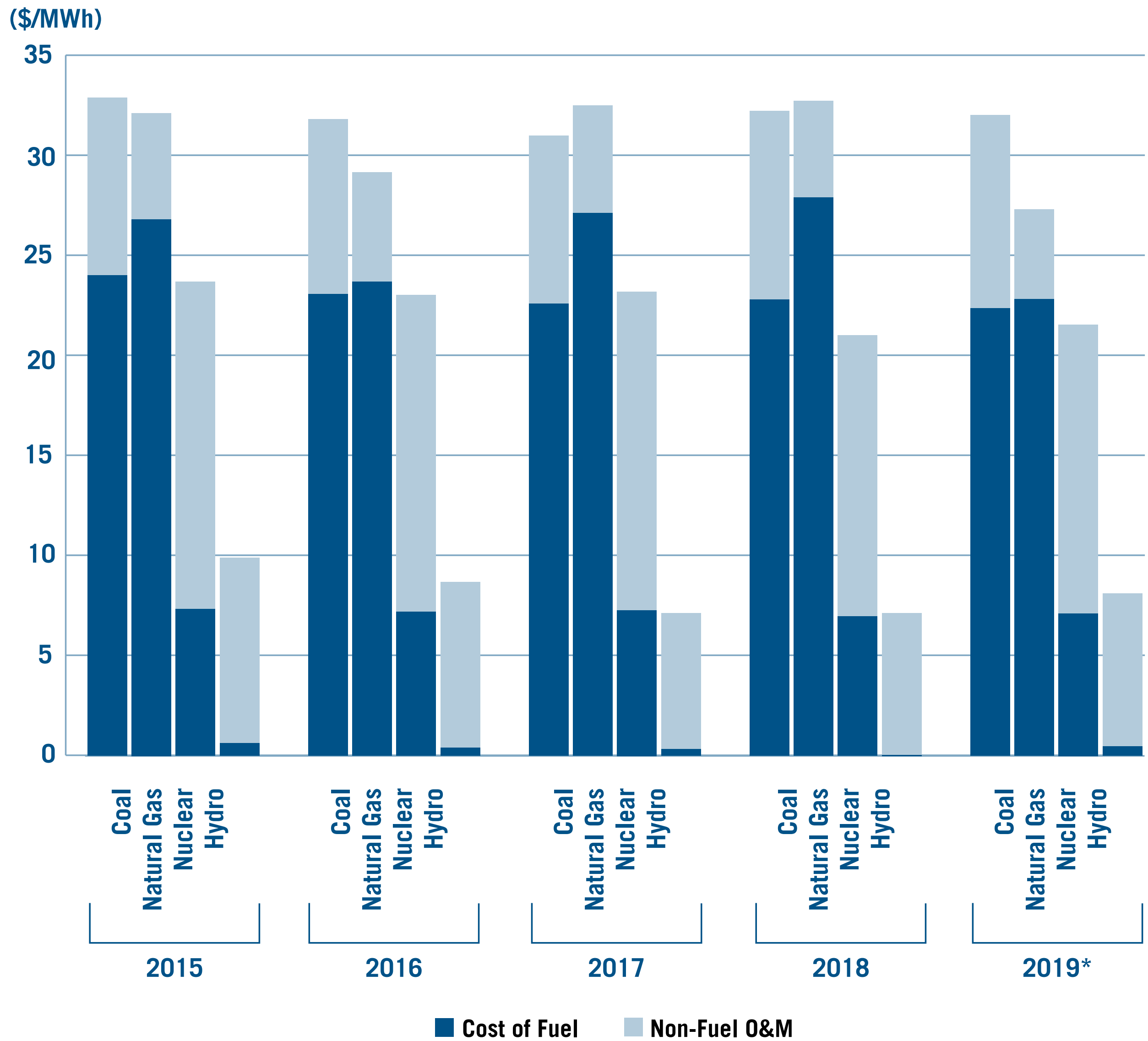
Electric utilities paid an average \$2.08 per million British Thermal Units (MMBtu) for coal in 2019, three cents less than in 2018 and 35 cents (or 14%) less than 2012's \$2.43/MMBtu, which was the highest level in a decade. The average cost of producing electricity from coal in 2019 remained the highest of all fuel types, at \$32.05/MWh, although the fuel component of this total cost was \$22.38/MWh, down 7% from \$24.03/MWh in 2015.

Natural Gas

Natural gas maintained its lead over coal as the primary fuel used for electricity generation in the U.S. The share of total generation fueled

Average Cost to Produce Electricity 2015–2019

U.S. ELECTRIC UTILITY AND NON-UTILITY



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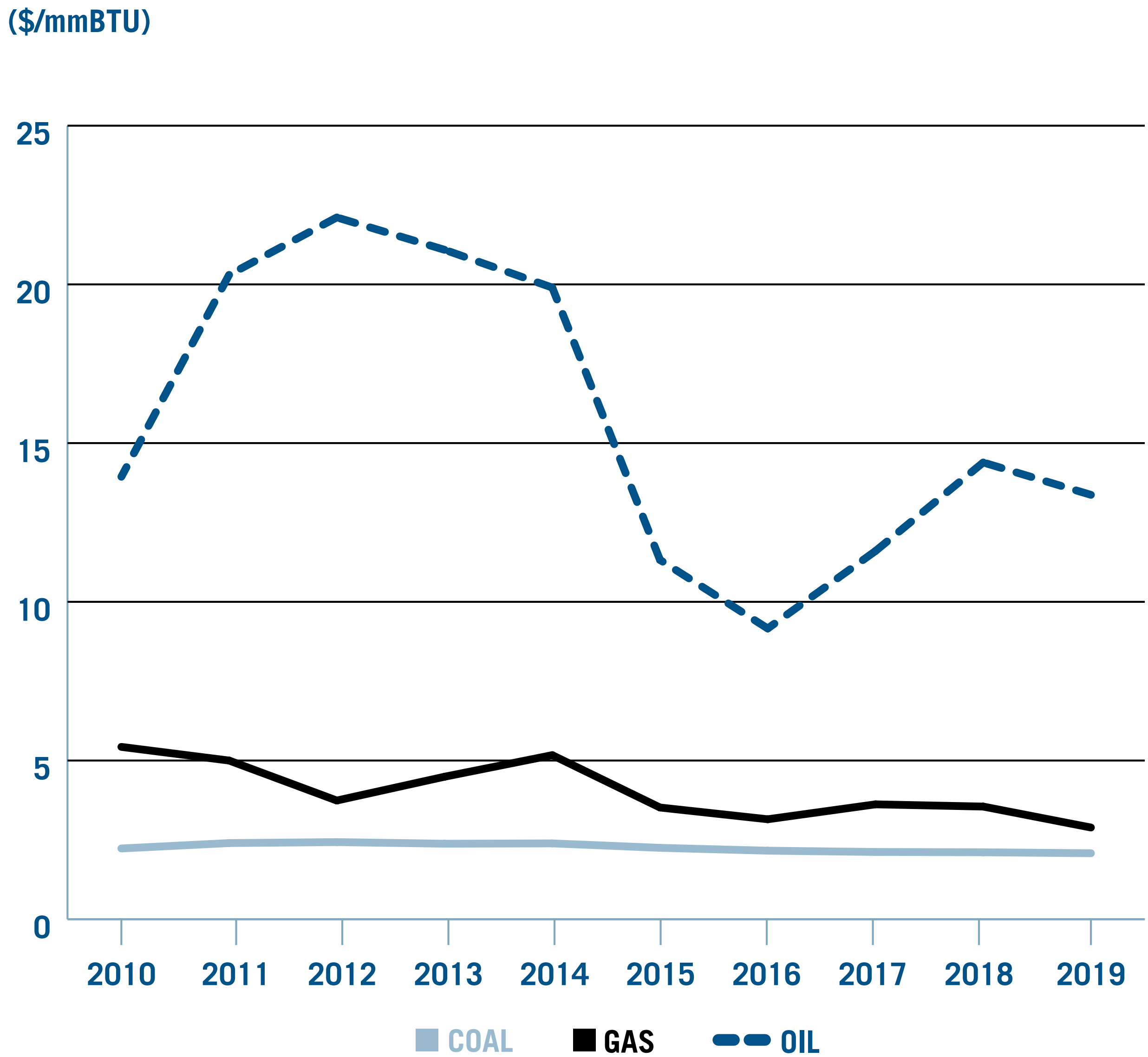
Non-Utility Power Producer: Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

*2019 results are preliminary. All years based on modeled data from Velocity Suite, ABB Enterprise Software March 2020

Average Cost of Fossil Fuels 2010–2019

U.S. ELECTRIC UTILITIES



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Source: U.S. Department of Energy, Energy Information Administration (EIA), March 2020.

by natural gas rose to 38.4% in 2019 from 35.2% in 2018, driven largely by natural gas-fired capacity additions.

Natural gas production surged 10% year-to-year, to 36,188 billion cubic feet (Bcf) in 2019, while a mild winter caused consumption to increase only 3%, or 31,014 Bcf. Demand for natural gas from the industrial and residential sectors barely changed, increasing only 0.12% and 0.08%, respectively versus 2018 levels. The electric power sector is the nation's single-largest user of natural gas; the sector's total gas consumption rose 7% in 2019 and its share among all sectors increased more than one percentage point, to 36.4%. The industrial sector, the second-largest user, saw its share decrease slightly, from 27.8% to 27.0%. The residential sector accounted for 16% of total consumption.

The average Henry Hub (HH) spot price — a widely watched benchmark — averaged $2.56 per MMBtu in 2019, down 19% from the prior year. This led to a 17% drop in the average cost to produce electricity from natural gas, to $27.32/MWh, which made the fuel cost component of coal and natural gas generation about equal. Operations and maintenance costs for natural gas generation also declined, by about 7% versus their 2018 level.

Nuclear

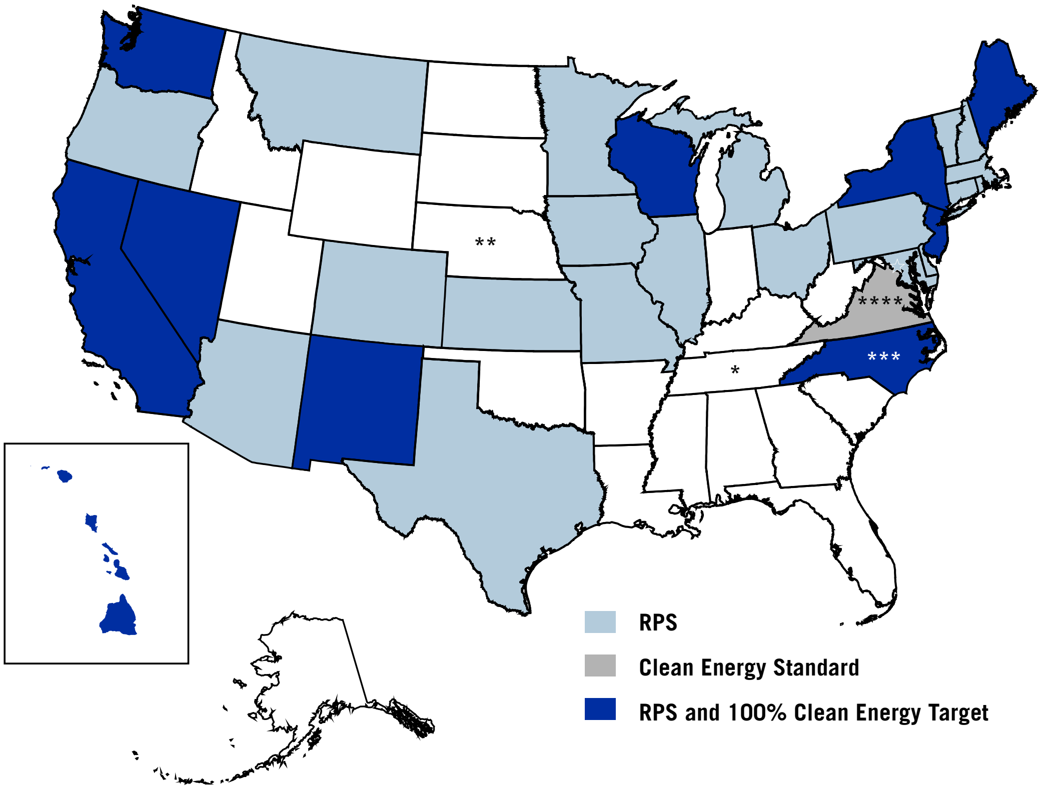
Nuclear power has fueled between 17.8% and 20.6% of total U.S. electric generation since 1988. In 2019, it accounted for 19.7% of the electricity used in the U.S., up less than one percentage point from 2018 and nearly matching the 19.6% annual average for data going back to 2001. High construction costs and lengthy permitting and building processes have made new nuclear plants largely uneconomical. Year-to-year changes in nuclear generation are driven primarily by the duration of downtime at existing plants that result from refueling, maintenance and uprates.

Since 1977, the Nuclear Regulatory Commission (NRC) has uprated 164 units, totaling 7, 921 MW of capacity, representing the equivalent of approximately seven new reactors. Almost all U.S. reactors have been uprated; that is, they have received NRC-approved expansions of original capacity. This includes a 2012 approval to add two new units, scheduled for completion in 2021 and 2022, to the two existing pressurized water reactors at Southern Company's Vogtle facility in Georgia, which will augment nameplate capacity by 2,320 MW. These two new nuclear units will be the first nuclear generation built in the U.S. in the last three decades and will also be the first to use the Westinghouse AP1000 advanced pressurized water reactor technology, considered to be the safest, most economical nuclear power plant technology in the world. It allows nuclear cores to be cooled in the absence of operator interventions or mechanical assistance.

In 2020, three plants are expected to have their uprate applications approved, totaling 46.7 MW. The NRC has approved the initial license renewal applications for 93 out of 96 operating reactors it oversees, and only six of these have ceased operation (Fort Calhoun, Kewaunee, Oyster Creek, Pilgrim, Three Mile Island and Vermont Yankee).

Many nuclear plants are now pursuing a second license renewal filing that would extend their operating life another 20 years, to a total of about 80 years. In 2019, the Nuclear Regulatory Commission (NRC) approved an extension for Florida's Turkey Point nuclear plant Units 3 and 4 until 2052 and 2053, respectively. In March 2020, the NRC extended the licenses of Peach Bottom's Atomic Power Station Units 2 and 3 until 2053 and 2054, respectively. Dominion is anticipating the NRC's extension in June 2020 of Dominion's Surry Power Station in Virginia; this would allow operations of Units 1 and 2 to continue to 2052 and 2053, respectively. Dominion is expected to file a second license application in late 2020 for its North Anna Units 1 and 2, while Duke Energy Carolinas is expected to file a second license application in 2021 for its Oconee Units 1,2 and 3. Duke has also announced intentions to file for renewal of its Catawba Nuclear Station Units 1 and 2, and McGuire Nuclear Station Units 1 and 2. Duke Energy Progress announced intentions to extend the life of the Brunswick Steam Electric Plant Units 1 and 2, Shearon Harris Nuclear Power Plant Unit 1, and the H.B. Robinson Steam Electric Plant Unit 2.

Renewable Electricity Portfolio Standards and Clean Energy Standards in the U.S.



AZ: 15% by 2025; 4.5% DG
CA: 50% by 2026, 60% by 2030, 100% by 2045
CO: 30% by 2020 (10% co-ops, munis), 3% DG and 1.5% customer sited. 100% by 2050
CT: 40% by 2030
DC: 100% by 2032, 10% solar by 2041
DE: 25% by 2026, 3.5% PV. Triple credit for PV
HI: 30% by 2020, 70% by 2040, 100% by 2045
IA: 105 MW; 1 GW wind goal by 2010
IL: 25% by 2026; wind 75%, 1.5% PV and 0.25% DG
IN: 10% by 2025 (goal)
KS: 20% by 2020
MA: 35% by 2030 (new resources); 1% each year thereafter
MD: 25% by 2020, 2.5% solar by 2020, 50% by 2030
ME: 8 GW wind goal by 2030, 100% by 2050
MI: 15% by 2021. 3.2 multiplier for solar electric
MN: 26.5% by 2025 (IOUs), 1.5% solar and 0.15% PV DG by 2020.
MO: 15% by 2021, 0.3% solar
MT: 15% by 2015
NC: 12.5% by 2021, 0.2% solar by 2018. (10% by 2018 co-ops, munis)
ND: 10% by 2015 (goal)
NH: 0.3% solar electric by 2014, 25.2% by 2025
NJ: 50% by 2030
NM: 80% by 2040, 100% by 2045 (IOUs)
NV: 50% by 2030, 1.5% solar by 2025. 2.4 multiplier for PV, 100% by 2050
NY: 50% by 2030, 0.58% customer sited by 2015
OH: 12.5% by 2026, 0.5% solar by 2027
OK: 15% by 2015 (goal)
OR: 50% by 2040 (5-10% - smaller utilities). 20 MW PV by 2025. Double credit for PV
PA: 18% by 2021, 0.5% PV by 2021
RI: 38.5% by end 2035
SC: 2% by 2021. 0.25 % DG by 2021 (goal).
SD: 10% by 2015 (goal)
TX: 5,880 MW by 2015, 500 MW non-wind goal, double credit for non wind
UT: 20% by 2025, 2.4 multiplier for solar electric (goal)
VA: 100% by 2045 for Dominion Energy Inc, and by 2050 for APCO)
VT: 55% in 2017, 75% 2032
WA: 15% by 2020, double credit for DG, 2 MW DG
WI: 10% by 2015

Updated March 2020.

Abbreviations: EE - Energy Efficiency; RE - Renewable Energy.

Notes: An RPS requires a percent of an electric provider's energy sales (MWh) or installed capacity (MW) to come from renewable resources. Most specify sales (MWh). Map percents are final years' targets. * TVA's goal is not state policy; it calls for 60% clean energy by 2030. ** Nebraska's two largest public power districts have renewable goals. *** Plan introduced by Gov. Cooper (D), requires approval from General Assembly. **** Renewable & carbon free - 14% by 2021, 100% by 2045 for Dominion Energy Inc., Virginia Electric and Power Co.; and 6% by 2021, and 100% by 2050 for American Electric Power Co. Inc. subsidiary Appalachian Power Co., and any retail provider in these territory.

Source: Database of State Incentives for Renewables and Efficiency, http://www.dsireusa.org.

Renewables

Renewable capacity growth continued to break records in 2019. Collectively, renewables (including hydro) accounted for a record-high 17.5%, or 720,435 million MWh, of total U.S. electric generation in 2019, nearly 70% more than in 2010 when renewables generated 427,367 million MWh. Non-hydro renewables also reached a record-high 10.9% of total generation in 2019, up one percentage point from 2018. Solar generation continued to grow at a faster rate than wind, but its growth rate slowed to 13% year-to-year in 2019 from a record-high 138% in 2012. Solar's share of total nationwide output remains small, at just under 2%, yet it accounted for 16% of total non-hydro renewable generation in 2019, the same level as in 2018.

Wind generation remained the leading renewable generation source, at 67% of 2019's total non-hydro renewable generation. Total MWh supplied by wind rose 10% relative to 2018. The total electricity generated from wind turbines overtook the total generated by hydro for the first time in 2019. Wind supplied 300,071,000 MWh, or 7.3% of the nation's total generation in 2019, versus hydroelectric's 273,707,000, or 6.7% share. Biomass and geothermal's contribution to nationwide electric generation remained stable in 2019, powering 1.8% of U.S. electric load.

Driven by the increase in renewable capacity, coal retirements and seasonal factors, monthly electric generation from renewables exceeded coal generation by 3% in April 2019, with renewables providing 23% of total electric generation for the month.

Oil

Oil supplied only 0.45% of U.S. electric output in 2019, down from 0.6% in 2018 as a result of retirements of oil-fueled electricity generation. Located away from U.S. railroad infrastructure, Hawaii and Alaska (the country's two non-contiguous states) account for more than 60% of the nation's oil-fueled generation. Hawaii, which accounts for about half of all oil used for power generation, plans to produce 100% of its electricity from renewable sources by 2045 and is actively retiring oil generation. Florida and New England also have oil-fueled capacity; this is mostly in the form of dual-fuel power plants built years ago to hedge the region's lack of natural gas infrastructure.

Industry Financial Performance

Income Statement

- Energy Operating Revenue grew just 0.1% versus last year. Nationwide electricity demand fell 1.7% due to cooler summer weather and the impact of trade tariffs on industrial load, which declined almost 5%. The average retail price of electricity nationwide rose less than 1%, according to EIA data.
- Energy Operating Expenses fell 6.7% as Electric Generation and Gas Costs declined. The average cost of natural gas was almost 20% lower for the year and coal costs were marginally lower too. Because reduced hydro generation offset growing solar and wind, the share of total generation from zero-fuel-cost power rose only half a percentage point, resulting in little impact on the industry-wide generation cost decline in 2019.
- The industry's attention to cost controls and productivity from smart-grid investments held Operations and Maintenance (O&M) expense inflation to just 1.0%.
- Depreciation & Amortization (D&A) expenses rose 6.3%, reflecting the industry's ongoing investments in new clean generation and grid modernization.
- Operating Income rose 8.3%, largely a result of lower electrical generation costs and the industry's overall cost management efforts.
- Interest Expense climbed 8.2% due to the increased short and long-term debt required to finance the industry's investment programs.
- Pre-tax Net Income increased 24.5% and Net Income rose 17.4%, yet much of these gains came from declines in Non-Recurring Expenses resulting from company-specific actions, rather than broad business fundamentals impacting the industry as a whole.
- The industry's aggregate declared Common Dividends rose 8.6% versus 2018; these offer a welcome source of income for savings-oriented investors given the meager bond yields throughout the year.

Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

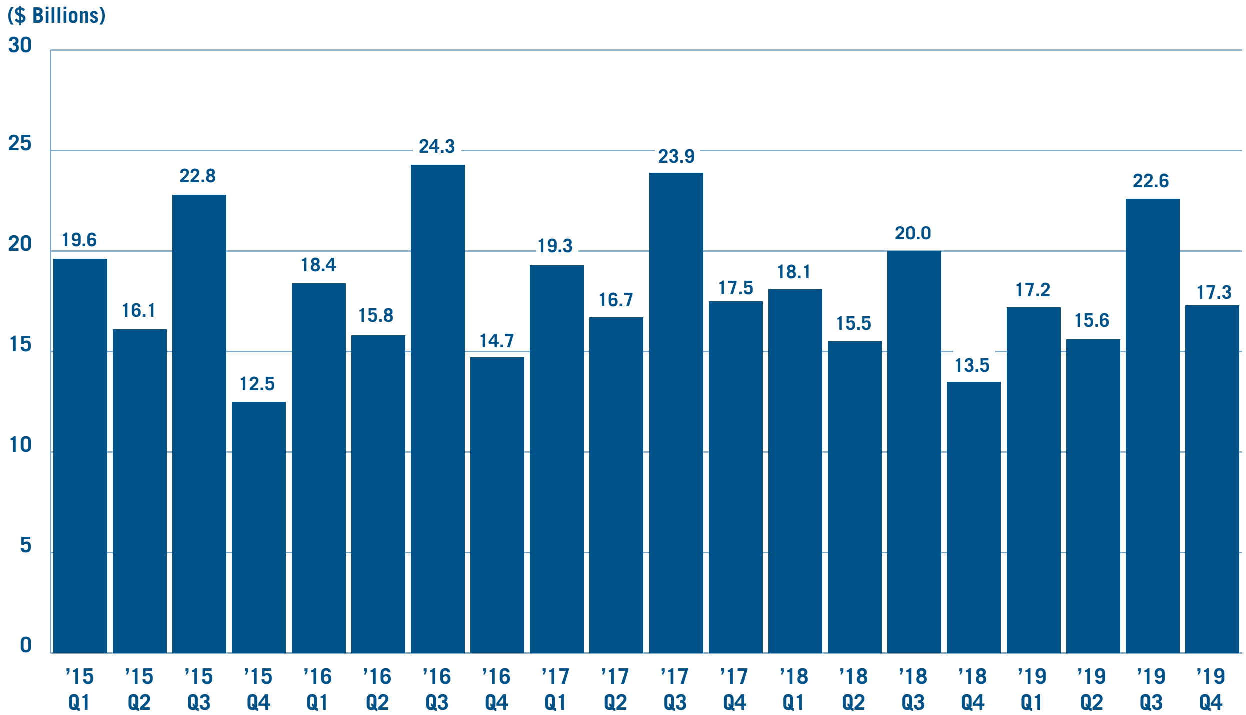
($ Millions)	12 Months Ended 12/31/2019	12/31/2018r	% Change
Energy Operating Revenues	$364,895	$364,383	0.1%
Energy Operating Expenses			
Total Electrical Generation Cost	89,452	96,195	(7.0%)
Gas Cost	18,758	19,761	(5.1%)
Total Energy Operating Expenses	**108,210**	**115,956**	**(6.7%)**
Revenues less energy operating expenses	**256,685**	**248,426**	**3.3%**
Other Operating Expenses			
Operations & Maintenance	93,921	92,948	1.0%
Depreciation & Amortization	53,468	50,278	6.3%
Taxes (not income) - Total	20,086	19,381	3.6%
Other Operating Expenses	16,525	18,731	(11.8%)
Total Operating Expenses	**292,210**	**297,295**	**(1.7%)**
Operating Income	**72,685**	**67,088**	**8.3%**
Other Recurring Revenue			
Partnership Income	1,781	1,949	(8.7%)
Allowance for Equity Funds Used for Construction	1,797	1,900	(5.4%)
Other Revenue	5,166	3,222	60.3%
Total Other Recurring Revenue	**8,744**	**7,072**	**23.6%**
Non-Recurring Revenue			
Gain on Sale of Assets	2,899	5,272	(45.0%)
Other Non-Recurring Revenue	117	131	(10.4%)
Total Non-Recurring Revenue	**3,016**	**5,403**	**(44.2%)**
Interest Expense	26,962	24,918	8.2%
Other Expenses	159	859	(81.5%)
Asset Writedowns	3,517	4,121	(14.6%)
Other Non-Recurring Expenses	14,174	17,841	(20.6%)
Total Non-Recurring Expenses	17,691	21,962	(19.4%)
Net Income Before Taxes	**39,633**	**31,824**	**24.5%**
Provision for Taxes	2,848	738	285.8%
Dividends on Preferred Stock of Subsidiary	-	-	NM
Other Minority Interest Expense	-	-	NM
Minority Interest Expense	-	-	NM
Trust Preferred Security Payments	-	-	NM
Other After-tax Items	-	-	NM
Total Minority Interest and Other After-tax Items	-	-	NM
Net Income Before Extraordinary Items	**36,786**	**31,086**	**18.3%**
Discontinued Operations	424	602	(29.6%)
Change in Accounting Principles	-	-	NM
Early Retirement of Debt	-	-	NM
Other Extraordinary Items	-	-	NM
Total Extraordinary Items	424	602	(29.6%)
Net Income	**37,209**	**31,688**	**17.4%**
Preferred Dividends Declared	359	542	(33.7%)
Other Preferred Dividends after Net Income	2	2	0.0%
Other Changes to Net Income	(1)	(2)	(39.0%)
Net Income Attributable to Noncontrolling Interests	60	(300)	NA
Net Income Available to Common	**36,786**	**31,442**	**17.0%**
Common Dividends	**27,938**	**25,726**	**8.6%**

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Net Operating Income

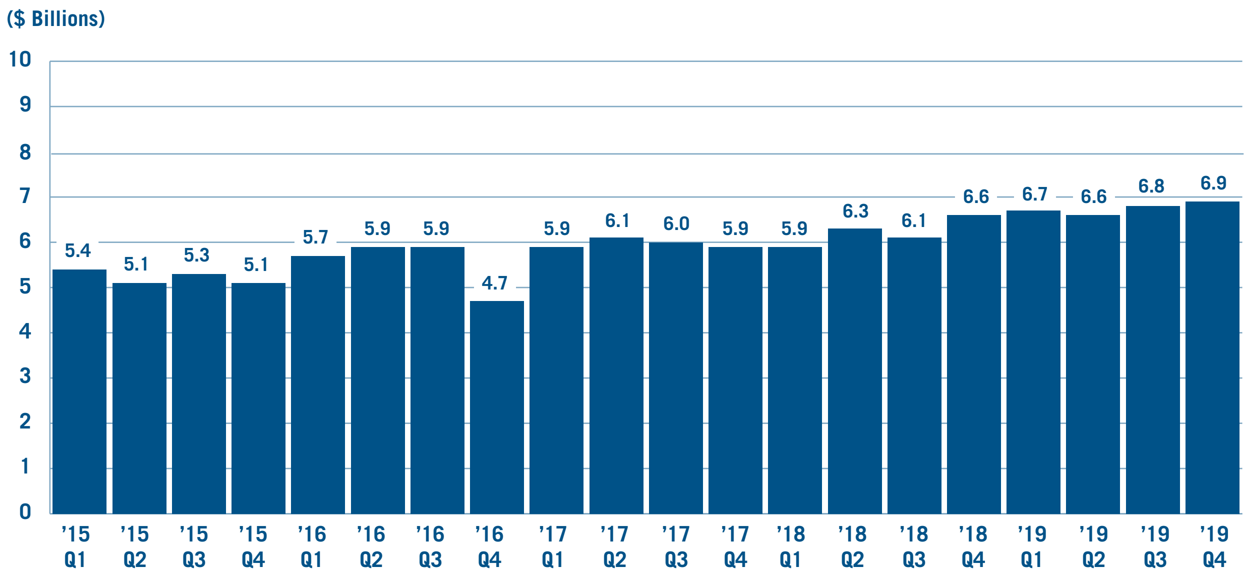
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Individual Non-Recurring and Extraordinary Items 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018r	2019
Net Gain (Loss) on Sale of Assets	3,410	891	311	414	996	789	767	1,012	5,272	2,899
Other Non-Recurring Revenue	2,065	946	264	78	296	(4)	888	493	131	117
Total Non-Recurring Revenue	**5,475**	**1,837**	**576**	**492**	**1,292**	**785**	**1,655**	**1,505**	**5,403**	**3,016**
Asset Writedowns	(8,805)	(2,743)	(5,646)	(4,276)	(8,762)	(5,189)	(17,487)	(4,166)	(4,121)	(3,517)
Other Non-Recurring Charges	(545)	(851)	(3,136)	(3,510)	(2,675)	(1,764)	(3,109)	(5,630)	(17,841)	(14,174)
Total Non-Recurring Charges	**(9,350)**	**(3,594)**	**(8,783)**	**(7,786)**	**(11,437)**	**(6,953)**	**(20,596)**	**(9,796)**	**(21,962)**	**(17,691)**
Discontinued Operations	(476)	(1,011)	(4,317)	(88)	295	(1,148)	(732)	(1,554)	602	424
Change in Accounting Principles	–	–	–	–	–	–	–	–	–	–
Early Retirement of Debt	–	–	–	–	–	–	–	–	–	–
Other Extraordinary Items	10	960	–	–	–	–	–	–	–	–
Total Extraordinary Items	**(466)**	**(51)**	**(4,317)**	**(88)**	**295**	**(1,148)**	**(732)**	**(1,554)**	**602**	**424**
Total Non-Recurring and Extraordinary Items	**(4,341)**	**(1,808)**	**(12,524)**	**(7,381)**	**(9,850)**	**(7,316)**	**(19,674)**	**(9,844)**	**(15,957)**	**(14,251)**

r = revised Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Top Net Non-Recurring and Extraordinary Gains (Losses) 2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

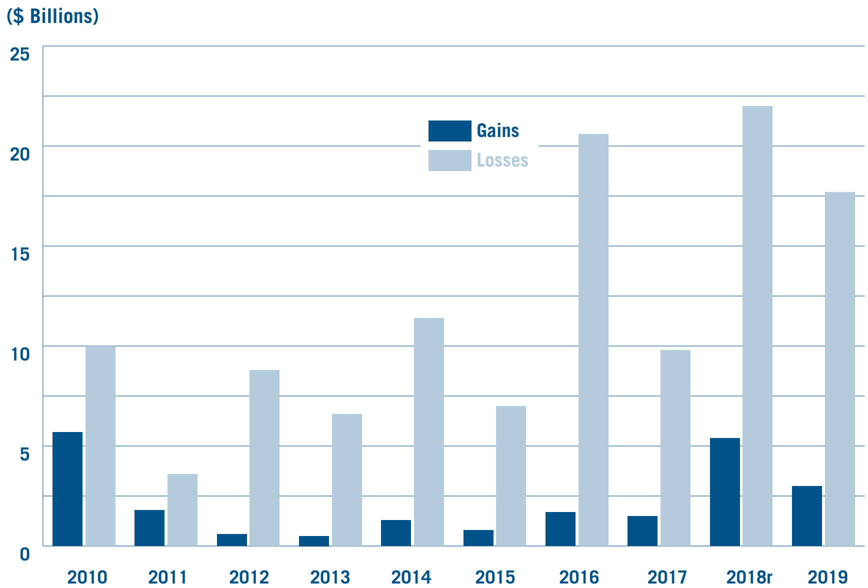
($ Millions)

Company	Gains	Losses	Net Total
PG&E Corp	–	11,781	11,781
Dominion Energy	162	2,870	2,708
Southern Company	2,569	192	2,377
Edison International	–	591	591
NiSource	–	415	415
Public Service Enterprise Group	(402)	–	402
NextEra Energy	461	103	358
Entergy	–	290	290
Berkshire Hathaway Energy	–	288	288
Eversource Energy	0	240	239

Source: S&P Global Market Intelligence and EEI Finance Department.

Aggregate Non-Recurring and Extraordinary Items 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



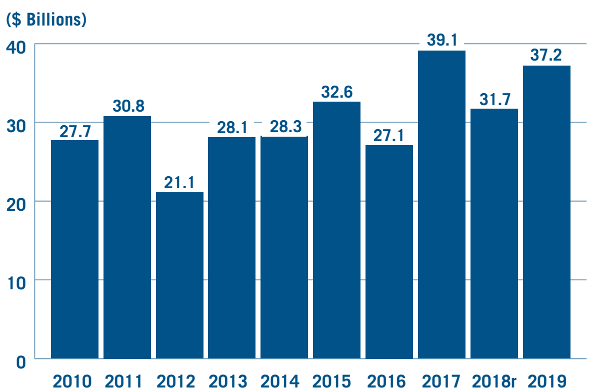
	2010	2011	2012	2013	2014	2015	2016	2017	2018r	2019	Total
Gains	5.7	1.8	0.6	0.5	1.3	0.8	1.7	1.5	5.4	3.0	22.2
Losses	10.0	3.6	8.8	6.6	11.4	7.0	20.6	9.8	22.0	17.7	117.5
Total	**(4.3)**	**(1.8)**	**(8.2)**	**(6.2)**	**(10.1)**	**(6.2)**	**(18.9)**	**(8.3)**	**(16.6)**	**(14.7)**	**(95.2)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

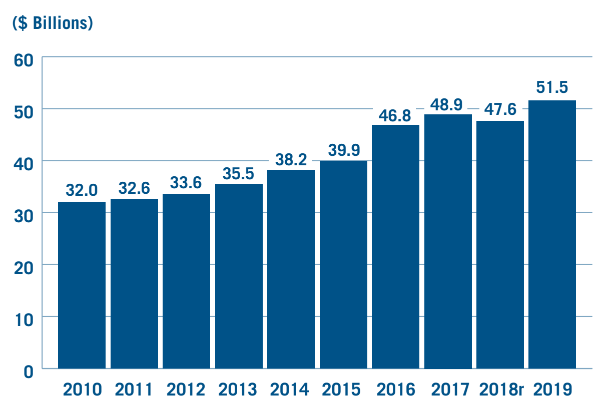


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Net Income Before Non-Recurring and Extraordinary Items 2010-2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

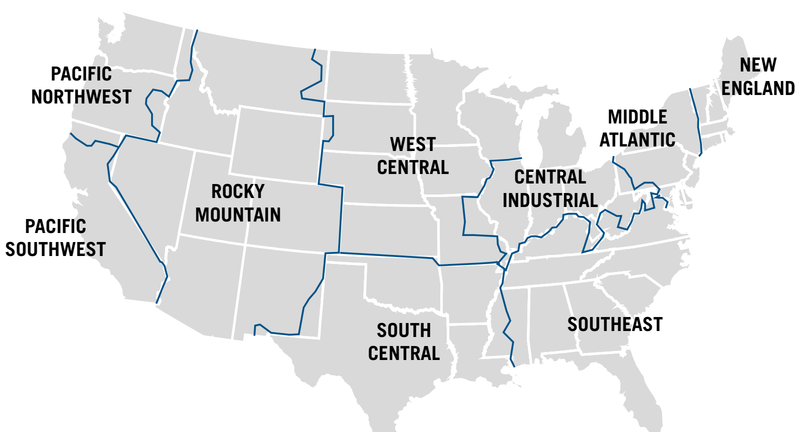
U.S. Electric Output (GWh)
Periods Ending December 31

Region	2019	2018	% Change
New England	117,133	122,211	(4.2%)
Mid-Atlantic	428,514	440,401	(2.7%)
Central Industrial	660,478	684,580	(3.5%)
West Central	329,870	337,891	(2.4%)
Southeast	1,027,445	1,051,898	(2.3%)
South Central	769,886	762,943	0.9%
Rocky Mountain	283,888	281,198	1.0%
Pacific Northwest	157,502	155,948	1.0%
Pacific Southwest	268,153	276,654	(3.1%)
Total United States	**4,042,869**	**4,113,724**	**(1.7%)**

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Analytics.

EEI U.S. Electric Output – Regions



Source: EEI Business Analytics.

U.S. Weather
January – December 2019

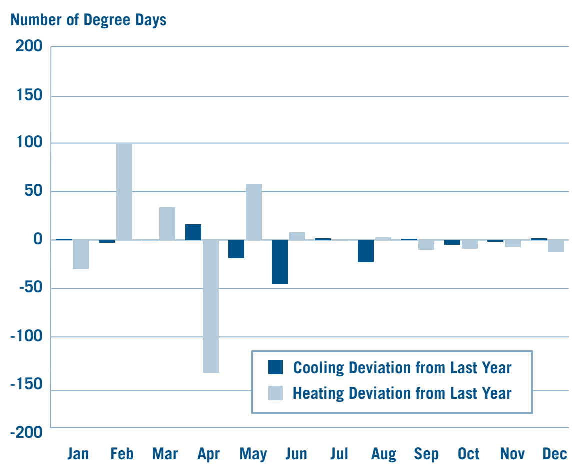
	Total	Dev from Norm	% Change	Dev from Last Year	% Change
Cooling Degree Days					
New England	562	145	35%	(178)	(24%)
Mid-Atlantic	827	171	26%	(164)	(17%)
East North Central	839	131	19%	(174)	(17%)
West North Central	1,006	78	8%	(175)	(15%)
South Atlantic	2,505	541	28%	61	2%
East South Central	1,945	397	26%	(24)	(1%)
West South Central	2,836	387	16%	75	3%
Mountain	1,371	128	10%	(87)	(6%)
Pacific	792	88	13%	(101)	(11%)
United States	**1,463**	**247**	**20%**	**(75)**	**(5%)**
Heating Degree Days					
New England	6,491	(120)	(2%)	101	2%
Mid-Atlantic	5,598	(313)	(5%)	(96)	(2%)
East North Central	6,332	(165)	(3%)	11	0%
West North Central	6,977	227	3%	68	1%
South Atlantic	2,433	(420)	(15%)	(236)	(9%)
East South Central	3,145	(459)	(13%)	(287)	(8%)
West South Central	2,177	(110)	(5%)	(95)	(4%)
Mountain	5,083	(126)	(2%)	303	6%
Pacific	3,175	(53)	(2%)	321	11%
United States	**4,327**	**(197)**	**(4%)**	**(4)**	**(0%)**

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

2019 Weather Compared to 2018

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS



Source: National Oceanic and Atmospheric Administration and National Weather Service.

	Cooling Deviation From Last Year	Heating Deviation From Last Year
Jan	1	(30)
Feb	(3)	99
Mar	0	34
Apr	16	(137)
May	(19)	58
Jun	(45)	8
Jul	2	(1)
Aug	(23)	3
Sep	1	(10)
Oct	(5)	(9)
Nov	(2)	(7)
Dec	2	(12)
Total	**(75)**	**(4)**

Heating and Cooling Degree Days and Percent Changes

January—December 2019

	COOLING DEGREE DAYS			HEATING DEGREE DAYS			PERCENTAGE CHANGE			
	Total	Deviation From Norm	Deviation From Last Yr	Total	Deviation From Norm	Deviation From Last Yr	Cooling Degree Change From Norm	Cooling Degree Change From Last Yr	Heating Degree Change From Norm	Heating Degree Change From Last Yr
Jan	5	(4)	1	867	(50)	(30)	(44.4%)	25.0%	(5.5%)	(3.3%)
Feb	14	6	(3)	726	(6)	99	75.0%	(17.6%)	(0.8%)	15.8%
Mar	15	(3)	0	642	49	34	(16.7%)	0.0%	8.3%	5.6%
First Quarter	**34**	**(1)**	**(2)**	**2,235**	**(7)**	**103**	**(2.9%)**	**(5.6%)**	**(0.3%)**	**4.8%**
Apr	38	8	16	293	(52)	(137)	26.7%	72.7%	(15.1%)	(31.9%)
May	122	25	(19)	153	(6)	58	25.8%	(13.5%)	(3.8%)	61.1%
Jun	220	7	(45)	30	(9)	8	3.3%	(17.0%)	(23.1%)	36.4%
Second Quarter	**380**	**40**	**(48)**	**476**	**(67)**	**(71)**	**11.8%**	**(11.2%)**	**(12.3%)**	**(13.0%)**
Jul	378	57	2	3	(6)	(1)	17.8%	0.5%	(66.7%)	(25.0%)
Aug	331	41	(23)	8	(7)	3	14.1%	(6.5%)	(46.7%)	60.0%
Sep	237	82	1	36	(41)	(10)	52.9%	0.4%	(53.2%)	(21.7%)
Third Quarter	**946**	**180**	**(20)**	**47**	**(54)**	**(8)**	**23.5%**	**(2.1%)**	**(53.5%)**	**(14.5%)**
Oct	79	26	(5)	262	(20)	(9)	49.1%	(6.0%)	(7.1%)	(3.3%)
Nov	14	(1)	(2)	591	52	(7)	(6.7%)	(12.5%)	9.6%	(1.2%)
Dec	10	3	2	716	(101)	(12)	42.9%	25.0%	(12.4%)	(1.6%)
Fourth Quarter	**103**	**28**	**(5)**	**1,569**	**(69)**	**(28)**	**37.3%**	**(4.6%)**	**(4.2%)**	**(1.8%)**
Full Year	**1,463**	**247**	**(75)**	**4,327**	**(197)**	**(4)**	**20.3%**	**(4.9%)**	**(4.4%)**	**(0.1%)**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Heating Degree Days Percentage Change from Historical Norm	(1.7)	(4.5)	(16.6)	(0.6)	1.1	(9.1)	(14.8)	(14.2)	(4.2)	(4.4%)
Cooling Degree Days Percentage Change from Historical Norm	19.9	21.5	22.4	10.9	5.8	19.2	29.4	16.0	26.4	20.3%

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

Balance Sheet

- The industry's financial condition remained strong in 2019. Aggregate balance sheet leverage increased slightly as the industry extended its multi-year trend toward a regulated focus with leverage appropriate for a lower risk profile. However, balance sheet structures show wide differentiation across the industry; aggregate figures are only suggestive of broad trends.

- Total debt rose as utilities took advantage of low interest rates and strong demand from investors to fund regulated investment programs, while managing balance sheet ratios and cash flows to maintain investment-grade credit ratings.

- Common Equity issuance was strong for a second straight year. Last year's issuance addressed the impact of tax reform. In 2019, utilities took advantage of high price-earnings ratios and welcoming capital markets to fund capex, offset debt issuance and strengthen balance sheets.

- U.S. economic growth slowed in 2019 with quarterly real GDP gains at just 2.0% from Q2 through Q4 after rising 3.1% in Q1. Inflation pressures remained muted and interest rates declined from already low levels. The 10-year U.S. Treasury yield ended the year under 2.0% from a high near 2.8% in January. Global growth also stalled and widespread negative interest rates persisted in Europe and Japan. As a result, utility debt and equity remained attractive for investors' searching for yield with relatively low business risk exposure.

- Property, Plant and Equipment in service (PPE in Service) rose 7.3% from year-end 2018 and 26.4% over the level at year-end 2015. This strong growth indicates the magnitude of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure and other capital projects.

- Debt-to-cap ratios by category show the dominance of regulated operations in the industry and a tendency, at the aggregate industry level, toward slightly higher leverage versus 2018. The dispersion of moves across individual companies, with some companies showing higher, some lower and others no change in leverage, indicates why individual company strategies are as meaningful as aggregate totals when assessing industry trends.

- Regulated companies as a group continued to report higher balance sheet leverage then their Mostly Regulated peers. This is to be expected given their lower business risk profile.

Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	12/31/2019	12/31/2018r	% Change	$ Change
PP&E in service, gross	1,591,259	1,490,766	6.7%	100,493
Accumulated depreciation	455,800	432,602	5.4%	23,198
PP&E in service, net	1,135,459	1,058,164	7.3%	77,295
Construction work in progress	76,266	72,540	5.1%	3,727
Net nuclear fuel	15,573	15,534	0.3%	40
Other property	17,144	1,732	890.0%	15,412
PP&E, net	1,244,443	1,147,970	8.4%	96,473
Cash & cash equivalents	11,741	16,139	(27.3%)	(4,398)
Accounts receivable	41,832	43,038	(2.8%)	(1,206)
Inventories	23,299	22,210	4.9%	1,089
Other current assets	45,082	43,922	2.6%	1,160
Total current assets	121,955	125,309	(2.7%)	(3,354)
Total investments	120,548	106,116	13.6%	14,431
Other assets	269,991	245,542	10.0%	24,449
Total Assets	**1,756,936**	**1,624,937**	**8.1%**	**131,999**
Common equity	464,217	437,843	6.0%	26,374
Preferred equity	9,262	4,949	87.1%	4,313
Noncontrolling interests	20,512	18,214	12.6%	2,297
Total equity	493,990	461,006	7.2%	32,984
Short-term debt	36,275	44,674	(18.8%)	(8,400)
Current portion of long-term debt	41,788	50,605	(17.4%)	(8,816)
Short-term and current long-term debt	78,063	95,279	(18.1%)	(17,216)
Accounts payable	70,441	68,870	2.3%	1,571
Other current liabilities	42,929	54,148	(20.7%)	(11,220)
Current liabilities	191,433	218,297	(12.3%)	(26,864)
Deferred taxes	106,533	98,919	7.7%	7,614
Non-current portion of long-term debt	592,712	510,805	16.0%	81,907
Other liabilities	370,961	334,622	10.9%	36,339
Total liabilities	1,261,639	1,162,643	8.5%	98,996
Subsidiary preferred	712	712	0.0%	0
Other mezzanine	596	577	3.3%	19
Total mezzanine level	1,307	1,289	1.5%	19
Total Liabilities and Owner's Equity	**1,756,936**	**1,624,937**	**8.1%**	**131,999**

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure

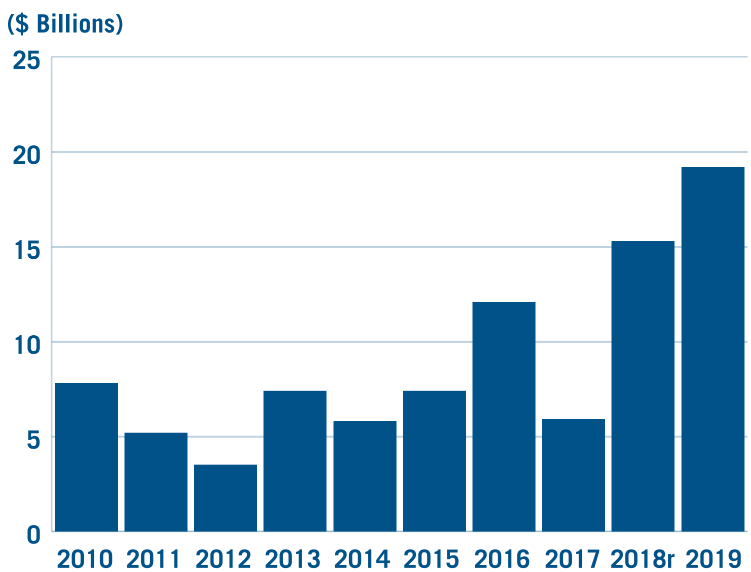
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

Capitalization Structure	12/31/2019	12/31/2018r	12/31/2017r
Common Equity	464,217	437,843	424,276
Preferred Equity & Noncontrolling Interests	29,774	23,163	13,486
Long-term Debt (current & non-current)*	634,500	561,409	548,813
Total	**1,128,491**	**1,022,415**	**986,574**
Common Equity %	41.1%	42.8%	43.0%
Preferred Equity %	2.6%	2.3%	1.4%
Long-term Debt %	56.2%	54.9%	55.6%
Total	**100.0%**	**100.0%**	**100.0%**

* Long-term debt not adjusted for (i.e., includes) securitization bonds.
r = revised
Source: S&P Global Market Intelligence and EEI Finance Department.

Proceeds from Issuance of Common Equity 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

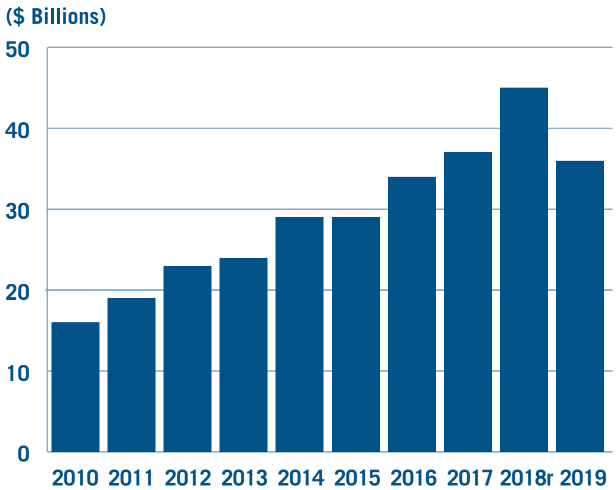


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Short-term Debt 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

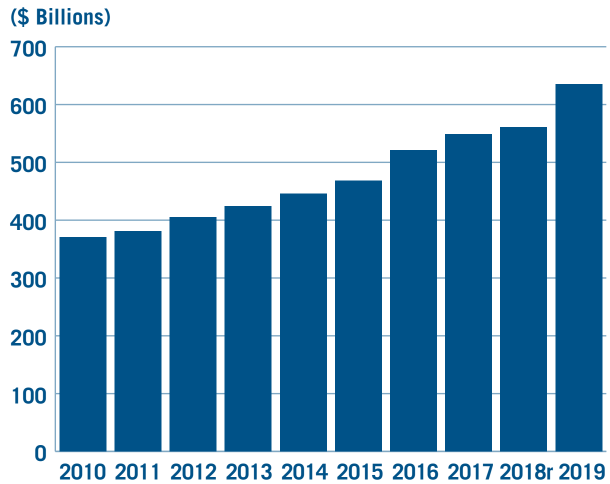


r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Long-term Debt 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

Debt-to-Cap Ratio by Category 2019 vs. 2018r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated		Mostly Regulated		Total Industry	
	Number	%	Number	%	Number	%
Lower	4	11.4%	0	0.0%	4	8.9%
No Change*	13	37.1%	5	50.0%	18	40.0%
Higher	18	51.4%	5	50.0%	23	51.1%
Total	**35**	**100.0%**	**10**	**100.0%**	**45**	**100.0%**

*No change defined as less than 1.0%

Note: December 31, 2019 vs. December 31, 2018. Refer to page v for category descriptions.

Source: S&P Global Market Intelligence and EEI Finance Department.

Capitalization Structure by Category 2019 vs. 2018r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	Regulated			Mostly Regulated		
	2019	2018r	Change	2019	2018r	Change
Common Equity	306,562	290,444	16,118	157,654	147,399	10,256
Total Preferred Equity	20,584	14,939	5,645	9,190	8,224	966
Long-term Debt (current & non-current)*	454,743	411,103	43,641	179,757	150,306	29,451
Total Capitalization	781,890	716,486	65,404	346,601	305,929	40,672
Common Equity %	39.2%	40.5%	-1.3%	45.5%	48.2%	-2.7%
Preferred Equity %	2.6%	2.1%	0.5%	2.7%	2.7%	0.0%
Long-term Debt %	58.2%	57.4%	0.8%	51.9%	49.1%	2.7%
Total	**100.0%**	**100.0%**	—	**100.0%**	**100.0%**	—

r = revised

Note: Long-term debt not adjusted for (i.e., includes) securitization bonds.

Source: S&P Global Market Intelligence and EEI Finance Department.

Date	PP&E in Service, Net ($Mil)	% Change from 12/31/2015
12/31/2019	$1,135,459	26.4%
12/31/2018r	$1,058,164	17.8%
12/31/2017r	$1,015,100	13.0%
12/31/2016	$969,838	8.0%
12/31/2015	$898,152	

Source: S&P Global Market Intelligence and EEI Finance Department.

Cash Flow Statement

- Net Cash Provided by Operating Activities decreased by $4.6 billion or 4.6%. An increase in cash supplied by net income, depreciation and amortization was offset by a reduction in cash sourced to changes in working capital.
- Cash provided by Deferred Taxes & Investment Credits has leveled off over the last two years, at about $3.0 billion per year, compared to much higher amounts previously. Deferred taxes had been at historically high levels due to elevated capex and use of bonus depreciation. The Tax Cuts & Jobs Act (TCJA), passed in late 2017, significantly reduced deferred taxes due to the reduction in the corporate income tax rate from 35% to 21% and the elimination of bonus depreciation.
- Net Cash Used in Investing Activities increased by $13.7 billion or 11.0%. The industry's capital spending — by far the largest component of this metric — totaled $124.1 billion in 2019, up $4.9 billion, or 4.1% from 2018. Industry capex has reached a new record high in each of the past eight years.
- Infrastructure investment in the form of Asset Purchases also increased, rising 12.0% to $25.5 billion. Activity was concentrated in a few large utilities. CenterPoint and NextEra each spent more than $5 billion, accounting for nearly half the industry total. AEP, Dominion, and Sempra were other primary contributors.
- Cash provided by Asset Sales decreased 21.1%, to $16.7 billion. Again, activity was driven by a few utilities. Southern Company's sale of Gulf Power to NextEra (recognized by NextEra as a purchase) accounted for nearly one-third of the 2019 total. Dominion, AEP and NextEra were other primary contributors to the industry total.
- Net Cash Provided by Financing Activities increased by $2.5 billion or 7.8%. Increased issuance of long-term debt and common equity produced 66.9% and 25.1% respective gains, versus 2018, in the cash provided by these capital sources. Issuance of short-term debt declined as long-term debt issuance was strong.
- Dividends Paid to Common Shareholders rose 9.1%, to $27.9 billion.

Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

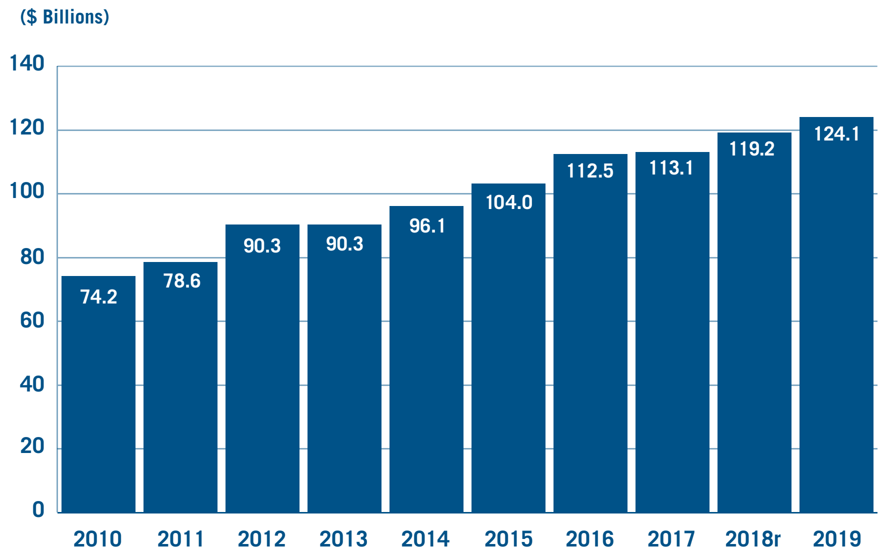
$ Millions	12 Months Ended 12/31/2019	12/31/2018r	% Change
Net Income	$37,209	$31,688	17.4%
Depreciation and Amortization	56,437	53,123	6.2%
Deferred Taxes and Investment Credits	3,004	2,986	0.6%
Operating Changes in AFUDC	(1,281)	(1,440)	(11.1%)
Change in Working Capital	(2,601)	12,363	NM
Other Operating Changes in Cash	2,777	1,403	97.9%
Net Cash Provided by Operating Activities	**95,545**	**100,123**	**(4.6%)**
Capital Expenditures	(124,140)	(119,248)	4.1%
Asset Sales	16,710	21,186	(21.1%)
Asset Purchases	(25,533)	(22,800)	12.0%
Net Non-Operating Asset Sales and Purchases	(8,823)	(1,614)	446.7%
Change in Nuclear Decommissioning Trust	(371)	(620)	(40.1%)
Investing Changes in AFUDC	144	123	17.7%
Other Investing Changes in Cash	(5,560)	(3,688)	50.8%
Net Cash Used in Investing Activities	**(138,750)**	**(125,047)**	**11.0%**
Net Change in Short-term Debt	(4,815)	7,861	NM
Net Change in Long-term Debt	45,822	27,453	66.9%
Proceeds from Issuance of Preferred Equity	2,786	6,567	(57.6%)
Preferred Share Repurchases	(50)	(87)	(42.4%)
Net Change in Prefered Issues	2,736	6,480	(57.8%)
Proceeds from Issuance of Common Equity	19,171	15,319	25.1%
Common Share Repurchases	(2,137)	(1,297)	64.7%
Net Change in Common Issues	17,035	14,022	21.5%
Dividends Paid to Common Shareholders	(27,938)	(25,616)	9.1%
Dividends Paid to Preferred Shareholders	(362)	(210)	72.2%
Other Dividends	–	–	NM
Dividends Paid to Shareholders	(28,300)	(25,827)	9.6%
Other Financing Changes in Cash	2,736	2,684	2.0%
Net Cash (Used in) Provided by Financing Activities	**35,215**	**32,674**	**7.8%**
Other Changes in Cash	33	(45)	NM
Net increase (decrease) in cash and cash equivalents	$(7,957)	$7,706	NM
Cash and cash equivalents at beginning of period	$19,698	$8,433	133.6%
Cash and cash equivalents at end of period	$11,741	$16,139	(27.3%)

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

Capital Expenditures 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

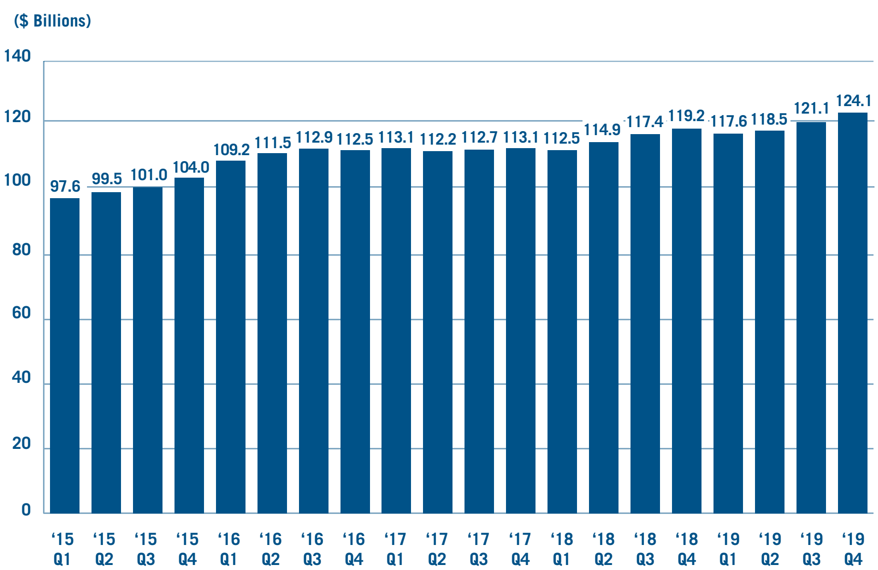


r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

Capital Spending—Trailing 12 Months

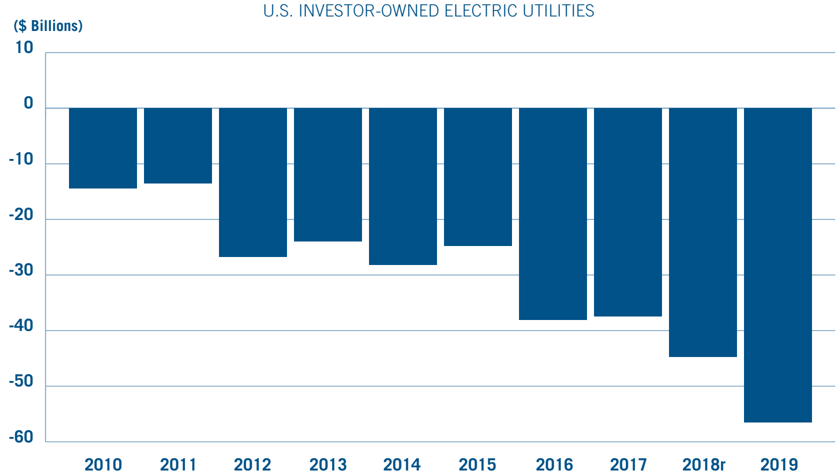
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence and EEI Finance Department.

Free Cash Flow (FCF) 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

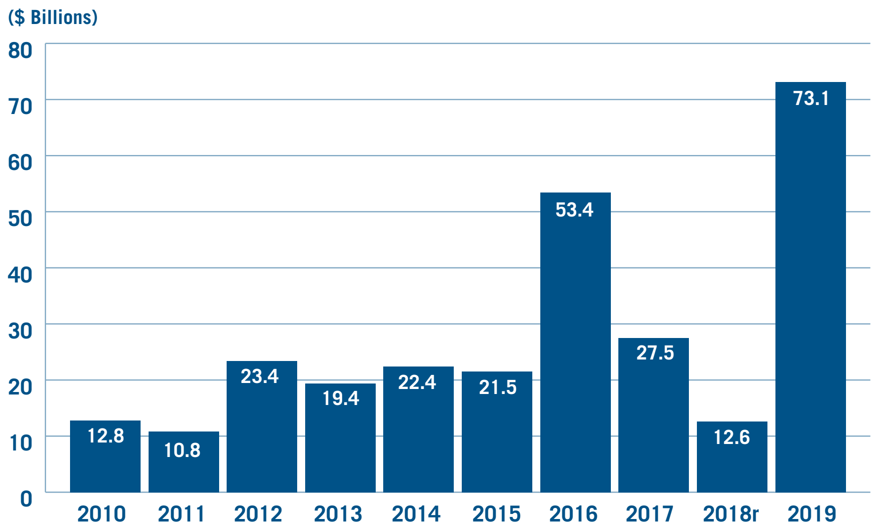


($ Billions)	2010	2011	2012	2013	2014	2015	2016r	2017	2018r	2019
Net Cash Provided by Operating Activities	77.7	84.4	84.0	87.1	89.0	101.6	98.3	101.2	100.1	95.5
Capital Expenditures	(74.2)	(78.6)	(90.3)	(90.3)	(96.1)	(104.0)	(112.5)	(113.1)	(119.2)	(124.1)
Dividends Paid to Common Shareholders	(18.0)	(19.3)	(20.5)	(20.8)	(21.1)	(22.5)	(23.8)	(25.5)	(25.6)	(27.9)
Free Cash Flow	**(14.4)**	**(13.5)**	**(26.8)**	**(24.0)**	**(28.2)**	**(24.8)**	**(38.1)**	**(37.5)**	**(44.7)**	**(56.5)**

r = revised
Note: Totals may not equal sum of components due to rounding.
Source: S&P Global Market Intelligence and EEI Finance Department.

Net Change in Long-term Debt 2010–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



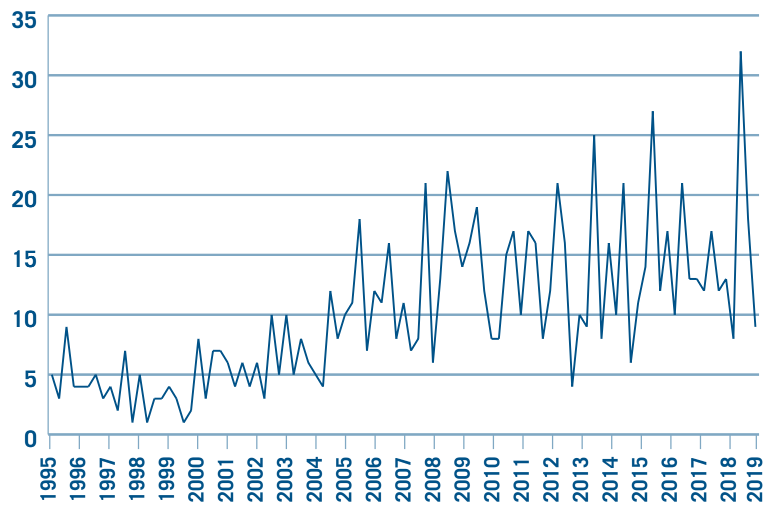
r = revised
Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

Rate Review Summary Charts

Number of Rate Reviews Filed 1995–2019

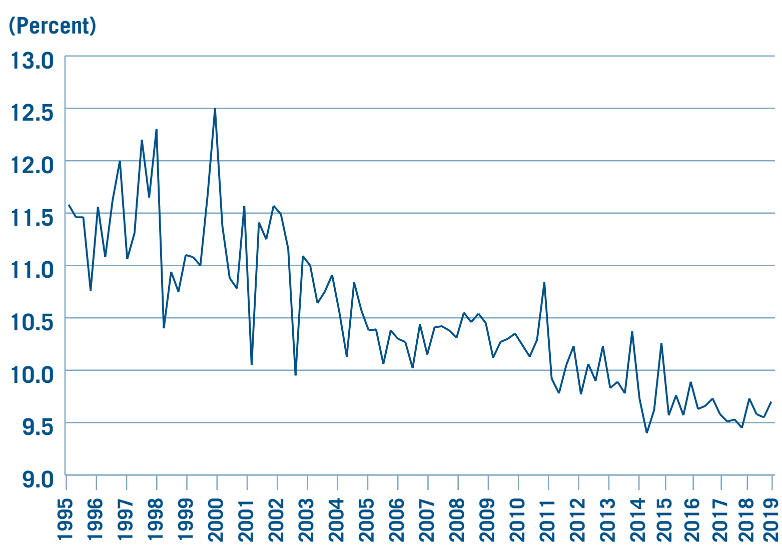
U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

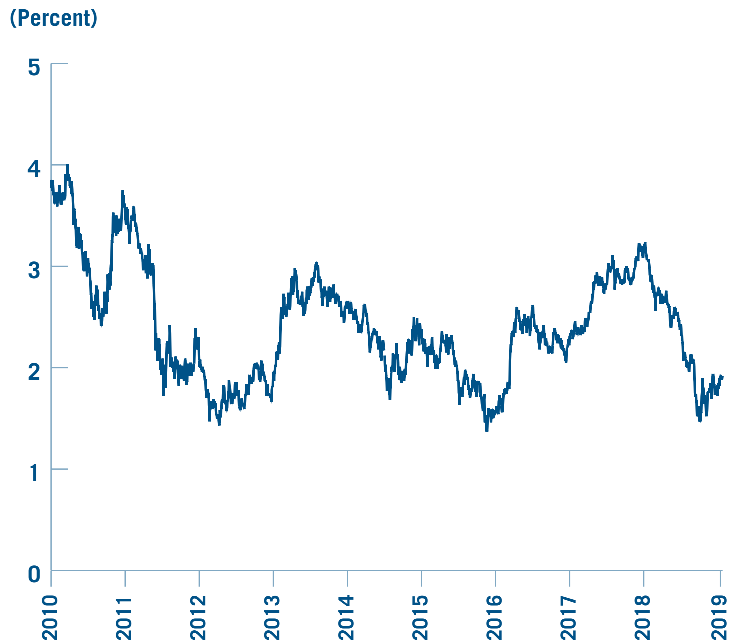
Average Awarded ROE 1995-2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



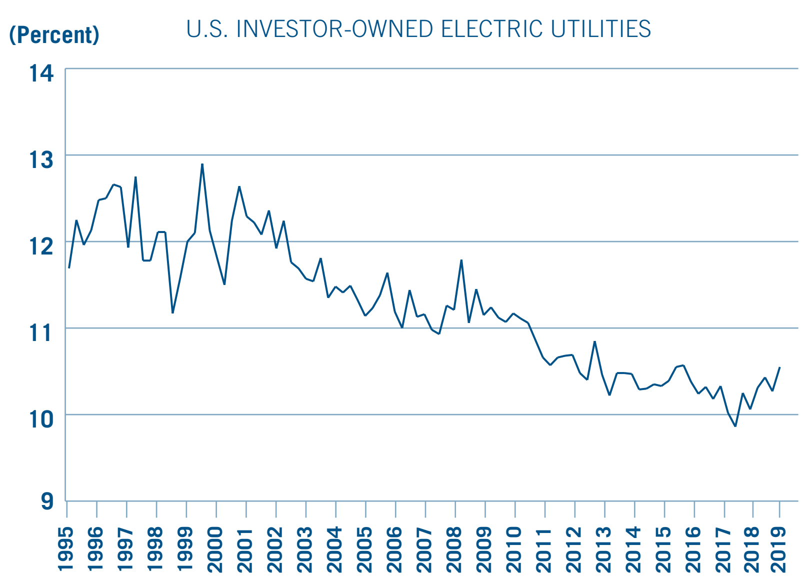
Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

10-Year Treasury Yield
1/1/10 through 12/31/19



Source: U.S. Federal Reserve.

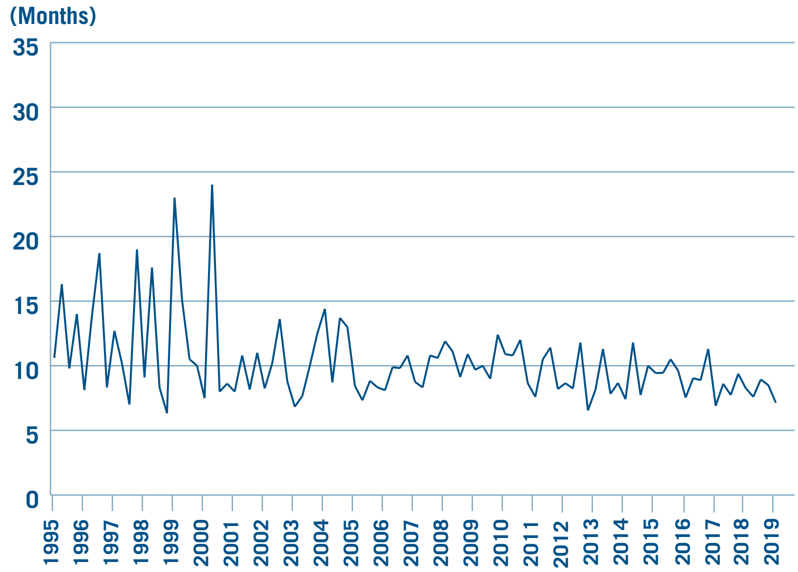
Average Requested ROE 1995–2019



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Average Regulatory Lag 1995–2019

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

Finance, Accounting, and Investor Relations

The Finance, Accounting, and Investor Relations teams are part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, and budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Finance, Accounting, or Investor Relations staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

Publications

Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly Financial Update (QFU) reports include stock performance, dividends, credit ratings, and rate review summary.

Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry including the QFU topics mentioned above as well as the industry's consolidated financial statements. The report also includes an analysis in the areas of business segmentation, mergers & acquisitions, construction and fuel sources at electric utilities.

EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The index, which measures total return and provides company rankings for one- and five-year periods, is widely used in company proxy statements and for overall industry benchmarking.

Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples. The 2013 edition features updated chapters on Tax Depreciation, Accounting for Asset Retirement Obligations (AROs) and includes a new chapter on Depreciation in an IFRS Environment.

Industry directories published by the Business Services and Finance Division:

- Electric Utility Investor Relations Executives Directory
- Accounting and Internal Audit Directory

For more information, please visit the EEI website at: www.eei.org.

Conference Highlights

Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,000 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Devin James or Aaron Cope for more information.

Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is open to member company chief financial officers only. Contact Devin James or Aaron Cope for more information.

Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Devin James or Aaron Cope for more information.

Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Devin James or Aaron Cope for more information.

Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Devin James or Aaron Cope for more information.

Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

EEI Accounting Standards Committee

Provides a forum for technical accounting, accounting research, financial reporting, and other interested member-company accounting leaders and staff, to update their knowledge on emerging accounting standards, implementation issues associated with newly issued standards, and other technical and business issues. This Committee meets in conjunction with the Spring Accounting Conference. Contact Randall Hartman for more information.

Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, the Budgeting & Financial Forecast Committee and the AGA Accounting Services Committee, the conference provides a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The spring meeting is intended for all aforementioned committees, while the fall meeting is designed for the Corporate Accounting Committee and the Property Accounting & Valuation Committee. The meetings are open to members of the Committees and other employees of EEI/ AGA member companies. Contact Dave Dougher for more information.

Tax School

Provides utility tax professionals with a forum to discuss developing tax issues impacting our member companies. This two and half day training is held every other year in the spring and is targeted for intermediate-level personnel. Contact Mark Agnew for more information.

Accounting Courses

Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman or Dave Dougher for more information.

Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect regulated companies in the changing and increasingly competitive environment of the electric and gas utility industries. Contact Randall Hartman or Dave Dougher for more information.

Property Accounting & Depreciation Training Seminar

This is a one and a half day seminar offered jointly with AGA that provides an introduction to property accounting and depreciation in the electric and natural gas utility industries. Contact Dave Dougher for more information.

Utility Internal Auditor's Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA – convenes for two and one-half days. Contact Randall Hartman or Dave Dougher for more information.

Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

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Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest to you. For further details, please contact Devin James at (202) 508-5057, Aaron Cope at (202) 508-5127, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

August 24–27, 2020

Introduction/Advanced Public Utility Accounting and Internal Auditor's Training Courses

Loews Atlanta
Atlanta, Georgia

November 8–10, 2020

EEI Financial Conference

JW Marriott Desert Ridge Resort & Spa
Phoenix, Arizona

November 8, 2020

EEI Treasury Group Meeting

(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge Resort & Spa
Phoenix, Arizona

November 8, 2020

Chief Financial Officers Forum

(Closed meeting, admittance by invitation only)
JW Marriott Desert Ridge Resort & Spa
Phoenix, Arizona

November 15–19, 2020

Fall Accounting Conference and Property Accounting & Depreciation Training

Disney's Grand Floridian
Lake Bueno Vista, Florida

December 3, 2020

Investor Relations Planning Group Meeting

(Closed meeting, admittance by invitation only)
Hyatt Centric Times Square New York
New York, New York

December 4, 2020

Wall Street Advisory Group Meeting

(Closed meeting, admittance by invitation only)
Hyatt Centric Times Square New York
New York, New York

Earnings Twelve Months Ending December 31

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Millions)	2019	2018r
Earnings Excluding Non-Recurring and Extraordinary Items	**51,461**	**47,644**
Non-Recurring Items (pre-tax)		
Gain on Sale of Assets	2,899	5,272
Other Non-Recurring Revenues	117	131
Asset Write-downs	(3,517)	(4,121)
Other Non-Recurring Expenses	(14,174)	(17,841)
Total Non-Recurring Items	**(14,675)**	**(16,559)**
Extraordinary Items (net of taxes)		
Discontinued Operations	424	602
Change in Accounting Principles	—	—
Early Retirement of Debt	—	—
Other Extraordinary Items	—	—
Total Extraordinary Items	**424**	**602**
Net Income	**37,209**	**31,688**
Total Non-Recurring and Extraordinary Items	**(14,251)**	**(15,957)**

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

U.S. Investor-Owned Electric Utilities

(At 12/31/2019)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Berkshire Hathaway Energy *
Black Hills Corporation
CenterPoint Energy, Inc.
Cleco Corporation *
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DPL Inc. *
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
IPALCO Enterprises, Inc. *
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
Puget Energy, Inc. *
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Note: Includes the 40 publicly traded electric utility holding companies plus an additional five electric utilities (shown in italics) that are not listed on U.S. stock exchanges for one of the following reasons—they are subsidiaries of an independent power producer; they are subsidiaries of foreign-owned companies; or they were acquired by other investment firms.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

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202-508-5000 | www.eei.org

S&P Global
Market Intelligence

FINANCIAL FOCUS

Utility electric T&D capex on upward trend; forecast nears $54B in 2020

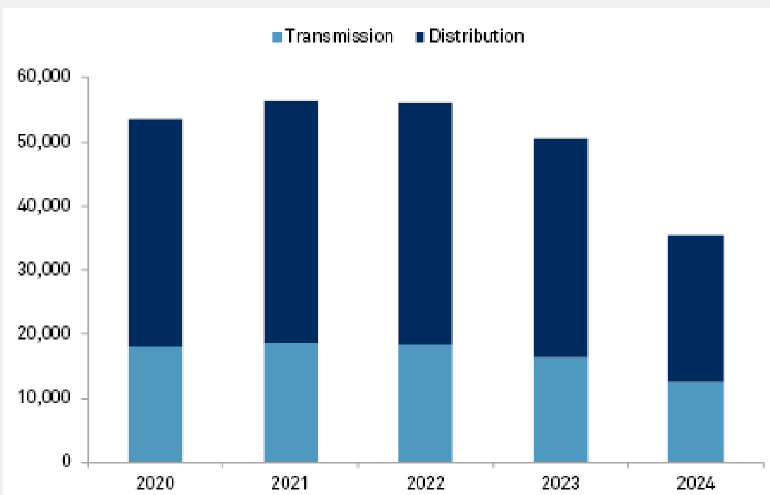
Monday, June 15, 2020 6:28 AM CT

By Jason Lehmann
Market Intelligence

Estimated capital expenditures for electric transmission and distribution (T&D) infrastructure for U.S. electric and multi-utility holding companies in the RRA universe are projected to reach $53.6 billion in 2020 and to rise approximately 5% in 2021 to $56.4 billion. T&D spending in 2022-2023 is expected to remain robust at more than $50 billion in each year, before tapering to $35.5 billion in 2024. These conclusions flow from the June 8 Financial Focus report, "US energy utility capex undeterred by coronavirus to date, slated to reach $141B."

By business category, T&D spending is forecast to comprise more than half of overall utility capex between 2020 and 2022, on par with levels observed in recent years and representing a substantial contribution to utility earnings growth in the years ahead. These investments also form an important component of many utilities' environmental, social and governance, or ESG, strategies, amid a broader utility sector transition toward decarbonization through electric grid modernization and renewable energy expansion. The increase in number of renewable generation sources, which are often great distances from load centers, will continue to drive new transmission line projects.

Estimated electric T&D capex breakout, 2020-2024 ($M)



Compiled May 27, 2020.
Source: S&P Global Market Intelligence, company surveys and RRA adjustments

Despite challenges to the rate of return levels authorized by the Federal Energy Regulatory Commission, the average return on equity allowed on transmission investments remains above the average equity return authorized by state commissions in traditional rate proceedings. Additionally, aging infrastructure within utility service territories across the U.S. and the growing scale of the nation's electric grid should drive considerable electric distribution investment in the coming years.

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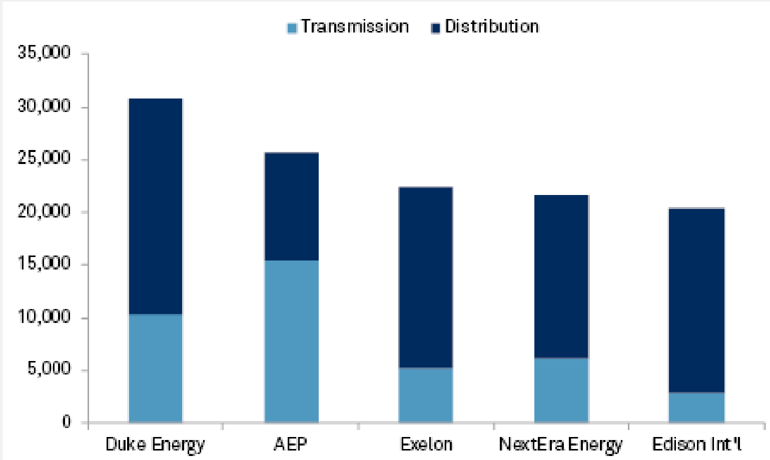
Largest estimated electric T&D capex budgets, 2020-2024 ($M)



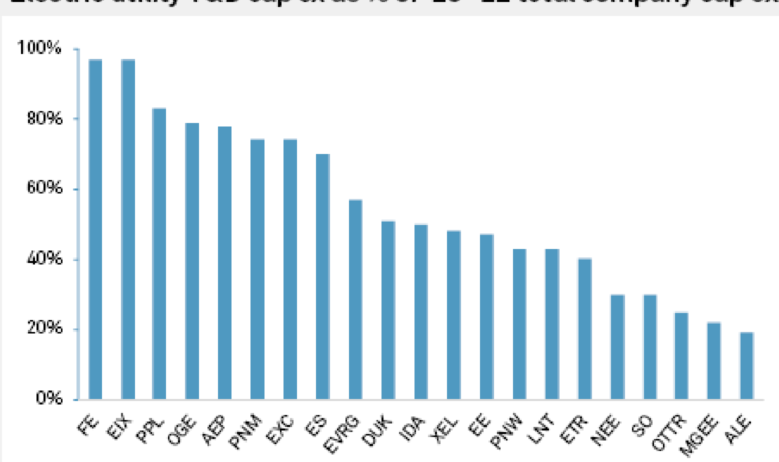
Compiled May 27, 2020.
Source: S&P Global Market Intelligence, company surveys and RRA adjustments

Although our data indicates that T&D capex in the industry will drop off in 2024, our observations in recent years indicate that actual investment generally continues to rise, or remains high, despite the industry's projected spending decline. Utilities have a lower federal income tax rate under the tax overhaul but are being required to pass on the benefit of those lower taxes to ratepayers in the form of lower rates. We believe utilities will have more "headroom" in proceedings seeking added capital investment before state regulators as customer rates decline nationwide, all else equal, due to the lower corporate tax rate.

In terms of projected energy industry profitability, S&P Global Market Intelligence consensus EPS projections, excluding outlier PG&E Corp. call for electric utility EPS to grow 1.2% in 2020 for companies in the RRA utility universe, with 6.6% expansion forecast in 2021 and 5.9% in 2022. Multi-utility EPS, excluding outlier CenterPoint Energy Inc., is forecast to grow 1.5% in 2020 and 7.7% and 5.7% in 2021 and 2022, respectively.

Notable T&D spenders

Electric utility T&D cap ex as % of '20-'22 total company cap ex



Compiled May 27, 2020.
Source: S&P Global Market Intelligence, company surveys and RRA adjustments

Duke Energy

As one of the largest electric T&D operators in the U.S. with more than 310,000 miles of line and approximately 7.8 million retail electric customers in the Midwest and Southeast, grid modernization and other transmission and distribution projects comprise a substantial portion of Duke Energy Corp. capital expenditure forecast over the next several years. The company's electric T&D capex are estimated at $30.75 billion between 2020 and 2024, with approximately two-thirds weighted toward electric distribution expenditures. By comparison, Duke's 2019-2023 estimated T&D forecast stood at about $24.86 billion.

Projects include battery storage and electric vehicle infrastructure, distribution line undergrounding, distribution hardening and resiliency, communication network upgrades and general transmission improvements. The company expects these investments will provide a number of tangible customer benefits, including improved reliability, enabling of distributed generation and cyber and physical security improvements. In addition, these investments are expected to support Duke's stated 4% to 6% EPS growth target through 2024.

In addition to retail electric distribution operations, Duke owns a 50% interest in Duke-American Transmission Co., a partnership with American Transmission Company LLC, formed to design, build and operate transmission infrastructure. DATC owns 72% of the transmission service rights to Path 15, an 84-mile transmission line in central California. Duke also holds a 50% interest in Pioneer Transmission LLC, which builds, owns and operates electric transmission facilities in North America.

FirstEnergy

FirstEnergy Corp.'s forecast electric T&D capex continues to account for the highest proportion of overall capex among electric and multi-utilities as the company executes on the expansion of its fully regulated utility operations to largely support projected 6% to 8% EPS growth through 2021 and 5% to 7% growth thereafter. The company's approximately $12 billion 2020-2023 construction program is expected to drive regulated distribution rate base growth of 4% annually and transmission formula rate base growth of 10% annually. The company owns 10 regulated retail electric utilities serving more than 6 million customers in six states, with approximately $5.18 billion of electric distribution capex forecast through 2023. Management notes its distribution business continues to explore additional growth avenues including electric system improvement and modernization investments intended to improve reliability and service to customers. FirstEnergy also indicates it is "exploring opportunities in customer engagement that focus on the electrification of customers' homes and businesses by providing a full range of products and services."

FirstEnergy also owns three standalone transmission operating companies, Mid-Atlantic Interstate Transmission, Trans-Allegheny Interstate Line Co. and American Transmission Systems Inc., and a transmission system that spans approximately 25,000 miles. Regulated transmission investments, including the company's Energizing the Future initiative, form the cornerstone of FirstEnergy's growth strategy, with $6.80 billion forecast to be invested through 2023. Approximately 90% of transmission segment capex is projected to be recoverable through formula rate mechanisms, minimizing regulatory lag. FirstEnergy believes there are meaningful investment opportunities for its existing transmission infrastructure beyond those identified through 2023, including grid strengthening initiatives, cybersecurity and resiliency investments.

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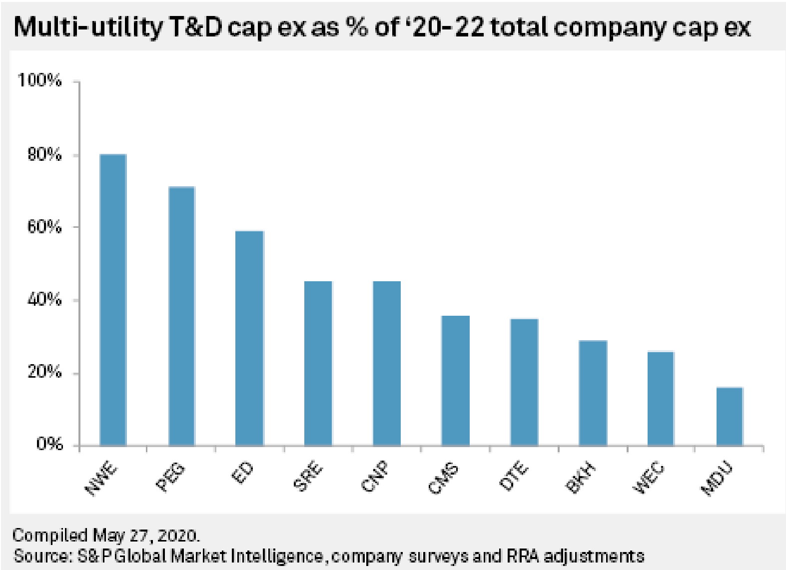

Public Service Enterprise Group

Among multi-utilities, Public Service Enterprise Group Inc.'s planned T&D capex account for a relatively high proportion of overall planned capex, comprising 71%, or $5.71 billion, of the company's $8.00 billion budget between 2020 and 2022. PSEG's Public Service Electric and Gas Co. continues to focus on T&D system reliability and resiliency enhancements through several ongoing initiatives, including its $842 million Energy Strong II program to harden, modernize and improve the resiliency of its electric and gas distribution systems. The utility indicates it expects to recover the majority of program costs through periodic rate recovery filings, with the balance to be recovered in its next distribution rate case. PSE&G expects to complete its Energy Strong II program by the end of 2023. The utility also has filings pending with New Jersey regulators to expand energy efficiency, electric vehicle infrastructure and energy storage.

PSE&G expects to invest $2.8 billion on transmission infrastructure between 2020 and 2022, focused on the maintenance and enhancement of system integrity and grid reliability, security and safety; accommodating new electric demand; the replacement and upgrade of aging infrastructure; technology enhancements to improve system operations; reducing transmission constraints; and to meet environmental regulations and requirements.

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Estimated electric T&D capex, 2020-2024 ($M)

	Electric transmission						Electric distribution						T&D
	2020	2021	2022	2023	2024	Total	2020	2021	2022	2023	2024	Total	Total
Electric													
ALLETE Inc.	35	110	190	115		450							450
Alliant Energy Corp.						0	570	535	525	540		2,170	2,170
American Electric Power Co. Inc.	2,707	3,173	3,174	3,173	3,173	15,400	1,810	2,122	2,123	2,122	2,123	10,300	25,700
Avangrid Inc.						0						0	0
Duke Energy Corp.	2,084	1,992	2,109	2,267	1,950	10,402	3,408	3,766	4,258	4,616	4,300	20,348	30,750
Edison International	700	800	800	600		2,900	4,100	4,400	4,400	4,600		17,500	20,400
El Paso Electric Co.	22	28	41	45	35	170	97	114	122	124	111	569	739
Entergy Corp.	955	820	630			2,405	880	690	620			2,190	4,595
Evergy Inc.	312	319	309	303	351	1,594	581	595	577	564	655	2,972	4,566
Eversource Energy	910	832	855	711	668	3,976	1,347	1,208	1,162	1,170	1,234	6,121	10,097
Exelon Corp.	1,300	1,320	1,341	1,326		5,287	4,225	4,292	4,358	4,308		17,183	22,470
FirstEnergy Corp.	1,200	1,325	1,325	1,325		5,175	1,700	1,700	1,700	1,700		6,800	11,975
IDACORP Inc.	50	50	50	50	50	250	105	105	105	105	105	525	775
MGE Energy Inc.						0	43	39	50			131	131
NextEra Energy Inc.	1,307	1,378	1,154	1,167	1,172	6,178	2,495	3,154	3,205	3,293	3,293	15,440	21,618
OGE Energy Corp.	45	40	35	35	35	190	335	575	575	575	575	2,635	2,825
Otter Tail Corp.	61	26	8	13	9	117	22	27	34	25	26	134	251
Pinnacle West Capital Corp.	181	201	205			587	556	444	446			1,446	2,033
PNM Resources Inc.	288	414	170	178	180	1,230	369	299	355	372	224	1,619	2,849
PPL Corp.	903	632	470	357	362	2,724	1,961	1,860	1,767	1,800	1,911	9,299	12,023
Southern Co.	1,000	1,000	1,200	1,200	1,200	5,600	1,300	1,500	1,500	1,500	1,600	7,400	13,000
Xcel Energy Inc.	625	835	1,295	1,270	1,260	5,285	885	1,140	1,415	1,470	1,350	6,260	11,545
Total electric	**14,685**	**15,295**	**15,360**	**14,135**	**10,445**	**69,920**	**26,789**	**28,564**	**29,298**	**28,884**	**17,507**	**131,043**	**200,962**
Multi-utility						0						0	0
Black Hills Corp.	74	61	51	41	46	272	123	102	85	69	76	454	726
CenterPoint Energy Inc.	415	500	440	466	442	2,263	623	749	660	699	663	3,394	5,657
CMS Energy Corp.						0	880	880	880	880	880	4,400	4,400
Consolidated Edison Inc.	10	24	76			110	2,303	2,317	2,182			6,802	6,912
DTE Energy Co.						0	1,190	1,453	1,453	1,453	1,453	7,000	7,000
MDU Resources Group Inc.	50	58	63			170	50	58	63			170	340
NorthWestern Corp.	130	132	109	108	108	587	196	198	163	162	162	881	1,469
Public Service Enterprise Group Inc.	1,200	950	660			2,810	910	938	1,055			2,903	5,713
Sempra Energy	1,466	1,485	1,351	1,351	1,351	7,003	1,669	1,813	1,447	1,447	1,447	7,821	14,824
WEC Energy Group Inc.	212	286	305	255	199	1,257	623	568	541	662	697	3,091	4,348
Total multi-utility	**3,557**	**3,495**	**3,054**	**2,221**	**2,145**	**14,473**	**8,566**	**9,074**	**8,528**	**5,371**	**5,377**	**36,916**	**51,389**
Grand total	**18,241**	**18,790**	**18,415**	**16,356**	**12,590**	**84,392**	**35,355**	**37,638**	**37,826**	**34,256**	**22,884**	**167,959**	**252,351**

Compiled May 27, 2020.
Source: S&P Global Market Intelligence, company surveys and RRA adjustments

This report is designed to identify capital expenditure trends in the U.S. utility sector using a range of sources of information. While S&P Global Market Intelligence takes all due care to ensure the data represented is accurate and represents our best interpretation of industry trends, the varying nature of the available sources of information in terms of depth, quality, availability and timeliness means this report should only be used as outlined. Those looking for company-specific capital expenditure information should use data filed with the U.S. Securities and Exchange Commission.

Regulatory Research Associates is a group within S&P Global Market Intelligence.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the S&P Global Market Intelligence Energy Research Library.

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June 8, 2020
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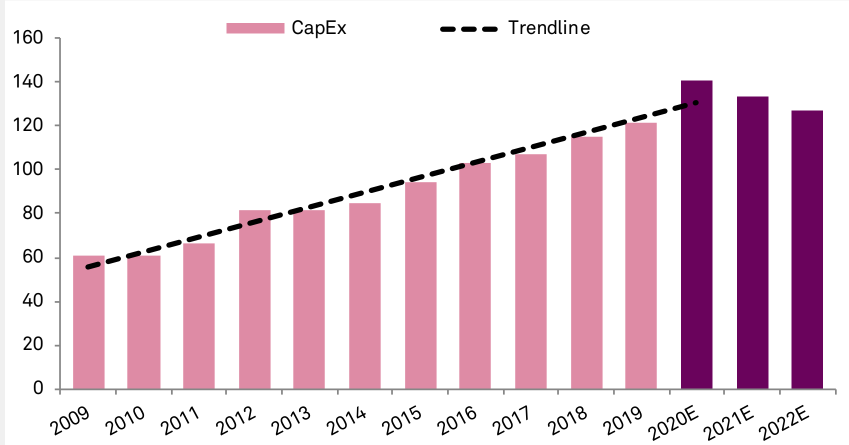
RRA Financial Focus
Utility Capital Expenditures Update

Capex plans undeterred thus far by virus-related hurdles

- Projected 2020 capital expenditures for the 48 energy utilities in the Regulatory Research Associates', a group with S&P Global Market Intelligence, universe currently stands at roughly $140.9 billion, well above 2019's $121.3 billion in capital investment.

- 2019's energy capital expenditures were a record high, and 5% above the $115.1 billion posted in 2018. If current projections hold, 2020 will be yet another record year, although there is reasonable uncertainty regarding the impacts of the coronavirus pandemic on supply chains. In addition, local and state government office closures may impede the permitting process, and mandatory social distancing — if implemented — at construction sites could slow construction progress.

Energy utility actual and estimated capital expenditures ($B)



Compiled May 27, 2020.
Source: S&P Global Market Intelligence

- Although 2021 and 2022 forecasts show a decline in capital expenditures, we anticipate both will rise as companies' plans for future projects solidify and new opportunities arise — which has been the case over the last several years. Considerable motivations exist for spending to remain elevated, including pent-up demand to replace and modernize aging infrastructure.

- Across the small investor-owned water utility sector, total capex grew 7% year over year to $2.9 billion in 2019. American Water, which represents over 55% of the sector's capex, experienced a year-over-year growth in capex spending of 4%. Total-sector capex is expected to increase 16.5% in 2020, including the additional investment Essential Utilities Inc. will make in the recently acquired People's Natural Gas.

The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures and battery storage. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future.

For Detailed Data

Click here to see supporting data tables.

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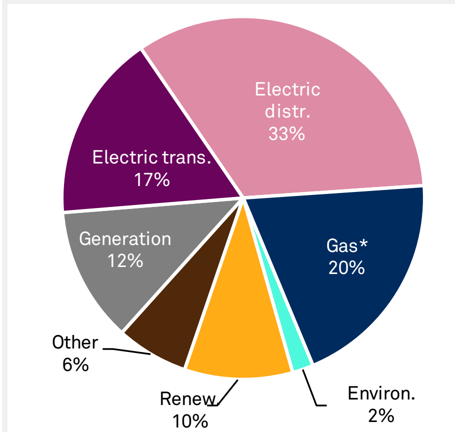
Spending on renewables is expected to total over $13 billion across our coverage universe in 2020. A number of factors will provide the impetus for ongoing electric utility renewable energy development, including falling technology costs, state policy and renewable portfolio standards, customer demand, and environmental, social and governance considerations, amid a broader trend toward utility sector decarbonization.

The increase in number of renewable generation sources, which are often great distances from load centers, will continue to drive new transmission line projects. Additionally, despite challenges to the rate of return levels authorized by the Federal Energy Regulatory Commission, the average return on equity allowed on transmission investments remains above the average equity return authorized by state commissions in traditional rate proceedings.

From a natural gas perspective, many utilities are participating in the sizable and ongoing expansion of the nation's gas midstream network. In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.

The federal tax code changes that took effect in 2018 preserved a provision strongly supported by the industry to encourage investment: the deductibility of interest expense for regulated utilities. Being among the most capital-intensive industries, utilities would have had a higher cost of capital absent this provision, which would have impacted capital investment planning and likely led to higher utility bills.

CapEx by business category, 2020E-2022E



Compiled May 27, 2020.
* Gas includes pipeline, storage, distribution and other gas infrastructure.
Source: S&P Global Market Intelligence

Individual company capex changes from fall 2019 forecast

For a third consecutive report, **ALLETE Inc.**'s capex growth forecast has topped the energy utility group. The addition of the company's Caddo wind project drove the 48% increase in its capital spending forecast through 2021, compared to the forecast collected for our fall 2019 report. The 303-MW wind farm, located in Caddo County, Okla., is slated to come online in late 2021. Two power purchase agreements for the project's output have been arranged, while a third and final agreement is pending. In addition to the known capital projects included in the forecast, ALLETE is exploring additional possibilities for renewable capex, including acquisition of existing renewable facilities and building, owning and transferring renewables to others.

Northwest Natural Holding increased its 2020-2021 planned capex by 43% compared to our previous report, with the increase largely driven by higher safety and reliability investment in the company's gas utility business, as well as water utility capex that was not previously gathered in our report. Northwest Natural is rapidly growing its water utility business, with $110 million in water utility acquisition investment already spent, and $30 million to $40 million in investment planned for the 2020-2024 period.

Sempra Energy increased its 2020-2021 capital forecast substantially since our last report with the addition of a range of roughly $1.2 billion to $1.4 billion in planned investment in its Sempra LNG segment.

Train 3 in the company's Cameron LNG project is projected to begin commercial operations in the third quarter of 2020, and the Cameron LNG Phase 2 project, which would add Trains 4 and 5 and one LNG storage tank, is progressing to advanced development. Additionally, the capex slated for the company's U.S. utilities increased to a range of $8.1 billion to $8.9 billion from the previous range of $5.7 billion to $7.0 billion for the 2020-2021 period. On the company's first quarter 2020 earnings call, management affirmed Sempra's 2020 and 2021 adjusted earnings guidance ranges — the company projects adjusted earnings growth of 11.9% through 2021 from a 2018 base.

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RRA Financial Focus: Utility Capital Expenditures

MGE Energy's capex plans grew meaningfully with the addition of the company's $65 million plan to acquire a second 50-MW share of the Badger Hollow solar project in Wisconsin through its utility subsidiary Madison Gas and Electric. On Feb. 20, Madison Gas and Electric received preliminary approval from the Wisconsin Public Service Commission to acquire the additional capacity, which is slated to commence commercial operations in late 2021. MGE Energy also plants to invest $64 million in various additional local solar projects, including installations to support the company's renewable energy rider and community solar programs.

Selected companies' CapEx forecast changes

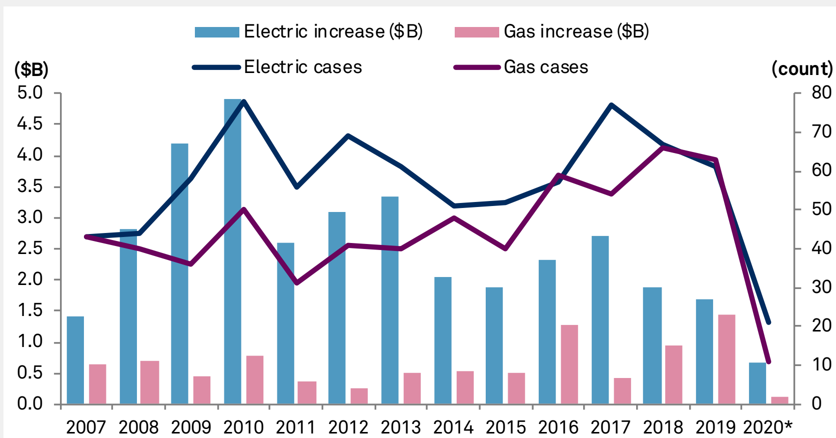
	Change from H2'19 (%)		2020-2021 forecast ($M)		
Companies	**2020**	**2021**	**H2'19**	**H1'20**	**Chg. (%)**
ALLETE Inc.	14.7	135.3	935	1,380	47.6
Northwest Natural Holding Co.	63.2	31.4	315	464	47.3
Sempra Energy	28.2	63.0	10,305	14,763	43.3
MGE Energy Inc.	43.3	41.1	317	451	42.2
MDU Resources Group Inc.	21.8	33.4	1,134	1,450	27.9

Compiled May 27, 2020.
Source: S&P Global Market Intelligence

The rate case front

The decline in the magnitude and number of base rate increases since 2010 is partly attributable to the increased use of riders and single-issue proceedings. In the first quarter of 2020, $683.8 million in electric base rate increases were authorized in 21 cases, compared to $1.7 billion in 61 cases during full-year 2019. The average ROE authorized electric utilities in the first quarter of 2020 was 9.58%, below the 9.65% average for 2019. Excluding limited-issue rider cases, the average authorized electric ROE was 9.45% for the first quarter of 2020 and 9.64% for full-year 2019.

Utility authorized base rate increases and rate case count



Compiled May 27, 2020.
* Year-to-date through Mar. 31, 2020.
Source: S&P Global Market Intelligence

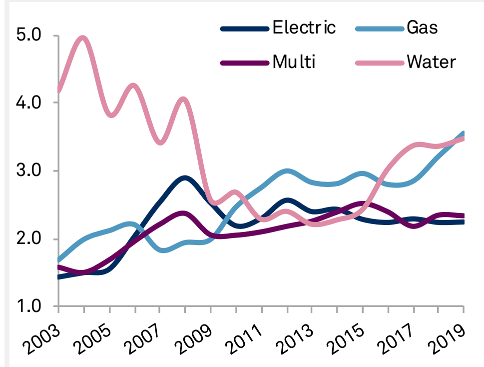
In the gas segment, despite substantial pipeline replacement underway nationwide, investment levels and rate case activity have been considerably lower compared to the electric sector. Gas base rate increases for the first quarter of 2020 were $124.4 million in 11 cases, compared to $1.5 billion in 63 cases for 2019. The average ROE authorized for gas utilities was 9.35% for the first three months of 2020, compared to 9.71% for full-year 2019. For additional detail, see the full report: Major Rate Case Decisions: January – March 2020 .

Capex versus depreciation and amortization

When utility capital expenditures outpace depreciation, the general implication is that the utility is growing its rate base. From 2003 through 2019, the ratio of electric utility capex to depreciation and amortization, or D&A, for the average company in the group fluctuated significantly from a low of 1.4x in 2003. The ratio ramped up to 2.9x in 2008, as utilities invested in generation assets to replace retiring coal units and continued to spend on environmental retrofits for coal units that would continue to operate. Post 2008 and the economic downturn, as utility spending moderated somewhat for a time, the ratio fell and ultimately settled at 2.2x-2.3x for 2015 through 2019.

The gas utility capex/D&A ratio showed modest variability from 2003 through 2009, ranging from 1.7x to 2.2x. However, after 2010, the ratio grew somewhat unevenly to ultimately reach 3.6x on average in 2019, likely as accelerated infrastructure replacement programs were implemented across the country. A series of high-profile gas leaks have spurred public and regulatory support for programs that incentivize pipeline replacement, such as riders that allow utilities to recover their investment outside of a general rate case.

Utility CapEx/D&A ratio, 2003-2019 (x)



Compiled May 27, 2020.
D&A = depreciation and amortization
Source: S&P Global Market Intelligence

Multi-utilities — those with both electric and significant gas utility operations — have perhaps held the steadiest path among energy utilities with regards to the capex/D&A ratio. Between 2003 and 2019, the sector reached a low capex/D&A ratio of 1.7x in 2005 and a high of 2.5x in 2015. In 2018 and 2019, the ratio was 2.3x.

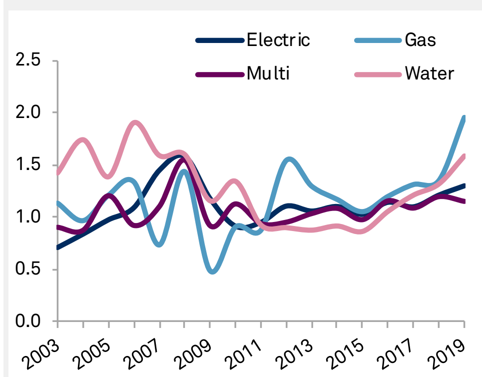
The historical capex to depreciation rate has been more volatile for the small investor-owned water utility sector. Just over half of the water sector's capex is invested by American Water, the largest water utility. Consequently, the more diminutive companies in the group are prone to larger percentage swings in their capex budgets, as large projects can have a meaningful impact for a few years. Spikes in 2004, 2006 and 2008 in the accompanying capex/D&A ratio chart are all related to large projects undertaken by the two smallest water utilities, Artesian Resources and York Water. Excluding these smallest stocks, the water utility capex/D&A ratio ranged from 2.6x to 3.1x from 2002 to 2010, still well above the ratio of electric and gas utilities. The ratio was 3.1x in 2019.

Capex versus operating cash flow

Comparing capex to operating cash flows, or OCF, can provide a window into how companies may fund their investments. As a company's capex/OCF ratio rises above 1.0, the implication is that the company is increasingly likely to require new external financing. For electric utilities, this ratio has largely followed the capex/D&A ratio, with a low of 0.7x in 2003 before a steep rise to 1.6x in 2008. Between 2009 and 2017, the electric utility ratio leveled off around 1.0x-1.1x. For 2018, the ratio ticked a hint upward to 1.2x, and in 2019, the ratio jumped meaningfully to 1.6x.

For gas utilities, the capex/OCF ratio has fluctuated far more substantially than for electric utilities. Gas utilities saw large swings in the ratio from 2003 through 2012, with a peak at 1.4x in 2008, a low of 0.5x in 2009, and another peak at 1.5x in 2012. The ratio shifted between 1.1x and 1.3x from 2013 to 2017, before moving up to 1.4x in 2018 and 2.0x in 2019.

Utility CapEx/OCF ratio, 2003-2019 (x)



Compiled May 27, 2020.
OCF = operating cash flow
Source: S&P Global Market Intelligence

As they did with the capex/D&A ratio, multi-utilities have held a relatively steady path with regard to their average capex/OCF ratio. Aside from a peak of 1.6x in 2008, multi-utilities vacillated between 0.9x and 1.2x between 2002 and 2019.

The relationship between capex and operating cash flow is a bit more complex than that of capex and depreciation and amortization, which is largely driven by fluctuations in capex. Operating cash flow can be meaningfully impacted by a variety of factors, including prepayments and other one-time events, and therefore should not be considered by itself as an indicator of the need for external funding.

For water utilities, the capex-to-operating cash flow ratio has fluctuated for similar reasons as the capex/D&A ratio, driven by spending changes by the smaller utilities. Between 2011 and 2015, the capex/OCF ratio for water utilities was in a narrow band of 0.87x to 0.93x. Recent expansion in the ratio is attributable to capex budget expansion. The ratio increased to 1.59x in 2019, up from 1.32x in 2018 and 1.22x in 2017.

This report is designed to identify capital expenditure trends in the U.S. utility sector using a range of sources of information. While S&P Global Market Intelligence takes all due care to ensure the data represented is accurate and represents our best interpretation of industry trends, the varying nature of the available sources of information in terms of depth, quality, availability and timeliness means this report should only be used as outlined. Though underlying data is included in this report, those looking for company-specific capital expenditure information should use data filed with the U.S. Securities and Exchange Commission.

S&P Global
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FINANCIAL FOCUS

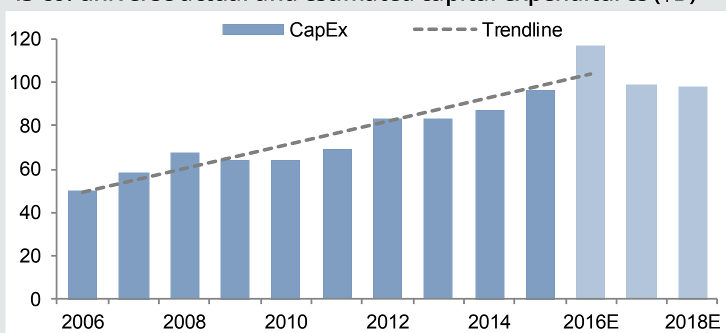
Topical Special Report   October 27, 2016

CAPITAL EXPENDITURE UPDATE

~ 2016 to represent high water mark for projected capital spending by utilities ~

Capital expenditures throughout the U.S. power and gas sectors in calendar-2016 are projected to be at an all-time high. The nation's largest electric and gas utilities are investing in infrastructure to comply with sweeping environmental regulations, implement new technologies, build new natural gas, solar and wind generation and upgrade aging transmission and distribution systems. Moreover, their near-term capital spending forecasts continue to escalate. Since our previous review of industry CapEx estimates, the utilities in the RRA Index have added about $11 billion of projects to their to-do lists for 2016-2018, according to our review of spending plans detailed in investor presentations. While most companies raised their forecasts or left them unchanged, a handful did reduce CapEx plans through 2018 (see below for individual examples.) Total CapEx in 2016 for the companies in the RRA Index is projected to be almost $117 billion.

43-co. universe actual and estimated capital expenditures ($B)

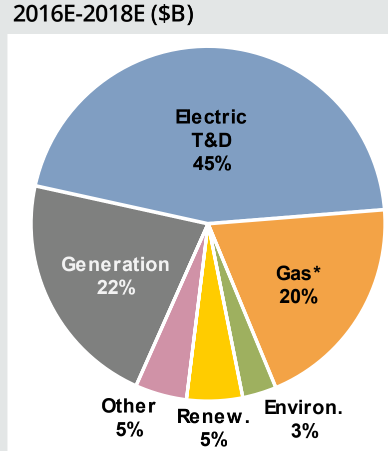


Source: RRA and SNL Energy, offerings of S&P Global Market Intelligence

We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future, although our data indicates that CapEx in the industry may fall modestly in 2017 and 2018. However, considering our observations of recent years, actual investment will likely continue to rise despite the industry's projected near-term spending declines. Considerable motivations exist for spending to remain elevated, including pent-up demand to replace and modernize aging infrastructure resulting from decades of under-investment in the electric transmission grid. The increase in renewable generation sources, which are often great distances from load centers, will continue to drive new transmission line projects. Additionally, despite challenges to the rate of return levels authorized by the FERC, the average ROE allowed on transmission investments remains above the average equity return authorized by state commissions in traditional rate proceedings.

From a natural gas perspective, many utilities are participating in the sizable and ongoing expansion of the nation's gas midstream network. In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety.

CapEx by business category, 2016E-2018E ($B)



*Gas includes pipeline, storage, distribution and other gas infrastructure.
Source: RRA and SNL Energy, offerings of S&P Global Market Intelligence

Largest CapEx Forecast Changes

Southern Company's capital spending forecast for 2016 grew nearly 44% since early this year as it continues to execute its "all the above strategy" by significantly increasing its investment in renewables. The company's spending plans for 2017 and 2018 remain unchanged. Southern Company expects "tremendous growth" at subsidiary Southern Power through continued investments in renewables. It expects 2016 to be a "high water" mark for spending by the wholesale energy unit, with $1.4 billion earmarked for wind projects and $2.5 billion for solar projects. Overall projected spending this year by subsidiary Southern Power, including maintenance, is estimated at $4.5 billion, up from a February 2016 forecast of $2.4 billion. Southern Company's total CapEx for 2016 is projected at $10.5 billion.

Companies with largest change in 2016-2018 CapEx forecast since H1'16

	Change from H1'16 (%)			2016-2018 forecast ($M)		
Companies	**2016**	**2017**	**2018**	**H2'16**	**H1'16**	**Change (%)**
Exelon Corp.	22.3	18.1	21.4	23,875	19,800	20.6
Southern Co.	43.8	0.0	0.0	21,200	18,000	17.8
AES Corp.	-3.1	0.0	38.0	6,754	5,827	15.9
Entergy Corp.	-7.1	-4.2	-3.4	11,305	11,900	-5.0
MDU Resources Group	12.8	-13.7	-9.5	1,327	1,407	-5.7
PPL Corp.	-6.8	-5.5	-5.9	9,270	9,870	-6.1

Source: RRA and SNL Energy, offerings of S&P Global Market Intelligence

Exelon Corp.'s capital spending through 2018 is projected to be almost 21% above the company's forecast earlier this year, as it puts considerable new investment into critical infrastructure, smart grid technology and other reliability improvements, and expands upon its recent acquisition of Pepco Holdings. More than $25 billion is now being invested through 2020 with additional investment being set aside for the company's electric transmission and distribution network. About $7 billion is tagged for reliability improvements at Pepco, $10 billion for Commonwealth Edison, about $4.5 billion for Baltimore Gas and Electric and about $750 million annually over the next five years at PECO Energy for electric transmission and smart grid upgrades, as well as electric or gas distribution reliability improvements.

Global power company **AES Corp.** earmarked additional spending in its latest CapEx plan to build a new coal plant in the Philippines and a new gas plant in Panama. AES set aside $740 million for expansion of the Masinloc 2 supercritical thermal coal plant in the Philippines, expected to come online in 2019. AES also is in the advanced development stage of its 380-MW combined-cycle Colon gas plant and related LNG facility in Panama. The combined-cycle gas turbine is expected to begin operation in 2018 followed by the LNG facility in 2019. Together the two projects boosted AES' five-year CapEx forecast to $8.52 billion from $6.85 billion,

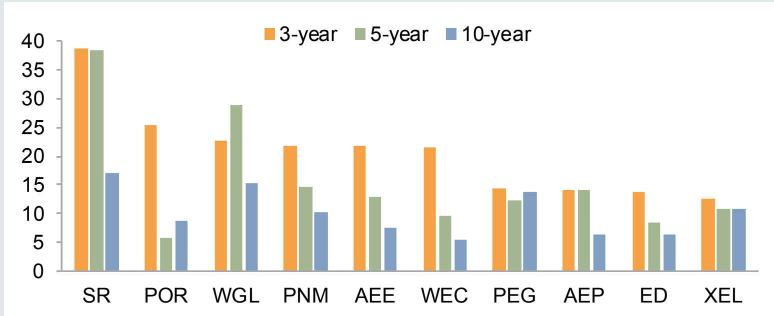
PPL Corp. has budgeted more than $15 billion over the next five years to improve reliability and efficiency at its regulated utility business and make environmental improvements at Kentucky operations. But near-term spending expectations have fallen slightly. PPL's latest CapEx estimate for the three years 2016-2018 is $9.27 billion, 6% below the company's forecast from earlier this year. Spending on generation and environmental mitigation projects remains the same; however, spending on electric transmission and distribution systems was reduced in the latest forecast. Analysts have suggested that PPL could make further investments into transmission projects in the future if its currency hedges on the British pound are monetized.

MDU Resources Group Inc. expects to spend about $2.3 billion over the next five years, primarily at its regulated gas and electric utilities, including a 160-mile transmission line serving MISO. MDU's latest capital spending expectation for 2016 is higher than MDU had forecast in its most recent 10-K. Higher spending on electric generation projects and improvements to its electric transmission and distribution systems accounts for the changes. The company plans to fund its 2016 CapEx without issuing equity. Overall CapEx estimates for the years 2016 through 2018 is about 5.7% below the company's earlier forecast.

In June 2016, **Entergy Corp.** updated its CapEx guidance, suggesting softer spending over the next few years than had been earlier forecast. The utility, whose capital plan is driven by the need to modernize aging infrastructure and maintain reliability, is now expected to spend about $11.3 billion from 2016 through 2018, compared with $11.9 billion forecasted in February. Lower spending on generation projects is the main source of the decline. Entergy has indicated that its in-house generation is projected to be adequate to meet MISO reserve requirements over the next several years, but that over the longer term, additional supply resources will be required. A substantial part of the generation investment will be in new-build infrastructure. Subsidiary Entergy Louisiana plans to construct an $869 million, 980-MW gas-fired combined-cycle plant in St. Charles Parish, La., with a targeted in-service date in June 2019.

CapEx Growth Rates

Largest 3-year utility CapEx CAGRs (%)

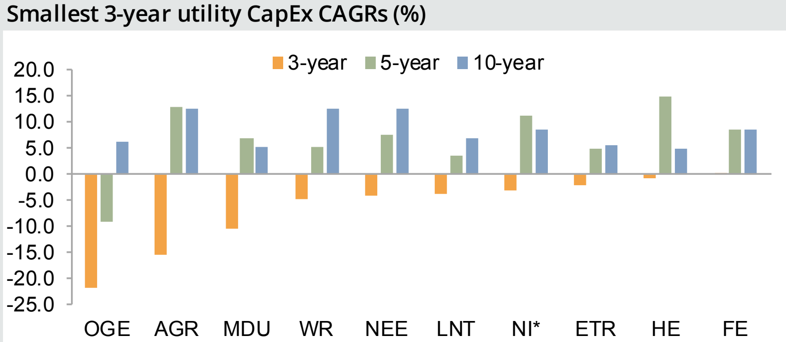


Through fiscal 2015.
Source: SNL Energy, an offering of S&P Global Market Intelligence.

Spire Inc.'s capital expenditure levels grew faster than any other RRA covered utility, surging almost 40% annually over the past five years. Spire has been able to execute its capital investment program with minimal regulatory lag, and timely recovery of its investments should continue; over the years 2016-2020, the company plans to invest $1.8 billion, 60% of which is expected to be recovered with minimal lag. The rate of CapEx growth in the future will pale in comparison to the 2010-2015 period, an acquisitive time for Spire when it was pouring money into its distribution infrastructure and replacing pipeline. In 2013, the company made the largest acquisition in its history, buying Missouri Gas Energy and expanding service to Kansas City, Joplin and St. Joseph, Mo. In 2014, Spire bought Alabama Gas Corp., the largest natural gas provider in Alabama.

OGE Energy Corp.'s capital expenditures fell nearly 10% annually, on average, during the past five years. Over the past three years, OGE's average annual capital spending dropped 22% on average, more than any other utility in the RRA Index. The utility had ratcheted up spending in the early part of the decade to complete a transmission reliability expansion, including construction of two 345-kV transmission projects in Oklahoma to support its new wind farms and population growth in its territories. But spending on such projects has slowed. The company's latest five-year plan calls for spending $2.8 billion on a range of transmission, distribution and generation projects in addition to installing dry scrubbers at its plants and making other environmental upgrades to comply with new U.S. EPA regulations. Spending is expected to increase in 2017 and then steadily decline.

Smallest 3-year utility CapEx CAGRs (%)

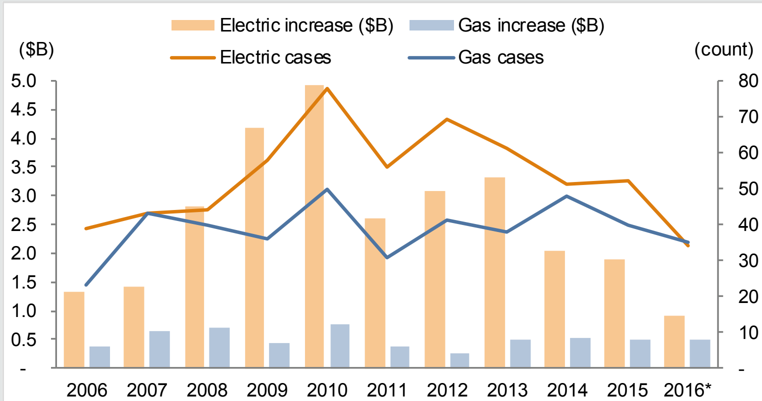


Through fiscal 2015.
*NiSource spun off Columbia Pipeline Group in mid-2015.
Source: SNL Energy, an offering of S&P Global Market Intelligence.

The Rate Case Front

Despite slow customer growth, increased costs associated with emissions compliance, generation and delivery infrastructure upgrades and expansion, and renewable generation mandates, among other factors, should drive an active rate case agenda over the next few years. When the Federal Reserve begins to gradually raise the federal funds rate in earnest, utilities would be facing higher capital costs and would need to reflect the higher capital costs in their rate case filings.

Utility authorized base rate increases and rate case count



*Through Sept. 30, 2016.
Source: RRA and SNL Energy, offerings of S&P Global Market Intelligence

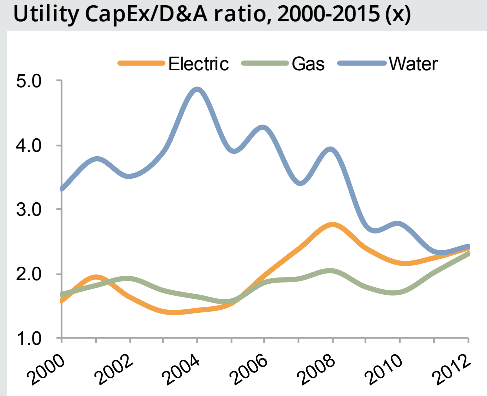
Since 2010, and despite continued strong spending throughout the electric sector, base rate increases have slowed in both magnitude of increases as well as in the number of cases. The decline is partly attributable to the increased use of riders and single-issue type increases. A total of $928 million in electric base rate increases (34 cases) was authorized during the first three quarters of 2016, down from $1.4 billion in the same time period in 2015 (33 cases). Electric base rate increases for the full-year 2015 were $1.9 billion (52 cases). The average ROE authorized for electric utilities was 9.91% in rate cases decided in the first three quarters of 2016, compared to 9.85% in calendar-2015 cases. Excluding limited issue rider cases, the average authorized electric ROE was 9.64% in rate cases decided in the first nine months of 2016 versus 9.6% in 2015.

In the gas sector, despite substantial pipeline replacement under way nationwide, investment levels and rate case activity have been considerably lower compared to the electric sector. Gas base rate increases during the first three quarters of 2016 have totaled $503 million (35 cases), up from $308 million (25 decisions) in the same period in 2015. Gas base rate increases for the full-year 2015 were $494 million (40 cases).The average ROE authorized for gas utilities was 9.45% in the first three quarters of 2016 versus 9.6% in all of 2015. For additional detail, see the full report: Major Rate Case Decisions, January-September 2016.

CapEx vs. depreciation, operating cash flow

When utility capital expenditures outpace depreciation, the general implication is that the utility is growing its rate base. From 2000 through 2015, the ratio of electric utility CapEx to depreciation and amortization for the average company in the group fluctuated significantly, reaching a low of 1.4x in 2003 and 2004 before ramping up to 2.8x in 2008, as utilities invested in generation assets to replace retiring coal units and environmental retrofits for coal units that would continue to operate. Post-2008 and the economic downturn, the ratio fell, ultimately settling at 2.4x for 2015. (See Table 2 for additional detail).

Utility CapEx/D&A ratio, 2000-2015 (x)



Source: SNL Energy, an offering of S&P Global Market Intelligence

As generation and emission control spending by utilities wound down, transmission investment took center stage. In 2005, the Energy Policy Act directed the FERC to entice investment in the largely neglected, aging transmission system. FERC's final rule, issued in 2006, called for incentive ROEs for new investment and other constructive rate treatments. Subsequently, FERC orders involving transmission incentives spiked to a peak of 37 orders in 2008 from five in 2006 — stakeholders even began referring to the incentives as "FERC candy." Intensive transmission spending would be delayed by a few years from the time of the FERC orders and therefore was likely not linked to the CapEx run-up to 2008; however, transmission investment has dominated utility capital expenditures in recent years.

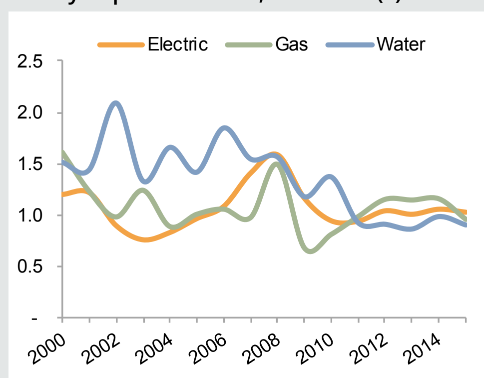
In 2011, FERC announced it would reexamine its transmission incentives policies, and in 2012 the commission indicated that transmission incentive applicants should mitigate the risks of a project before seeking an incentive ROE. Additionally, beginning in 2011, state regulators and consumer advocates filed a series of complaints arguing that FERC-authorized transmission ROEs were unreasonably high. A September 2016 FERC decision lowered MISO base transmission ROEs to 10.32% from 12.38%, and in April 2016, an administrative law judge recommended that FERC lower ISO-New England base ROEs to 10.9%. Despite the decreases, FERC-authorized transmission ROEs are still generally higher than state commission-authorized ROEs, and therefore transmission projects continue to attract investors.

Conversely, the ratio of gas utility CapEx to depreciation and amortization was largely flat from 2000 through 2010, ranging from 1.6x to 2.0x. However, after 2010, the ratio grew fairly steadily to reach 2.6x, on average, in 2015, likely as accelerated infrastructure replacement programs were implemented across the country. A series of high-profile gas leaks have spurred public and regulatory support for programs that incentivize pipeline replacement, such as riders that allow utilities to recover their investment without having to wait for a general rate case.

Comparing CapEx to operating cash flows can provide a window into how companies may fund their investments. As a company's CapEx-to-operating cash flow ratio rises above 1.0, the implication is that the company is increasingly likely to require new external financing. For electric utilities, this ratio has largely tracked the CapEx-to-depreciation and amortization ratio, with an average low of 0.8x in 2003 and 2004, before a steep rise to 1.6x in 2008. Since 2008, the electric utility ratio has leveled off around 1.0x.

For gas utilities, the CapEx-to-operating cash flow ratio has fluctuated far more substantially than for electric utilities. Gas utilities saw large swings in the ratio from 2000 through 2012, with a peak of 1.6x in 2000 and a low of 0.7 in 2009. Since reaching 1.2x in 2012, the ratio appears to have stabilized somewhat, although 2015 was slightly lower at 1.0x.

Utility CapEx/OCF ratio, 2000-2015 (x)



Source: SNL Energy, an offering of S&P Global Market Intelligence

The relationship between CapEx and operating cash flow is a bit more complex than that of CapEx and depreciation and amortization, which is largely driven by fluctuations in CapEx. Operating cash flow can be meaningfully impacted by a variety of factors, including prepayments and other one-time events, and therefore should not be considered by itself as an indicator of the need for external funding.

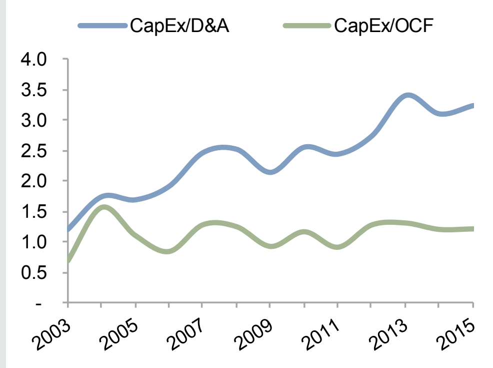
Across the small water utility sector, year-to-date CapEx is trending well above last year's levels. Those familiar with the niche-water utility sector have heard the frequent-cited estimations of $385 billion to $1.3 trillion, which are needed to upgrade, replace, and expand the nation's water & wastewater infrastructure over the next 20 years range. RRA expects this trend of accelerated CapEx spending to continue for some time.

After peaking in 2004-2005, the water sector's CapEx to depreciation and amortization has trended downward, and in the past five years spending levels have settled around 2.5x to 2.7x. The average CapEx to operating cash flow stood as high as 2.1x in 2002, and has been below 1.0x every year since 2010. (Please see the RRA water utility CapEx report for more details.)

Xcel Energy provides a good example of the relationship between these two ratios. As Xcel increased its capital expenditures to nearly $3.7 billion in 2015 from just under $1 billion in 2003, the company's depreciation and amortization grew at a markedly slower pace, and so the CapEx-to-depreciation and amortization ratio more than doubled, reaching 3.2x in 2015 from 1.2x in 2003, and significantly surpassing the 2015 electric utility average of 2.4x.

Meanwhile, Xcel Energy's CapEx-to-operating cash flow ratio remained fairly steady, ranging from 0.8x to 1.3x since 2005. A brief uptick to 1.6x in 2004 was driven by a drop in Xcel's operating cash flow related to the company's 2003 spin-off of NRG Energy. The company has historically relied primarily on cash from operations for its investments with supplemental debt issuances.

Xcel Energy ratios, 2003-2015 (x)



Source: SNL Energy, an offering of S&P Global Market Intelligence

Dan Lowrey
Charlotte Cox
Contributor: Heike Doerr

Most data in this report has been updated to include revisions to capital expenditure plans through mid-October 2016. Details for the individual 43 companies are shown in Tables 1 and 3. Table 3 provides a detailed analysis of industry spending, segregated into: Generation; Electric Transmission and Distribution; Environmental; Renewables; Gas Pipeline/Storage and Distribution; and, Corporate/Other.

Category identification and disclosure continue to improve since we began issuing this study in 2008. However, due to an absence of uniformity in forecasting methods and details among companies in the group, coupled with limitations caused by some incomplete or limited updates, a detailed breakdown by spending category for all companies was not possible, and we have included such companies as "below the line" in Table 3.

Additionally, coincident with the absence of uniformity with respect to spending forecasts, we note that some companies employ "accrual" accounting for forecasting purposes, which may result in a timing disconnect between projections and historical data (derived from cash flow statements and therefore done on a "cash" basis). Not all companies distinguish regulated generation from competitive generation in formal forecasts; however, the vast majority of generation spending plans under way for the universe of companies in this study are allocated to the regulated sphere. Regarding natural gas operations, we found that the majority of companies do not provide a clear breakdown of planned spending for utility, pipeline, storage, and distribution; we therefore group all planned gas spending into a combined gas category in Table 3.

Table 1 Utility historical and forecast CapEx

		Historical capital expenditures ($M)											CAGR (%)			Forecast CapEx ($M)			
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	3-year	5-year	10-year	2016E	2017E	2018E	3-year CAGR (%)
	ELECTRIC																		
1	AES CORP.	826	1,460	2,425	2,850	2,520	2,310	2,430	2,108	1,988	2,016	2,308	3.1	0.0	10.8	2,073	1,074	3,607	16.0
2	ALLIANT ENERGY	538	399	542	879	1,203	867	673	1,158	798	903	1,034	-3.7	3.6	6.8	1,165	1,330	1,275	7.2
3	AMEREN	935	992	1,381	1,896	1,710	1,042	881	1,063	1,379	1,785	1,917	21.7	13.0	7.4	2,155	2,234	2,234	5.2
4	AMERICAN ELECTRIC POWER	2,404	3,528	3,556	3,800	2,792	2,345	2,669	3,025	3,624	4,130	4,508	14.2	14.0	6.5	5,062	5,001	5,000	3.5
5	AVANGRID INC.	331	408	444	516	324	593	822	1,789	944	1,030	1,082	-15.4	12.8	12.6	1,900	1,900	1,900	20.6
6	CMS ENERGY	593	670	1,263	792	818	821	882	1,227	1,325	1,577	1,564	8.4	13.8	10.2	1,700	1,700	1,700	2.8
7	CONSOLIDATED EDISON	1,636	1,853	1,934	2,326	2,193	2,029	1,967	2,069	2,538	2,419	3,054	13.9	8.5	6.4	5,281	3,686	3,682	6.4
8	DOMINION RESOURCES	3,358	4,052	3,972	3,554	3,837	3,422	3,652	4,145	4,065	5,345	5,575	10.4	10.3	5.2	6,910	4,852	4,253	-8.6
9	DTE ENERGY	1,065	1,403	1,299	1,373	1,035	1,099	1,484	1,820	1,876	2,049	2,020	3.5	12.9	6.6	2,085	1,876	1,868	-2.6
10	DUKE ENERGY	2,413	3,470	3,216	4,533	4,433	4,855	4,413	5,507	5,607	5,474	7,029	8.5	7.7	11.3	9,220	8,775	8,300	5.7
11	EDISON INTERNATIONAL	1,868	2,536	2,826	2,824	3,282	4,543	4,122	4,149	3,599	3,906	4,225	0.6	-1.4	8.5	3,700	4,400	5,000	5.8
12	EL PASO ELECTRIC CO.	88	103	145	199	210	170	178	202	237	277	281	11.6	10.6	12.3	234	156	182	-13.5
13	ENTERGY	1,458	1,633	1,578	2,212	1,931	1,974	2,040	2,675	2,288	2,119	2,501	-2.2	4.8	5.5	4,021	3,617	3,667	13.6
14	EVERSOURCE ENERGY	775	872	1,115	1,255	908	954	1,077	1,472	1,457	1,604	1,724	5.4	12.6	8.3	2,084	2,546	2,529	13.6
15	EXELON CORP.	2,165	2,418	2,674	3,117	3,273	3,326	4,042	5,789	5,395	6,077	7,624	9.6	18.0	13.4	8,650	8,000	7,225	-1.8
16	FIRSTENERGY	1,208	1,315	1,633	2,888	2,203	1,780	2,129	2,678	2,638	3,312	2,704	0.3	8.7	8.4	2,977	2,799	2,554	-1.9
17	NEXTERA ENERGY	2,546	3,739	5,019	5,236	6,006	5,846	6,628	9,461	6,682	7,017	8,377	-4.0	7.5	12.6	9,145	4,510	3,745	-23.5
18	GREAT PLAINS ENERGY	327	476	512	1,024	841	618	457	610	669	774	677	3.5	1.8	7.5	680	581	541	-7.2
19	IDACORP INC.	193	222	287	244	252	338	338	240	247	274	294	7.0	-2.8	4.3	305	280	297	0.3
20	HAWAIIAN ELECTRIC INDUSTRIES	224	211	218	282	305	182	235	371	389	365	364	-0.6	14.8	5.0	450	480	500	11.2
21	NORTHWESTERN CORP.	81	101	117	125	189	228	189	219	230	270	284	9.0	4.4	13.4	308	324	365	8.8
22	OGE ENERGY	297	487	558	1,185	848	880	1,270	1,151	991	569	548	-21.9	-9.0	6.3	665	900	540	-0.5
23	PG&E CORP.	1,804	2,402	2,769	3,628	3,958	3,802	4,038	4,624	5,207	4,833	5,173	3.8	6.4	11.1	5,569	5,950	5,950	4.8
24	PINNACLE WEST CAPITAL	661	738	960	936	765	748	884	890	1,016	911	1,076	6.6	7.5	5.0	1,205	1,307	1,124	1.5
25	PNM RESOURCES	211	321	456	345	288	281	327	309	348	461	559	21.8	14.7	10.2	568	415	398	-10.7
26	PORTLAND GENERAL ELECTRIC	255	371	455	383	696	450	300	303	656	1,007	598	25.4	5.9	8.9	648	402	318	-19.0
27	PPL CORP.	811	1,394	1,657	1,418	1,225	1,597	2,487	3,105	4,212	3,674	3,533	4.4	17.2	15.9	3,160	3,070	3,040	-4.9
28	PUBLIC SRV. ENT. GROUP	1,053	1,015	1,348	1,771	1,794	2,160	2,083	2,574	2,811	2,820	3,863	14.5	12.3	13.9	4,380	4,100	3,852	-0.1
29	SOUTHERN COMPANY	2,370	2,994	3,546	3,961	4,670	4,086	4,525	4,809	5,331	5,246	5,674	5.7	6.8	9.1	10,500	5,200	5,500	-1.0
30	WESTAR ENERGY	213	345	748	937	556	540	697	810	780	852	700	-4.7	5.3	12.6	1,102	704	703	0.1
31	WEC ENERGY GROUP	745	929	1,212	1,136	815	798	831	707	687	761	1,266	21.4	9.7	5.4	1,974	2,349	2,046	17.3
32	XCEL ENERGY	1,311	1,628	2,097	2,114	1,778	2,216	2,206	2,570	3,395	3,200	3,683	12.7	10.7	10.9	3,060	2,975	3,120	-5.4
	Total Electric ($M)	34,765	44,484	51,961	59,737	57,656	56,902	60,956	73,629	73,410	77,056	85,820	5.2	8.6	9.5	102,936	87,495	87,014	0.5
	GAS																		
33	ATMOS ENERGY CORP.	333	425	392	472	509	543	623	733	845	835	975	10.0	12.4	11.3	1,100	1,100	1,200	7.2
34	CENTERPOINT ENERGY	693	1,007	1,114	1,020	1,160	1,509	1,303	1,212	1,286	1,372	1,584	9.3	1.0	8.6	1,318	1,256	1,170	-9.6
35	MDU RESOURCES GROUP INC.	378	480	558	746	449	449	497	873	909	608	625	-10.5	6.8	5.2	386	471	470	-9.1
36	NISOURCE	590	627	787	1,300	777	801	1,123	1,499	1,880	1,283	1,361	-3.2	11.2	8.7	1,506	1,387	1,387	0.6
37	ONE Gas #	NA	NA	NA	NA	NA	NA	NA	272	292	297	294	2.7	NA	NA	305	310	315	2.3
38	SCANA CORP.	385	527	725	904	914	876	884	1,077	1,106	1,092	1,153	2.3	5.6	11.6	1,656	2,097	1,659	12.9
39	SEMPRA ENERGY	1,377	1,907	2,011	2,061	1,912	2,062	2,844	2,956	2,572	3,123	3,156	2.2	8.9	8.6	5,620	2,645	2,645	-5.7
40	SOUTHWEST GAS	294	345	341	300	217	215	381	396	364	397	488	7.2	17.8	5.2	460	500	540	3.4
41	SPIRE INC.	60	63	59	57	52	57	68	109	131	171	290	38.6	38.4	17.0	310	365	370	8.5
42	VECTREN CORP.	232	281	335	391	432	277	321	366	393	448	477	9.2	11.5	7.5	510	490	430	-3.4
43	WGL HOLDINGS	113	160	165	135	139	130	202	251	312	395	464	22.7	29.0	15.2	725	810	710	15.2
	Total Gas ($M)	4,455	5,823	6,486	7,386	6,562	6,920	8,245	9,743	10,091	10,021	10,868	3.7	9.4	9.3	13,895	11,431	10,896	0.1
	Total ($M)	39,220	50,307	58,447	67,124	64,218	63,822	69,201	83,372	83,502	87,077	96,687	5.1	8.7	9.4	116,832	98,925	97,910	0.4

Became public in 2014

Source: SNL Energy, company surveys, and RRA adjustments

Table 2 **Utility depreciation, CapEx, and operating cash flow**

	2015					2010					2005				
	Depr. & amort.	CapEx	Operating cash flow	CapEx/ D&A	CapEx/ OCF	Depr. & amort.	CapEx	Operating cash flow	CapEx/ D&A	CapEx/ OCF	Depr. & amort.	CapEx	Operating cash flow	CapEx/ D&A	CapEx/ OCF
ELECTRIC															
1 AES CORP.	1,144	2,308	2,134	2.0	1.1	1,178	2,310	3,465	2.0	0.7	864	826	2,232	1.0	0.4
2 ALLIANT ENERGY	414	1,034	871	2.5	1.2	344	867	985	2.5	0.9	390	538	565	1.4	1.0
3 AMEREN	777	1,917	2,017	2.5	1.0	746	1,042	1,823	1.4	0.6	656	935	1,251	1.4	0.7
4 AMERICAN ELECTRIC POWER	2,010	4,508	4,819	2.2	0.9	1,641	2,345	2,662	1.4	0.9	1,348	2,404	1,877	1.8	1.3
5 AVANGRID INC.	709	1,082	1,361	1.5	0.8	284	593	696	2.1	0.9	383	331	505	0.9	0.7
6 CMS ENERGY	750	1,564	1,640	2.1	1.0	576	821	959	1.4	0.9	525	593	598	1.1	1.0
7 CONSOLIDATED EDISON	1,130	3,054	3,277	2.7	0.9	840	2,029	2,381	2.4	0.9	584	1,636	790	2.8	2.1
8 DOMINION RESOURCES	1,669	5,575	4,475	3.3	1.2	1,258	3,422	1,825	2.7	1.9	1,538	3,358	2,623	2.2	1.3
9 DTE ENERGY	852	2,020	1,911	2.4	1.1	1,027	1,099	1,825	1.1	0.6	872	1,065	1,001	1.2	1.1
10 DUKE ENERGY	3,613	7,029	6,676	1.9	1.1	1,994	4,855	4,511	2.4	1.1	1,884	2,413	2,818	1.3	0.9
11 EDISON INTERNATIONAL	2,005	4,225	4,509	2.1	0.9	1,522	4,543	3,477	3.0	1.3	1,061	1,868	2,247	1.8	0.8
12 EL PASO ELECTRIC CO.	90	281	247	3.1	1.1	81	170	239	2.1	0.7	82	88	107	1.1	0.8
13 ENTERGY	2,117	2,501	3,291	1.2	0.8	1,705	1,974	3,926	1.2	0.5	1,002	1,458	1,468	1.5	1.0
14 EVERSOURCE ENERGY	666	1,724	1,424	2.6	1.2	301	954	1,093	3.2	0.9	440	775	441	1.8	1.8
15 EXELON CORP.	2,281	7,624	7,616	3.3	1.0	1,144	3,326	5,244	2.9	0.6	1,582	2,165	2,147	1.4	1.0
16 FIRSTENERGY	1,282	2,704	3,447	2.1	0.8	750	1,780	3,076	2.4	0.6	588	1,208	2,220	2.1	0.5
17 NEXTERA ENERGY	2,831	8,377	6,116	3.0	1.4	1,788	5,846	3,834	3.3	1.5	1,397	2,546	1,547	1.8	1.6
18 GREAT PLAINS ENERGY	378	677	753	1.8	0.9	327	618	552	1.9	1.1	164	327	417	2.0	0.8
19 IDACORP INC.	143	294	353	2.1	0.8	122	338	305	2.8	1.1	124	193	161	1.6	1.2
20 HAWAIIAN ELECTRIC INDUSTRIES	196	364	356	1.9	1.0	159	182	341	1.1	0.5	142	224	220	1.6	1.0
21 NORTHWESTERN CORP.	145	284	340	2.0	0.8	92	228	219	2.5	1.0	74	81	147	1.1	0.6
22 OGE ENERGY	308	548	865	1.8	0.6	291	880	783	3.0	1.1	183	297	438	1.6	0.7
23 PG&E CORP.	2,612	5,173	3,753	2.0	1.4	1,905	3,802	3,206	2.0	1.2	1,698	1,804	2,409	1.1	0.7
24 PINNACLE WEST CAPITAL	572	1,076	1,094	1.9	1.0	473	748	750	1.6	1.0	389	661	760	1.7	0.9
25 PNM RESOURCES	223	559	387	2.5	1.4	186	281	287	1.5	1.0	158	211	210	1.3	1.0
26 PORTLAND GENERAL ELECTRIC	305	598	517	2.0	1.2	238	450	391	1.9	1.2	233	255	372	1.1	0.7
27 PPL CORP.	942	3,533	2,615	3.8	1.4	780	1,597	2,033	2.0	0.8	423	811	1,388	1.9	0.6
28 PUBLIC SRV. ENT. GROUP	1,214	3,863	3,919	3.2	1.0	974	2,160	2,164	2.2	1.0	767	1,053	970	1.4	1.1
29 SOUTHERN COMPANY	2,395	5,674	6,274	2.4	0.9	1,831	4,086	3,991	2.2	1.0	1,398	2,370	2,530	1.7	0.9
30 WESTAR ENERGY	311	700	715	2.3	1.0	272	540	608	2.0	0.9	151	213	354	1.4	0.6
31 WEC ENERGY GROUP	584	1,266	1,294	2.2	1.0	317	798	810	2.5	1.0	350	745	579	2.1	1.3
32 XCEL ENERGY	1,143	3,683	3,026	3.2	1.2	872	2,216	1,894	2.5	1.2	782	1,311	1,184	1.7	1.1
Total Electric ($M)				**2.4**	**1.0**				**2.2**	**0.9**				**1.5**	**1.0**
GAS															
33 ATMOS ENERGY CORP.	276	975	837	3.5	1.2	217	543	726	2.5	0.7	179	333	387	1.9	0.9
34 CENTERPOINT ENERGY	970	1,584	1,865	1.6	0.8	864	1,509	1,386	1.7	1.1	541	693	63	1.3	11.0
35 MDU RESOURCES GROUP INC.	228	625	641	2.7	1.0	329	449	552	1.4	0.8	219	378	484	1.7	0.8
36 NISOURCE	524	1,361	1,457	2.6	0.9	595	801	725	1.3	1.1	544	590	712	1.1	0.8
37 ONE Gas #	133	294	394	2.2	0.7	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38 SCANA CORP.	368	1,153	1,059	3.1	1.1	341	876	811	2.6	1.1	518	385	467	0.7	0.8
39 SEMPRA ENERGY	1,250	3,156	2,905	2.5	1.1	866	2,062	2,154	2.4	1.0	626	1,377	534	2.2	2.6
40 SOUTHWEST GAS	270	488	547	1.8	0.9	190	215	371	1.1	0.6	156	294	238	1.9	1.2
41 SPIRE INC.	131	290	322	2.2	0.9	38	57	107	1.5	0.5	27	60	103	2.3	0.6
42 VECTREN CORP.	256	477	505	1.9	0.9	229	277	385	1.2	0.7	158	232	268	1.5	0.9
43 WGL HOLDINGS	122	464	504	3.8	0.9	94	130	291	1.4	0.4	90	113	232	1.3	0.5
Total Gas ($M)				**2.6**	**1.0**				**1.7**	**0.8**				**1.6**	**2.0**
Total ($M)				**2.4**	**1.0**				**2.1**	**0.9**				**1.6**	**1.2**

Became public in 2014

Source: SNL Energy, company surveys, and RRA adjustments

Table 3 — Utility forecast CapEx by category

Companies with Segment Breakdown ("Above the line")

(Amount $M)	Note	Generation 2016	Generation 2017	Generation 2018	Generation 2019	Generation 2020	% '16-'18 Total	Electric T&D** 2016	Electric T&D** 2017	Electric T&D** 2018	Electric T&D** 2019	Electric T&D** 2020	% '16-'18 Total	Environmental 2016	Environmental 2017	Environmental 2018	Environmental 2019	Environmental 2020	% '16-'18 Total
Electric																			
AES CORP.	4	1,508	850	2,580	740									454	224				
ALLIANT ENERGY	4	470	435	350	275		33%	300	425	515	565		33%	110	75	55	15		6%
AMERICAN ELECTRIC POWER	4	502	502	502			10%	3,705	3,705	3,705			74%	353	292	291			6%
AVANGRID INC.	4,5							1,005	1,005	1,005	1,005	1,005							
CMS ENERGY	4,5				100	100	0%	914	914	914	914	914	54%	157	157	157	157	157	9%
CONSOLIDATED EDISON								2,176	2,139	2,109			51%						
DOMINION RESOURCES	4	2,507	1,384	1,229			32%	1,586	1,500	1,524			29%	232	161	70	300	300	
DTE ENERGY	4,7,9	155	73	210	336	464	8%	611	674	630	599	624	33%						0%
DUKE ENERGY	3,4	1,975	1,550	1,325	1,625	1,525	18%	3,270	3,588	3,650	4,075	3,788	40%	775	725	525	300	325	8%
EDISON INTERNATIONAL	4,6	200	200	200	200	200	5%	3,500	4,200	4,800	4,900	4,700	95%						
ENTERGY	1,2	2,286	1,687	1,927			52%	1,455	1,730	1,565			42%						
EL PASO ELECTRIC CO.	7	110	41	81	120	179	41%	78	91	79	94	86	43%						
EVERSOURCE ENERGY	4	20					0%	1675	2140	2108	1888		83%						
EXELON CORP.		3,025	2,575	1,950			32%	5,050	4,825	4,650	4,150	4,050	61%						
GREAT PLAINS ENERGY	2	252	238	230	201	243	40%	229	197	192	217	204	34%	100	46	21	99	152	9%
HAWAIIAN ELECTRIC INDUSTRIES	4	124	132	138			28%	265	283	294			59%						
IDACORP INC.	4,5	33	33	33	33	33	11%	125	125	125	125	125	43%	23	0	15	15	15	4%
NEXTERA ENERGY	2,4	2,175	1,370	950	1,000	1,025	26%	1,930	1,990	1,985	2,485	2,335	34%						
NORTHWESTERN CORP.	4		20	65	88	14	9%	255	249	237	242	176	74%						
OGE ENERGY	4	200	235	100	75	75	25%	300	385	245	225	225	44%	105	200	130	50		21%
PG&E CORP.	4,5	699	742	747	747	747		3,223	3,249	3,443	3,443	3,443							
PNM RESOURCES		293	163	168	94		45%	238	233	216	244		50%						
PINNACLE WEST CAPITAL		297	459	402			32%	481	563	537			43%	227	201	103			15%
PORTLAND GENERAL ELECTRIC	4	398	179	142	127	135	53%	238	219	174	155	166	46%						
PPL CORP.	2	550	590	550	580	670	18%	2,210	2,130	2,050	2,000	2,080	69%	400	350	440	400	350	13%
PUBLIC SRV. ENT. GROUP	4	1253	974	656	303	347	23%	2,777	2,712	2,702	2506	2492	66%	41	50	59	62	41	1%
SOUTHERN COMPANY	2	3,300	2,700	2,900			42%	1,400	1,600	1,600			22%	700	500	600			8%
WESTAR ENERGY	2	190	225	210			25%	364	377	405			46%	85	27	15			5%
WEC ENERGY GROUP	8	304	368	438	358	277	17%	741	849	675	463	456	36%						
XCEL ENERGY	2	955	630	625	615	550	24%	1,345	1,600	1,665	1,770	1,810	50%						
Total - Electric ($M)		23,780	18,354	18,706				41,447	43,697	43,801				3,761	3,007	2,480			
Gas																			
ATMOS ENERGY CORP.	5																		
CENTERPOINT ENERGY								833	786	735	685	686	63%						
MDU RESOURCES GROUP INC.	4	72	91	92	95	95	19%	60	66	66	66	66	14%	15	4	3			2%
NISOURCE	4,6							400	368	368			27%						
ONE Gas #	5																		
SCANA CORP.	2	1,163	1,551	1,160			72%	192	163	187			10%						
SEMPRA ENERGY	4,5							710	508	508	508	508	16%						
SOUTHWEST GAS	5																		
SPIRE INC.																			
VECTREN CORP.	4							95	95	115	100	90	21%						
WGL HOLDINGS																			
Total - Gas ($M)		1,235	1,642	1,252				2,290	1,986	1,979	1,359	1,350		15	4	3			
Companies without Segment Breakdown ("Below the line")*																			
AMEREN	5																		
FIRSTENERGY	6																		
Total - ($M)																			
Grand total ($M)																			

(Amount $M)	Renewables 2016	Renewables 2017	Renewables 2018	Renewables 2019	Renewables 2020	% '16-'18 Total	Gas Pipeline/Storage/Distribution/ and other 2016	Gas 2017	Gas 2018	Gas 2019	Gas 2020	% '16-'18 Total	Corporate / Other 2016	Corporate / Other 2017	Corporate / Other 2018	Corporate / Other 2019	Corporate / Other 2020	% '16-'18 Total	Total 2016	Total 2017	Total 2018	Total 2019	Total 2020	3 Year Total*** '16-'18
Electric																								
AES CORP.	111		1027	1027															2,073	1,074	3,607	1,767		6,754
ALLIANT ENERGY							200	225	195	160		16%	85	170	160	200		11%	1,165	1,330	1,275	1,215		3,770
AMERICAN ELECTRIC POWER												0%	502	502	502			10%	5,062	5,001	5,000			15,063
AVANGRID INC.	560	560	560	560	560		281	281	281	281	281	15%	54	54	54	54	54	3%	1,900	1,900	1,900	1,900	1,900	5,700
CMS ENERGY							629	629	629	629	629	37%							1,700	1,700	1,700	1,800	1,800	5,100
CONSOLIDATED EDISON							1,870	1,147	1,173			33%	1,235	400	400			16%	5,281	3,686	3,682			12,649
DOMINION RESOURCES				300	300		2,540	1,766	1,391	600	600	36%	45	41	39	300	300	1%	6,910	4,852	4,253			16,015
DTE ENERGY							430	375	265	265	265	18%	889	754	763	845	714	41%	2,085	1,876	1,868	2,045	2,067	5,829
DUKE ENERGY	1000	500	500	500	500	8%	1,875	2,188	2,100	1,425	1,388	23%	325	225	200	200	200	3%	9,220	8,775	8,300	8,125	7,725	26,295
EDISON INTERNATIONAL												0%							3,700	4,400	5,000			13,100
ENTERGY													280	200	175			6%	4,021	3,617	3,667			11,305
EL PASO ELECTRIC CO.													45	24	22	17	17	16%	234	156	182	232	283	572
EVERSOURCE ENERGY							284	318	339	357	357	13%	105	88	82	87		4%	2,084	2,546	2,529	2,332		7,159
EXELON CORP.	100	100	100			1%	475	500	525	525	550	6%							8,650	8,000	7,225			23,875
GREAT PLAINS ENERGY												0%	100	100	99	57	69	17%	680	581	541	573	668	1,802
HAWAIIAN ELECTRIC INDUSTRIES	61	65	68									0%						0%	450	480	500			1,430
IDACORP INC.	33	15	15	15	15	7%						0%	93	108	109	109	109	35%	305	280	297	297	297	882
NEXTERA ENERGY	3280	85	30	25	25	20%	1,020	740	465	35	15	13%	740	325	315	235	250	8%	9,145	4,510	3,745	3,780	3,650	17,400
NORTHWESTERN CORP.						0%	53	56	64	59	81	17%							308	324	365	389	270	998
OGE ENERGY												0%	60	80	65	25	25	10%	665	900	540	375	325	2,105
PG&E CORP.							1,647	1,741	1,760	1,760	1,760								5,569	5,950	5,950	5,950	5,950	17,469
PNM RESOURCES						0%						0%	37	19	14	15	15	5%	568	415	398	353	15	1,381
PINNACLE WEST CAPITAL	107	1	1			3%						0%	93	83	81			7%	1,205	1,307	1,124			3,636
PORTLAND GENERAL ELECTRIC	12	4	2	1	15	1%						0%							648	402	318	283	316	1,368
PPL CORP.												0%						0%	3,160	3,070	3,040	2,980	3,100	9,270
PUBLIC SRV. ENT. GROUP	63	42	35	28	0	1%	240	305	315			7%	6	18	85	6	0	1%	4,380	4,100	3,852			12,332
SOUTHERN COMPANY	3900						800					4%	400	400	400			6%	10,500	5,200	5,500			21,200
WESTAR ENERGY	399	1	1									0%	64	75	72			8%	1,102	704	703			2,509
WEC ENERGY GROUP							843	1,071	837	858	866	43%	86	61	96	97	99	4%	1,974	2,349	2,046	1,776	1,698	6,369
XCEL ENERGY		120	250	110			390	335	395	390	400	12%	370	290	185	185	180	9%	3,060	2,975	3,120	3,070	2,940	9,155
Total - Electric ($M)	9,625	1,493	2,588				13,577	11,676	10,734				5,613	4,016	3,917				**97,804**	**82,461**	**82,226**			**262,491**
Gas																								
ATMOS ENERGY CORP.							1,050	1,100	1,200	1,300	1,400	99%							1,100	1,100	1,200	1,300	1,400	3,400
CENTERPOINT ENERGY							485	470	435	430	430	37%							1,318	1,256	1,170	1,115	1,116	3,744
MDU RESOURCES GROUP INC.							172	218	218	218	218	46%	67	92	91	92	91	19%	386	471	470	471	470	1,327
NISOURCE							1,100	1,013	1,013			73%	6	6	6			0%	1,506	1,387	1,387			4,279
ONE Gas #							305	310	315	320	325	100%							305	310	315	320	325	930
SCANA CORP.							259	342	272			16%	42	41	40			2%	1,656	2,097	1,659			5,412
SEMPRA ENERGY	950	103	103	103	103	11%	3,960	2,034	2,034	2,034	2,034	74%							5,620	2,645	2,645	2,645	2,645	10,910
SOUTHWEST GAS							460	500	540			100%							460	500	540			1,500
SPIRE INC.							310	365	370	435	335	100%							310	365	370	435	335	1,045
VECTREN CORP.							375	365	275	275	275	71%	40	30	40	70	50	8%	510	490	430	445	415	1,430
WGL HOLDINGS	165	100	100	100	100	16%	547	710	610	414	435	83%	12	0	0	0	0	1%	725	810	710	514	536	2,245
Total - Gas ($M)	1,115	203	203	203	203		9,023	7,426	7,282	5,426	5,452		167	169	177	162	141		**13,895**	**11,431**	**10,896**			**36,222**
Companies without Segment Breakdown ("Below the line")*																								
AMEREN																			2,155	2,234	2,234	2,234	2,234	6,624
FIRSTENERGY																			2,977	2,799	2,554			8,330
Total - ($M)																			**5,132**	**5,034**	**4,788**			**14,954**
Grand total ($M)																			**116,832**	**98,925**	**97,910**			**313,667**

Source: SNL Energy, company surveys, and RRA adjustments.

Notes to Table 3:

1 Entergy Wholesale Commodities included as part of generation spending

2 Nuclear spending included in generation

3 Includes potential capital expenditures that may not be realized

4 Capital expenditures calculated, apportioned, and/or estimated per RRA adjustments

5 Average shown for any range provided by the company

6 CapIQ median consensus estimates for years in which company has not provided data

7 Capital expenditure estimates determined by RRA through the use of digitized, X-Y located company disclosed charts and graphs

8 Electric T&D includes capital contributions to American Transmission Company projects averaging $317 million per year 2016-2018

9 Generation spending reflects new generation projects only. Corp./Other includes maintenance, other expansion, and other investments within electric that were not separately disclosed

* Classification by business type unavailable for some or all years, resulting in "below the line" listing

** Electric T&D includes Smart Metering/AMI

*** Percentages of three-year total shown next to each category

\# Became public in 2014

S&P Global
Ratings

Industry Top Trends 2019

North America Regulated Utilities

November 8, 2018

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Key Takeaways

- **Ratings Outlook:** Rating trends across regulated electric, gas, and water utilities in North America remain mostly stable, reflecting generally supportive regulatory oversight. However, the industry's financial measures weakened in 2018 as a result of U.S. tax reform, robust capital spending, and flat to slightly negative load growth. In general, those utilities most affected by these developments were those who strategically operate with a minimal financial cushion at their current rating.
- **Forecasts:** We expect only modest financial improvement in 2019, reflecting somewhat improving margins partially offset by rising debt. Margin improvement will reflect productivity improvements from technological investments, favorable fuel cost trends, and higher revenues from robust capital investments and acquisitions.
- **Assumptions:** We expect overall capital spending to remain elevated through 2020, primarily due to rising infrastructure spending needs. Sales growth will generally remain flat to slightly negative, reflecting customer growth offset by conservation.
- **Risks and Opportunities:** To grow, utilities are merging and acquiring higher-risk businesses outside of the industry. The transformation of fossil generation to renewables provides utilities with an opportunity to grow while reducing their environmental risks. Also, increasing electric vehicles sales will lead to higher load growth, partially offsetting the negative effects of conservation.
- **Industry Trends:** The North America utility industry is mostly stable with some downside ratings exposure. Weaker credit measures from tax reform will likely persist in 2019, reflecting tax-related rate reductions carryovers. However, we expect that some utilities will offset this reduced revenue with further equity infusions or asset sales. Other developing trends include rising interest rates, inflation, technology, climate change, and regulatory lag, which could further stress the industry's credit quality.

Ratings trends and outlook

North America Regulated Utilities

Chart 1

Ratings distribution

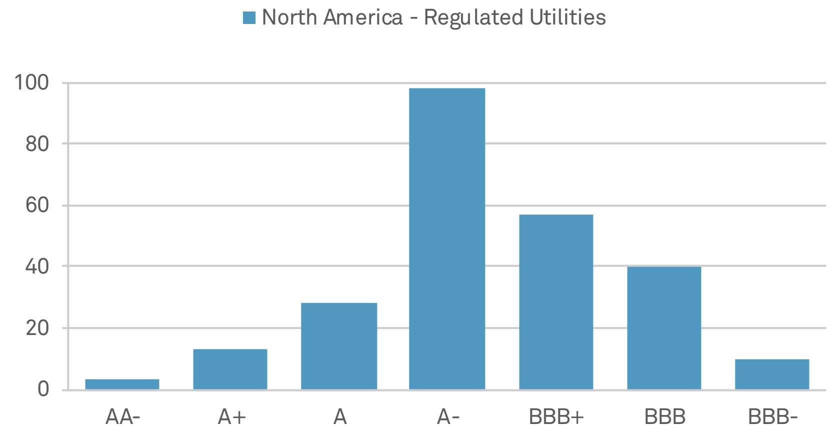


Chart 2

Ratings outlooks

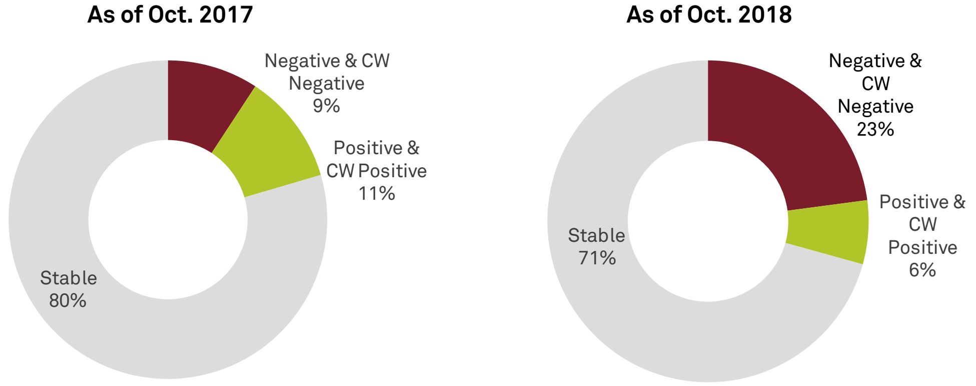
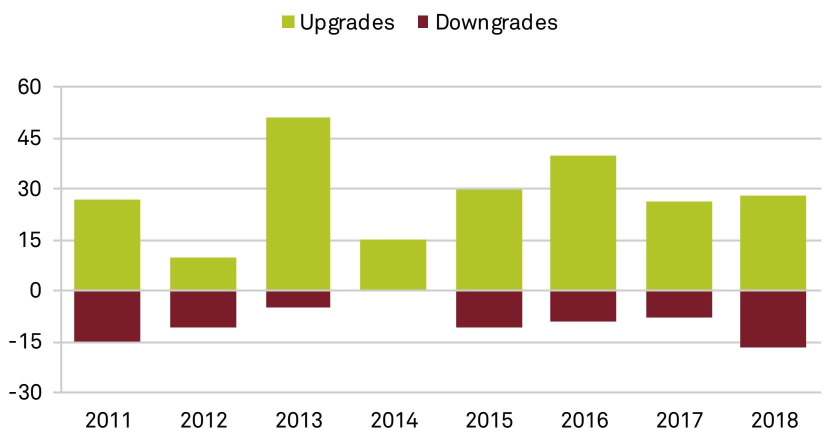


Chart 3

Ratings upgrades and downgrades



Source: S&P Global Ratings. Ratings data as of October 15, 2018

Industry credit metrics

North America Regulated Utilities

Chart 4

Debt / EBITDA (median, adjusted)

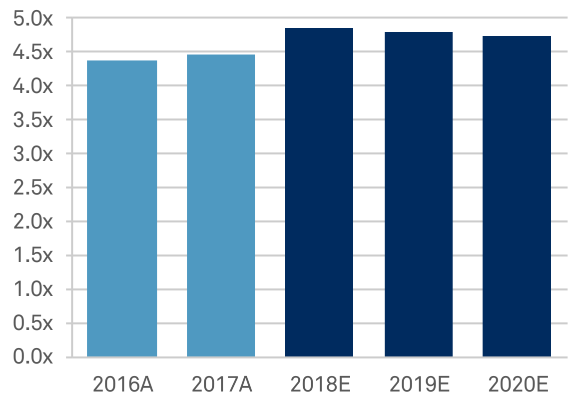


Chart 5

FFO / Debt (median, adjusted)

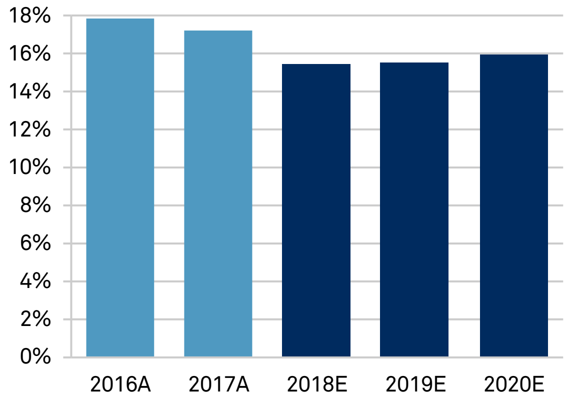


Chart 6

Cash flow and primary uses

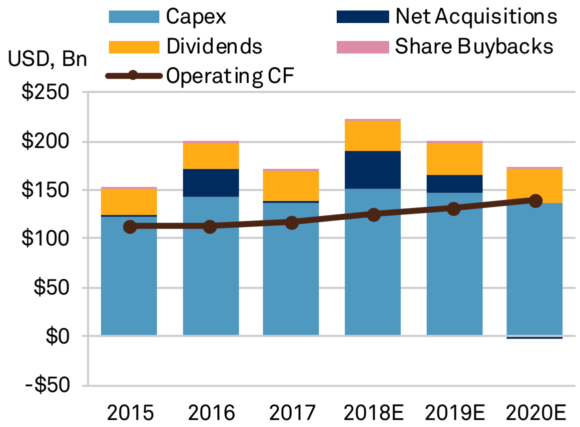


Chart 7

Equity Issuance

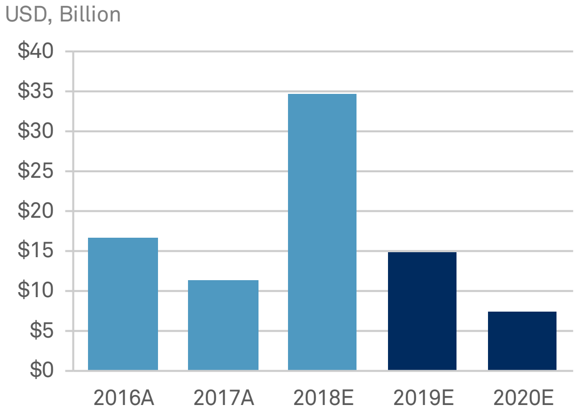
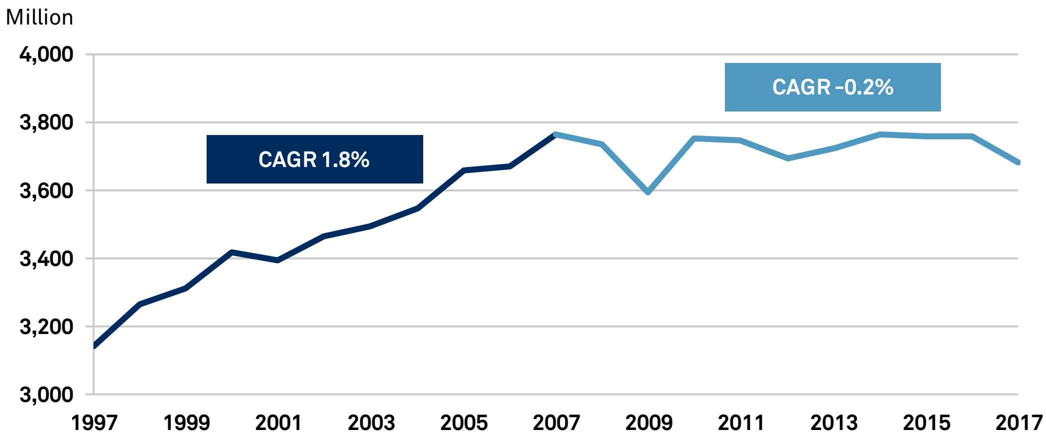


Chart 8

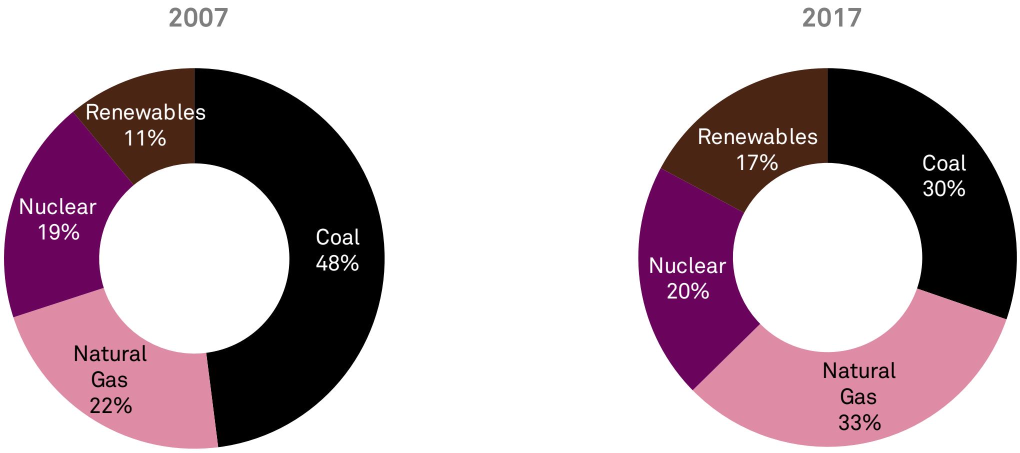
Total U.S. megawatt hours sold



Source: S&P Global Ratings, S&P Global Market Intelligence, EIA U.S. sales growth 1990-2016. FFO--Funds from operations.

Chart 9

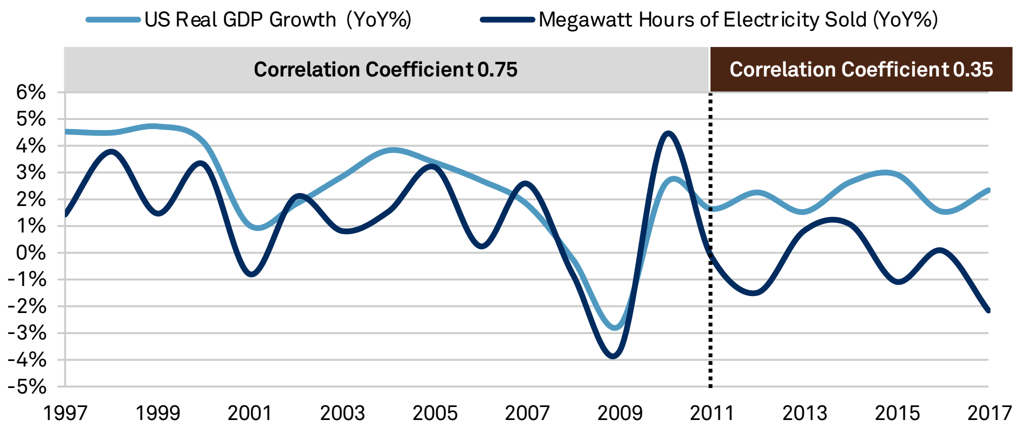
Generation Mix By Energy Source



Source: S&P Global Ratings, S&P Global Market Intelligence

Chart 10

Correlation Of U.S. GDP and Electricity Sales



Source: S&P Global Ratings

Industry outlook

Key assumptions

1. Conservation has reduced demand tied to economic growth

Historically, a strong correlation existed between economic growth and the demand for electricity. Since 2011, conservation has significantly curtailed sales growth, leading to a very weak correlation between utility sales and economic growth. Our base case incorporates flat to slightly negative sales growth over the next three years, reflecting new customer growth offset by conservation. To achieve growth, we expect that utilities will pursue mergers with other utilities as well as acquisitions of slightly higher-risk businesses outside of the direct utility industry.

2. Regulation and public policy support earnings and cash flow

We expect that regulators will continue to provide utilities with constructive frameworks that support credit quality. For most regulators, the requirement that utilities provide safe, reliable, and affordable utility services remains a priority. This regulatory perspective is balanced against an increasing awareness that the utility infrastructure in North America is aging, and that utilities may have to invest necessary capital to maintain and improve the infrastructure apparatus for electric, gas, and water systems. Such regulated infrastructure capital spending most often translates to low-risk rate base growth. In addition, regulatory support ensuring timely recovery of costs generally remains favorable for utilities' credit quality. Numerous cost recovery riders, trackers, and forward mechanisms provide more timely recovery of utility costs and reduce the regulatory lag. As such, we expect low-risk rate base growth to drive utilities' earnings and cash flows despite flat to slightly negative sales growth. From a public policy perspective, we also expect utilities will be given sufficient time to adapt to various public policy initiatives, including those relating to renewable energy, grid resilience, reduced emissions, improved technology, and higher safety standards.

3. Elevated capital spending to meet infrastructure needs

We assume that capital spending for North America's regulated electric, gas and water utilities will remain robust for 2019 and 2020 at about $140 billion annually. In general, we expect that the industry will invest in smaller scale infrastructure projects that improve safety and reliability and boost productivity. Capital spending can provide margin growth when sales are diminished by recovering investments made on a growing rate base and by reducing cost through technology investments. Furthermore, capital spending is often welcomed by policymakers that appreciate the economic stimulus and the benefits of a safer and more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for the capital investment is an important factor in our assumptions and forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and therefore ratings. Investments in new generation with reduced emissions will drive higher capital spending. These types of investments would focus on renewable and natural gas-fired generation. Other areas of investment would include smart grids, electric vehicle charging stations, batteries, mergers within the industry, and acquisitions outside of the utility industry.

4. Generally flat operating and maintenance expense

We expect utilities to continue to lower operating and maintenance expenses through productivity initiatives and technological improvements. Because utilities earn on their capital investments, each dollar saved in operating expense provides headroom in the customer bill for increased capital investments, boosting a utility's financial performance without excessively increasing the customer bill. The deployment of technology such as digital meters can increase efficiency of operations while also securing the integrity of a utility's operations. Furthermore, investing in solar generation not only reduces operating and environmental risks, compared to fossil fuel generation, but also lowers a utility's operating and maintenance expenses. A solar generation installation requires very few people to operate, which reduces maintenance expenses, and it does not require any fossil fuel to generate electricity. As a comparison, coal generation burns fossil fuel to generate electricity and a nuclear generating facility could require thousands of employees to safely operate and maintain the facility.

5. Equity, hybrids, and asset sales to support credit quality

In2018, North America regulated utilities took steps to preserve credit quality, by issuing common equity and hybrid securities, and by selling assets to support their financial measures. In particular, the industry utilities issued about $35 billion of common equity in 2018, compared to about $10 billion in 2017 and about $15 billion in 2016. Driving this trend were weaker financial measures because of U.S. tax reform, robust capital spending, and M&A. For 2019, we expect equity issuance to temper to about $15 billion. Credit quality remains important to the utility industry and the large 2018 equity issuances demonstrates that utilities will take the necessary steps to protect credit quality when facing financial challenges.

Key risks and opportunities

1. Mergers and acquisitions

In order to respond to sector challenges and disruption, we expect continued M&A activity despite rising interest rates. Due to conservation and sluggish load growth, two primary M&A strategies have developed within the industry. The first is to grow the absolute size of the utility business across multiple states and regulatory jurisdictions. This strategy attempts to reduce costs by identifying synergies and implements best practices across utilities. Canadian and U.S. utilities have also been focusing on growing by diversifying their utility portfolio (gas utilities buying electric utilities and vice versa, and even an electric/gas utility holding company acquiring water utilities) or cross-border combinations (mostly Canadian holding companies acquiring U.S. utilities). The second strategy is to grow through the acquisition of slightly higher-risk businesses (contracted assets) outside of the utility industry. Low interest rates by historical standards, strong stock prices, and plentiful leverage have justified paying large multiples of late. We've also seen holding companies once again thinking about rationalizing their portfolios with selective sales and purchases of smaller, less strategic utilities to gain scale within a jurisdiction or exit if scale is not feasible. Cost of capital has been slowly rising but is still well below the historical average. As a result, 2019 could bring more transactions before higher interest rates start to dissuade purchasers.

2. Generation transformation and disruption

Regulated electric utilities have been modifying their generation fleets to reduce emissions from power plants, electing to close aging coal plants and build low or zero emissions generation. Utilities have been shifting away from building bigger baseload generating stations, particularly coal and nuclear, to more modular construction that can be scaled up at an existing site on an as-needed basis. Improved economics associated with renewable generation support this trend, and utilities are able to benefit from efficiencies of scale.

These scale efficiencies along with a reduction in costs will support increased investments in utility-scale renewable generation. Electricity generated from renewables and natural gas has increased in recent years due to economics and regulation. During the past decade, electricity generated from coal has decreased to about 30% from about 50%. We believe this trend will continue as utility management teams proactively work to reduce greenhouse gas emitting power plants and add generation sources with low or zero emissions.

While renewable generation is being added to the electric grid, renewable sources can be intermittent and may not create electricity when needed. Sunshine, wind, and water flow are not constant and therefore electricity storage capacity is needed to offset this intermittency when consumption exceeds supply. As battery costs have declined, utilities have begun to install batteries as a way to store the unused electricity generated so it will be available when demand outstrips generation. The combination of renewable generation and batteries for storage will present new growth opportunities for electric utilities. Although this is in its infancy, we expect that as battery prices continue to decrease, utilities will capitalize on the growing need for energy storage.

3. Grid transformation and energy storage

In the U.S., a complete transformation of electric generation is underway. Natural gas now generates the largest percentage of the U.S.'s electricity at about 35% and renewable energy is trending toward 20%. A decade ago, electricity from natural gas was only at about 20% and renewable energy approximated 10%. While these material changes are significant to an industry that had barely changed over the prior 50 years, we believe this is just the beginning of the overhaul. Over the next decade, we expect that renewable energy will account for an ever greater share of all U.S. electricity and we expect that a rising percentage of renewable energy will include distributed generation on customer premises, especially in states with above-average sun strength. A key reason for our projection is the continued decrease in energy storage costs combined with increased efficiencies.

To adapt to these changes, utilities will have to remain focused on modernizing the electric grid by transforming it to a smart grid with smart meters. These upgrades will allow for the two-way flow of electricity, incorporating distributed generation and customer battery storage as key components of a newly modernized grid. While U.S. distributed generation penetration is only about 2% today, we expect that as energy storage costs continue to decrease and efficiencies increase, distributed generation will account for a much greater market share over the next decade. The utility industry will have the operational responsibility to seamlessly incorporate all of these new forms of generation, while preserving the appearance of a single uniformed electric grid.

4. Credit cycle exposure

Our base-case outlook for credit quality reflects our view that North American utilities will remain mostly stable despite a confluence of intensifying headwinds. In some cases, the lingering effects of tax reform and debt-financed M&A deals have eroded the cushion that existed in financial metrics, leaving relatively little room for disappointments. This is the key reason why the proportion of negative outlooks in the sector has increased to near 20%. These developments are exacerbated by persistent shift toward higher capital spending, as utilities capitalize on opportunities to harden infrastructure, modernize the grid, and transition to a cleaner emissions profile. While we view the capital spending story as favorably from an enterprise risk management (ERM) and environmental, social, and governance (ESG) perspective, as longer range risks are being mitigated through these actions, the immediate impact of this spending is adding balance sheet pressure. This highlights a dilemma for some management teams and elevates utilities' exposure to the developing credit cycle. Inflationary pressures are increasing labor-related costs and the interest rates are moving higher. With this in mind, we have to consider if the environment of generally low electricity bills is nearing the end. While we don't think there is cause for immediate concern, we believe the environment that has supported a wide open throttle on capital spending may be changing. If inflation increases and consumer rate pressure becomes more evident, we can anticipate more difficult regulatory proceedings. That could pressure capital spending, which could be bad news for longer-range risk mitigation of disruption. Nevertheless, we expect that companies will continue to aggressively seek operating and management (O&M) cost reductions to release more capital spending opportunities without affecting rates, but we think these prospects may slow if inflationary headwinds start to blow harder than forecast. That could be a trend with wide-ranging implications and certainly worth watching.

5. Climate change and adverse weather

For utilities, we increasingly factor in the impact of climate change and adverse weather events into our credit discussions. We focus both on companies' longer-term preparedness to adapt to disruptive changes related to the environment and on the day-to-day weather events that can present real and unexpected challenges to the sector. The severity of environmental events of 2018 underscored the harsh reality of weather-related credit risks. Most notably, the extreme weather and unprecedented wildfire damage in California resulted in several high-profile negative rating actions on electric utilities in the state. While wildfires are certainly not new, the severity of the most recent events revealed a weakness in the regulatory compact that increased credit risk and left utilities with exposure to substantial contingent liabilities.

We also followed closely the extraordinary efforts of several utilities in Southeast states to respond to widespread damage to critical infrastructure as Hurricanes Irma and Michael pounded coastal communities. While the recovery of storm costs varies by state, it typically can be deferred and recovered in future rates over a number of years. Several states also build storm planning into the regulatory process by assuming some level of storm costs in base rates each year or allow utilities to fund a storm reserve with funds collected from ratepayers. We believe these mechanisms are prudent and protect the utilities from the burden of extreme weather events, even as these incidents appear to be growing in severity and frequency. This is important as utilities are generally expected to bear a considerable burden to respond to weather outages to help restore social and economic order to the state. The quality of the response is crucial and can mitigate risk that has important implications for the regulatory relationship.

Lastly, as weather-related issues have increased, we see utilities take more proactive steps to modernize and harden infrastructure. This trend has contributed to successive record levels of capital investments and debt issuance in the sector. In this way, extreme weather events are causing companies to revamp their strategies and strategic priorities.

Industry developments

Leveraging and U.S. tax reform pressure credit metrics

The combination of ratepayers benefiting from lower corporate tax rates and the return of accumulated deferred income taxes resulted in lower revenues and pressured the industry's financial measures and credit quality. This was especially true for utilities that entered this period with minimal financial cushion at their current rating level. However, the extent of the impact varied considerably from company to company depending on their unique tax positions. We expect that this trend will linger through 2020 or until the rate base sufficiently grows and utilities recover their capital investments in rates. Further stressing credit measures is the industry's continued robust capital investments, which remain high and aligned with the utilities' strategic decisions to invest in grid modernization and to reduce emissions. We do not project a significant slowdown in capital spending in 2019 or 2020 but expect such spending to be funded in a balanced manner.

Environmental, social, and governance

S&P Global Ratings incorporates its analysis of environment, social, and governance (ESG) risks into its credit ratings. Our ratings can be directly affected when these factors are material and visible. Of these three factors, governance is the most common factor cited for a ratings change. Recently, Hydro One Ltd. was downgraded because of a weakening to its governance structure. Our analysis of utilities' business risk, financial risk, and management and governance will continue to incorporate these ESG risk factors in our assessment of credit risk. Some of these factors may include climate change, carbon emissions, pollution, effectiveness in terms of maintaining employee and community relations, adherence to legal and regulatory requirements, management of human capital, safety, and changing consumer behaviors (i.e., distributed generation).

For example, as climate change has intensified the severity and frequency of wildfires in California, environmental factors have become an integral part of our credit analysis of electric utilities in the state. We also see ESG as presenting opportunities for utilities to demonstrate aptitude in managing social risks, adopting corporate responsibility initiatives in key areas such as environmental stewardship, community involvement, safety, reliability, and affordability, all of which support their overall ability to effectively manage regulatory risk.

Technological changes are accelerating

Key technological breakthroughs that may disrupt the utility industry include battery storage and renewable energy. The auto industry invests heavily in battery technology, which has led to a sharp decrease in the cost of a battery during the current decade. In 2010, the cost of a battery was about $1,000 per kilowatt hour (kWh) and has subsequently decreased by more than 70% to about $200 per KWh. Similarly, the cost of solar and wind power has also decreased over the past decade. As these technologies continue to become more efficient and their costs decrease, we expect that distributed generation, particularly in areas with above-average sun strength, will accelerate, possibly pressuring the credit quality of some fully integrated regulated utilities that do not proactively address these risks.

However, the utility industry will also likely benefit from these technological changes. Many in the automotive industry are strategically investing in the growth of electric vehicles (EV), even though they represent only about 2% of the auto market. This partially reflects EVs historical growth rate, which has significantly outpaced the auto industry's overall growth rate. If EVs take hold as anticipated, the utility industry's sales growth will likely improve, partially offsetting conservation. These strategic decisions are consistent with our view that the pace of technological advancements within the utility industry will continue to rapidly accelerate.

Key regulatory developments

The utility industry's ability to effectively manage regulatory risk is key to maintaining investment-grade ratings. Recent developments in California, South Carolina, and Nevada in the U.S. and in Ontario in Canada, have or may affect the credit quality of those utilities operating in these jurisdictions.

The governor of **California** recently signed Senate Bill 901 into law. The bill reduces some of a utility's wildfire risk by allowing the California Public Utilities Commission (CPUC) to consider a broader range of factors when deciding if costs can be passed onto ratepayers, permits the securitization of wildfire liabilities through cost-recovery bonds, and mandates the utility to file a wildfire mitigation plan. Although we view this law as modestly supportive of credit quality in the short term, we revised the outlooks on the largest California electric utilities to negative because the regulation does not address the longer-term risks of inverse condemnation.

In **South Carolina**, following South Carolina Electric & Gas Co.'s (SCE&G) and Santee Cooper's decisions to abandon construction of two nuclear construction plants, the South Carolina General Assembly overrode Gov. Henry McMaster's veto to repeal the Base Load Review Act and temporarily reduced SCE&G's rates by 15% retroactive to April 1, 2018, until the commission rules in the company's proceeding addressing the abandoned project. Since the decision to abandon construction of the nuclear units, we downgraded SCE&G by two notches and we continue monitor this developing situation.

After initially passing in 2016, a majority of **Nevada** voters in November 2018 rejected a ballot measure that would have allowed customers to choose their electricity supplier beginning in mid-2023. For the ballot initiative to become law, it requires two ballot approvals. We assess the voter's decision to maintain the fully regulated utility model as supportive of credit quality, averting many of the unintended consequences that could occur when a jurisdiction deregulates. Separately, a ballot initiative to increase renewable generation to 50% by 2030 passed the first time and will need to be passed again in a second election to become law. If implemented, we expect that the initiative would be manageable by the state's large electric utilities that already have plans to add more renewable generation and close down coal-fired power plants.

Recently in **Canada**, the Ontario province undermined Hydro One's governance structure. Specifically, the Government of Ontario dismissed Hydro One's entire board of directors and the CEO resigned. The Government then implemented legislation, requiring Hydro One's new board of directors to establish a new executive compensation framework for the board, CEO, and other executives. The legislation also amended the current Ontario Energy Board Act, requiring the Ontario Energy Board to exclude any compensation paid to the CEO and other executives from consumer rates. We viewed the government's interference as explicitly weakening Hydro One's corporate governance and lowered our ratings on the company by one notch.

This report does not constitute a rating action.

spglobal.com/ratings

MOODY'S
INVESTORS SERVICE

OUTLOOK
7 November 2019

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Regulated electric and gas utilities – US

2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics

We are changing our outlook for the US regulated utility sector to stable from negative as the industry's funds from operations (FFO)-to-debt ratio stabilizes. The implementation of more proactive regulatory and financial actions, along with savings mainly related to tax credits, tax deductions and net operating losses (NOLs), are helping to buoy the sector's cash flows following US tax reform.

» **FFO-to-debt ratios will hold steady in 2020 but at lower levels.** We expect the utility sector's consolidated FFO-to-debt ratio to hold steady at around 15% to 16% over the next 12 to 18 months. The elimination of bonus depreciation for regulated utilities and the refund of excess deferred tax liabilities in the aftermath of the Tax Cuts & Jobs Act (TCJA) contributed to the deterioration in the industry average FFO-to-debt ratio. Holding company leverage will remain high, limiting financial flexibility, but we expect FFO-to-debt to hold steady at the current, lower than historical, levels.

» **Customer rates remain steady despite elevated capital spending to grow rate base.** Lower tax rates, a continued focus on operational and maintenance (O&M) cost savings, as well as low natural gas prices and fuel costs amid a growing penetration of renewables have created some headroom in rates, allowing utilities to recover their investments without significant increases in customer bills. Although capital spending will remain elevated, we expect a modest decline in the ratio of capital expenditures to depreciation and amortization from historical levels. This will help keep consolidated FFO-to-debt relatively steady over the next 12 to 18 months.

» **State regulators and legislators will remain supportive of utility credit quality.** The regulatory environment remains supportive with mostly credit positive state regulatory and legislative developments over the course of the past year. Positive initiatives in several states, largely in the Southeast and Midwest, to offset the impact of tax reform on utility credit metrics include authorization to amortize regulatory assets and/or increase authorized equity layers.

» **What could change our outlook**. We would consider shifting our outlook to positive if regulation turns more credit-supportive or if the sector's consolidated FFO-to-debt ratio rises to around 18% on a sustainable basis. We would consider changing our outlook to negative if weakened cash flow causes the ratio to fall to around 14%. A more contentious regulatory environment or an increase in leverage within the utility sector's capital structure could also change our outlook to negative.

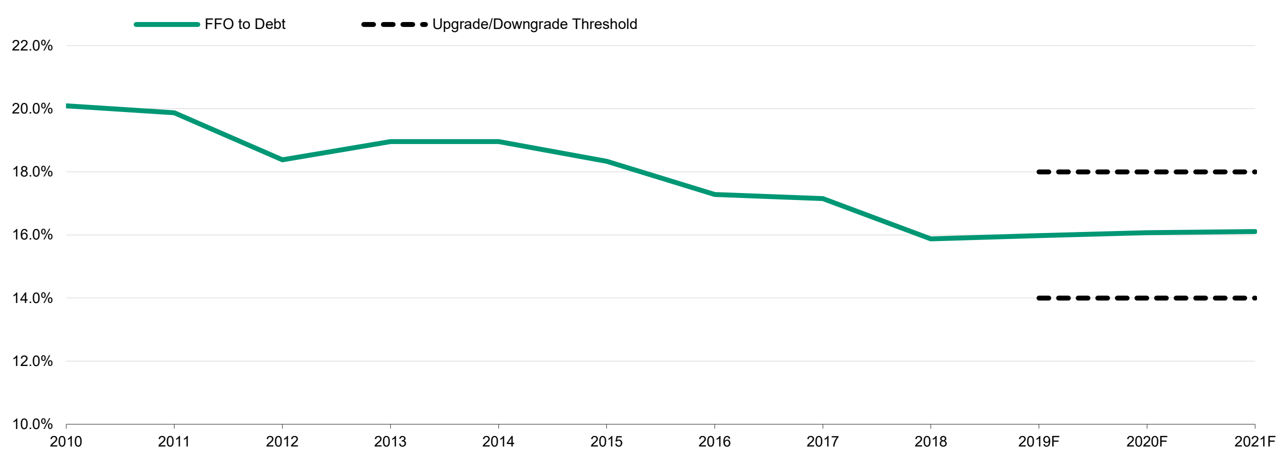
Industry outlooks reflect our view of fundamental business conditions for an industry over the next 12-18 months. Since outlooks represent our forward-looking view on business conditions that factor into our ratings, a negative (positive) outlook suggests that negative (positive) rating actions are more likely on average. However, the industry outlook does not represent a sum of upgrades, downgrades or ratings under review, or an average of the rating outlooks of issuers in the industry, but rather our assessment of the main direction of business fundamentals within the overall industry.

FFO-to-debt ratios will hold steady in 2020 but at lower levels

We are changing our outlook on the US regulated utility industry to stable from negative based on our expectation that the industry's consolidated FFO-to-debt ratio will hold steady at around 15% to 16% over the next 12 to 18 months. The implementation of more proactive regulatory and financial initiatives, along with savings mainly related tax credits, tax deductions and net operating losses (NOLs), are helping to buoy the sector's cash flows in the aftermath of the TCJA. However, financial flexibility remains limited because holding company leverage remains high as companies continue to issue debt to fund capital requirements and acquisitions.

We expect parent companies to continue to issue some equity (or securities with equity-like characteristics) but at a more modest pace compared to last year's new equity issuance of nearly $23 billion, much of it done to offset the impact of tax reform (see "Regulated electric and gas utilities - North America: Free cash flow and capital allocation: external capital needs to decline in 2019"). Lower operating expenses will help to mitigate the impact of higher capital spending on customer bills. Keeping revenue requirements in line with inflation will help utilities maintain a supportive and constructive relationship with regulators.

Exhibit 1
FFO to debt to stabilize at lower levels
Consolidated ratio of FFO to debt for rated US investor-owned utilities



Source: Moody's Investors Service

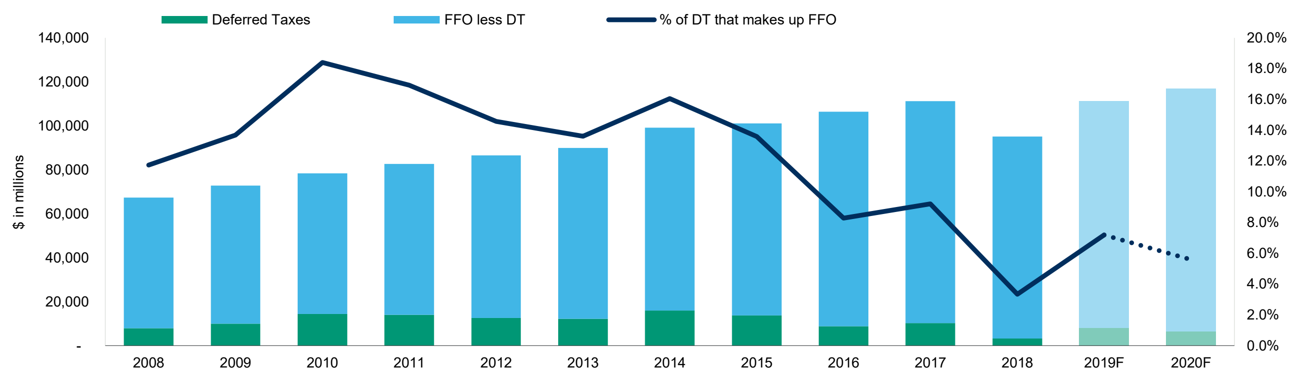
The reduction in deferred tax liabilities following the elimination of bonus depreciation, along with the refund of excess deferred tax liabilities (particularly the unprotected portion), help to explain the drop in cash flow from operations and the deterioration in FFO-to-debt in 2018. However, we expect the FFO-to-debt ratio to hold relatively steady over the next 12 to 18 months. Our projection is based on our expectation of a slight moderation in capital spending and lower deferred income tax liabilities that contribute to a growing net rate base. Our forecast also considers regulatory actions to increase authorized utility equity layers in several states, which partially offset the impact of the TCJA.

In addition, many utility holding companies do not expect to be significant federal cash taxpayers over the next 12 to 18 months mainly because of their existing NOL positions, tax credits (such as production and investment tax credits) and the continuation of tax deductions. However, the contribution of these tax savings to the utilities' cash flows will be lower compared to historical levels.

Exhibit 2

Deferred income taxes accounted for only about 3% of utilities' funds from operations in 2018 after averaging nearly 14% during the preceding eight years

Contribution of deferred income taxes to utilities' combined funds from operations for rated US investor-owned utilities



Source: Moody's Financial Metrics

Customer rates remain steady despite elevated capital spending

The implementation of the TCJA reduced the tax expenses that are recoverable from ratepayers. These tax savings created revenue "headroom" in customer bills that utilities use to recover other costs and investments.

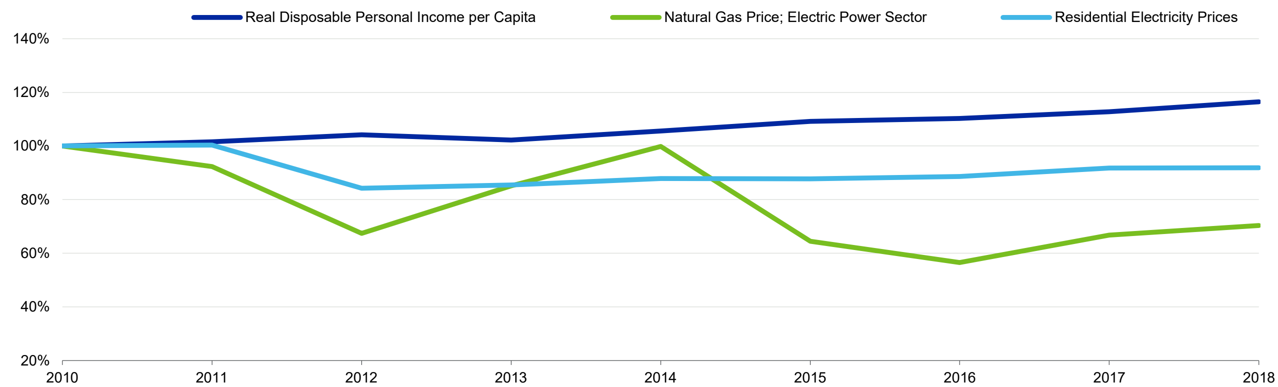
We expect a continued focus on lowering costs, including reducing pass-through operational and maintenance costs, excluding those service territories that are prone to severe events such as wildfires or storms that require enhanced risk mitigation efforts. Low natural gas prices, the declining importance of coal-fired generation, and the growing proportion of renewable sources in the industry's energy mix help to explain the low commodity cost component embedded in ratepayers bills.

For vertically integrated utilities, particularly in the Midwest, the retirement of older, less efficient coal-fired power plants is also reducing their fixed costs; a cost saving that can also be passed through in ratepayers' bills. At the same time, some states have authorized subsidies for unregulated, at-risk nuclear plants, which has the potential to erode a portion of the headroom in rates available to utilities for the recovery of investments and costs related to delivery services (see "Power generation – US: Nuclear zero emission credits reduce carbon transition risk but change market dynamics"). Keeping at-risk nuclear plants in service helps states avoid the increase in CO2 emissions that would result if the plants were replaced by fossil-fuel generation. These states are also motivated by the need for reliable baseload generation and may be sensitive to the political impact of lost jobs.

Exhibit 3

US residential electricity rates have remained largely stable amid a sharp decline in natural gas prices and a gradual increase in disposable personal income

Trend in US residential electricity prices, US real disposable personal income per capita and natural gas prices since 2010



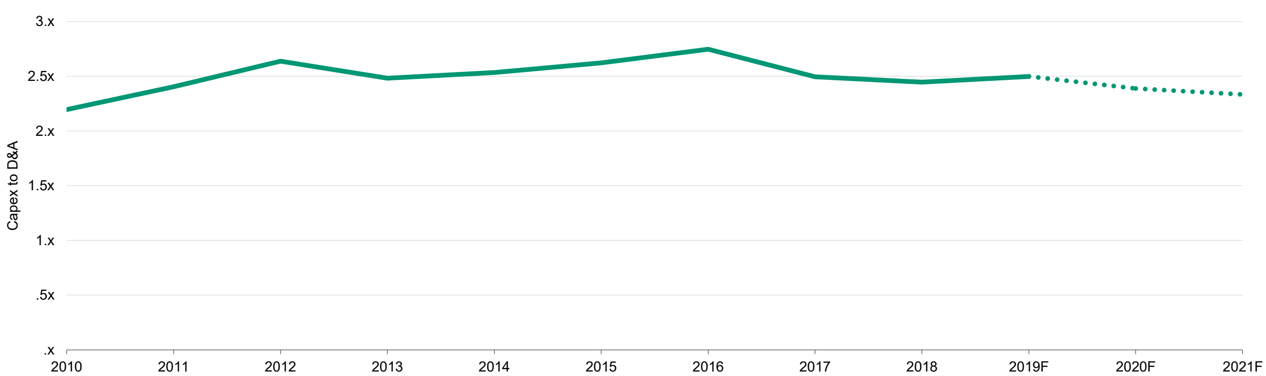
The residential electricity prices reflect delivery, energy as well as bundled rates.
For comparison purposes between the different variables' units we use 2010 as the base year (100) to outline the trend.
In 2014, the Polar Vortex caused a spike in natural gas prices.
Sources: US Energy Information Administration and Moody's Analytics

Although capital spending will likely remain elevated over the next 12 to 18 months, we expect a modest decline in the ratio of capital expenditures to depreciation and amortization from historical levels. Some parent companies continue to pursue or have started to invest in growing their non-utility operations. The TCJA introduced a new limitation on the deductibility of net interest expense related to non-regulated operations, a factor that we believe deters parent companies from significantly increasing holding company leverage to fund these growth opportunities.

Exhibit 4

Utility investments will remain high on an absolute basis, but will moderate relative to depreciation and amortization

Ratio of capital expenditures to total depreciation and amortization expenses for rated US investor-owned utilities



Source: Moody's Financial Metrics

State regulators and legislators to remain generally credit supportive

State regulatory and legislative developments have been mostly credit positive over the past year, including new legislation supporting renewable goals, utility recovery mechanisms and continuing initiatives to offset the impact of tax reform on utility credit metrics (see "Regulated electric and gas utilities – US: Recent regulatory, legislative developments have been largely credit positive"). In addition, the cost savings discussed above have created headroom in customers' rates, which is important because it allows the vast majority of utilities to recover their elevated capital investments without significant opposition from stakeholders.

As long as rates remain generally reasonable and service is reliable, the relationship between the utilities and its stakeholders, including regulatory agencies, should remain constructive. However, a significant spike in costs or service disruptions can rapidly shift the rapport between utilities and regulators which can translate into a higher degree of regulatory risk for the utility.

In Maine, Central Maine Power Company's (CMP, A2 stable) constructive relationship with utility regulators has become more uncertain because of a continuing investigation into its metering and billing practices after customers began receiving higher bills following the installation of new meters. Although the utility points to colder weather, rather than the new meters, as the primary reason for the higher bills, the Maine Public Utilities Commission's resolution of CMP's pending rate case has been stayed until completion of the investigation.

In California, legislators passed a law (Assembly Bill 1054) establishing a wildfire fund to provide the state's investor-owned utilities with an immediate source of liquidity to cover damages caused by a wildfire ignited by utility equipment. The law also implemented prudency standards that are more favorable to the utilities and capped the cost disallowance related to wildfire claims to 20% of the utility's transmission and distribution equity over any three-year period. The new wildfire law was credit positive for the utilities because it involved the state taking a leading role in managing wildfire liabilities. But the political backlash arising from Pacific Gas & Electric Company's (PG&E) implementation of public safety power shutoffs to reduce the risk of wildfires illustrates how quickly unforeseen developments can change the political and regulatory environment, although the risk is highest for PG&E (see "ESG - California: Public safety power shutoffs highlight links between environmental and social risks" and "Regulated electric utilities – California: Customer bill credits after power shutoffs signal weakening political support").

Credit positive developments have included the implementation of new clean energy standards in the state of Washington that includes the potential for enhanced cost recovery mechanisms that can improve utility financial performance and provides a legal and regulatory framework to reduce carbon exposure risks. A new law in Nevada gives utility regulators the flexibility to establish different types of ratemaking plans as an alternative to the currently mandated three-year general rate cycle. These plans could include such elements as revenue sharing, performance-based rates, decoupling, formula rates, or multiyear rate plans. We view the ability to employ these nontraditional mechanisms as credit positive.

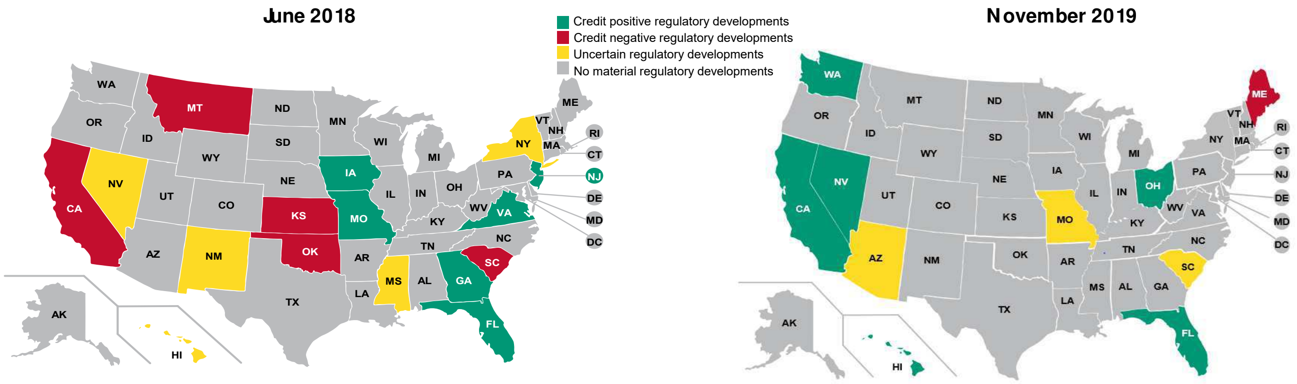
In Ohio, new legislation codified the ability of the Public Utilities Commission of Ohio to allow FirstEnergy Corp.'s (Baa3 stable) Ohio subsidiaries to benefit from a decoupling mechanism before their next rate case filing in 2024. This mechanism insulates their cash flows from power demand volatility. The law also approves subsidies for nuclear plants that are at risk of closing. Positive regulatory developments also include the enactment of a new law in Florida that requires investor-owned utilities to harden their transmission and distribution infrastructure while also providing cost recovery. We also see a growing number of jurisdictions, most recently Hawaii and Maryland, that are proposing a shift to performance-based regulation, which incentivizes utilities to improve cost controls, as well as administrative efficiency and effectiveness.

At the same time, regulatory uncertainty has increased in a few states. Arizona Public Service Company (A2 stable) was ordered by the Arizona Corporation Commission to file a rate case by the end of October amid heightened scrutiny of its 2018 rate increase. Duke Energy Corporation (Baa1 stable) has challenged certain aspects of the South Carolina Public Service Commission's decisions in rate cases for its operating subsidiaries. And in Missouri, a recent nonbinding vote of the Missouri Public Service Commission on deferring the operations and maintenance cost savings from the early retirement of Evergy Missouri West Inc.'s (Baa2 stable, formerly KCP&L Greater Missouri Operations Company) Sibley coal plant in 2018 raises questions about the consistency of the utility's regulation.

Exhibit 5

Utility regulatory and legislative environments have improved since June 2018

Moody's view of the status of state utility regulation



Source: Moody's Investors Service

During 2019, utilities continued to seek, and regulators have approved, increases in their authorized equity layer to offset the impact of tax reform. In some instances, the final orders and/or settlement agreements have also resulted in small reductions in their authorized return on equity (ROE), in the wake of a steeper decline in the average 30-year US Treasury yield. Pending decisions in several open rate cases, which stakeholders expect before year-end 2019 or in early 2020, will be key for some utility credit metrics going forward. We see the potential for increased equity layers to mitigate the trend of lower authorized ROE's in the current declining interest rate environment.

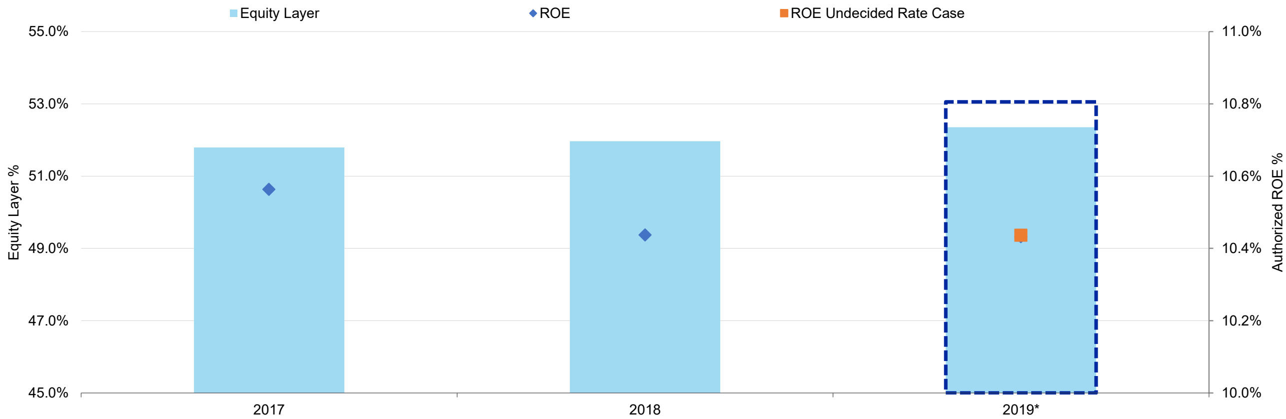
Recent examples of rate case outcomes and/or settlement agreements reached between the utilities and stakeholders that allow for a significant increase in the utilities' authorized equity ratio include the Illinois Commerce Commission's (ICC) final order in Northern Illinois Gas Company's (A2 stable) rate case that allowed an increase in the utility's equity ratio to 54.2% from 52% and authorized ROE to 9.73% from 9.80%. In Iowa, the terms of Interstate Power and Light Company's (Baa1 negative) settlement with key parties in its electric rate case also included a 200 basis point increase in its equity ratio to 51% from 49%, while its current allowed ROE is 9.50%, down from 9.60%.

Similarly, as part of their pending rate cases for the 2020-2021 period, WEC Energy Group, Inc's subsidiaries agreed on a slight reduction in their authorized ROE to 10.2% for Wisconsin Gas LLC (A2 negative; currently: 10.3%) and 10% for Wisconsin Electric Power Company (WEPCO, A2 stable) and Wisconsin Public Service Corporation (WPSC, A2 stable) from 10.2%. However, the three utilities also settled to increase their authorized equity layer to 52.5%. The increase is particularly material for Wisconsin Gas because its current allowed common equity ratio is 49.5%. It is also relevant for sister companies WEPCO and WPSC given their current authorized equity layers of 51%. The Public Service Commission of Wisconsin's decision on the settlement is expected before year-end. If approved, the new equity layers would be in line with their peers in the state, such as Northern States Power Company (Wisconsin) (A2 stable), following the commission's September 2019 interim order approving Northern States' settlement agreement. In California, the utility regulator's pending cost-of-capital decision could also result in an increase in the authorized equity layers of San Diego Gas & Electric Company (Baa1 positive), Southern California Gas Company (A1 negative) and Southern California Edison Company (Baa2 stable).

Exhibit 6

Average authorized equity layers for gas utilities are rising, while average ROEs have declined slightly

Comparison of authorized natural gas utility ROEs and equity layers before and after TCJA, including pending regulatory decisions

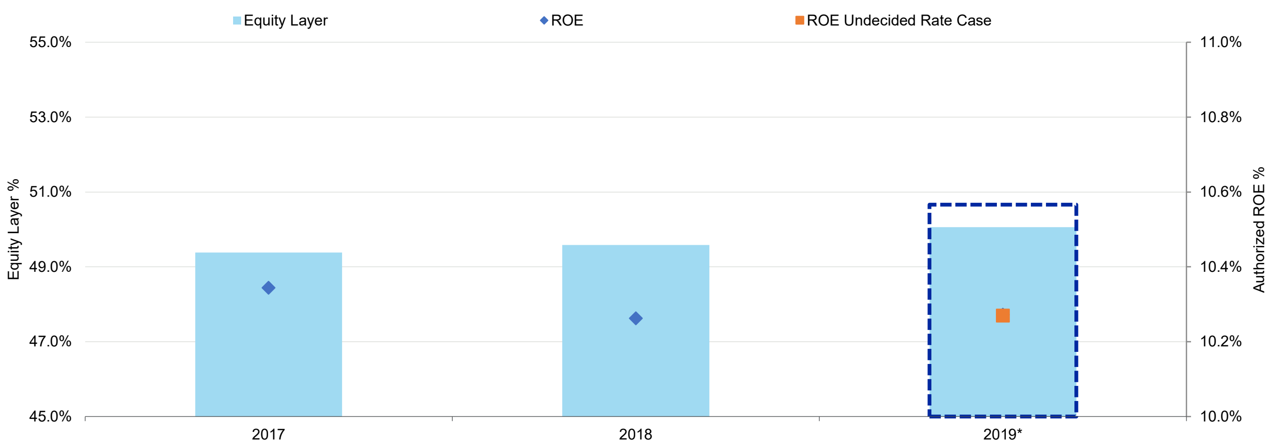


*Dashed line for 2019 shows undecided rate case equity layer.
Sources: S&P Global Market Intelligence and company filings

Exhibit 7

Average authorized equity layers for electric utilities are also climbing, while average ROEs have declined slightly

Comparison of authorized electric utility ROEs and equity layers before and after TCJA implementation, including pending regulatory decisions



The average equity layer is distorted because in some states (such as Arkansas, Florida, Michigan and Indiana) the definition of the authorized regulatory equity layer differs significantly from the definition of equity layer applied in other states, resulting in regulatory equity layers well below 50%.
*Dashed line for 2019 shows undecided rate case equity layer.
Sources: S&P Global Market Intelligence and company filings

What could change our outlook

We would consider shifting our outlook to positive if regulation turns more credit-supportive or if the sector's consolidated FFO-to-debt ratio rises to around 18% on a sustainable basis. We would consider changing our outlook to negative if weakened cash flow causes the ratio to fall to around 14%. A more contentious regulatory environment or an increase in leverage within the utility sector's capital structure could also change our outlook to negative.

Environmental, social and governance considerations for regulated utilities

Environmental

North American regulated electric and gas utilities are well positioned to benefit from carbon transition risk. Although the sector is one of the largest producers of CO2 emissions, it is also reducing its CO2 emissions by about 532 million tons by 2030, which would be equivalent to 10% of total US CO2 emissions in 2018 (see "Electric utilities and power producers – US: Power companies on pace to reduce CO2 emissions"). So far, large-scale closures of coal-fired plants have not created material stranded assets because most of the retired plants were older and less efficient, with little remaining book value. The sector exposure to stranded asset risk could rise but US regulators have a strong track record of allowing utilities to recover the undepreciated costs of their authorized rate base. Utilities operating newer, more efficient coal plants are less likely to pursue early retirements because the plants are still needed when growing renewable production is unavailable (see "Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk").

The sector is exposed to high levels of physical risks associated with climate change. Wildfires in California are the most pronounced example, but the increasing severity of floods, droughts and storms can also damage a utility's infrastructure. Regulators generally allow extraordinary recovery provisions in storm-prone states, including securitization structures for storm cost recovery. In addition a growing number of states are authorizing securitization structures to recover costs related to the early retirement of coal-fired plants. We remain focused on the willingness of customers to finance these costs.

Social

From a social perspective, risks related to product disclosure and labeling are low, with the exception of green electricity. There is a moderate risk of boycotts and customer activism in the form of objections to pipelines and transmission lines, as well as social implications as a result of rate increases. Human capital risk is moderate, as is labor relations risk. Although the utility industry is heavily unionized, this has not been an issue for utility companies. Labor retention risk is moderate because utility skills are generally not difficult to acquire, though nuclear plants require specialized skills and the workforce is aging. In common with other sectors, white males dominate management, though the sector has largely avoided lawsuits or controversies to date.

Working with gas and electricity can be dangerous, and there have been regular injuries and fatalities. Ongoing health issues are moderate because exposure to an industrial environment can affect human health over time. Government regulations in respect of worker health and safety are extensive, while the safety and reliability of utility services are very important to customers. Supply chain risk is moderate because companies depend on fuel supplies and natural resources, as well as suppliers of equipment such as transformers. Maintaining good customer relationships is important to utilities because this affects how the public perceives them, as well as the regulatory treatment they receive. Demand for distributed generation and renewable energy is increasing, while the younger generation is more attuned to demand response technology and clean energy. Social policy agenda risk is moderate because energy policy initiatives are often implemented through utility operations. (See "ESG – Global: Heat map: Social considerations pose high credit risk for 14 sectors, $8 trillion debt.")

Governance

From a corporate governance perspective, publicly traded North American utilities and power companies show generally credit-friendly governance characteristics. Around 56% out of the 50 North American utilities in our sample group received a governance assessment (GA) score of GA-1, indicating corporate governance characteristics and disclosures that are closely aligned with what we define as a credit friendly benchmark. The vast majority of the rest of the companies were assigned a score of GA-2. The bulk of the utility groups have broadly diversified share ownership, with the sole exception being Avangrid, which is 81.6% controlled by Iberdrola. Avangrid was the only utility to receive a score of GA-3. (See "Utilities and power companies – North America: Corporate governance assessments show generally credit-friendly characteristics.")

Appendix

Exhibit 8
Holding companies
Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO	Total Debt	CFO/Debt	Capex	Dividend
Berkshire Hathaway Energy Company	A3 Stable	$6,270	$42,152	14.9%	-$6,347	$0
Pinnacle West Capital Corporation	A3 Stable	$1,315	$6,140	21.4%	-$1,083	$319
Alliant Energy Corporation	Baa1 Negative	$503	$7,188	7.0%	-$1,586	$315
Sempra Energy	Baa1 Negative	$3,524	$27,673	12.7%	-$3,592	$1,142
WGL Holdings, Inc.	Baa1 Negative	$52	$2,768	1.9%	-$549	$113
NextEra Energy, Inc.	Baa1 Stable	$6,863	$41,010	16.7%	-$12,151	$2,396
OGE Energy Corp.	Baa1 Stable	$719	$3,585	20.1%	-$606	$288
ALLETE, Inc.	Baa1 Stable	$372	$1,723	21.6%	-$426	$118
Ameren Corporation	Baa1 Stable	$2,232	$10,235	21.8%	-$2,363	$467
American Electric Power Company, Inc.	Baa1 Stable	$5,160	$28,552	18.1%	-$6,302	$1,309
Avangrid, Inc.	Baa1 Stable	$1,627	$8,197	19.9%	-$2,338	$606
CMS Energy Corporation	Baa1 Stable	$1,741	$12,002	14.5%	-$2,086	$426
Consolidated Edison, Inc.	Baa1 Stable	$3,416	$22,698	15.1%	-$3,810	$880
Duke Energy Corporation	Baa1 Stable	$7,616	$61,494	12.4%	-$11,209	$2,587
Eversource Energy	Baa1 Stable	$2,116	$16,303	13.0%	-$2,659	$647
IDACORP, Inc.	Baa1 Stable	$453	$2,260	20.1%	-$264	$126
Public Service Enterprise Group Incorporated	Baa1 Stable	$3,049	$16,672	18.3%	-$3,445	$930
Southwest Gas Holdings, Inc.	Baa1 Stable	$610	$2,860	21.3%	-$931	$108
UNS Energy Corporation	Baa1 Stable	$490	$2,280	21.5%	-$553	$105
WEC Energy Group, Inc.	Baa1 Stable	$2,269	$12,222	18.6%	-$2,064	$735
Xcel Energy Inc.	Baa1 Stable	$3,059	$19,243	15.9%	-$3,768	$758
Black Hills Corporation	Baa2 Stable	$474	$3,249	14.6%	-$620	$115
CenterPoint Energy, Inc.	Baa2 Stable	$1,600	$15,660	10.2%	-$2,136	$581
Dominion Energy, Inc.	Baa2 Stable	$4,637	$44,377	10.4%	-$4,420	$2,599
DTE Energy Company	Baa2 Stable	$2,739	$15,886	17.2%	-$2,988	$734
Entergy Corporation	Baa2 Stable	$2,552	$21,708	11.8%	-$4,281	$672
Evergy, Inc.	Baa2 Stable	$1,810	$10,733	16.9%	-$1,231	$482
Exelon Corporation	Baa2 Stable	$7,865	$41,673	18.9%	-$7,541	$1,380
NiSource Inc.	Baa2 Stable	$663	$9,882	6.7%	-$1,861	$310
Otter Tail Corporation	Baa2 Stable	$170	$747	22.7%	-$116	$54
PPL Corporation	Baa2 Stable	$2,809	$23,370	12.0%	-$3,217	$1,183
Southern Company (The)	Baa2 Stable	$7,359	$46,185	15.9%	-$8,594	$3,800
Spire Inc.	Baa2 Stable	$431	$3,006	14.3%	-$781	$117
TECO Energy, Inc.	Baa2 Stable	$998	$4,462	22.4%	-$1,273	$0
Cleco Corporate Holdings LLC	Baa3 Stable	$373	$3,392	11.0%	-$292	$31
Duquesne Light Holdings, Inc.	Baa3 Stable	$228	$2,812	8.1%	-$348	$25
Edison International	Baa3 Stable	$2,605	$19,543	13.3%	-$4,584	$854
FirstEnergy Corp.	Baa3 Stable	$2,686	$23,523	11.4%	-$2,843	$796
IPALCO Enterprises, Inc.	Baa3 Stable	$359	$2,731	13.1%	-$235	$140
PNM Resources, Inc.	Baa3 Stable	$493	$3,338	14.8%	-$575	$89
Puget Energy, Inc.	Baa3 Stable	$576	$6,721	8.6%	-$1,072	$58
DPL Inc.	Ba1 Stable	$211	$1,515	14.0%	-$116	$0

List excludes intermediate holding companies unless the ultimate parent company is excluded from the holding company peer group (e.g. AES Corporation) or is domiciled outside of the US.
Source: Moody's Investors Service

Exhibit 9

Vertically integrated operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO	Total Debt	CFO/Debt	Capex	Dividends
Alabama Power Company	A1 Stable	$1,982	$8,396	23.6%	-$2,198	$820
Duke Energy Carolinas, LLC	A1 Stable	$2,872	$12,003	23.9%	-$3,048	$250
Florida Power & Light Company	A1 Stable	$4,996	$14,328	34.9%	-$5,026	$1,900
Madison Gas and Electric Company	A1 Stable	$144	$578	24.9%	-$191	$20
MidAmerican Energy Company	A1 Stable	$1,301	$6,450	20.2%	-$2,512	$0
Wisconsin Power and Light Company	A2 Negative	$429	$2,422	17.7%	-$461	$142
Arizona Public Service Company	A2 Stable	$1,231	$5,670	21.7%	-$1,083	$349
Consumers Energy Company	A2 Stable	$1,702	$7,164	23.8%	-$1,971	$559
DTE Electric Company	A2 Stable	$1,755	$8,312	21.1%	-$2,251	$478
Duke Energy Indiana, LLC.	A2 Stable	$1,105	$4,258	25.9%	-$915	$100
Duke Energy Progress, LLC	A2 Stable	$1,829	$9,639	19.0%	-$2,645	$175
Gulf Power Company	A2 Stable	$240	$1,654	14.5%	-$466	$76
Northern States Power Company (Minnesota)	A2 Stable	$1,405	$5,515	25.5%	-$1,242	$450
Northern States Power Company (Wisconsin)	A2 Stable	$171	$900	19.0%	-$193	$101
Virginia Electric and Power Company	A2 Stable	$2,699	$14,006	19.3%	-$2,305	$396
Wisconsin Electric Power Company	A2 Stable	$868	$5,705	15.2%	-$573	$401
Wisconsin Public Service Corporation	A2 Stable	$340	$1,616	21.0%	-$437	$140
Black Hills Power, Inc.	A3 Stable	$85	$403	21.1%	-$96	$10
Cleco Power LLC	A3 Stable	$301	$1,579	19.0%	-$279	$50
Duke Energy Florida, LLC.	A3 Stable	$1,272	$8,308	15.3%	-$1,823	$75
Idaho Power Company	A3 Stable	$381	$2,260	16.9%	-$264	$126
Indiana Michigan Power Company	A3 Stable	$743	$3,376	22.0%	-$706	$98
Kentucky Utilities Co.	A3 Stable	$658	$2,678	24.6%	-$611	$201
Louisville Gas & Electric Company	A3 Stable	$488	$2,146	22.7%	-$494	$146
Oklahoma Gas & Electric Company	A3 Stable	$571	$3,345	17.1%	-$605	$185
Otter Tail Power Company	A3 Stable	$128	$595	21.6%	-$92	$44
PacifiCorp	A3 Stable	$1,748	$7,896	22.1%	-$1,583	$275
Portland General Electric Company	A3 Stable	$610	$2,863	21.3%	-$604	$129
Public Service Company of Colorado	A3 Stable	$1,050	$5,497	19.1%	-$1,397	$394
Public Service Company of Oklahoma	A3 Stable	$337	$1,579	21.3%	-$275	$36
Southern Indiana Gas & Electric Company	A3 Stable	$107	$758	14.1%	-$257	$29
Tampa Electric Company	A3 Stable	$781	$3,070	25.4%	-$1,182	$342
Tucson Electric Power Company	A3 Stable	$425	$1,870	22.7%	-$476	$85
Interstate Power and Light Company	Baa1 Negative	$56	$3,142	1.8%	-$1,035	$163
San Diego Gas & Electric Company	Baa1 Positive	$1,581	$7,002	22.6%	-$1,412	$250
ALLETE, Inc.	Baa1 Stable	$372	$1,723	21.6%	-$426	$118
Appalachian Power Company	Baa1 Stable	$828	$4,636	17.9%	-$790	$180
Duke Energy Kentucky, Inc.	Baa1 Stable	$167	$697	23.9%	-$258	$0
Empire District Electric Company (The)	Baa1 Stable	$243	$908	26.7%	-$153	$80
Entergy Arkansas, LLC	Baa1 Stable	$378	$4,006	9.4%	-$686	$208
Entergy Louisiana, LLC	Baa1 Stable	$1,297	$7,868	16.5%	-$1,897	$174
Entergy Mississippi, LLC	Baa1 Stable	$392	$1,759	22.3%	-$402	$11
Evergy Metro, Inc.	Baa1 Stable	$701	$3,452	20.3%	-$420	$125
Georgia Power Company	Baa1 Stable	$2,884	$13,385	21.5%	-$3,566	$1,496
Indianapolis Power & Light Company	Baa1 Stable	$375	$1,856	20.2%	-$235	$160
Nevada Power Company	Baa1 Stable	$637	$2,860	22.3%	-$364	$95

Issuer	Rating and Outlook	CFO	Total Debt	CFO/Debt	Capex	Dividends
Northern Indiana Public Service Company	Baa1 Stable	$690	$2,527	27.3%	-$691	$50
Puget Sound Energy, Inc.	Baa1 Stable	$658	$4,739	13.9%	-$1,016	$154
Sierra Pacific Power Company	Baa1 Stable	$203	$1,195	17.0%	-$218	$46
Union Electric Company	Baa1 Stable	$1,198	$4,664	25.7%	-$1,005	$428
Hawaiian Electric Company, Inc.	Baa2 Positive	$432	$2,121	20.4%	-$453	$104
Mississippi Power Company	Baa2 Positive	$571	$1,677	34.0%	-$212	$1
Avista Corp.	Baa2 Stable	$340	$2,297	14.8%	-$443	$100
El Paso Electric Company	Baa2 Stable	$261	$1,642	15.9%	-$273	$60
Evergy Missouri West, Inc.	Baa2 Stable	$351	$1,197	29.3%	-$149	$40
Monongahela Power Company	Baa2 Stable	$326	$1,822	17.9%	-$276	$154
NorthWestern Corporation	Baa2 Stable	$279	$2,323	12.0%	-$315	$113
Public Service Company of New Mexico	Baa2 Stable	$375	$1,956	19.2%	-$311	$78
Southwestern Electric Power Company	Baa2 Stable	$471	$2,989	15.8%	-$403	$67
Southwestern Public Service Company	Baa2 Stable	$415	$2,573	16.1%	-$908	$209
Dominion Energy South Carolina, Inc.	Baa3 Positive	$731	$4,281	17.1%	-$404	$47
Entergy Texas, Inc.	Baa3 Positive	$350	$1,952	17.9%	-$686	$0
Alaska Electric Light and Power Company(AELP)	Baa3 Stable	$13	$136	9.7%	-$6	$11
Kentucky Power Company	Baa3 Stable	$100	$988	10.1%	-$142	$5
Entergy New Orleans, LLC.	Ba1 Stable	$171	$617	27.7%	-$213	$9

Source: Moody's Investors Service

Exhibit 10

Transmission and distribution operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO	Total Debt	CFO/Debt	Capex	Dividends
NSTAR Electric Company	A1 Stable	$873	$3,630	24.0%	-$793	$250
Ohio Power Company	A2 Stable	$950	$2,601	36.5%	-$806	$198
PECO Energy Company	A2 Stable	$812	$3,299	24.6%	-$889	$197
Public Service Electric and Gas Company	A2 Stable	$1,920	$10,336	18.6%	-$2,698	$0
Oncor Electric Delivery Company LLC	A2 Stable*	$1,371	$9,952	13.8%	-$1,917	$351
CenterPoint Energy Houston Electric, LLC	A3 Negative	$912	$5,234	17.4%	-$995	$186
Ohio Edison Company	A3 Positive	$453	$1,208	37.5%	-$186	$50
Pennsylvania Power Company	A3 Positive	$81	$242	33.4%	-$47	$20
Ameren Illinois Company	A3 Stable	$824	$3,759	21.9%	-$1,212	$3
Narragansett Electric Company	A3 Stable	$147	$205	71.6%	-$136	$0
Boston Gas Company	A3 Stable	$231	$583	39.7%	-$171	$0
Massachusetts Electric Company	A3 Stable	$207	$537	38.5%	-$196	$0
Niagara Mohawk Power Corporation	A3 Stable	$938	$3,038	30.9%	-$435	-$1
New York State Electric and Gas Corporation	A3 Stable	$398	$1,549	25.7%	-$596	$0
Metropolitan Edison Company	A3 Stable	$276	$1,073	25.7%	-$165	$130
Duquesne Light Company	A3 Stable	$360	$1,413	25.5%	-$330	$93
Baltimore Gas and Electric Company	A3 Stable	$807	$3,449	23.4%	-$1,097	$216
Rochester Gas & Electric Corporation	A3 Stable	$271	$1,185	22.9%	-$321	$0
PPL Electric Utilities Corporation	A3 Stable	$878	$3,925	22.4%	-$1,161	$383
West Penn Power Company	A3 Stable	$221	$1,032	21.4%	-$265	$55
Central Hudson Gas & Electric Corporation	A3 Stable	$133	$710	18.7%	-$212	$0
Commonwealth Edison Company	A3 Stable	$1,822	$10,004	18.2%	-$2,066	$487
Consolidated Edison Company of New York, Inc.	A3 Stable	$3,039	$16,804	18.1%	-$3,355	$879
Connecticut Light and Power Company (The)	A3 Stable	$687	$3,885	17.7%	-$878	$278
Texas-New Mexico Power Company	A3 Stable	$122	$702	17.4%	-$235	$46
Public Service Company of New Hampshire	A3 Stable	$224	$1,834	12.2%	-$262	$233
Electric Transmission Texas, LLC	Baa1 Negative	$181	$1,509	12.0%	-$81	$125
Jersey Central Power & Light Company	Baa1 Positive	$297	$1,982	15.0%	-$327	$40
Toledo Edison Company	Baa1 Stable	$123	$421	29.1%	-$44	$115
Pennsylvania Electric Company	Baa1 Stable	$357	$1,378	25.9%	-$168	$130
United Illuminating Company	Baa1 Stable	$287	$1,132	25.3%	-$250	$0
Orange and Rockland Utilities, Inc.	Baa1 Stable	$220	$1,007	21.8%	-$222	$11
Delmarva Power & Light Company	Baa1 Stable	$317	$1,631	19.4%	-$368	$126
Unitil Energy Systems, Inc.	Baa1 Stable	$22	$130	17.2%	-$31	$4
Fitchburg Gas & Electric Light Company	Baa1 Stable	$22	$129	17.1%	-$30	$3
AEP Texas Inc.	Baa1 Stable	$715	$4,342	16.5%	-$1,303	$0
Atlantic City Electric Company	Baa1 Stable	$228	$1,426	16.0%	-$398	$64
Potomac Electric Power Company	Baa1 Stable	$432	$2,980	14.5%	-$675	$191
Dayton Power & Light Company	Baa2 Stable	$225	$656	34.3%	-$111	$170
Potomac Edison Company (The)	Baa2 Stable	$158	$631	25.0%	-$122	$40
Cleveland Electric Illuminating Company (The)	Baa2 Stable	$269	$1,546	17.4%	-$132	$220

*senior secured rating

Source: Moody's Investors Service

Exhibit 11

Local distribution operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO	Total Debt	CFO/Debt	Capex	Dividend
New Jersey Natural Gas Company	Aa3 Negative*	$97	$855	11.3%	-$319	$0
Southern California Gas Company	A1 Negative	$978	$4,684	20.9%	-$1,433	$51
Spire Missouri Inc.	A1 Stable	$304	$1,351	22.5%	-$351	$38
Wisconsin Gas LLC	A2 Negative	$117	$686	17.1%	-$176	$80
Washington Gas Light Company	A2 Negative	-$32	$1,565	-2.1%	-$479	$94
Atmos Energy Corporation	A2 Positive	$919	$3,895	23.6%	-$1,600	$237
UGI Utilities, Inc.	A2 Stable	$301	$1,168	25.8%	-$379	$20
Spire Alabama Inc.	A2 Stable	$130	$548	23.7%	-$168	$25
North Shore Gas Company	A2 Stable	$35	$160	21.6%	-$63	$0
Peoples Gas Light and Coke Company	A2 Stable	$281	$1,429	19.6%	-$497	$0
ONE Gas, Inc	A2 Stable	$340	$1,764	19.3%	-$407	$101
Northern Illinois Gas Company	A2 Stable	$264	$1,458	18.1%	-$781	$0
South Jersey Gas Company	A3 Negative	$152	$1,125	13.5%	-$251	$0
Public Service Co. of North Carolina, Inc.	A3 Negative	$97	$755	12.8%	-$193	$35
Connecticut Natural Gas Corporation	A3 Positive	$68	$267	25.7%	-$80	$0
KeySpan Gas East Corporation	A3 Stable	$254	$510	49.7%	-$122	$0
Colonial Gas Company	A3 Stable	$62	$124	49.7%	-$24	$0
Brooklyn Union Gas Company, The	A3 Stable	$444	$1,039	42.7%	-$177	$125
Boston Gas Company	A3 Stable	$231	$583	39.7%	-$171	$0
Indiana Gas Company, Inc.	A3 Stable	$148	$474	31.3%	-$183	$54
Berkshire Gas Company	A3 Stable	$18	$74	24.1%	-$23	$0
DTE Gas Company	A3 Stable	$382	$1,679	22.7%	-$470	$117
Southern Connecticut Gas Company	A3 Stable	$68	$319	21.4%	-$106	$0
UNS Gas, Inc.	A3 Stable	$18	$103	17.6%	-$25	$0
Southwest Gas Corporation	A3 Stable	$420	$2,397	17.5%	-$765	$90
Piedmont Natural Gas Company, Inc.	A3 Stable	$329	$2,428	13.6%	-$864	$0
Questar Gas Company	A3 Stable	$80	$887	9.0%	-$195	$0
CenterPoint Energy Resources Corp.	Baa1 Positive	$523	$2,423	21.6%	-$731	$252
Northwest Natural Gas Company	Baa1 Stable	$182	$1,087	16.7%	-$207	$39
SEMCO Energy, Inc.	Baa1 Stable	$146	$454	32.1%	-$105	$18
Northern Utilities, Inc.	Baa1 Stable	$52	$198	26.1%	-$66	$10
Southern Company Gas Capital	Baa1 Stable	$889	$6,156	14.4%	-$1,325	$468
Yankee Gas Services Company	Baa1 Stable	$47	$691	6.9%	-$183	$78
PNG Companies LLC	Baa2 Positive	$238	$1,397	17.0%	-$298	$89

*Senior secured rating

Source: Moody's Investors Service


Six themes will shape global credit in 2020
RECESSION RISKS
Recession risks will rise amid a pronounced global economic slowdown.
LOWER-FOR-LONGER INTEREST RATES
An increasing share of assets globally will yield very low or negative interest rates.
ESG IMPACT
Climate risks will constrain the availability of capital for the most-exposed sectors; demographic and social trends will create risks and opportunities.
TRADE TENSIONS
An enduring US-China trade deal will remain elusive and trade disputes will weigh on credit conditions.
DISRUPTIVE TECHNOLOGIES
Scaling up of digital technologies will accelerate the transformation of traditional businesses.
POLITICAL RISKS
Domestic policy shifts and geopolitical uncertainty will threaten to undermine credit conditions in many regions.
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Moody's related publications

Sector In-Depth

- Electric utilities and power producers – US: Power companies on pace to reduce CO2 emissions, September 2019
- Utilities and power companies – North America: Corporate governance assessments show generally credit-friendly characteristics, September 2019
- Regulated electric and gas utilities – US: Recent regulatory, legislative developments have been largely credit positive, September 2019
- Regulated electric and gas utilities - North America: Free cash flow and capital allocation: external capital needs to decline in 2019, August 2019
- Regulated electric utilities – US: FAQ on the credit implications of California's new wildfire law, August 2019
- Power generation – US: Nuclear zero emission credits reduce carbon transition risk but change market dynamics, June 2019
- Power generation – US: FAQ on the economics of renewable energy, battery storage and fossil-fuel power plants, June 2019
- Electric and Gas Utilities - US: California utilities struggle with inverse condemnation exposure, April 2019
- Regulated Electric & Gas Utilities - US: Capital expenditures will remain high, thanks to regulatory recovery mechanisms that provide timely recovery, December 2018
- Regulated Electric and Gas Utilities - US: Climate-related disclosures by four major utilities vary in both depth and scope, December 2018
- Regulated Electric & Gas Utilities - US: LDC Utilities Exposed to Operational Hazards, But Sector Still Viewed as Low Risk, November 2018
- Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk, November 2018
- Regulated electric and gas utilities - US: Cyber risk is on the rise, but the likelihood of government relief is high, September 2018
- Power generation - US: Coal, nuclear plant closures continue CO2 decline but power market impact muted, June 2018

Sector Comments

- Regulated electric utilities – California: Customer bill credits after power shutoffs signal weakening political support, October 2019
- ESG - California: Public safety power shutoffs highlight links between environmental and social risks, October 2019
- Regulated electric utilities – US: Proposed California wildfire risk legislation is credit positive but questions remain, July 2019
- Regulated electric utilities – US: New Florida law requiring storm-hardening measures is credit positive for utilities, July 2019

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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FitchRatings

Fitch Ratings 2020 Outlook: North American Utilities, Power & Gas

Constructive Regulation Supports Recovery in Credit Metrics

Fitch's Sector Outlook: Stable

Fitch Ratings' stable outlook embeds an expectation that sector credit metrics will begin to stabilize in 2020, driven by an increase in FFO after the record capex in 2019 and conclusion of a majority of tax reform-related refunds. Low commodity prices and interest rates, O&M cost savings, in part due to the ongoing transition to cleaner generation mix, and tax refunds are providing ample headroom to utilities to seek recovery for capital investments without undue pressure on customer bills.

We expect utility capex to remain elevated in 2020. Much of this is driven by investments in grid modernization and resiliency, renewable generation, and natural gas pipeline replacement and safety, all of which are consistent with public policy goals and garner wide regulatory support.

Rating Outlook: Stable

With approximately 88% of ratings on Stable Outlook, we expect limited rating movement in 2020. Unforeseen deterioration in state regulation is nevertheless always a rating risk, as borne out by the Negative Outlooks for Arizona Public Service Co. and NorthWestern Corporation. Georgia Power Co.'s Negative Outlook highlights the execution challenges with construction of complex projects. Rating pressure could manifest for those developing other large projects, such as offshore wind, interstate natural gas pipelines and liquefied natural gas terminals.

Finally, the Negative Watch on DTE Energy Company is a reminder that debt-financed M&A remains an event risk with sustained easy monetary conditions. An upgrade of Vistra Energy Corp. to 'BB+' is likely if management executes on its deleveraging goals.

Rating Distribution Weighting: Investment Grade

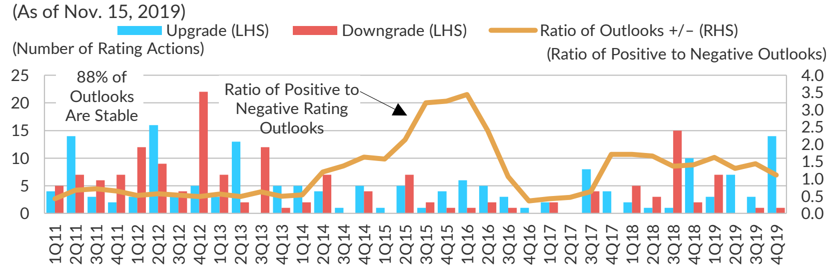
Median Issuer Default Ratings (IDRs) for electric and gas utilities should remain on the cusp of 'BBB+' and 'A–'. Long-term debt instrument ratings for Fitch's universe of regulated utilities carry investment-grade ratings, indicative of the industry's strong credit profile. Median IDRs for parent holding companies should remain at 'BBB+'.

Shalini Mahajan, Managing Director

"Fitch forecasts a broadly stable regulatory environment for electric and gas utilities in 2020. Continued low commodity prices and financing costs, tax refunds and O&M cost reduction are expected to keep customer bill increases manageable despite high capex and modest sales growth. Fitch expects elevated leverage metrics to stabilize in 2020 as utilities digest the full impact of The Tax Cut and Jobs Act of 2017 (TCJA) and holding companies remain focused on prudent balance sheet management."

Quarterly Upgrades and Downgrades and Ratio of Positive to Negative Outlooks

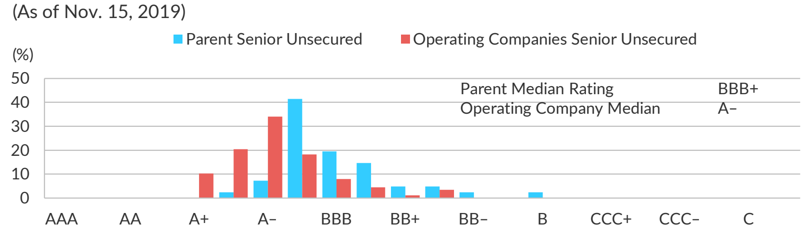
(As of Nov. 15, 2019)



Source: Fitch Ratings.

Rating Distributions of Senior Unsecured Debt, Corporate Parents Versus Operating Companies

(As of Nov. 15, 2019)



Source: Fitch Ratings.

What to Watch

- Outcomes of federal and state elections in the U.S.
- Adoption of aggressive clean energy goals by states.
- Shift from cost of service to performance-based regulation.
- M&A activity, albeit at a slower pace.
- Trends in battery storage and electrification of transportation.
- Wider application of environmental, social and governance (ESG) principles.

Sector Forecast — Leverage Trend: Stabilizing

Median leverage metrics for the sector steadily deteriorated since 2014 due to debt-funded M&A and the adverse impact of TCJA. A significant increase in capex in 2019 compounded the weakness. Fitch expects median FFO-adjusted leverage to stabilize around 4.8x in 2020 as utilities absorb the impact of tax refunds and see a rebound in FFO from growth investments.

High parent-level debt continues to be a concern, though some holding companies made significant efforts to deleverage in 2019 by selling assets and issuing equity. FFO fixed-charge coverage metrics remain robust for the sector and there is adequate headroom to absorb a moderate rise in interest rates. Debt maturities are well spread out.

Sector Forecast — Cash Flow Generation: Improved Predictability

Cash flow predictability improved significantly over the years, aided by periodic rate-adjustment mechanisms, multiyear rate plans and a higher proportion of fixed charges in tariffs. Fitch expects these trends to continue in 2020, reducing regulatory lag between authorized and earned ROEs.

Increased implementation of cost-adjustment mechanisms reduces the need for utilities to seek large base rate increases, which can be controversial and draw political scrutiny. However, a persistent decline in interest rates could resume the fall in authorized ROEs, which in the U.S. began to stabilize in 2019 around a median of 9.6%.

Sector Forecast — Liquidity Position: Generally Strong

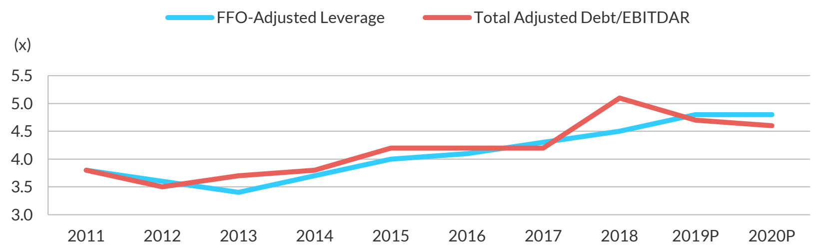
Fitch expects regulated utilities' and parent holding companies' liquidity to remain strong. The companies maintain large credit lines and benefit from unfettered access to capital markets. For competitive generators, robust FCF generation supports liquidity.

Potential Disrupting Factor: Aggressive Clean Energy Goals and Alternative Regulation

In the absence of strong federal leadership on carbon emissions reduction in the U.S., many states are forging their own paths to address climate issues, and are setting aggressive renewable and clean energy goals. With competing Green New Deal proposals, climate change has also become a major issue in the 2020 presidential elections. The path to achieving these mandates and the ultimate impact on customer bills is unknown at this time. Fitch is concerned certain state mandates provide for no cost caps or appropriate off-ramps to protect customers from a material increase in utility bills. Future changes in technology, and long lead times and high capex associated with certain technologies, such as offshore wind, are additional concerns.

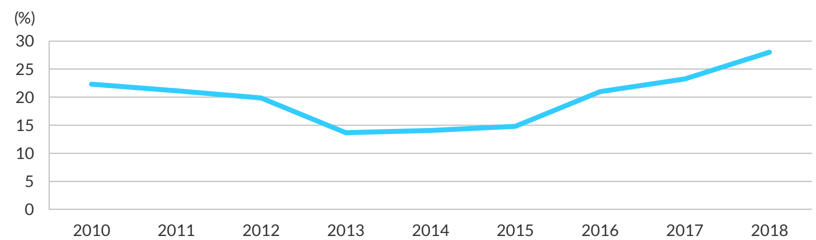
The move to alternative forms of regulation is picking up steam. To accommodate fast-growing distributed energy resources and more aggressive renewable goals, more than one-third of U.S. states are considering moving to performance-based rating making (PBR) mechanisms. PBR has been prevalent in Canadian provinces for some time. Depending upon what form it takes, this can break the link between utility earnings and capital investment and customer usage, and instead align utility incentives with optimizing operations and improving efficiency.

Median Metrics for Utilities, Power & Gas Sector



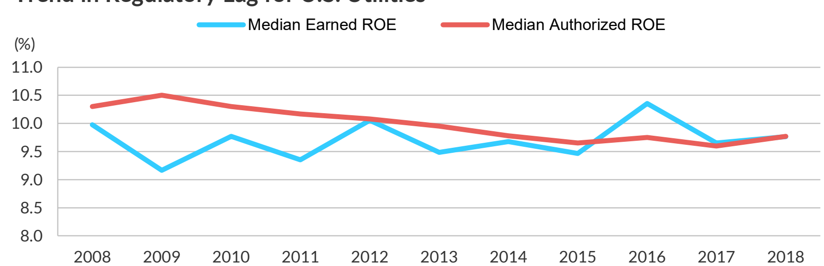
P – Projected.
Source: Fitch Ratings, company reports.

Proportion of Parent-Level Debt to Consolidated Debt



Source: Fitch Ratings, company reports.

Trend in Regulatory Lag for U.S. Utilities



Sources: Fitch Ratings, S&P Global Market Intelligence, company reports.

Sector Fundamentals — Weak Customer Usage

Fitch expects total retail electric sales to grow between 0.0% and 0.5% in 2020 as energy-efficiency initiatives, demand-side management, and to a small extent, growing distributed generation continue to restrain retail sales growth. After a strong 2018, residential and commercial sales declined YTD, in part driven by unfavorable weather. Industrial sales slowed in tandem with U.S. GDP growth slowing. Export-oriented industries were hurt by the strong dollar and uncertainty created by trade wars.

Sector Fundamentals — Elevated Capex

According to Edison Electric Institute (EEI), industry capex is on pace to hit a record $136 billion in 2019. In contrast with 2018, when estimates were revised down by 6% as utilities curtailed capex to preserve creditworthiness in the face of tax reform, 2019 capex estimates were revised upward by 16%. This coupled with historically low interest rates resulted in record debt issuance by utilities in 2019.

Fitch expects industry capex to moderate somewhat in 2020 based on announced plans, but 2020 industry capex estimates are 20% higher than EEI estimates one year ago. Higher than expected capex and/or widening of regulatory lag is likely to put pressure on credit metrics.

Sector Fundamentals — Muted Outlook for Wholesale Power Prices

We tempered our forward price expectations across most competitive power markets given our outlook for muted power demand, increased supply from natural gas and renewables new build, and persistently low natural gas prices. In PJM, state support for at-risk nuclear capacity is undermining the competitiveness of the capacity construct and led to postponement of the capacity auction, creating near-term uncertainty.

We have a favorable view of power prices in ERCOT. Scarcity pricing witnessed in August and September is symptomatic of tight supply and we expect such conditions to recur, offering upside to power generators with exposure to this market.

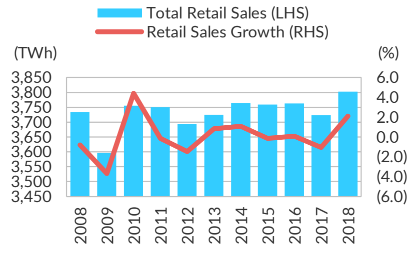
Sector Fundamentals — ESG Relevance Scores

Analysis of Fitch's ESG Relevance Scores indicates North American electric and gas utilities are managing exposure to various ESG elements well, so these are not a credit issue for most issuers. Only 4% of the approximately 150 North American utility issuers rated by Fitch had either one or more '4' or '5' scores. A Relevance Score of '4' indicates the ESG risk is either an emerging risk or a contributing factor to the credit decision, while a score of '5' indicates the ESG risk itself drove a rating change.

Social elements seem to be affecting utility ratings the most. Elevated social risks include customer welfare and product safety for NiSource Inc., which is facing heightened financial and regulatory risk due to gas pipeline explosions in its service territory. Exposure to social impact is a risk for both Duke Energy Corporation and Dominion Energy, Inc., given environmental groups' opposition to their natural gas pipeline projects leading to construction delays and cost increases.

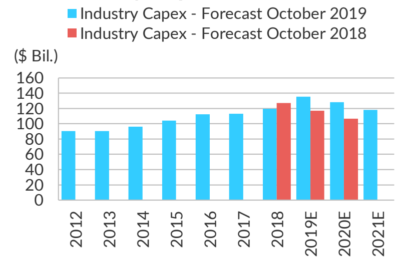
Elevated environmental risks include waste and hazardous materials management for Duke, which is facing uncertainty regarding timely recovery of its ongoing coal ash remediation costs. Exposure to environmental impact is a risk faced by the California investor-owned utilities given the increased frequency and size of catastrophic wildfires.

Trend in Total U.S. Electric Retail Sales



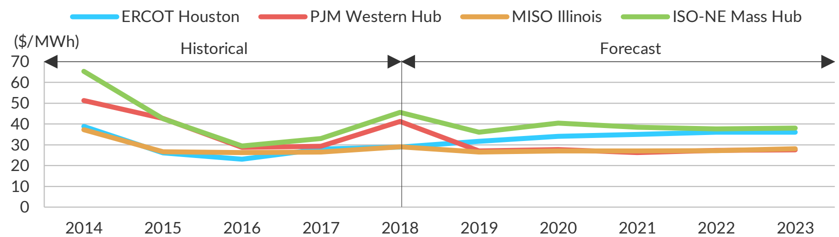
TWh – Terawatt-hour.
Source: EIA, Department of Commerce.

U.S. Industry Capex



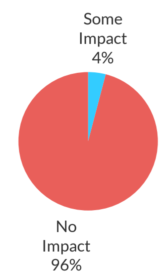
E – Estimate.
Source: Edison Electric Institute.

Around the Clock Power Prices in Select Markets



ERCOT – Electric Reliability Council of Texas. PJM – Pennsylvania-New Jersey-Maryland Interconnection. M – Midcontinent. ISO – Independent System Operator, Inc.
Source: Fitch Ratings, Wood Mackenzie.

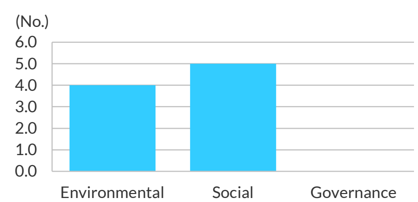
Relevance to Issuer Portfolio



Source: Fitch Ratings.

ESG Elements Driving Issuer Credit Impact

(ESG Score of 4 or 5)



Source: Fitch Ratings.

Appendix

Key Rating Triggers for Select Issuers on Watch, Positive or Negative Outlook

Issuer	IDR	Outlook/ Watch	Adjusted Debt/ EBITDA 2019F (x)	FFO-Adjusted Leverage 2019F (x)	Key Downgrade Trigger	Key Upgrade Trigger
DTE Energy Company	BBB+	Rating Watch Negative	5.6	5.1	Sustained FFO-adjusted leverage > 4.7x.	While not anticipated at this time given the sizable capital program and elevated leverage, sustained FFO-adjusted leverage < 4.0x.
Georgia Power Company	BBB+	Negative	3.6	4.0	Material cost and/or schedule overruns for Vogtle 3 and 4 units, further increases to project costs not recoverable from ratepayers, cancellation of project and FFO-adjusted leverage > 4.5x on a sustained basis.	Not anticipated at this time.
Mississippi Power Company	BBB	Positive	3.5	4.7	Sustained FFO-adjusted leverage > 5.0x.	Sustained FFO-adjusted leverage of 4.0x or better.
NorthWestern Corporation	BBB+	Negative	5.2	5.1	FFO-adjusted leverage to exceed 5.0x by 2020.	The Rating Outlook could be revised to Stable if Fitch were to expect FFO-adjusted leverage to maintain below 5.0x by 2020.
Pinnacle West Capital Corp.	A–	Negative	3.9	4.2	Sustained FFO-adjusted leverage > 4.5x.	Sustained FFO-adjusted leverage of 3.5x or better.
Dominion Energy South Carolina, Inc.	BBB	Positive	3.3	3.4	Sustained FFO-adjusted leverage > 5.5.	Successful outcome in 2020 rate case and sustained FFO-adjusted leverage < 4.5x.
The Southern Company	BBB+	Negative	5.1	5.3	Inability to bring down the FFO-adjusted leverage to below 5.3x on a sustainable basis. Once the Vogtle units are operational, Fitch would expect The Southern Company to maintain FFO-adjusted leverage between 4.7x and 5.0x.	Enhanced pace of deleveraging such that FFO-adjusted leverage sustains at or below 4.7x.
Vistra Energy Corp.	BB	Positive	3.2	3.3	Gross debt/EBITDA above 3.5x on a sustainable basis.	Execution of deleveraging as per management's stated goal such that gross debt to EBITDA is below 3.0x on a sustainable basis.

IDR – Issuer Default Rating. F – Forecast.
Source: Fitch Ratings.

Outlooks and Related Research

2020 Outlooks

Global Economic Outlook - September 2019 (September 2019)

U.S. Competitive Generators Handbook (A Detailed Review of Competitive Generation Companies) (November 2019)

U.S. Utility Parent Companies Handbook (A Detailed Review of Utility Parent Holding Companies) (November 2019)

U.S. Integrated Electric Utilities Handbook (A Detailed Review of Integrated Electric Utilities) (August 2019)

U.S. Transmission and Distribution Utilities Handbook (A Detailed Review of Electric and Gas T&D Utilities) (May 2019)

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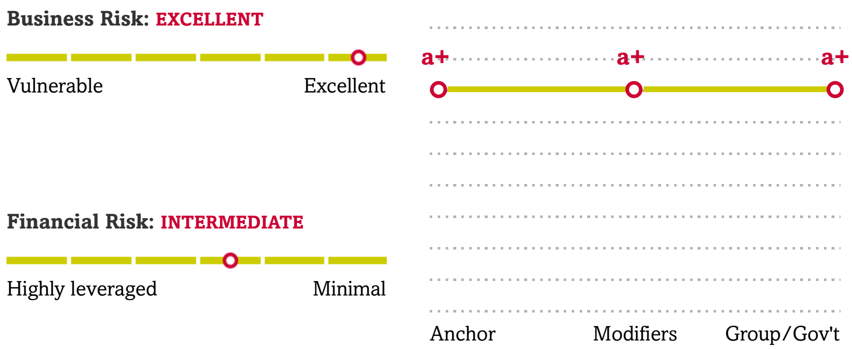
American Transmission Co.



Issuer Credit Rating

A+/Stable/A-1

Credit Highlights

Overview

Key strengths	Key risks
Formulaic, forward-looking rate-setting structure under the Federal Energy Regulatory Commission (FERC) supports American Transmission Co.'s (ATC's) effective management of regulatory risk.	ATC faces third-party challenges, and FERC could pressure the company's authorized return on equity.
ATC is in the higher half of the excellent business risk profile category compared with peers.	We project negative discretionary cash flow for ATC, largely due to its elevated capital spending plan.
ATC has relatively low operating risk.	

We expect American Transmission Co. (ATC) to effectively manage regulatory risk, supporting our assessment of its excellent business risk profile. This reflects the company's essential transmission operations under a credit-supportive Federal Energy Regulatory Commission (FERC) regulatory framework.

We expect ATC's credit metrics will remain in the middle of the intermediate financial risk profile category. On a forward-looking basis, we forecast funds from operations (FFO) to debt will average about 16%. We evaluate that ratio using our low-volatility financial benchmark tables.

Outlook: Stable

Our stable outlook on ATC reflects its low-risk business model, highly constructive regulation, and predictable cash flow from a reliable electricity transmission network. The stable outlook also incorporates ATC's FFO-to-debt ratio, which we expect will remain steady.

Downside scenario

We could lower the rating if ATC's financial metrics weaken such that FFO to debt stays below 15%. This could occur if the regulatory cost-recovery construct weakens, or if ATC materially increases its dividends. This could also occur if ATC's authorized return on equity (ROE), which third parties are challenging, is reduced significantly enough by FERC to hurt credit quality.

Upside scenario

We could raise the rating if ATC's financial measures consistently strengthen such that FFO to debt exceeds 20%. Although less likely, this could occur if capital spending or dividends decrease or if ATC rebalances its capital structure.

Our Base-Case Scenario

Assumptions

- Capital spending averages about $420 million annually over the next three years;
- Regulated capital structure is maintained;
- Dividend payout ratio of about 80%; and
- All debt maturities will be refinanced.

Key Metrics

	2019a	2020e	2021e
FFO to debt (%)	16.7	15.5-16.5	15.5-16.5
Debt to EBITDA (x)	4.7	4.5-5	4.5-5

a--Actual. e--Estimate. FFO--Funds from operations.

Company Description

ATC is an electric transmission company that owns and operates electric transmission systems primarily in Wisconsin, Illinois, Michigan, and Minnesota. The company owns and operates close to 10,000 miles of transmission lines and 550 substations. ATC was founded in 2001 and is based in Waukesha, Wis.

Business Risk: Excellent

Our assessment of ATC's business risk reflects our view of the company's low-risk, rate-regulated electric transmission operations and effective management of regulatory risk under FERC's highly supportive regulatory rate construct. ATC's ability to earn a cash return on construction work in progress, recover abandoned plant costs for certain projects, and have rates set prospectively with annual true-ups exemplify such support. Our business risk assessment also reflects Midcontinent Independent System Operator Inc.'s (MISO's) operational control of ATC's facilities, which shifts the responsibility of transmission grid monitoring and congestion management away from ATC. For these reasons, we view ATC as being in the higher half of the excellent business risk profile category compared with peers.

Financial Risk: Intermediate

We assess ATC's financial risk profile using our low-volatility table, reflecting the company's low-risk transmission business and effective management of regulatory risk under FERC's supportive regulatory construct. Under our base-case scenario, we expect financial measures to remain in the middle of the financial risk profile category. Specifically, we expect the company's FFO to debt to average about 16% over our forecast. Our base case assumes formulaic cost recovery of investments under FERC's regulatory construct, annual capital spending averaging about $420 million over the next three years, and a dividend payout ratio of about 80%. Our base case further reflects capital contributions made by ATC's equity owners to maintain its capital structure.

Historically, FERC authorized a 12.2% ROE on a hypothetical capital structure of 50% equity. Customers and related parties in the MISO service area have challenged ATC's ROE in recent years. Specifically, two complaints pursuing refunds were filed at FERC. In 2016, FERC recommended lowering the base ROE. That recommendation was then vacated by the D.C. Circuit of the U.S. Court of Appeals in 2017. Since then, FERC has updated its ROE analysis methodology, and it issued a final order in December 2019, ruling that the new base ROE would be reset at 9.88% in response to the first complaint. The second complaint was dismissed. Even though this order is in effect, FERC is considering requests for a rehearing on the decision. ATC has set aside a refund liability to address lower authorized ROEs. If FERC materially reduces the company's base authorized ROE beyond our base-case expectation, ATC's cash flows could be hurt.

Liquidity: Adequate

ATC has adequate liquidity, reflecting our expectation that its liquidity sources will exceed uses by more than 1.1x over the next 12 months even if EBITDA declines 10%. Under our stress scenario, we do not expect that ATC would require access to the capital markets to meet its liquidity needs. ATC could likely absorb a high-impact, low-probability event with limited need for refinancing, and it maintains sound relationships with banks, a generally satisfactory standing in the credit markets, and generally prudent risk management practices.

Principal Liquidity Sources	Principal Liquidity Uses

- FFO of about $460 million;
- Credit facility availability of about $400 million; and
- Minimal cash assumed.

- Debt maturities of about $260 million over the next 12 months;
- Maintenance capital spending of about $230 million; and
- Dividend payments of about $220 million in 2020.

Environmental, Social, And Governance

ATC is somewhat exposed to environmental risks. The company is subject to various environmental laws and regulations, which monitor and regulate the discharge of pollutants into the environment and require ATC to investigate and remediate contamination in certain circumstances. From a social perspective, ATC's internal safety system processes enable it to effectively provide transmission services to its customers across several states. The company must also maintain good relations and communications with residents and officials in the areas where it operates its transmission facilities in order to grow its operations because these operations are subject to strict regulatory requirements. We view governance factors as neutral for ATC. ATC's board of directors mostly comprises members who are independent of majority owner WEC Energy Group Inc. (WEC). Overall, the ATC board, in our view, is capably engaged in risk oversight on behalf of all stakeholders.

Group Influence

Although WEC owns 60% of ATC, we do not view WEC as controlling ATC because of FERC's merger order, which restricts WEC's general voting rights to 34%. Therefore, we assess ATC's credit quality as a stand-alone entity.

Issue Ratings

We rate ATC's commercial paper 'A-1', reflecting our 'A+' issuer credit rating on the company.

Ratings Score Snapshot

Issuer Credit Rating

A+/Stable/A-1

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/leverage:** Intermediate

Anchor: a+

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a+

- **Group credit profile:** a+

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of April 29, 2020)*

American Transmission Co.	
Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Local Currency	A-1
Issuer Credit Ratings History	
29-Jun-2015	A+/Stable/A-1
23-Jun-2014	A+/Watch Neg/A-1
18-Jul-2005	A+/Stable/A-1

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

S&P Global
Ratings

RatingsDirect®

Summary:

ITC Midwest LLC

Primary Credit Analyst:
Gabe Grosberg, New York (1) 212-438-6043; gabe.grosberg@spglobal.com

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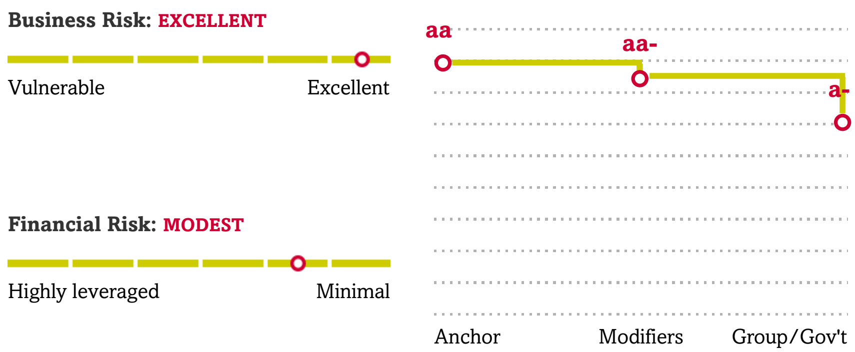
Summary:

ITC Midwest LLC



CORPORATE CREDIT RATING

A-/Stable/--

Rationale

Business Risk: Excellent	Financial Risk: Modest
• Low-operating-risk electric transmission business; • Formulaic, forward-looking rate-setting structure under the Federal Energy Regulatory Commission (FERC); • Timely recovery of costs and expenditures; • Effective management of regulatory risk; and • Third-party challenges before the FERC continues pressuring authorized return on equity (ROE).	• We assess the company's financial risk profile against our most relaxed financial benchmark tables, compared with the typical corporate issuer, reflecting the company's low-risk transmission business and effective management of regulatory risk; • Sustainable and highly predictable cash flow and leverage measures; and • Financial measures consistent with the lower-end of the range for its financial risk profile category.

Outlook: Stable

The stable outlook reflects S&P Global Ratings' view of Cedar Rapids, Iowa-based ITC Midwest LLC's ultimate parent Fortis Inc.'s stable and predictable cash flow, underpinned by Fortis' regulated operations with generally supportive regulatory framework. During our two-year outlook period, we expect Fortis to focus on its regulated businesses. In addition, we expect Fortis will focus on measured organic growth opportunities rather than growth from acquisitions, leading to continued strengthening in credit metrics. Although Fortis' credit metrics were weak in 2016 due to the timing of the acquisition's closing, we expect these to improve during our outlook period, with funds from operations (FFO)-to-debt of 10.5%-11.0%.

Downside scenario

We could take a negative rating action on ITC Midwest if consolidated FFO to debt of Fortis Inc. were to fall below 10% during our outlook period with no prospect for improvement. This could happen because of material adverse regulatory decisions, significant debt-funded acquisitions, or operational difficulties leading to unexpected cost increases.

Upside scenario

We could take a positive rating action on ITC Midwest if Fortis improves its financial position, with consolidated FFO to debt approaching 15% with no increase in business risk. However, based on our financial forecast, the company's capital programs, and the regulated nature of Fortis' cash flow, we believe the prospect of a positive rating action is unlikely during our outlook horizon.

Our Base-Case Scenario

ITC Midwest LLC

Assumptions

- Capital spending averaging $300 million-$350 million over the next three years;
- Minimal dividends in 2017;
- Reduced ROE stemming from third-party challenges before the FERC;
- Long-term debt maturities are refinanced; and
- Negative discretionary cash-flow.

Key Metrics

	2016A	2017E	2018E
FFO to total debt (%)	35.1	26-30	23-27
Total debt to EBITDA (x)	3.0	2.8-3.2	3.1-3.5
Total debt to total capital (%)	36.0	34-38	36-40

A--Actual. E—Estimated.

Business Risk: Excellent

Our assessment of ITC Midwest's business risk reflects our view of its fully rate-regulated and lower-risk transmission business operating within the FERC's highly supportive regulatory construct. ITC Midwest plans, builds, operates, owns, and maintains electric transmission facilities in Iowa, Illinois, Minnesota, and Missouri. FERC is the sole regulator for ITC Midwest and allows the company to recover its costs and return on investments on a forward-looking basis with a true up mechanism and achieve authorized rates of return that are often incentive-based. Further supporting our view of ITC Midwest's business risk is the Midcontinent Independent System Operator Inc.'s (MISO) operational control over the company's facilities. This mitigates ITC Midwest's operational risk because it places responsibility away from the company for such oversight matters as the monitoring and directing of operations for congestion and outages, though the company may still be heavily involved in such matters.

Historically, the FERC authorized a 12.38% ROE, plus additional ROE incentives, on a capital structure of 60% equity for ITC Midwest. However, in September 2016, FERC issued an order in the first of two ongoing ROE complaints against MISO transmission owners, including ITC Midwest, lowering the base ROE to 10.32% from 12.38% and limiting the high end of the zone of reasonableness to 11.35%. A second complaint is ongoing, and an administrative law judge in that case ruled MISO transmission owners' authorized base ROEs should be further lowered to 9.7% with a high end of the zone of reasonableness of 10.68%. In September 2017, ITC Midwest, along with other MISO transmission owners, filed for the FERC to dismiss the second complaint. The ruling on the second complaint and the file for dismissal remain pending with the FERC.

Financial Risk: Modest

We assess ITC Midwest's financial risk profile against our most relaxed financial benchmark tables, compared to the typical corporate issuer, reflecting the company's low-risk transmission business and its effective management of regulatory risk under the FERC's supportive regulatory construct.

Under our base-case of declining capital spending after 2017, formulaic transmission rates, maintenance of the company's capital structure, capital spending averaging about $300 million-$350 million through 2019, and increasing dividend distributions after 2017, we expect ITC Midwest to achieve FFO to debt of about 24%, consistent with the lower end of the range for the modest financial risk profile category.

Liquidity: Adequate

In our view, ITC Midwest has adequate liquidity, and can more than cover its needs for the next 12 months, even if EBITDA declines by 10%. We expect the company's liquidity will exceed uses by more than 1.1x. Under our stress scenario, we do not expect that ITC Midwest will require access to capital markets during that period to meet liquidity needs. ITC Midwest's ability to absorb high-impact, low-probability events with limited need for refinancing, flexibility to lower capital spending or sell assets, sound bank relationships, and generally prudent risk management also support our assessment that liquidity is adequate.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of about $300 million; • Credit facility availability of about $225 million; and • Minimal cash assumed.	• No long-term debt maturities in 2018; • Capital spending of about $325 million in 2018; and • Dividend payments of about $50 million in 2018.

Other Credit Considerations

We assess the comparable rating analysis modifier as negative, reflecting our view that the company's financial measures will consistently be at the lower end of the range for its financial risk profile category.

Group Influence

Under our group rating methodology, we assess ITC Midwest to be a core subsidiary of ITC Holdings, since it is highly unlikely to be sold and has a strong long-term commitment from senior management. Furthermore, we consider ITC Holdings to be a core subsidiary of Fortis Inc. We assess the issuer credit rating on ITC Midwest as consistent with Fortis' 'a-' group credit profile.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Modest

- **Cash flow/Leverage:** Modest

Anchor: aa

Modifiers

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

Stand-alone credit profile : aa-

- **Group credit profile:** a-
- **Entity status within group:** Core (-3 notches from SACP)

Recovery Analysis

- We assign recovery ratings to first mortgage bonds (FMB) issued by U.S. utilities, which can result in issue ratings notched above the issuer credit rating (ICR) on the utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property," published Feb. 14, 2013).
- The historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist supports the recovery methodology.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed the ICR on a utility by one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.
- ITC Midwest's FMBs benefit from a first-priority lien on substantially all of its real property owned or subsequently acquired. Collateral coverage greater than 1.5x supports a recovery rating of '1+', leading to an 'A' issue rating, one notch above the ICR.

Related Criteria

- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
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- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile: Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	**aa**	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Market Intelligence

November 25, 2019
spglobal.com/marketintelligence

RRA Regulatory Focus
An Overview of Transmission Ratemaking in the New York ISO – 2019 Update

Introduction and overview

Net transmission plant in service among six utilities that are members of the New York Independent System Operator, or NYISO, showed continued moderate growth from 2017 to 2018, rising to an aggregate $7.44 billion from $6.93 billion, an increase of 7.4%. This compares to year-over-year growth for the same six companies of 6.4% and 7.6% in 2016 and 2017, respectively.

New York independent system operator

Source: FERC

Among utilities in New York, only Niagara Mohawk Power Corp. has fully unbundled transmission assets from distribution assets, therefore, net transmission plant in service data from company Form 1 filings at the Federal Energy Regulatory Commission is used in this report for all companies to provide a comparable measure of size and growth. New York Transco LLC, which began filing the FERC Form 1 in 2017 with 2016 data, is also included in this 2019 update to the report *An Overview of Transmission Ratemaking in the NYISO* — 2018 Update, published Nov. 12, 2018, by Regulatory Research Associates, a group within S&P Global Market Intelligence.

Niagara Mohawk separately reports transmission rate base through a FERC-authorized formula rate for transmission that is updated annually, and data from those updates is included in this report. New York Transco, which was formed in 2014, now annually reports transmission rate base separately through a FERC-authorized formula rate, and five years of New York Transco formula rate data is also included in this report.

The other five utility operating companies in New York have not unbundled their transmission assets from their distribution assets, and they continue to recover their combined transmission and distribution, or T&D, revenue requirement through traditional "delivery" rate cases before the New York Public Service Commission. Data for those five operating companies and their delivery rate cases are also included in this report.

History of the New York ISO

The New York Power Pool, or NYPP, was formed in 1969 in response to the first Northeast Blackout, which occurred in 1965. In 1977, the NYPP began conducting real-time economic dispatch of generation in the state.

The NYPP was not an independent entity as it comprised the utilities in New York who were involved in the market as participants. The creation of the NYISO as an independent system operator was authorized by FERC in 1998, and NYISO was launched in 1999. The NYISO footprint covers the entire state of New York.

NYISO is responsible for operating wholesale power markets in the state, in addition to operating New York's high-voltage transmission network and performing long-term system planning.

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Transmission ratemaking in New York

New York implemented electric retail competition for all customers in the late 1990s. The restructuring framework that New York adopted required the separation of the newly competitive generation business from T&D operations. T&D continues to be rate-regulated by the PSC for most utilities in the state. However, New York did not require utilities to unbundle transmission assets from distribution assets. Five of the six investor-owned utilities in New York did not unbundle transmission from distribution assets and, therefore, continue to recover their combined T&D revenue requirements through traditional "delivery" rate cases before the PSC.

Only Niagara Mohawk unbundled transmission from distribution, and Niagara Mohawk employs a FERC jurisdictional transmission formula-based framework to determine annual transmission rate base and revenue requirements. Niagara Mohawk's distribution rates, rate base and revenue requirements continue to be determined through traditional rate cases at the PSC. The accompanying table provides a summary of net transmission plant in service for the companies in NYISO, based on available Form 1 data, and identifies any authorized ROE incentives where applicable.

New York ISO utilities transmission summary

Ticker	Parent company	Filing entity	2017 net transmission plant in service ($000)[1]	2018 net transmission plant in service ($000)[1]	2017-2018 increase (%)	Transmission base ROE (%)	Year ROE established	Transmission rate base subject to incentive ROE ($000)[2]	Incentive ROE (%)
FTS	Fortis Inc./CH Energy Group	Central Hudson Gas & Electric Co.	260,726	300,010	15.07	10.93	1997	None	NA
ED	Consolidated Edison Inc.	Consolidated Edison Co. of NY	2,813,313	2,919,371	3.77	10.50	1997	None	NA
ED	Consolidated Edison Inc.	Orange and Rockland Utilities Inc.	188,928	194,814	3.12	11.11	1997	None	NA
AGR	Avangrid Inc.	New York State Electric & Gas Corp.	674,749	739,850	9.65	11.00	1997	None	NA
AGR	Avangrid Inc.	Rochester Gas & Electric Corp.	647,629	762,872	17.79	11.50	1997	None	NA
NGG	National Grid US	Niagara Mohawk Power Co.[3]	2,343,519	2,525,875	7.78	9.80	2012	1,871,863	10.3
na	na	New York Transco LLC[4]	70,658	69,679	-1.39	9.50	2016	NA	10.0

Data compiled Nov. 20, 2019.
NA = Not applicable or not available
[1] Data from annual FERC Form 1 calculated as transmission plant in service net of transmission depreciation. Form 1 data for 2019 will not be filed until 2020.
[2] Transmission rate base for Niagara Mohawk Power subject to incentive ROE is from annual transmission formula rate update filed in 2019 with FERC.
[3] Incentive ROE inclusive of 50 basis point adder for membership in NYISO.
[4] Base ROE and Incentive ROE apply only to specific projects.
Note: "Transmission plant in service" is reported by utilities in their annual FERC Form 1 filing and does not equal transmission rate base. "Transmission base ROE (%)" for Niagara Mohawk and New York Transco is from each company's FERC-approved annual formula rate filings; for the other five utilities the transmission base ROE is from their Open Access Transmission Tariffs filed with FERC in the late 1990s.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Because only Niagara Mohawk and now New York Transco report a separate transmission rate base through their FERC formula-based framework, separate transmission rate base data is not available for the other utilities in New York. In lieu of transmission rate base, and in order to provide a measure of comparability among all utilities in New York, "net transmission plant in service," i.e., net of depreciation, has been extracted from each utility's FERC Form 1 as a rough measure of transmission rate base in this report to illustrate transmission asset size and growth.

The appendix tracks the changes in net transmission plant in service from FERC Form 1s for utilities in NYISO from 2010 through 2018. Data for 2019 will not be available until April 2020.

The NYISO transmission charge, known as the wholesale transmission service charge, or TSC, is based on a license plate tariff where each transmission owner has a different tariff for the use of their transmission network. Transmission revenue collected by the NYISO for utilities during the year through the TSC is credited to retail customers to offset retail rates. For example, Consolidated Edison Co. of New York utilizes a monthly adjustment charge to reconcile TSC revenues received, other than from firm transmission contracts, on an annual basis net of any NYISO-related adjustments.

Because five of the six utilities in New York continue to have bundled transmission and distribution revenue requirements, information and data from delivery rate cases at the PSC are included in this report. All references have been identified as transmission, distribution or delivery. In addition, all data values reference the relevant time period of the available data.

The table below tracks the changes in delivery rate base for utilities in NYISO from 2010 through 2019.

Delivery rate base values for NYISO companies ($000)[1]

Ticker	Parent company	Filing entity	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	'16-'19 CAGR (%)	'11-'19 CAGR (%)
FTS	Fortis Inc. /CH Energy Group	Central Hudson Gas & Electric Co.	692,900	728,800	764,400	764,400	764,400	830,100	888,500	948,200	999,500	1,080,800	6.75	5.05
ED	Consolidated Edison Inc.	Consolidated Edison Co.of NY	14,887,000	15,987,000	16,826,000	16,826,000	17,322,800	18,113,000	18,902,000	19,530,000	20,277,000	21,659,543	4.64	3.87
ED	Consolidated Edison Inc.	Orange and Rockland Utilities Inc.	596,700	629,900	671,000	708,400	759,000	763,200	804,800	804,800	877,800	906,400	4.04	4.65
AGR	Avangrid Inc.	New York State Electric & Gas Corp.	1,459,900	1,565,817	1,637,287	1,674,262	1,674,262	1,674,262	1,752,900	1,818,000	1,887,000	2,457,000	11.91	5.79
AGR	Avangrid Inc.	Rochester Gas & Electric Corp.	NA	922,875	931,378	1,080,905	1,080,905	1,080,905	1,146,400	1,347,000	1,499,000	1,520,000	9.86	6.44
NGG	National Grid US	Niagara Mohawk Power Co.[2]	NA	3,995,500	NA	4,107,000	4,365,000	4,626,000	4,626,000	4,626,000	5,261,000	5,605,000	6.61	4.32

Data compiled Nov. 20, 2019.
NA = Not applicable or not available
[1] Delivery rate base represents combined transmission and distribution assets for each utility except Niagara Mohawk Power.
[2] Values for Niagara Mohawk Power are distribution only.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Return on equity in NYISO

A base transmission ROE of 11% was established by FERC for Niagara Mohawk in 2009, when the utility switched from a stated transmission rate to a formula-based rate. In 2015, Niagara Mohawk's base transmission ROE was lowered to 9.8% effective in 2012. In 2009, FERC granted Niagara Mohawk a 50 basis point ROE adder for continued membership in the NYISO. None of the other five investor-owned utilities in New York were identified as having applied for or received ROE adders.

A base transmission ROE of 9.5% was established by FERC for New York Transco in 2016, as well as a 50 basis point adder to the base ROE for specific projects described in the New York Transco section below.

The base ROE applicable to transmission for the other five New York investor-owned utilities is from each utility's open access transmission tariff, or OATT, filed in the mid-to-late ,1990s with FERC. OATTs were filed by all utilities pursuant to FERC's Orders 888 and 889 issued in 1996.

Individual company details

The sections that follow provide a closer look at transmission and delivery ratemaking for each company with operations in NYISO that is covered by RRA. For each, there is a summary description, followed by a table or tables that provide details regarding authorized base ROE, rate of return, delivery rate base, or, in the case of Niagara Mohawk, separate transmission and distribution rate bases, net annual revenue requirement, TSC, equity ratio, any additional ROE incentives that apply to the company's rate base, and the portion of total rate base that is accorded incentive ROEs, where applicable. Summary descriptions are also included for the New York Power Authority, or NYPA, and the Long Island Power Authority, or LIPA.

Available transmission data is also included in a separate table in the New York Transco section. As a transmission-only entity, New York Transco does not own or control distribution assets.

For this report, revenue requirements and other data may not reflect subsequent revisions filed by individual companies to incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

Avangrid Inc.

Iberdrola USA and UIL Holdings completed their merger in 2015 and now operate under the name Avangrid Inc. Avangrid subsidiaries New York State Electric & Gas Co. and Rochester Gas & Electric Co., or RG&E, serve 881,000 electric customers across more than 40% of upstate New York and 371,000 electric customers in a nine-county region centered on the City of Rochester.

RG&E, in conjunction with parent company Avangrid, is planning to invest approximately $290 million to upgrade the electricity transmission system in the Rochester region by 2020. The project, known as the Rochester Area Reliability Project, would be located in the towns of Chili, Gates and Henrietta and in the City of Rochester. The project would provide additional power to fill growing demand, increase reliability and accommodate growth and economic development in the Rochester region.

New York State Electric & Gas delivery rates

Rate period	Adjustment frequency	Adjustment date	Delivery base ROE (%)	Delivery ROR (%)	Total delivery rate base ($000)	Total delivery annual rev. req. ($000)	TSC ($/MWh)[1]	Equity (%)
05/19-04/20[2]	TBD	TBD	9.50	6.74	2,457,000	1,038,069	NA	50.00
05/18-04/19	Annual	05/01/18	9.00	6.81	1,887,000	881,369	4.39	48.00
05/17-04/18	Annual	05/01/17	9.00	6.81	1,818,000	851,069	3.53	48.00
05/16-04/17	Annual	05/01/16	9.00	6.68	1,752,900	821,169	4.12	48.00
01/14-04/16	NA	NA	10.00	7.48	1,674,262	791,569	5.30	48.00
09/12-12/13	Annual	09/01/12	10.00	7.48	1,674,262	791,569	5.66	48.00
09/11-08/12	Annual	09/01/11	10.00	7.48	1,637,287	768,356	5.81	48.00
09/10-08/11	Annual	08/25/10	10.00	7.48	1,565,817	748,719	5.76	48.00
09/09-08/10	Annual	NA	9.55	7.18	1,459,900	NA	4.71	41.60

Data compiled Nov. 20, 2019.
[1] Transmission Service Charge for the New York Control Area for November 2019.
[2] Rate case filed on May 20, 2019 pending at New York PSC, data reflects initial company position.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Rochester Gas & Electric delivery rates

Rate period	Adjustment frequency	Adjustment date	Delivery base ROE (%)	Delivery ROR (%)	Total delivery rate base ($000)	Total delivery annual rev. req. ($000)	TSC ($/MWh)[1]	Equity (%)
05/19-04/20[2]	TBD	TBD	9.50	7.24	1,520,000	522,203	3.09	50.00
05/18-04/19	Annual	5/1/2018	9.00	7.48	1,499,000	490,503	3.50	48.00
05/17-04/18	Annual	5/1/2017	9.00	7.47	1,347,000	464,603	3.48	48.00
05/16-04/17	Annual	5/1/2016	9.00	7.55	1,146,400	443,003	3.46	48.00
01/14-04/16	NA	NA	10.00	8.47	1,080,905	440,003	3.64	48.00
09/12-12/13	Annual	9/1/2012	10.00	8.47	1,080,905	440,003	3.67	48.00
09/11-08/12	Annual	9/1/2011	10.00	8.47	931,378	414,410	3.68	48.00
08/10-08/11	Annual	8/25/2010	10.00	8.47	922,875	398,914	3.66	48.00
09/09-08/10	NA	NA	NA	NA	NA	NA	3.71	48.00

Data compiled Nov. 20, 2019.
[1] Transmission Service Charge for the New York Control Area for November 2018.
[2] Rate case filed on May 20, 2019 pending at New York PSC, data reflects initial company position.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Consolidated Edison Inc.

Consolidated Edison Co.'s subsidiaries Consolidated Edison of New York Inc., or Con Ed, and Orange and Rockland Utilities own and operate transmission facilities located in New York City and Westchester, Orange, Rockland, Putnam and Dutchess counties in New York State.

Consolidated Edison of New York delivery rates

Rate period	Adjustment frequency	Adjustment date	Delivery base ROE (%)[1]	Delivery ROR (%)	Total delivery rate base ($000)	Total delivery annual rev. req. ($000)	TSC ($/MWh)[2]	Equity (%)
01/20-12/20[3]	Annual	01/01/20	8.80	6.61	21,659,543	NA	7.13	48.0
01/19-12/19	Annual	01/01/19	9.00	6.73	20,277,000	8,919,679	6.44	48.0
01/18-12/18	Annual	01/01/18	9.00	6.80	19,530,000	8,720,679	7.24	48.0
01/17-12/17	Annual	01/01/17	9.00	6.82	18,902,000	8,521,679	7.76	48.0
01/16-12/16	NA	01/01/16	9.00	7.05	18,113,000	8,322,679	7.85	48.0
01/15-12/16	Annual	01/01/15	9.20	7.05	18,113,000	8,322,679	7.85	48.0
01/14-12/14	Annual	01/01/14	9.20	7.05	17,322,800	8,198,711	7.42	48.0
04/13-12/13	NA	NA	10.15	7.76	16,826,000	8,274,903	6.81	48.0
04/12-03/13	Annual	04/01/12	10.15	7.76	16,826,000	8,274,903	6.11	48.0
04/11-03/12	Annual	04/01/11	10.15	7.76	15,987,000	7,854,903	5.53	48.0
04/10-03/11	Annual	04/01/10	10.15	7.76	14,887,000	7,434,903	5.63	48.0

Data compiled Nov. 20, 2019.
[1] Earnings sharing mechanism approved in 2017 for duration of three year rate plan: ROE between 9.5% to 10% shared 50%/50% between ratepayers/shareholders; ROE between 10% to 10.5% shared 75%/25% between ratepayers/shareholders; ROE above 10.5% shared 90%/10% between ratepayers/shareholders.
[2] Transmission Service Charge for the New York Control Area for November 2018.
[3] Pending joint proposal filed Oct. 18, 2019.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Orange and Rockland Utilities delivery rates

Rate period	Adjustment frequency	Adjustment date	Delivery base ROE (%)[1]	Delivery ROR (%)	Total delivery rate base ($000)	Total delivery annual rev. req. ($000)	TSC ($/MWh)[2]	Equity (%)
01/20-12/20[3]	Annual	01/01/20	9.00	6.96	906,400	503,271	6.03	48.00
01/19-12/19[4]	Annual	01/01/19	9.00	6.97	877,800	495,271	6.06	48.00
11/17-12/18	NA	NA	9.00	7.06	804,800	NA	5.84	48.00
11/16-10/17	Annual	11/01/16	9.00	7.06	804,800	NA	6.04	48.00
11/15-10/16	Annual	11/01/15	9.00	7.10	763,200	NA	5.98	48.00
07/14-11/15	Annual	07/01/14	9.60	7.61	759,000	NA	6.16	48.00
07/13-06/14	Annual	07/01/13	9.50	7.61	708,400	NA	6.04	48.00
07/12-06/13	Annual	07/01/12	9.40	7.61	671,000	NA	6.04	48.00
07/11-06/12	Annual	07/01/11	9.20	7.22	629,900	NA	6.11	48.00
07/10-06/11	Annual	07/01/10	9.40	7.69	596,700	NA	6.00	48.00

Data compiled Nov. 20, 2019.
[1] Earnings sharing mechanism approved in 2019: ROE between 9.6% and 10.2% shared 50%/50% by ratepayers/shareholders; ROE between 10.2% and 10.8% shared 75%/25% between ratepayers/shareholders; ROE above 10.8% shared 90%/10% between ratepayers/shareholders.
[2] Transmission Service Charge for the New York Control Area for November 2018.
[3] Three-year rate plan approved by New York PSC March 14, 2019. Data reflects second year of rate plan.
[4] Three-year rate plan approved by New York PSC March 14, 2019. Data reflects first year of rate plan.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Fortis Inc./CH Energy Group

CH Energy Group subsidiary Central Hudson Gas & Electric Co. serves approximately 300,000 electric customers in a service territory in New York's Mid-Hudson River Valley.

Central Hudson Gas & Electric delivery rates

Rate period	Adjustment frequency	Adjustment date	Delivery base ROE (%)[1]	Delivery ROR (%)	Total delivery rate base ($000)	Total delivery annual rev. req. ($000)	TSC ($/MWh)[2]	Equity (%)
07/19-06/20[3]	Annual	07/01/19	8.80	6.49	1,080,800	365,223	3.27	49.00
07/18-06/19	Annual	07/01/18	8.80	6.44	999,500	346,623	3.25	48.00
07/17-06/18	Annual	07/01/17	9.00	6.58	948,200	326,923	3.38	48.00
07/16-06/17	Annual	07/01/16	9.00	6.62	888,500	312,823	3.35	48.00
07/15-06/16	Annual	07/01/15	9.00	6.62	830,100	296,823	3.38	48.00
07/14-06/15	NA	NA	10.00	7.43	764,400	281,523	3.47	48.00
07/13-06/14	Annual	07/01/13	10.00	7.43	764,400	281,523	3.13	48.00
07/12-06/13	Annual	07/01/12	10.00	7.43	764,400	272,423	3.30	48.00
70/11-06/12	Annual	07/01/11	10.00	7.43	728,800	263,123	2.96	48.00
07/10-06/11	Annual	07/01/10	10.00	7.43	692,900	251,323	2.81	48.00

Data compiled Nov. 20, 2019.
[1] Earnings sharing mechanism approved in 2018: ROE between 9.3% and 9.8% shared 50%/50% between ratepayers/shareholders; ROE between 9.8% and 10.3% shared 80%/20% between ratepayers/shareholders; ROE above 10.3% shared 90%/10% between ratepayers/shareholders.
[2] Transmission Service Charge for the New York Control Area for November 2018.
[3] Three year rate plan approved by New York PSC effective July 1, 2018 through June 30, 2021. Data reflects second year of rate plan.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

National Grid US

National Grid subsidiary Niagara Mohawk Power Co. distributes electricity to approximately 1.6 million customers in upstate New York.

Niagara Mohawk Power Company - distribution rates

Rate period	Adjustment frequency	Adjustment date	Distribution base ROE (%)[1]	Distribution ROR (%)	Distribution rate base ($000)	Distribution annual rev. req. ($000)	Equity (%)
04/19-03/20[2]	Annual	04/01/19	9.00	6.48	5,605,040	2,629,040	48.0
04/18-03/19	Annual	04/01/18	9.00	6.53	5,260,727	2,634,887	48.0
04/17-03/18	NA	NA	9.00	6.85	4,626,000	NA	48.0
04/16-03/17	NA	NA	9.00	6.85	4,626,000	NA	48.0
04/15-03/16	Annual	04/01/15	9.30	6.85	4,626,000	NA	48.0
04/14-03/15	Annual	04/01/14	9.30	6.65	4,365,000	NA	48.0
04/13-03/14[3]	Annual	04/01/13	9.30	6.50	4,107,000	NA	48.0
01/12-03/13	NA	NA	NA	NA	NA	NA	48.0
01/11-12/11	Annual	01/01/11	9.30	6.51	3,995,500	NA	48.0

Data compiled Nov. 20, 2019.
[1] Earnings sharing mechanism adopted in 2018: ROE between 9.5% and 10% shared 50%/50% between ratepayers/shareholders; ROE between 10% and 10.5% shared 75%/25% between ratepayers/shareholders; ROE above 10.5% shared 90%/10% between ratepayers/shareholders.
[2] Three year rate plan approved March 15, 2018 covering the April 1, 2018, through March 31, 2021 period. Data reflects second year of rate plan.
[3] Three year rate plan approved effective April 1, 2013, through March 31, 2016. In May 2016, the PSC extended the rate plan by two years, through March 31, 2018.
Sources: New York PSC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Niagara Mohawk transitioned from a stated transmission rate to a formula-based rate in 2009 and was originally authorized a transmission ROE of 11.5% by FERC, including a 50 basis point adder for participation in the NYISO.

In 2012, the New York Association of Public Power and the Municipal Electric Utilities Association filed complaints at FERC against Niagara Mohawk, seeking to have the base ROE of 11% used in calculating rates for transmission service lowered. FERC ordered the parties to participate in settlement procedures, and the parties subsequently agreed to settle the complaints by reducing the base ROE to 9.8%, exclusive of any incentive adders, from Nov. 2, 2012, forward. The commission approved the settlement agreement in May 2015.

Transmission values from Niagara Mohawk's annual formula rate updates filed with FERC are presented in the table below.

Niagara Mohawk Power Company - transmission

Rate period	Adjustment frequency	Adjustment date	Transmission base ROE (%)	Transmission ROR (%)	Transmission rate base ($000)[1]	Transmission annual rev. req. ($000)	Transmission charge ($/MWh)	Equity (%)	Incentive rate base ($000)[1]	Incentive ROE (%)[2]
2019-2020	Annual	07/01/19	9.8	7.12	2,039,412	410,357	11.33	50.00	2,039,412	10.3
2018-2019	Annual	07/01/18	9.8	7.17	1,871,863	385,708	12.02	50.00	1,871,863	10.3
2017-2018	Annual	07/01/17	9.8	7.06	1,814,817	418,968	11.57	50.39	1,814,817	10.3
2016-2017	Annual	07/01/16	9.8	7.00	1,662,592	414,417	11.79	50.40	1,662,592	10.3
2015-2016	Annual	07/01/15	9.8	6.90	1,496,441	435,182	10.27	50.40	1,496,441	10.3
2014-2015	Annual	07/01/14	9.8	7.55	1,370,809	376,694	7.51	50.44	1,370,809	10.3
2013-2014	Annual	07/01/13	9.8	7.67	1,269,685	301,255	7.44	50.45	1,269,685	10.3
2012-2013	Annual	07/01/12	11.0/9.8[3]	7.73	1,152,172	279,004	6.93	50.47	1,152,172	11.5/10.3[3]
2011-2012	Annual	07/01/11	11.0	7.85	1,127,782	276,957	7.10	50.45	1,127,782	11.5
2010-2011	Annual	07/01/10	11.0	7.50	1,012,349	250,607	4.96	50.43	1,012,349	11.5

Data compiled Nov. 20, 2019.
[1] Values represent transmission rate base from annual formula rate updates filed with FERC.
[2] Inclusive of 50 basis point adder for membership in New York ISO.
[3] Base ROE reduced from 11% to 9.8% effective 11/2/12.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Niagara Mohawk continues to be subject to PSC regulation and files periodic rate cases applicable to its electric distribution operations.

New York Power Authority

NYPA provides transmission service in various parts of New York State over more than 1,400 circuit-miles of transmission facilities, which account for one-third of the state's high-voltage lines.

NYPA is engaged in a multiyear life extension and modernization, or LEM, of its transmission lines in northern, western and central New York and of related facilities, such as switchyards and substations. The $720 million transmission LEM program, begun in 2013 and extending to 2025, is a key element of New York's Energy Highway Blueprint, an initiative to modernize the state's electric power system. The NYPA transmission LEM includes capital investments in smart grid technologies to enhance awareness of the conditions of power lines to help quickly address matters that could threaten equipment and power service reliability.

The NYISO OATT allows NYPA to recover a stated annual transmission revenue requirement of $175.5 million, an increase of 6.1% authorized by FERC in a 2012 proceeding. In that proceeding, NYPA indicated that the rate increase was "the first in a probable series of proposed [revenue requirement] increases that will likely culminate in NYPA requesting, in some future filing, authorization to implement a formula rate in order to make annual updates to its transmission [revenue requirement]."

In 2015, citing mounting operation and maintenance expenses, capital improvements and life extension upgrades for aging facilities, and investments in new projects, including those identified through the NYISO's FERC Order 1000 regional planning process, NYPA sought to convert its stated revenue requirement and rate to a formula-based rate that would be updated on an annual basis.

NYPA proposed to increase its revenue requirement by $16.9 million to $192.4 million and sought a base ROE of 8.85%, plus a 50 basis point ROE adder in recognition of its participation in the NYISO. NYPA also asked FERC to remove an annual capital investment cap limiting its ability to recover costs through a transmission adjustment charge. In August 2015, FERC rejected NYPA's request in its entirety without prejudice, finding that certain existing provisions in the NYISO tariff provide NYPA with several options for recovering capital expenditures exceeding the annual investment cap.

In 2016, NYPA re-filed its request to transition to a formula based transmission rate. The proposed formula rate incorporated a base ROE of 8.65%, which was based on a two-step discounted cash flow analysis, plus a 50 basis point adder for NYPA's continued participation in NYISO. In its request, NYPA used calendar-year 2014 data from its Annual Report to produce a projected annual revenue requirement of $190 million for its initial rate year. NYPA requested that FERC allow the NYISO to begin collecting the projected revenue requirement effective April 1, 2016, through the duration of the initial rate year ending June 30, 2016, subject to true-up in accordance with the annual update process defined in its request.

FERC subsequently approved NYPA's 2016 request for a 50 basis point ROE adder for participation in the NYISO but ordered a hearing and settlement discussions regarding NYPA's formula rate template and protocols. The parties filed a settlement in the case on Sept. 30, 2016, that would set NYPA's base ROE at 8.95%, and would impose a moratorium prohibiting NYPA and any other party from filing to revise the settlement or any provisions of the NYISO tariff affected by the settlement before April 1, 2020.

In January 2017, FERC approved the settlement and determined that the 50 basis point ROE adder as it relates to the Marcy South Series Compensation Project will be identified as a "Congestion Relief Adder" in recognition of the project's benefits to customers, including congestion relief. FERC further found that the Congestion Relief Adder will apply only to the original book cost of the project that does not exceed $55.72 million and that any capital costs of the project that exceed $55.72 million will earn a return that reflects NYPA's base ROE of 8.95%.

New York Transco LLC

New York Transco LLC is a New York limited liability company formed in 2014 that is owned by the following affiliates of New York utilities: Consolidated Edison Transmission, Grid NY, Iberdrola USA Networks and Central Hudson Electric Transmission. New York Transco's sole business focus is to plan, develop, construct and own major new high-voltage electric transmission projects in New York and to operate and maintain those projects under the functional and operational control of the NYISO. Service over New York Transco's transmission facilities is provided through NYISO's OATT. NYISO collects New York Transco's FERC authorized revenue requirement from load-serving entity transmission customers taking service under NYISO's OATT.

New York Transco LLC

Rate period	Adjustment frequency	Adjustment date	Base ROE (%)	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	Equity (%)	Incentive rate base ($000)	Incentive ROE (%)*
2020	Annual	01/01/20	9.50	6.51	226,472	34,580	52.96	195,122	10.00
2019	Annual	01/01/19	9.50	6.41	203,339	35,084	52.67	NA	10.00
2018	Annual	01/01/18	9.50	6.40	195,996	36,220	53.00	195,996	10.00
2017	Annual	01/01/17	9.50	6.40	204,414	35,973	53.00	204,414	10.00
2016	Annual	01/01/16	9.50	6.80	133,355	25,720	60.00	133,355	10.00

Data compiled Nov. 20, 2019.
* Includes 50 basis point ROE adder for the benefits of specified projects.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Long Island Power Authority

LIPA is a municipal subdivision of the State of New York that oversees PSEG Long Island, the electricity service provider for most of Long Island. LIPA was originally created under the Long Island Power Act of 1985 to acquire Long Island Lighting Company's, or LILCO's, assets and securities after the cancellation of the Shoreham Nuclear Power Plant. A second Long Island Power Authority, a wholly owned subsidiary of the first, acquired LILCO's T&D system in 1998.

LIPA played a significant role in day-to-day operations of the Long Island T&D system and was operated under its brand name, though National Grid US maintained the T&D system under a management services agreement that expired at the end of 2013. In 2011, LIPA selected Public Service Enterprise Group, or PSEG, to assume management and operation of the electric grid from National Grid, beginning in 2014. PSEG now manages LIPA's electric system under the name PSEG Long Island.

For a complete, searchable listing of RRA's in-depth research and analysis please go to the S&P Global Market Intelligence Research Library.

Appendix: Net transmission plant in service values for NYISO companies ($000)

Ticker	Parent company	Filing entity	2010	2011	2012	2013	2014	2015	2016	2017	2018	2015-2018 CAGR (%)	2010-2018 CAGR (%)
FTS	Fortis Inc./ CH Energy Group	Central Hudson Gas & Electric Co.	142,437	153,627	170,319	180,876	192,822	216,975	232,894	260,726	300,010	11.41	9.76
ED	Consolidated Edison Inc.	Consolidated Edison Co. of NY	2,021,253	2,339,549	2,371,411	2,446,442	2,586,343	2,667,849	2,788,723	2,813,313	2,919,371	3.05	4.70
ED	Consolidated Edison Inc.	Orange and Rockland Utilities Inc.	107,537	151,227	152,529	151,623	181,244	181,172	188,674	188,928	194,814	2.45	7.71
AGR	Avangrid Inc.	New York State Electric & Gas Corp.	393,047	447,582	453,860	469,852	487,891	470,810	553,209	674,749	739,850	16.26	8.23
AGR	Avangrid Inc.	Rochester Gas & Electric Corp.	334,803	356,591	367,507	448,319	467,635	463,631	503,281	647,629	762,872	18.06	10.84
NGG	National Grid US	Niagara Mohawk Power Co.	1,345,753	1,448,070	NA	1,698,473	1,830,470	2,049,977	2,243,942	2,343,519	2,525,875	7.21	8.19
NA	NA	New York Transco LLC	NA	NA	NA	NA	NA	NA	72,801	70,658	69,679	NA	NA

Data compiled Nov. 20, 2019.
NA = Not applicable or not available
Note: Values from annual FERC Form 1 calculated as transmission plant in service net of transmission depreciation. Form 1 data for 2018 will not be filed until 2019.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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RRA Regulatory Focus
An Overview of Transmission Ratemaking in the California ISO – 2020 Update

Overview

Based on new data available for 2020 rate periods, the growth rate in aggregated transmission rate base for the three large utilities in the California Independent System Operator, or CAISO, more than doubled year over year for the second consecutive year, rising to $17.48 billion in 2020 from $16.22 billion in 2019, or 7.8%. The three utilities reported an aggregate transmission rate base growth of 3.8% from 2018 to 2019 and just 1.5% from 2017 to 2018.

Year-over-year transmission rate base growth from 2019 to 2020 for the three utilities was mixed, ranging from 10.4% for PG&E Corp. subsidiary Pacific Gas and Electric, or PG&E, to 9.3% for Sempra Energy subsidiary San Diego Gas & Electric, or SDG&E. Edison International subsidiary Southern California Edison, or SCE, reported transmission rate base growth from 2019 to 2020 of 3.6%.

California ISO

Source: FERC

History of the California ISO

In 1996, California Assembly Bill 1890 restructured the state's electric power market and established the CAISO as a nonprofit public benefit corporation. Also in 1996, the Federal Energy Regulatory Commission issued final rules in Order No. 888 regarding transmission open access. Order No. 888 required functional unbundling of vertically integrated utility functions, and FERC-regulated utilities were directed to file non-discriminatory, open access transmission tariffs to provide service to all wholesale sellers and buyers.

Subsequently, SCE, PG&E and SDG&E filed a joint application with FERC to transfer control of their transmission facilities to CAISO. CAISO incorporated in 1997 and in 1998 began serving 80% of the state, with the purpose of managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions. Other participating transmission owners in CAISO include the cities of Anaheim and Pasadena, the Imperial Irrigation District and the Western Area Power Administration.

The California Power Exchange, also established by AB 1890, operated the state's competitive wholesale power market and customer choice program until the 2000-2001 western energy crisis forced it into bankruptcy in 2001. The Power Exchange ultimately ceased operation, leaving the state without a day-ahead energy market until 2009 when the CAISO launched a nodal market.

Today, the CAISO includes 18 participating transmission owners, including the three large investor-owned utilities, six transmission-only companies, seven municipal California utilities, the Western Area Power Administration and Valley Electric Association, an electric cooperative in Southwest Nevada.

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Transmission ratemaking in the CAISO

Transmission rates are typically determined through either a traditional rate case or a formula-based framework. A traditional rate case to establish transmission rates at FERC produces a rate that is fixed until the utility's next rate case, or a "stated" rate. Formula-based rates, on the other hand, are updated annually based on a utility's costs, largely as reported in its annual FERC Form 1 filing, subject to true-ups for various items.

California utilities calculate both wholesale and retail base revenue requirements; the wholesale base revenue requirement values are presented in this report. These revenue requirements are generally recovered through the CAISO's transmission access charge, or TAC. CAISO's current TAC structure is a two-part rate charged to each megawatt-hour of internal load and exports. Revenue requirements associated with facilities rated 200 kV and above are recovered through a system wide "postage stamp" rate, known as the high-voltage or regional rate, whereas revenue requirements for facilities rated below 200 kV are recovered via utility-specific rates charged to load within the utility's service territory, known as the low-voltage or local rate. The regional TAC recovers the revenue requirement for all participating transmission owners, which the CAISO then distributes to each individual transmission owner based on its FERC-approved revenue requirement.

Background

Current California ISO transmission rate base summary

Ticker	Parent company	Filing entity	2019 transmission rate base ($000)	2020 transmission rate base ($000)	2019-2020 rate base change (%)	Base ROE (%)	Portion of rate base subject to incentive ROE ($000)	Portion of rate base subject to incentive ROE (%)	Incentive ROE (%)
EIX	Edison International	Southern California Edison Co.	5,624,393	5,829,102	3.64	12.47*	147,863	2.54	13.22*
							678,332	11.64	13.47*
							2,693,150	46.20	13.72*
PCG	PG&E Corp.	Pacific Gas and Electric Co.	6,927,768	7,646,547	10.37	12.50*	None	NA	NA
SRE	Sempra Energy	San Diego Gas & Electric Co.	3,665,148	4,005,298	9.28	10.60*	None	NA	NA
NA	NA	DATC Path 15 LLC	104,850	104,850	NA	13.50	None	NA	NA
NA	NA	Trans Bay Cable LLC	476,383	522,202	9.62	13.50	None	NA	NA

Pending as of Jan. 21, 2020.
NA = not available or not applicable
* Inclusive of 50 basis point adder for membership in California ISO.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Regulatory Research Associates, a group within S&P Global Market Intelligence, first published this survey of transmission rate bases for utilities with formula rates in CAISO in 2016. The first report compiled six years of data for each of the companies — 2016 data and five years of historical data. RRA has published annual updates to that first report, for a total historical data set covering 10 years through this report, which is an update of An Overview of Transmission Ratemaking in the California ISO — *2019 Update, a report published Jan. 21, 2019*.

For this report, RRA analyzed the transmission formula rate updates filed by the three large investor-owned utilities and traditional rate cases filed by two transmission-only companies, Trans Bay Cable LLC and DATC Path 15 LLC. The accompanying summary table lists the CAISO companies in this report, their reported transmission rate base for 2019 and 2020, where available, their base ROE, and any additional ROE incentive adders where applicable. The appendix includes the same companies with rate base values for the years 2011 through 2020, where available.

Formula transmission rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that updates rates annually based on updated cost of service data, generally drawn from the same data filed by a company in its annual FERC Form 1. More than 100 utilities nationwide employ FERC-approved formula rate frameworks for transmission. A "stated" transmission rate is also based on traditional cost of service data, but the rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward-looking projected costs, subject to a true-up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation in each utility's annual update includes transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base.

Among companies in the CAISO, SCE and SDG&E have employed formula-based rates for years. SDG&E has been operating under a formula-based framework since 2007, and SCE transitioned from a stated rate to a formula-based framework in 2013. PG&E has historically operated under a traditional rate case framework, with new rate cases typically filed every year, but the company proposed switching to a formula-based approach in October 2018. See the PG&E company section below for additional details. The two independent transmission companies covered in this report, DATC Path 15 LLC and Trans Bay Cable LLC, operate under traditional rate case frameworks, with new rate cases typically filed at FERC every three years.

Given the complexities inherent in determining a company's transmission rate base from an outside perspective, the RRA reports, with limited exceptions, include transmission rate base only for those companies that report such data in their annual updates under a formula-based rate framework. For additional information on the complex issues associated with determining a utility's rate base, see RRA's July 2, 2019, Topical Special Report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

CAISO return on equity

Base ROEs, a 50 basis point ROE adder for ISO participation, and any additional ROE incentives for CAISO transmission owners have been filed or authorized by FERC on a company by company basis. All three investor-owned utilities have filed formula rate updates including proposed ROEs. PG&E proposed a 12.5% ROE in its initial formula rate filing and 2020 update after years of filing traditional rate cases. SCE's formula rate filing incorporates a 12.47% ROE, while SDG&E's formula rate filing incorporates an 11.2% ROE.

The ROEs for each of the three utilities include a 50 basis point incentive ROE adder for continued CAISO membership.

The 13.5% ROEs for DATC Path 15 and Trans Bay Cable were originally approved in individual FERC proceedings in 2002 and 2005, respectively, and were re-authorized in subsequent rate cases for both companies. DATC Path 15 filed a new transmission rate case in February 2017, while Trans Bay Cable filed a new rate case on Sept. 20, 2019. Both rate cases are pending at FERC; see the company sections below for additional details.

Individual company details

The sections that follow provide a closer look at transmission ratemaking for five CAISO transmission owners. For each there is a summary description, followed by a table or tables that provide detail regarding authorized base ROE, ROR, rate base, annual revenue requirement, equity ratio, any additional ROE incentives that apply to the company's rate base, and the portion of total rate base that is accorded incentive ROEs, where applicable.

Edison International

SCE is the primary electricity supplier for much of southern California, serving 14 million people across a service territory of approximately 50,000 square miles.

In 2011, SCE proposed to implement a formula rate for the costs associated with its transmission facilities to replace the stated rate it had used since 1998. In 2013, FERC approved a settlement and SCE's formula rate in the case and established a base ROE of 9.8%, inclusive of the 50 basis point ROE adder for participation in the CAISO.

Southern California Edison Co.

Company filing reference	Rate period	Adjustment frequency	Adjustment date	Base ROE[1] (%)	ROR (%)	Transmission rate base ($000)	Wholesale transmission annual rev. req. ($000)	Equity (%)	Incentive portion of rate base ($000)	Incentive ROE[1] (%)
TO2020[2]	01/01/20-12/31/20	Annual	01/01/20	12.47	8.46	5,829,102	957,694	55.54	147,863	13.22
									678,332	13.47
									2,693,150	13.72
TO2019A[3]	06/12/19-12/31/19	One-time	06/12/19	17.62	9.17	5,624,393	1,322,194	57.93	150,232	18.37
									687,752	18.62
									2,728,701	18.87
TO2019	01/01/19-12/31/19	Annual	01/01/19	10.80	7.94	5,624,393	1,033,000	59.07	150,232	11.55
									687,752	11.80
									2,728,701	12.05
TO2018[4]	01/01/18-12/31/18	Annual	01/01/18	10.80	7.99	5,451,343	1,169,307	59.80	157,349	11.55
									717,950	11.80
									2,564,374	12.05
TO12	01/01/18-12/31/18	Annual	01/01/18	9.80	7.25	5,429,899	1,169,295	57.14	157,349	10.55
									717,950	10.80
									2,564,374	11.05
TO11	01/01/17-12/31/17	Annual	01/01/17	9.80	7.22	5,483,030	1,182,582	56.23	159,718	10.55
									729,083	10.80
									2,721,169	11.05
TO10	01/01/16-12/31/16	Annual	01/01/16	9.80	7.30	5,171,547	1,092,228	55.48	164,470	10.55
									749,035	10.80
									2,529,461	11.05
TO9	01/01/15-12/31/15	Annual	01/01/15	9.80	7.45	4,679,376	910,235	56.06	169,212	10.55
									739,091	10.80
									2,088,842	11.05
TO8	10/01/14-12/31/14	Semi-annual	10/01/14	9.80	7.49	4,076,161	815,375	55.22	173,713	10.55
									536,601	10.80
									1,811,255	11.05
TO7	10/01/12-09/30/13	Annual	10/01/12	9.80	8.15	3,256,238	893,796	56.36	179,234	11.18
									151,361	11.43
									1,447,909	11.68
TO6	10/01/11-09/30/12	Annual	10/01/11	10.43	8.24	2,568,633	716,202	56.90	183,961	11.18
									46,790	11.43
									954,848	11.68
TO5	06/01/10-09/30/11	Semi-annual	06/01/10	NA	9.56	2,064,394	530,084	NA	NA	NA

As of Jan. 21, 2020.
Note: Data represents initial company filings and does not reflect any subsequent settlement terms.
NA = Not available or not applicable; ROR = Rate of return
[1] Inclusive of 50 basis point adder for membership in CAISO.
[2] Pending at FERC.
[3] Pending at FERC. Sept. 27, 2019 settlement reduced ROE to 12.47%.
[4] Sept. 16, 2019 settlement reduced ROE to "all-in" 11.2% including all incentives.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

2018 rate year — Because SCE's original formula rate framework approved in 2013 was set to terminate in December 2017, the company was required to propose a successor formula rate in late 2017. SCE filed the proposed new successor formula rate, known as TO2018, with FERC in October 2017.

According to SCE, the proposed TO2018 formula rate "maintains the same basic structure" as the original formula rate. However, SCE proposed several revisions aimed at: improving the operation of the formula rate, including moving "closer to industry standard practice and commission policy for the recovery of certain costs and reflecting current market and regulatory conditions with respect to certain stated values in the proposed formula rate, such as return on equity or depreciation rates." In SCE's TO2018 rate filing, the utility sought an increased ROE of 10.8%, inclusive of the 50 basis point CAISO membership adder.

In December 2017, FERC issued an order accepting and suspending SCE's TO2018 filing and establishing hearing and settlement judge procedures. On Sept. 16, 2019, SCE filed a proposed settlement of all issues in the case.

On Dec. 3, 2019, FERC approved the settlement, which established an "all-in return on equity" of 11.2% for SCE for the 2018 rate year. The settlement specified that the 11.2% figure includes the base ROE, a 50 basis point adder for SCE's participation in the CAISO, and project-specific incentive ROE adders of 0.75% to 1.25% that FERC previously granted to SCE for certain transmission projects described below.

2019 rate year — In November 2018, in accordance with the company's formula rate protocols, SCE filed an annual formula rate update, known as TO2019. The TO2019 filing reduced SCE's annual revenue requirement by $131 million, due primarily to the lowering of the federal corporate income tax rate to 21% from 35% due to federal tax reform. The TO2019 filing incorporated the same 10.8% ROE, inclusive of the 50 basis point CAISO membership adder, as SCE originally proposed in the TO2018 filing.

On April 11, 2019, SCE filed proposed revisions to its transmission formula rate for the 2019 rate year, including a request for a base ROE of 17.12%, exclusive of any incentive ROE adders, "due to dramatic material changes to SCE's regulatory and financial conditions that have occurred since SCE filed its currently effective Formula Rate ... in October 2017." SCE's April 11, 2019, filing, known as TO2019A, cited the risks associated with recent severe wildfires in California and the state's inverse condemnation laws in support of the dramatic increase in the company's requested ROE.

SCE's TO2019A filing asserted that "[a]s a result of these laws and recent fires, SCE is exposed to significant potential wildfire damage claims" and "significant [California Public Utilities Commission]-related cost-recovery uncertainty. Accordingly, SCE is filing proposed revisions to its Formula Rate to account for this risk in a manner sufficient to attract the capital necessary to provide safe and reliable electric service."

SCE also asserted that it was proposing a base ROE request that is "founded on, and fully supported by, the Commission's established ROE policies." SCE determined what it called the "conventional" ROE of 11.12%, excluding any ROE incentives, "that is required to reflect the significant non-wildfire regulatory and legislative risks that SCE faces as a public electric utility operating in California." SCE then asserted that "[t]he conventional ROE does not reflect the extraordinary wildfire risks faced by SCE," and applied a 6.0% upward adjustment to the requested ROE "to account for the extraordinary wildfire risks."

On June 11, 2019, FERC issued an order accepting and suspending SCE's TO2019A filing and establishing hearing and settlement judge procedures. On Dec. 3, 2019, FERC approved a partial settlement filed by SCE and the parties on Sept. 27, 2019, addressing only the ROE used to calculate the company's base transmission revenue requirement for the company's 2019 rate year in the TO2019A filing. The partial settlement reduced SCE's ROE on an interim basis from the requested 17.62% to 12.47%; both include the base ROE and a 50 basis point adder associated with SCE's membership in the CAISO.

The TO2019A filing is still pending at FERC before a commission administrative law judge, and the next settlement conference among the parties in the proceeding is scheduled for Feb. 20, 2020.

2020 rate year — On Nov. 22, 2019, in accordance with the company's formula rate protocols, SCE filed an annual formula rate update, known as TO2020. The TO2020 annual update reduced SCE's wholesale base transmission revenue requirement from $1.033 billion to $0.958 billion. SCE noted that the decrease in the company's revenue requirement reflects interim settlement rates previously established for the 2018 and 2019 rate years, in addition to wildfire-related expenses that are not anticipated to reoccur in 2020.

SCE's TO2020 filing incorporated the 12.47% ROE approved in the partial settlement in the TO2019A proceeding described above. SCE asserted that the TO2020 submission is an informational update and does not subject the company's formula rate to modification.

Transmission incentives — In 2007, FERC authorized a series of ROE incentive adders for SCE's investment in certain transmission projects. First, FERC approved a 75 basis point incentive ROE adder for SCE's Rancho Vista transmission project. The Rancho Vista Project included a new 500-kV substation which was completed in 2009.

Second, FERC approved a 100 basis point incentive ROE adder for SCE's Devers-Palo Verde II Project, or DPV2. DPV2 consisted of the construction of two major transmission lines: (1) a 230-mile, 500-kV transmission line between Central Arizona near the Harquahala Generating Station and SCE's existing Devers substation located in North Palm Springs in Riverside County, Calif.; and (2) a 500-kV transmission line between the Devers substation and SCE's Valley substation in Southeastern California. The $560 million DPV2 project was completed in 2013.

Finally, FERC approved a 125 basis point incentive ROE adder for SCE's Tehachapi transmission project. The Tehachapi project is a $1.7 billion project distributed into 11 segments, which consist of more than 200 miles of 500-kV transmission line, approximately 10 miles of 220-kV transmission line, and three new substation facilities.

The Tehachapi project interconnects up to 4,500 MW of generating resources, consisting primarily of wind generation in the Tehachapi area, to SCE's transmission system in the Tehachapi and Big Creek corridor areas. The first elements of the multi-phase project were placed in service in 2008, and in late 2016, SCE brought online the final portions of the project.

PG&E Corp.

PG&E's electric transmission and distribution network covers 70,000 square miles in northern and central California, serving over 15 million customers. Major facilities include 18,600 miles of interconnected transmission lines, 850 substations, 123,000 miles of distribution lines, and more than a million transformers.

2019 rate year — PG&E has historically filed a traditional transmission rate case with FERC each year. In October 2018, however, PG&E filed to move away from the traditional rate case approach that the company had used since 1997 and requested that FERC approve a new formula-based rate. The new formula rate proposal, known as Transmission Owner 20, or TO20, would align PG&E's transmission ratemaking process with California's other two investor-owned utilities, SCE and SDG&E, as well as more than 100 other electric utility companies in the U.S. that employ formula rates for transmission.

Pacific Gas and Electric Co.

Company filing reference	Rate period	Adjustment frequency	Adjustment date	Base ROE[1] (%)	ROR (%)	Transmission rate base ($000)	Wholesale transmission annual rev. req. ($000)	Equity (%)	Incentive portion of rate base ($000)	Incentive ROE[1] (%)
RY2020[2]	01/01/20-12/31/20	Annual	10/01/20	12.50	8.74	7,646,547	2,236,494	52.46	None	NA
TO20[2]	01/01/19-12/31/19	Annual	01/01/19	12.50	8.79	6,927,768	1,950,236	52.93	None	NA
TO19	03/01/18-02/28/19	Annual	03/01/18	10.25	8.03	6,935,253	1,779,000	53.00	None	NA
TO18[2]	03/01/17-02/28/18	Annual	03/01/17	10.90	8.16	6,712,509	1,718,572	53.16	None	NA
TO17[2]	03/01/16-02/28/17	Annual	03/01/16	10.96	7.96	5,120,000	1,366,000	53.52	None	NA
TO16[2]	03/01/15-02/28/16	Annual	03/01/15	11.26	8.08	4,086,597	1,188,000	53.35	None	NA
TO15	10/01/13-02/28/15	Periodic	10/01/13	10.90	8.59	3,765,866	1,027,900	52.42	None	NA
TO14	05/01/13-09/30/13	Periodic	05/01/13	11.00	8.80	3,867,792	1,004,300	53.02	None	NA
TO13	10/01/11-04/30/13	Periodic	10/01/11	11.50	8.79	3,045,904	778,204	53.60	None	NA
TO12	03/01/10-09/30/11	Periodic	03/01/10	12.30	8.78	2,717,253	726,966	54.20	None	NA

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NA = Not available or not applicable; ROR = rate of return
[1] Inclusive of 50 basis point adder for membership in CAISO.
[2] Pending at FERC.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In addition to the proposed formula transmission rate, PG&E asserted that its filing "is also significant because it addresses critical issues related to the California-specific circumstances impacting PG&E's ongoing ability to provide safe and reliable service to its customers." PG&E noted "the devastating impact of extreme weather and climate-driven natural disasters, including, the massive wildfires that occurred in Northern and Southern California in 2017, and the largest wildfires in California's history during 2018."

Citing these and other factors, PG&E proposed an increase to 12.0% in the base ROE it had requested in recent traditional transmission rate case filings. In support of its requested ROE, PG&E asserted "[b]ecause of the overhanging uncertainties associated with catastrophic wildfires, the risks faced by PG&E's common equity investors vastly exceed those of other electric utilities. Given the unique challenges currently confronting PG&E, it is not possible to identify a proxy group of comparable risk, and cost of equity estimates for other electric utilities fall well below the return that investors require to compensate for the significantly greater risks associated with an investment in PG&E's common stock."

In addition to the requested base ROE of 12.0%, PG&E requested a 50 basis point incentive ROE adder for its continued participation in the CAISO.

In November 2018, FERC issued an order accepting and suspending PG&E's TO20 formula rate filing and establishing hearing and settlement judge procedures, and the proceeding is still pending before a commission administrative law judge. On Dec. 17, 2019, the FERC law judge issued a status report to the commission stating that "the participants are actively exchanging settlement papers with the expectation of making an offer of settlement by March 31, 2020."

2020 rate year — On Nov. 26, 2019, in accordance with its formula rate protocols, PG&E filed an annual update for the 2020 rate year, known as RY2020. The RY2020 update incorporated a 12.5% ROE and increased PG&E's transmission revenue requirement to $2.24 billion from $1.95 billion. In support of the increase, PG&E cited growth in transmission plant in service due to PG&E's completion of transmission projects in 2018. Specifically, PG&E stated the 2020 rate year base revenue requirement reflects the addition of $873 million in transmission plant in service in 2018 compared to 2017. In addition, PG&E forecasts that it will add $1.96 billion in net transmission capital additions during 2019 and 2020 that are scheduled to be operative by the end of 2020.

PG&E asserted that the RY2020 update submission is an informational filing and does not subject the company's formula rate to modification.

Transmission incentives — In 2014, FERC granted PG&E's request for transmission rate incentives for its investment in the 230-kV Central Valley Transmission Upgrade Project in central California. PG&E requested two rate incentives for its investment in the project: (1) recovery of prudently incurred costs in the event the project must be abandoned for reasons outside PG&E's control; and (2) confirmation that the 50 basis point incentive ROE adder to PG&E's base ROE attributable to CAISO membership also applies to the project.

Sempra Energy

SDG&E serves 3.4 million people through 1.4 million electric meters and 870,000 natural gas meters in San Diego and southern Orange counties, covering a service territory of 4,100 square miles. SDG&E has operated under a formula-based transmission rate framework since 2007.

2019 rate year — In October 2018, SDG&E proposed new formula rates for the costs of its transmission facilities for the 2019 rate year in a filing known as TO5 Cycle 1. The company proposed a base ROE of 10.7% plus a 50 basis point adder for continuing participation in the CAISO, for a total ROE of 11.2%. SDG&E's ROE from the company's last formula rate filing was 10.05%. SDG&E asserted that it now required a higher ROE because the company faces more risk than other regulated utilities, in large part due to catastrophic wildfires in California. SDG&E also proposed to increase the company's transmission revenue requirement to $906.94 million from $817.70 million.

In December 2018, FERC accepted the proposed TO5 Cycle 1 rates, suspended them for five months and set them for hearing and settlement judge procedures. FERC's order noted that "based on our preliminary analysis, we find that SDG&E's proposed rates may yield substantially excessive revenues."

San Diego Gas & Electric Co.

Company filing reference	Rate period	Adjustment frequency	Adjustment date	Base ROE[1] (%)	ROR (%)	Transmission rate base ($000)	Wholesale transmission annual rev. req. ($000)	Equity (%)	Incentive portion of rate base ($000)	Incentive ROE[1] (%)
TO5 Cycle 2[2]	01/01/20-12/31/20	Annual	01/01/20	10.60	7.55	4,005,298	865,455	55.83	None	NA
TO5 Cycle 1[3]	01/01/19-12/31/19	Annual	01/01/19	11.20	8.07	3,665,148	906,943	55.13	None	NA
TO4 Cycle 5	01/01/18-12/31/18	Annual	01/01/18	10.05	7.51	3,244,395	817,704	56.56	None	NA
TO4 Cycle 4	01/01/17-12/31/17	Annual	01/01/17	10.05	7.76	3,207,000	700,700	56.46	None	NA
TO4 Cycle 3	01/01/16-12/31/16	Annual	01/01/16	10.05	7.63	2,895,781	693,958	54.52	None	NA
TO4 Cycle 2	01/01/15-12/31/15	Annual	01/01/15	10.05	7.58	2,820,111	809,301	53.35	None	NA
TO4 Cycle 1	09/01/13-12/31/14	Semi-annual	09/01/13	10.05	7.30	1,222,194	538,410	51.37	None	NA
TO3 Cycle 6	09/01/12-08/31/13	Annual	09/01/12	11.35	8.01	1,185,324	602,624	51.96	None	NA
TO3 Cycle 5	09/01/11-08/31/12	Annual	09/01/11	11.35	8.05	1,085,868	409,081	52.09	None	NA
TO3 Cycle 4	09/01/10-08/31/11	Annual	09/01/10	11.35	8.45	1,001,092	322,442	56.31	None	NA

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NA = Not available or not applicable; ROR = Rate of return
[1] Inclusive of 50 basis point adder for membership in CAISO.
[2] Pending at FERC.
[3] Pending at FERC. Oct. 18, 2019 settlement reduced ROE to 10.6% and revenue requirement to $819.97 million.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

On Oct. 18, 2019, SDG&E filed a settlement in the TO5 Cycle 1 proceeding that would establish a 10.6% ROE for the company, inclusive of the 50 basis point adder for participation in the CAISO. The settlement also provides that the 50 basis point adder would be refunded if FERC issues an order ruling that SDG&E is no longer eligible for the CAISO adder.

The settlement would further provide for a moratorium on changes to SDG&E's base ROE of 10.1% through June 30, 2021, and a reduction in the company's transmission revenue requirement to $819.97 million. The settlement is now pending FERC action.

2020 rate year — On Dec. 2, 2019, in accordance with the company's formula rate protocols, SDG&E filed a formula rate update for the 2020 rate year, known as TO5 Cycle 2. SDG&E incorporated a base ROE of 10.6% in the 2020 update, inclusive of the 50 basis point CAISO membership adder. The TO5 Cycle 2 includes a transmission revenue requirement of $865.46 million, representing a $45.49 million increase, or a 5.5% change, compared to the wholesale revenue requirement for TO5 Cycle 1 in the pending settlement described above. SDG&E attributed the net increase in transmission revenue requirement to increases in operations and maintenance expenses, depreciation expense and transmission rate base.

SDG&E asserted that the TO5 Cycle 2 submission is an informational update and does not subject the company's formula rate to modification.

Transmission incentives — In 2014, CAISO selected SDG&E in a competitive bid process to construct the Sycamore-to-Penasquitos 230-kV transmission project, which will provide a 16.7-mile transmission connection between SDG&E's Sycamore Canyon and Penasquitos substations. The estimated $120 million to $150 million project was identified by CAISO and a state task force as necessary to ensure grid reliability given the closure of the San Onofre Nuclear Generating Station. The project will also serve to strengthen renewable energy infrastructure in the region and was energized in September 2018.

In 2014, SDG&E filed a request with FERC seeking, among other things, a 100 basis point ROE incentive adder for the Sycamore-Penasquitos project. In 2015, FERC rejected the proposed ROE adder, finding that SDG&E failed to demonstrate that the risks and challenges faced by the project were either accounted for in its base ROE or addressed through risk-reducing incentives, including a requested abandonment incentive that FERC granted in its order.

Trans Bay Cable

Trans Bay Cable owns a 53-mile, 400-MW high-voltage, direct-current submarine transmission line buried beneath the San Francisco Bay, with converter stations at each end. The line provides direct electric transmission between PG&E's Pittsburg and Potrero substations, both located in San Francisco. As a participating CAISO transmission owner, Trans Bay recovers its transmission revenue requirement pursuant to CAISO's transmission tariff.

On March 21, 2019, FERC approved NextEra Energy Transmission LLC's proposed $1 billion acquisition of Trans Bay Cable. The transaction was completed on July 16, 2019.

Trans Bay Cable LLC

Rate period	Adjustment frequency	Base ROE (%)	ROR (%)	Transmission rate base ($000)	Transmission annual rev. req. ($000)	Equity (%)	Incentive rate base ($000)	Incentive ROE (%)
2021-TBD[1]	TBD	13.5	9.78	522,202	157,284	65.00	None	NA
2017-2020[2]	Triennial	13.5	9.27	476,383	153,170	60.00	None	NA
2013-2016	Triennial	13.5	9.11	488,469	131,134	55.00	None	NA

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Note: Data represents initial company filings and does not reflect any subsequent settlement terms.
NA = Not available or not applicable; ROR = Rate of return
[1] Pending at FERC.
[2] November 2017 settlement reduced revenue requirement to $133.9 million.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In 2005, FERC accepted a proposed operating memorandum setting forth the rate principles and operational responsibilities pursuant to which Trans Bay would undertake the development, financing, construction and operation of the transmission project upon its completion.

Specifically, FERC approved the following requested rate principles for the line: (1) a 13.5% ROE; (2) a three-year rate moratorium beginning with Trans Bay's first revenue requirement filing; (3) a 50/50 debt/equity structure for the first three years of the line's commercial operation; and (4) a 30-year depreciation period. In granting the rate principles, FERC noted that Trans Bay, as a newly formed, transmission-only company, faced unique and elevated risks that justified the "enhanced" 13.5% ROE, particularly in light of the reliability and economic benefits the line would provide in addressing the critical need for generation within the City of San Francisco.

In 2016, Trans Bay filed to revise its transmission owner tariff and to increase its annual transmission revenue requirement from $131.13 million to $153.17 million. Trans Bay sought a continuation of its previously authorized ROE of 13.5% and requested that the commission summarily accept its proposed ROE, its cost-of-service and resulting revenue requirement without refund, suspension or hearing, to become effective in late-2016.

FERC subsequently set Trans Bay's rate case filing for hearing, stating: "given that Trans Bay can no longer be characterized as a start-up entity and the Project has been successfully operating for six years, it is not evident that the 13.5% ROE may be justified based on an older risk profile. Furthermore, the 13.5% incentive ROE ... constitutes an overall ROE without specific incentive adders. Historically, the Commission has allowed certain transmission companies qualifying for enhanced rate treatment to maintain an incentive ROE of 13.5%, so long as that level of return fell within the company's DCF range of reasonableness."

In November 2017, FERC approved a settlement in Trans Bay's rate case that reduced the company's requested annual transmission revenue requirement of $153.17 million to $133.9 million and a rate moratorium that provided that no party would propose changes to Trans Bay's revenue requirement to be effective prior to Nov. 23, 2019. The settlement, which was silent on traditional rate of return parameters, also described procedures to be followed in connection with Trans Bay's next rate filing to become effective as of the end of the rate moratorium.

On Sept. 20, 2019, Trans Bay Cable filed a new transmission rate case requesting that FERC "at a minimum, summarily affirm the continued application of Trans Bay's incentive return on equity ... at the top of the zone of reasonableness, not to exceed 13.5%." Trans Bay also proposed an increase in its annual transmission revenue requirement from $133.9 million to $157.3 million for service over Trans Bay's transmission line.

In support of its request to continue the 13.5% ROE, Trans Bay asserted that: "(i) Project development was extremely risky; (ii) the Project was developed to provide significant economic, reliability, and public policy benefits to California and San Francisco ratepayers and the CAISO grid; (iii) those significant benefits were realized, and importantly, continue today; (iv) the incentive ROE was one of a suite of rate principles relied upon by Trans Bay and its investors to develop the Project and provide those significant benefits to ratepayers; and (v) without the incentive ROE the Project would likely not have been developed and those benefits would not be flowing to ratepayers."

In Trans Bay's view, it "would be inappropriate to remove the incentive ROE now, only nine years into the Project's life, given the ongoing significant benefits to ratepayers. Doing so could have significant impacts on investors' willingness to fund, and the Commission's ability to incentivize, future investments in critical infrastructure." In addition, Trans Bay asserts that "recent and unforeseen risks have arisen related to wildfires and California's inverse condemnation laws that elevate Trans Bay's current risk profile."

On Nov. 21, 2019, FERC issued an order accepting and suspending Trans Bay's rate filing and establishing hearing and settlement judge procedures. The first settlement conference before the settlement judge was held on Jan. 14, 2020, and the next settlement conference is scheduled for April 30, 2020.

DATC Path 15

DATC Path 15, a Delaware limited liability company, was formed, among other things, to hold and manage the transmission service rights to the Path 15 Upgrade. The Path 15 Upgrade is an 83-mile, 500-kV transmission line built along the existing Path 15 corridor in California. The upgraded Path 15 transmission line went into operation in 2004, adding roughly 1,500 MW to the existing 5,400 MW of transmission capacity from southern to northern California and increasing transmission capacity from north to south by about 1,100 MW.

DATC Path 15 LLC

Rate period	Adjustment frequency	Base ROE (%)	ROR (%)	Transmission rate base ($000)	Transmission annual rev. req. ($000)	Equity (%)	Incentive rate base ($000)	Incentive ROE (%)
2018-2021*	Triennial	13.5	11.03	104,850	25,571	55.17	None	NA
2014-2017	Triennial	13.5	NA	119,456	25,925	51.53	None	NA

As of Jan. 21, 2020.
NA = Not available or not applicable; ROR = Rate of return
* Pending at FERC.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

In February 2017, DATC submitted a proposed decrease to the transmission revenue requirement from $25.9 million to $25.6 million. DATC stated that "the proposed rate reduction reflects the fact that DATC Path 15 has not made, and has no current plans to make, significant capital additions to its sole asset, the transmission facility known as the Path 15 Upgrade."

DATC Path 15 also asserted that it is entitled to a continuation of the previously granted ROE of 13.5% authorized in 2002, arguing that the 13.5% ROE is an incentive rate granted to DATC Path 15 "to attract investment in a critical infrastructure project required to address a bottleneck in California that contributed materially to the California Energy Crisis."

Certain stakeholders in California protested DATC's filing, including the continuation of the proposed 13.5% incentive ROE. The protesters asserted that DATC's proposed ROE is too high because an incentive ROE is no longer necessary and because "it is out of line with the actual returns that DCF models are yielding."

In April 2017, FERC accepted the filing by DATC but noted that "preliminary analysis indicates that DATC Path 15's proposed rate decrease has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Additionally, a further rate decrease may be appropriate. Accordingly … DATC Path

15's proposed rate decrease is accepted for filing, to become effective April 20, 2017, as requested, subject to further Commission order. In addition, pursuant to section 206 of the FPA, a proceeding is hereby instituted … concerning the justness and reasonableness of DATC Path 15's proposed rate decrease, with such proceeding held in abeyance pending further Commission order."

In October 2017, FERC set for hearing and settlement judge procedures DATC's proposed reduction in its transmission revenue requirement, including the DCF zone of reasonableness for DATC's ROE, and noted that "the resulting ROE should be set at the upper end of that zone, not to exceed 13.5%."

On Nov. 15, 2019, a FERC administrative law judge issued an initial decision in DATC's rate case and determined that the company's 13.5% ROE remains just and reasonable. The law judge's decision is subject to briefs on exceptions by the parties and subsequent FERC action.

For a complete, searchable listing of RRA's in-depth research and analysis please go to the S&P Global Market Intelligence Research Library.

Transmission rate base values for California ISO utilities ($000)

Ticker	Parent company	Filing entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2017-2020 CAGR	2011-2020 CAGR
EIX	Edison International	Southern California Edison Co.	2,064,394	2,568,633	3,256,238	4,076,161	4,679,376	5,171,547	5,483,030	5,451,343	5,624,393	5,829,102	2.06	12.23
PCG	PG&E Corp.	Pacific Gas and Electric Co.	2,717,253	3,045,904	3,867,792	3,765,866	4,086,597	5,120,000	6,712,509	6,935,253	6,927,768	7,646,547	4.44	12.18
SRE	Sempra Energy	San Diego Gas & Electric Co.	1,001,092	1,085,868	1,185,324	1,222,194	2,820,111	2,895,781	3,207,000	3,244,395	3,665,148	4,005,298	7.69	16.66

As of Jan. 21, 2020.
CAGR = Compound annual growth rate
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

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RRA Regulatory Focus
An Overview of Transmission Ratemaking in the PJM Interconnection – 2019 Update

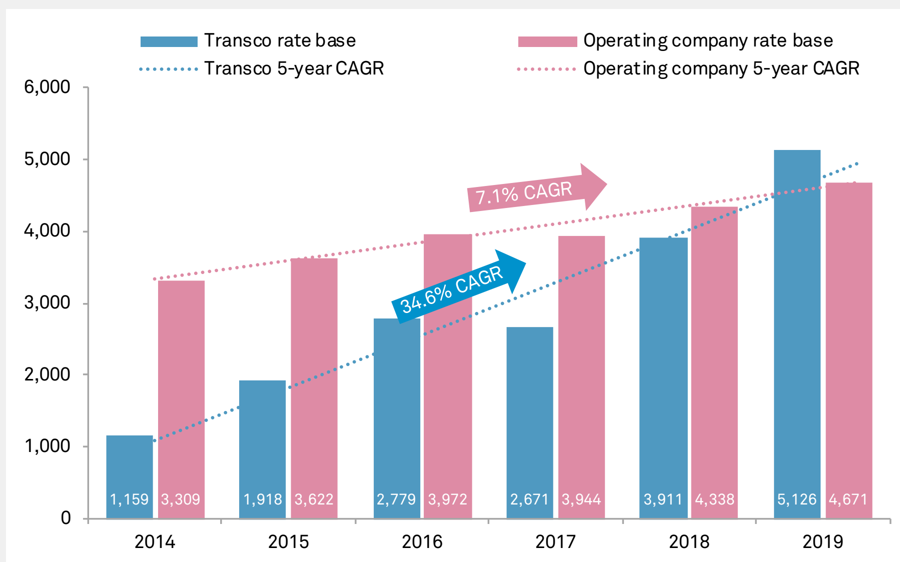
Overview

Aggressive and sustained capital investment at American Electric Power Co.'s, or AEP's, five transmission-only, or transco, subsidiaries in the PJM Interconnection footprint is clearly reflected in impressive growth in transmission rate base for the companies, with each reporting a year-over-year increase from 2018 to 2019 in transmission rate base in excess of 20%.

With a three-year and five-year CAGR of 22.6% and 34.6%, respectively, the aggregate rate base for the AEP transcos for the first time exceeds the total for AEP's six operating utilities in PJM. By comparison, the operating utilities' aggregate transmission rate base demonstrated a three-year CAGR of 5.5% and a five-year CAGR of 7.1%.

The transmission rate base data is sourced from newly available transmission formula rate filings with the Federal Energy Regulatory Commission, which show that the aggregate transmission rate base for all 11 AEP companies in PJM rose to $9.80 billion in 2019 from $8.25 billion in 2018, an increase of 18.8%. The year-over-year growth was largely driven by a 31.2% increase in aggregate rate base reported by the company's five transco subsidiaries. For comparison, AEP's six operating utilities reported an aggregate year-over-year increase in transmission rate base in 2019 of only 7.7%.

Growth in transmission rate base for American Electric Power companies in PJM ($M)



Data as of Aug. 26, 2019.
CAGR = Compound annual growth rate
Sources: FERC; S&P Global Market Intelligence

Of the 26 companies that operate in PJM and employ formula transmission rates followed by Regulatory Research Associates, a group within S&P Global Market Intelligence, 16 reported a year-over-year increase in transmission rate base greater than 10%. The aggregate transmission rate base for all 26 companies in PJM grew to $43.60 billion in 2019 from $38.86 billion in 2018, an increase of 12.2%.

At the individual company level, Public Service Enterprise Group, or PSEG, subsidiary Public Service Electric & Gas Co., or PSE&G, remained at the top of the list of largest utilities in PJM as measured by transmission rate base at

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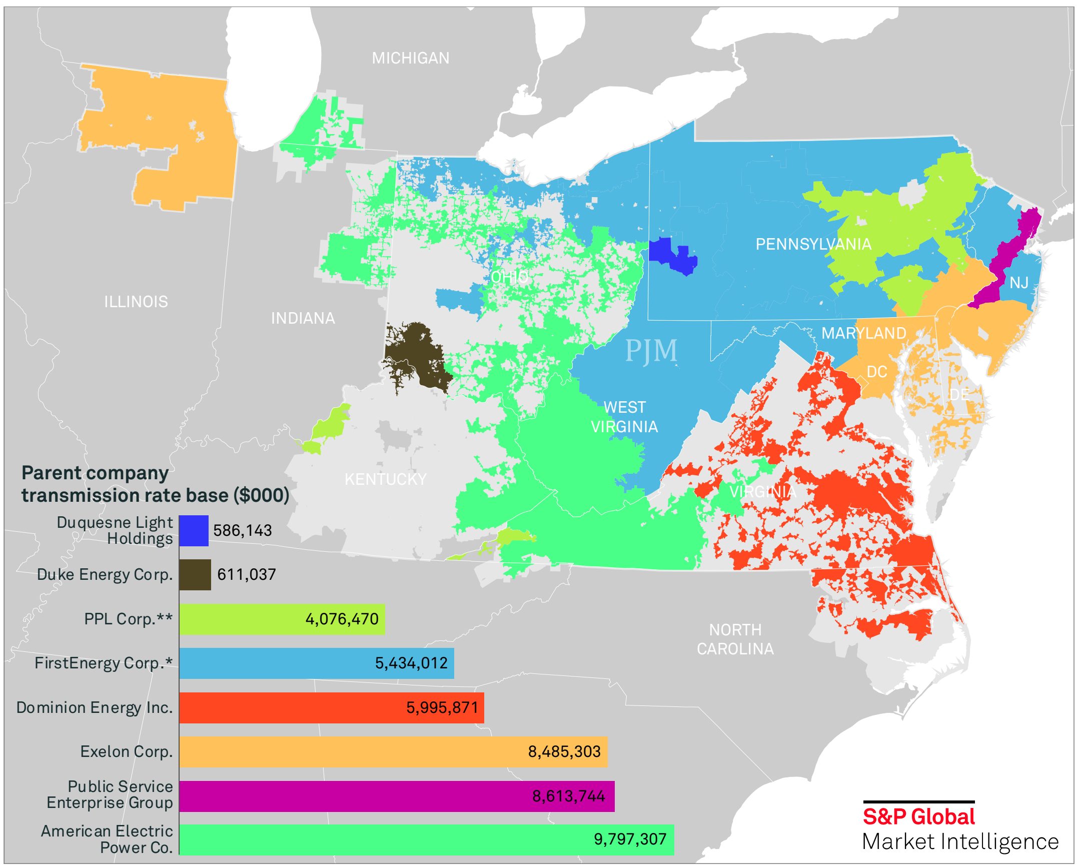
$8.61 billion. PSE&G was followed by Dominion Energy Inc.'s Dominion Virginia Power Co., whose legal name is Virginia Electric and Power Co., at $6.00 billion, and by PPL Corp. subsidiary PPL Electric Utilities Corp. at $4.08 billion.

AEP continues to rank first among parent companies in PJM in 2019 as measured by transmission rate base, at $9.80 billion, followed by PSEG with $8.61 billion and Exelon Corp. with $8.49 billion.

2019 transmission rate base in PJM



Data compiled Aug. 28, 2019.
* Not including Monongahela Power, Jersey Central Power & Light, Pennsylvania Electric Co., Potomac Edison and West Penn Power.
** Not including Louisville Gas and Electric and Kentucky Utilities.
Map credit: Elizabeth Thomas
Sources: S&P Global Market Intelligence; FERC

For the companies in the sample that employed formula rates for the years 2011 through 2019, PSE&G reported the fastest growth in transmission rate base, with a CAGR of 25.92% that brought the company's transmission rate base value to $8.61 billion in 2019 from $1.36 billion in 2011. PSE&G was followed by PPL Electric Utilities, with a CAGR of 21.92%, AEP's Wheeling Power Co., with a CAGR of 21.19%, and FirstEnergy's American Transmission Systems Inc., with a CAGR of 21.15%.

Apart from a 50-basis-point ROE adder enjoyed by all the companies in PJM for participation in a regional transmission organization, or RTO, FERC has authorized additional ROE incentive adders on a company-by-company or project-specific basis for at least 10 companies in PJM.

Authorized ROEs in the region, excluding the 8.11% for the cancelled Potomac-Appalachian Highline Transmission project described below, range from 10.35% for AEP's subsidiaries to 13% for specific projects developed by Exelon Corp.'s Commonwealth Edison, including all incentives. Details on ROE incentive adders are included in the company sections below.

Background

RRA first published this survey of transmission rate bases for utilities with formula rates in PJM in 2015. The first report compiled five years of data for each of the companies — 2015 data and four years of historical data. RRA has published annual updates to that first report, for a total historical data set covering nine full years from 2011 through 2019. This report is an update of *An Overview of Transmission Ratemaking in the PJM Interconnection — 2018 Update*, a report published on Aug. 13, 2018.

Transmission summary for PJM utilities with formula rates

Ticker	Parent company	Filing company	2018 total transmission rate base ($000)	2019 total transmission rate base ($000)	Rate base growth 2018-2019 (%)	Base ROE* (%)	Rate base authorized ROE adder ($000)	ROE including adder* (%)
AEP	American Electric Power Co.	Appalachian Transmission Co.	3,427	29,318	755.50	10.35	None	NA
AEP	American Electric Power Co.	Indiana Michigan Transmission Co.	1,219,216	1,724,392	41.43	10.35	None	NA
AEP	American Electric Power Co.	Kentucky Transmission Co.	80,519	99,470	23.54	10.35	None	NA
AEP	American Electric Power Co.	Ohio Transmission Co.	1,983,985	2,416,084	21.78	10.35	None	NA
AEP	American Electric Power Co.	West Virginia Transmission Co.	623,627	857,200	37.45	10.35	None	NA
AEP	American Electric Power Co.	Appalachian Power Co.	1,822,868	2,101,335	15.28	10.35	None	NA
AEP	American Electric Power Co.	Indiana Michigan Power Co.	747,314	770,863	3.15	10.35	None	NA
AEP	American Electric Power Co.	Kentucky Power Co.	300,309	342,717	14.12	10.35	None	NA
AEP	American Electric Power Co.	Kingsport Power Co.	21,179	21,683	2.38	10.35	None	NA
AEP	American Electric Power Co.	Ohio Power Co.	1,368,524	1,355,197	-0.97	10.35	None	NA
AEP	American Electric Power Co.	Wheeling Power Co.	77,860	79,048	1.53	10.35	None	NA
D	Dominion Energy Inc.	Virginia Electric and Power Co.	5,350,060	5,995,871	12.07	11.40	278,594	12.65
D	Dominion Energy Inc.	Virginia Electric and Power Co.	5,350,060	5,995,871	12.07	11.40	578,371	12.90
DUK	Duke Energy Corp.	Duke Energy Kentucky	20,589	21,346	3.68	11.38	None	NA
DUK	Duke Energy Corp.	Duke Energy Ohio	464,965	589,691	26.82	11.38	None	NA
NA	Duquesne Light Holdings	Duquesne Light Company	570,454	586,143	2.75	11.40	NA	12.40
NA	Duquesne Light Holdings	Duquesne Light Company	570,454	586,143	2.75	11.40	NA	12.90
EXC	Exelon Corp.	Atlantic City Electric Co.	714,619	822,316	15.07	10.50	56,233	12.00
EXC	Exelon Corp.	Baltimore Gas & Electric Co.	1,039,327	1,175,192	13.07	10.50	157,178	11.50
EXC	Exelon Corp.	Commonwealth Edison Co.	3,603,685	3,737,904	3.72	11.50	257,106	13.00
EXC	Exelon Corp.	Delmarva Power & Light Co.	808,736	912,738	12.86	10.50	56,187	12.00
EXC	Exelon Corp.	PECO Energy**	915,538	970,462	6.00	10.35	None	NA
EXC	Exelon Corp.	Potomac Electric Power Co.	823,989	866,691	5.18	10.50	154,700	12.00
FE	FirstEnergy Corp.	American Transmission Systems Inc.	2,634,976	2,922,890	10.93	10.38	None	NA
FE	FirstEnergy Corp.	Mid-Atlantic Interstate Transmission	675,790	1,020,420	51.00	10.30	None	NA
FE	FirstEnergy Corp.	Trans-Allegheny Interstate (TrAILCo)	1,492,892	1,490,702	-0.15	11.70	945,590	12.70
PPL	PPL Corp.	PPL Electric Utilities	3,581,503	4,076,470	13.82	11.68	633,941	12.93
PEG	Public Service Enterprise Group	Public Service Electric and Gas	7,917,998	8,613,744	8.79	11.68	976,119	11.93
PEG	Public Service Enterprise Group	Public Service Electric and Gas	7,917,998	8,613,744	8.79	11.68	768,277	12.93

* Including 50 basis point ROE adder for RTO membership.
** Settlement pending at FERC as of Aug. 25, 2019.
NA = not applicable or not available; ROE = return on equity
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

FirstEnergy Corp. subsidiary Mid-Atlantic Interstate Transmission and Exelon Corp. subsidiary PECO Energy Co. filed proposals with FERC in 2016 and 2017, respectively, to transition from stated transmission rates to formula transmission rates; both companies filed formula rate data in 2017, 2018 and 2019 and are now included in this report.

FirstEnergy's Jersey Central Power & Light Co subsidiary also filed a proposed formula transmission rate in 2016, but in accordance with a 2018 settlement, the utility continues to employ a stated rate and is not included in this report.

The Potomac-Appalachian Highline Transmission project, or PATH, a 2007 joint venture between AEP and FirstEnergy, was a proposed $2.1 billion transmission line between West Virginia and Maryland. In 2012, PJM cancelled the project because previously identified reliability needs justifying development of the project no longer existed. Also in 2012, FERC found that the project was abandoned for reasons beyond the control of the PATH companies and that the PATH companies were eligible to recover their prudently incurred costs. Since 2012, the transmission rate base for the abandoned PATH project has dropped to only about $8 million, and the project has been removed from this report.

RRA analyzed the transmission formula rate updates filed by 26 companies in PJM for each company's latest rate year. The formula rate updates may not reflect subsequent revisions that incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

The accompanying table highlights the PJM companies in this report that employ formula transmission rates, their reported transmission rate base for 2018 and 2019, where available, their base ROE, and any additional ROE incentive adders where applicable. The appendix lists the companies with rate base values for the years 2011 through 2019, where available.

Formula rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that updates rates annually based on updated cost of service data, generally drawn from the same data filed by a company in its annual FERC Form 1. Approximately 100 utilities nationwide employ FERC-approved formula rate frameworks for transmission. A "stated" transmission rate is also based on traditional cost of service data, but the rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward-looking projected costs, subject to a true up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation in each utility's annual update includes, among other things, transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base.

Given the complexities inherent in determining a company's transmission rate base from an outside perspective, the RRA reports, with very limited exceptions, include transmission rate base only for those companies that report such data in their annual updates under a formula-based rate framework. For additional information on the complex issues associated with determining a utility's rate base, see RRA's July 2, 2019, Topical Special Report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Individual company details

The sections that follow provide a closer look at transmission ratemaking for each PJM company in this report that employs formula based rates. For each there is a summary description, followed by a table or tables that provide detail for each operating company regarding authorized base ROEs, rate of return, rate base, annual revenue requirement, network integration service rate, equity ratio, any additional ROE incentives that apply to the company's rate base, and what portion of total rate base is accorded these incentive ROEs.

American Electric Power Co.

AEP's transmission assets are owned by numerous distinct subsidiaries, including AEP Transmission Company LLC, or AEP Transco, and the AEP operating utilities. AEP Transco is the holding company for AEP's seven transmission-only companies, five of which are located in PJM: AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc. and AEP West Virginia Transmission Company Inc. AEP's operating utilities in PJM include Appalachian Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co. and Wheeling Power Co.

AEP Transco and its subsidiaries were formed in 2009 to focus on incremental upgrades to AEP's existing transmission system. The AEP Transco companies are independent of, but overlay, AEP's existing vertically integrated operating utilities and the transmission operations of Ohio Power.

With respect to AEP's ROE, in 2016, American Municipal Power, or AMP, and other AEP customers filed a complaint against the AEP companies in PJM. The complaint asserted that the AEP companies' authorized base ROE of 10.99% adopted in 2010, excluding any incentives, was excessive and should be reduced to 8.32%.

In 2018, the presiding FERC administrative law judge in the complaint case issued a "Report of Contested Settlement" to the commission. The contested settlement would set a base ROE of 9.85%, excluding any incentive adders, for the AEP companies and would cap the equity component included in each of the companies' capital structure at the lesser of the company's actual equity capital component or 55%.

Appalachian Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.64	2,101,335	330,494	NA	49.73	None	NA
2018-2019	Annual	07/01/18	10.35	7.67	1,822,868	289,103	NA	50.45	None	NA
2017-2018	Annual	07/01/17	11.49	7.91	1,633,809	304,012	NA	46.88	None	NA
2016-2017	Annual	07/01/16	11.49	7.93	1,658,135	291,575	NA	46.71	None	NA
2015-2016	Annual	07/01/15	11.49	8.08	1,373,465	243,541	NA	45.73	None	NA
2014-2015	Annual	07/01/14	11.49	7.73	1,226,158	216,555	NA	43.44	None	NA
2013-2014	Annual	07/01/13	11.49	8.02	1,237,984	228,845	NA	45.37	None	NA
2012-2013	Annual	07/01/12	11.49	8.17	1,202,875	212,663	NA	44.49	None	NA
2011-2012	Annual	07/01/11	11.49	8.27	1,081,169	204,375	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Indiana Michigan Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.07	770,863	133,329	NA	45.11	None	NA
2018-2019	Annual	07/01/18	10.35	7.45	747,314	128,851	NA	47.63	None	NA
2017-2018	Annual	07/01/17	11.49	8.46	690,054	148,853	NA	52.50	None	NA
2016-2017	Annual	07/01/16	11.49	8.89	692,759	155,932	NA	56.69	None	NA
2015-2016	Annual	07/01/15	11.49	9.08	647,973	145,140	NA	55.33	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	611,623	27,182	NA	52.46	None	NA
2013-2014	Annual	07/01/13	11.49	8.89	590,308	125,013	NA	53.82	None	NA
2012-2013	Annual	07/01/12	11.49	9.03	569,934	122,598	NA	53.38	None	NA
2011-2012	Annual	07/01/11	11.49	8.83	539,738	116,901	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Kentucky Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.21	342,717	61,493	NA	45.66	None	NA
2018-2019	Annual	07/01/18	10.35	7.05	300,309	56,020	NA	44.12	None	NA
2017-2018	Annual	07/01/17	11.49	7.99	304,612	62,704	NA	43.50	None	NA
2016-2017	Annual	07/01/16	11.49	7.92	312,148	60,499	NA	43.31	None	NA
2015-2016	Annual	07/01/15	11.49	8.09	320,431	61,331	NA	45.00	None	NA
2014-2015	Annual	07/01/14	11.49	8.47	315,864	59,711	NA	52.97	None	NA
2013-2014	Annual	07/01/13	11.49	8.81	292,301	55,321	NA	46.60	None	NA
2012-2013	Annual	07/01/12	11.49	8.76	266,844	50,880	NA	45.60	None	NA
2011-2012	Annual	07/01/11	11.49	8.74	253,538	49,044	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Kingsport Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.06	21,683	5,424	NA	47.72	None	NA
2018-2019	Annual	07/01/18	10.35	7.08	21,179	3,417	NA	48.25	None	NA
2017-2018	Annual	07/01/17	11.49	9.07	14,412	4,077	NA	65.24	None	NA
2016-2017	Annual	07/01/16	11.49	8.68	15,765	4,085	NA	59.70	None	NA
2015-2016	Annual	07/01/15	11.49	8.77	14,808	3,925	NA	61.00	None	NA
2014-2015	Annual	07/01/14	11.49	8.76	13,791	3,695	NA	60.84	None	NA
2013-2014	Annual	07/01/13	11.49	8.70	14,948	3,454	NA	59.96	None	NA
2012-2013	Annual	07/01/12	11.49	8.67	10,864	2,746	NA	59.56	None	NA
2011-2012	Annual	07/01/11	11.49	8.62	8,095	2,491	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Ohio Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	8.06	1,355,197	308,953	NA	54.97	None	NA
2018-2019	Annual	07/01/18	10.35	6.94	1,368,524	302,402	NA	55.77	None	NA
2017-2018	Annual	07/01/17	11.49	9.10	1,219,826	340,777	NA	56.36	None	NA
2016-2017	Annual	07/01/16	11.49	8.75	1,209,515	328,510	NA	49.92	None	NA
2015-2016	Annual	07/01/15	11.49	8.63	1,181,403	311,709	NA	48.76	None	NA
2014-2015	Annual	07/01/14	11.49	8.04	1,063,852	271,293	NA	39.48	None	NA
2013-2014	Annual	07/01/13	11.49	8.82	1,075,078	271,849	NA	54.61	None	NA
2012-2013	Annual	07/01/12	11.49	8.66	997,539	250,111	NA	53.15	None	NA
2011-2012	Annual	07/01/11	11.49	8.48	953,959	250,505	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Wheeling Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.28	79,048	11,191	NA	54.63	None	NA
2018-2019	Annual	07/01/18	10.35	7.27	77,860	8,892	NA	54.10	None	NA
2017-2018	Annual	07/01/17	11.49	7.70	81,734	14,738	NA	54.13	None	NA
2016-2017	Annual	07/01/16	11.49	7.65	83,380	14,530	NA	53.73	None	NA
2015-2016	Annual	07/01/15	11.49	10.22	83,748	18,190	NA	79.63	None	NA
2014-2015	Annual	07/01/14	11.49	10.41	77,983	16,336	NA	82.67	None	NA
2013-2014	Annual	07/01/13	11.49	10.14	70,339	14,851	NA	78.37	None	NA
2012-2013	Annual	07/01/12	11.49	9.54	57,990	9,999	NA	68.70	None	NA
2011-2012	Annual	07/01/11	11.49	9.45	16,983	4,875	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Appalachian Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.57	29,318	3,781	NA	52.18	None	NA
2018-2019	Annual	07/01/18	10.35	7.98	3,427	486	NA	75.11	None	NA
2017-2018	Annual	07/01/17	11.49	8.17	6	123	NA	49.12	None	NA
2016-2017	Annual	07/01/16	11.49	NA	72	109	NA	NA	None	NA
2015-2016	Annual	07/01/15	11.49	NA	40	219	NA	NA	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	117	179	NA	46.15	None	NA
2013-2014	Annual	07/01/13	11.49	8.44	147	150	NA	49.52	None	NA
2012-2013	Annual	07/01/12	11.49	8.39	17	112	NA	48.45	None	NA
2011-2012	Annual	07/01/11	11.49	8.39	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Indiana Michigan Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.42	1,724,392	254,215	NA	54.20	None	NA
2018-2019	Annual	07/01/18	10.35	7.20	1,219,216	170,985	NA	51.37	None	NA
2017-2018	Annual	07/01/17	11.49	7.05	720,340	96,973	NA	44.96	None	NA
2016-2017	Annual	07/01/16	11.49	7.26	757,006	97,839	NA	49.97	None	NA
2015-2016	Annual	07/01/15	11.49	7.77	311,082	43,819	NA	50.00	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	211,623	27,182	NA	52.46	None	NA
2013-2014	Annual	07/01/13	11.49	7.67	136,393	15,981	NA	49.70	None	NA
2012-2013	Annual	07/01/12	11.49	5.75	20,378	2,788	NA	NA	None	NA
2011-2012	Annual	07/01/11	11.49	8.39	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Kentucky Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19	10.35	7.38	99,470	14,210	NA	54.30	None	NA
2018-2019	Annual	07/01/18	10.35	7.27	80,519	11,028	NA	52.07	None	NA
2017-2018	Annual	07/01/17	11.49	8.17	55,059	8,225	NA	49.12	None	NA
2016-2017	Annual	07/01/16	11.49	6.89	59,005	6,832	NA	53.00	None	NA
2015-2016	Annual	07/01/15	11.49	8.42	26,465	3,318	NA	48.75	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	1,230	276	NA	100.00	None	NA
2013-2014	Annual	07/01/13	11.49	NA	19	124	NA	NA	None	NA
2012-2013	Annual	07/01/12	11.49	NA	NA	NA	NA	NA	None	NA
2011-2012	Annual	07/01/11	11.49	8.39	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Ohio Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19		7.46	2,416,084	464,514	NA	54.21	None	NA
2018-2019	Annual	07/01/18	10.35	7.23	1,983,985	367,605	NA	50.97	None	NA
2017-2018	Annual	07/01/17	11.49	7.41	1,452,176	282,963	NA	47.51	None	NA
2016-2017	Annual	07/01/16	11.49	7.52	1,503,860	258,168	NA	49.97	None	NA
2015-2016	Annual	07/01/15	11.49	8.42	1,299,306	191,022	NA	51.28	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	879,928	124,095	NA	50.54	None	NA
2013-2014	Annual	07/01/13	11.49	7.68	415,820	53,832	NA	49.52	None	NA
2012-2013	Annual	07/01/12	11.49	5.75	222,253	27,235	NA	NA	None	NA
2011-2012	Annual	07/01/11	11.49	8.39	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP West Virginia Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	07/01/19		7.43	857,200	126,098	NA	53.84	None	NA
2018-2019	Annual	07/01/18	10.35	7.26	623,627	87,743	NA	51.55	None	NA
2017-2018	Annual	07/01/17	11.49	8.17	443,818	60,107	NA	49.12	None	NA
2016-2017	Annual	07/01/16	11.49	7.15	459,222	56,959	NA	49.58	None	NA
2015-2016	Annual	07/01/15	11.49	7.77	281,054	34,567	NA	48.75	None	NA
2014-2015	Annual	07/01/14	11.49	8.32	65,835	8,142	NA	100.00	None	NA
2013-2014	Annual	07/01/13	11.49	NA	129	160	NA	NA	None	NA
2012-2013	Annual	07/01/12	11.49	8.39	9	123	NA	48.45	None	NA
2011-2012	Annual	07/01/11	11.49	8.39	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

While the contested settlement is still pending at FERC, formula rate updates filed in 2018 and 2019 by AEP's companies in PJM included the stipulated 9.85% base ROE in the settlement and is reflected in this report.

Dominion Energy Inc.

Dominion Energy subsidiary Virginia Electric and Power, or VEPCO, which does business as Dominion Virginia Power Co., employs formula-based transmission rates that reflect an 11.4% ROE, including the 50 basis point ROE adder for participation in PJM. Of VEPCO's total transmission rate base of $6.00 billion in 2019, legacy assets of about $5.14 billion are accorded the 11.4% ROE. Approximately 13 VEPCO transmission projects, representing about $279 million of rate base, are accorded a 12.65% incentive ROE, and approximately 23 projects, representing about $578 million of rate base, are accorded a 12.9% ROE that includes incentives.

Virginia Electric and Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	01/01/19	11.40	8.17	5,995,871	1,033,304	47,471	52.1	278,594	12.65
									578,371	12.90
2018	Annual	01/01/18	11.40	8.21	5,350,060	1,031,382	52,457	52.8	275,242	12.65
									579,252	12.90
2017	Annual	01/01/17	11.40	8.35	5,083,699	953,772	47,376	52.9	275,228	12.65
									582,136	12.90
2016	Annual	01/01/16	11.40	8.44	4,655,808	879,872	41,245	54.1	279,851	12.65
									578,894	12.90
2015	Annual	01/01/15	11.40	8.69	4,075,586	805,068	42,997	57.0	279,756	12.65
									578,548	12.90
2014	Annual	01/01/14	11.40	8.92	3,343,567	664,640	35,936	57.7	280,474	12.65
									546,371	12.90
2013	Annual	01/01/13	11.40	8.50	2,754,969	547,933	27,446	56.7	278,449	12.65
									573,839	12.90
2012	Annual	01/01/12	11.40	8.92	2,416,341	499,547	24,569	57.7	272,045	12.65
									569,042	12.90
2011	Annual	01/01/11	11.40	8.50	2,099,058	432,330	22,237	56.7	252,951	12.65
									546,730	12.90

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Duke Energy Corp.

Duke Energy subsidiaries Duke Energy Kentucky Inc., or DEK, and Duke Energy Ohio Inc., or DEO, are members of PJM. In 2015, FERC approved a settlement for DEK and DEO pertaining to the two companies' move from the Midcontinent System Operator, or MISO, to PJM, in 2012. The settlement reduced the companies' authorized transmission ROE to 11.38% from 12.38%, including the 50 basis point ROE RTO adder.

Duke Energy Kentucky

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.38	7.71	21,346	5,258	NA	52.0	None	NA
2018-2019	Annual	06/01/18	11.38	7.66	20,589	4,899	NA	53.0	None	NA
2017-2018	Annual	06/01/17	11.38	8.11	18,302	5,113	NA	55.0	None	NA
2016-2017	Annual	06/01/16	11.38	8.19	19,546	5,450	NA	56.0	None	NA
2015-2016	Annual	06/01/15	11.38	NA	15,939	4,594	NA	57.0	None	NA
2014-2015	Annual	06/01/14	11.38	NA	14,167	3,992	NA	53.0	None	NA
2013-2014	Annual	06/01/13	11.38	NA	8,876	3,521	NA	53.0	None	NA
2012-2013	Annual	06/01/12	11.38	NA	22,449	6,912	NA	52.0	None	NA
2011-2012	Annual	06/01/11	12.38	NA	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Duke Energy Ohio

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.38	8.7	589,691	129,929	NA	56.0	None	NA
2018-2019	Annual	06/01/18	11.38	8.40	464,965	116,402	NA	52.0	None	NA
2017-2018	Annual	06/01/17	11.38	8.05	431,213	110,813	NA	48.0	None	NA
2016-2017	Annual	06/01/16	11.38	8.28	388,252	102,571	NA	47.0	None	NA
2015-2016	Annual	06/01/15	11.38	NA	349,981	86,772	NA	45.0	None	NA
2014-2015	Annual	06/01/14	11.38	NA	345,845	78,996	NA	62.0	None	NA
2013-2014	Annual	06/01/13	11.38	NA	327,499	67,788	NA	64.0	None	NA
2012-2013	Annual	06/01/12	11.38	NA	359,899	71,798	NA	55.0	None	NA
2011-2012	Annual	06/01/11	12.38	NA	NA	NA	NA	NA	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Duquesne Light Holdings

Duquesne Light Holdings is the parent company of Duquesne Light Company and is owned by a consortium of private equity investors.

In 2006, Duquesne Light filed with FERC to: (1) convert from a stated transmission rate to a formula rate and (2) request incentives for the Duquesne Transmission Enhancement Plan, or DTEP. By orders issued in 2007 and 2008, FERC approved the formula rate, a base ROE of 11.4% that included a 50 basis point ROE adder for continued PJM membership and a 100 basis point ROE incentive adder for the DTEP. The DTEP is a high-voltage transmission line intended to enhance the reliability of the 138-kV and 345-kV transmission service to Pittsburgh and surrounding areas. Duquesne Light also planned to increase the capacity of two existing underground 345-kV lines by using a state of the art forced cooling technology between its Brunot Island and Arsenal substations. Further, the DTEP involved upgrading various 69-kV facilities to 138 kV.

Duquesne Light Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.4	8.13	586,143	133,002	49,200	51.68	NA	12.4
									NA	12.9
2018-2019	Annual	06/01/18	11.4	8.33	570,454	137,961	52,793	53.53	NA	12.4
									NA	12.9
2017-2018	Annual	06/01/17	11.4	8.27	569,262	130,776	47.892	55.14	NA	12.4
									NA	12.9
2016-2017	Annual	06/01/16	11.4	8.87	559,683	128,525	50,695	54.75	1,943	12.4
									64,043	12.9
2015-2016	Annual	06/01/15	11.4	8.61	525,519	112,066	38,879	59.18	NA	12.4
									NA	12.9
2014-2015	Annual	06/01/14	11.4	8.87	NA	104,697	35,397	61.17	NA	12.4
									NA	12.9
2013-2014	Annual	06/01/13	11.4	9.32	490,443	99,415	34,042	63.80	NA	12.4
									NA	12.9
2012-2013	Annual	06/01/12	11.4	9.65	488,684	87,067	31,015	66.72	NA	12.4
									NA	12.9
2011-2012	Annual	06/01/11	11.4	9.64	461,309	77,815	29,161	68.00	NA	12.4
									NA	12.9

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

As required by PJM's 2007 Regional Transmission Expansion Plan, or RTEP, Duquesne Light proposed to construct a major new substation and related 345-kV and 138-kV transmission lines, including extensive underground cables, to maintain reliable service to Pittsburgh and the surrounding tristate area. The Brady Project was designed to complement the aforementioned DTEP by completing a 345-kV transmission ring around Pittsburgh. The project was accorded an incentive ROE of 12.9% by FERC in 2008 and was placed in service in June 2012.

Exelon Corp.

In 2014, FERC approved Exelon's acquisition of Pepco Holdings LLC, the parent company of utility subsidiaries Potomac Electric Power Company, or Pepco, Delmarva Power & Light Company, and Atlantic City Electric Company, or ACE. Exelon is also the parent of utilities Baltimore Gas & Electric, or BG&E, Commonwealth Edison Co., or ComEd, and PECO Energy Co.

In 2016, FERC approved a settlement filed by Pepco, Delmarva, ACE and BG&E, together with regulators and public advocates in the District of Columbia, Maryland, Delaware and New Jersey, to resolve two complaints regarding the utilities' authorized transmission base ROE. The settlement approved by FERC provided for a base ROE of 10% for each of the utilities, excluding the 50 basis point RTO ROE adder. Pepco, Delmarva, ACE, BG&E and ComEd have also been authorized additional incentive ROEs of 100 or 150 basis points for specific transmission projects.

ComEd is a part-owner of the $1.6 billion Reliability Interregional Transmission Extension, or RITELine, project, which is planned to extend from the western Ohio border through Indiana to northern Illinois. The RITELine companies, which include ComEd, Exelon and AEP, describe the project as an approximately 420-mile, 765-kV line that will strengthen the transmission system in Illinois, Indiana, and Ohio. The project will include five 765-kV substations and other transmission facilities. The RITELine companies state that they expect the project to be placed into service approximately five to six years after obtaining RTEP approval by the PJM RTO.

Atlantic City Electric Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.5	7.79	822,316	139,104	56,171	50.0	56,233	12.0
2018-2019	Annual	06/01/18	10.5	8.02	714,619	127,817	53,775	50.0	56,234	12.0
2017-2018	Annual	06/01/17	10.5	8.02	629,136	123,466	50,960	50.0	56,234	12.0
2016-2017	Annual	06/01/16	10.5	7.83	544,622	103,640	36,810	50.0	56,234	12.0
2015-2016	Annual	06/01/15	11.3	8.51	476,688	95,387	40,731	50.0	56,234	12.8
2014-2015	Annual	06/01/14	11.3	8.66	422,072	85,595	32,049	50.0	56,234	12.8
2013-2014	Annual	06/01/13	11.3	8.85	392,758	81,362	28,526	50.0	56,234	12.8
2012-2013	Annual	06/01/12	11.3	8.73	370,124	80,175	26,934	50.0	56,234	12.8
2011-2012	Annual	06/01/11	11.3	9.14	376,197	79,269	27,793	50.0	56,234	12.8

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Baltimore Gas & Electric Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.5	7.35	1,175,192	209,003	29,860	54.0	157,178	11.5
2018-2019	Annual	06/01/18	10.5	7.61	1,039,327	218,653	35,762	55.0	157,178	11.5
2017-2018	Annual	06/01/17	10.5	7.47	887,350	208,306	32,851	53.0	NA	11.5
2016-2017	Annual	06/01/16	10.5	8.09	705,211	177,320	27,285	59.0	157,178	11.5
2015-2016	Annual	06/01/15	11.3	8.46	646,901	165,585	25,237	58.0	157,176	12.3
2014-2015	Annual	06/01/14	11.3	8.53	600,119	165,390	25,047	56.1	157,178	12.3
2013-2014	Annual	06/01/13	11.3	8.35	564,419	157,344	22,369	52.9	157,178	12.3
2012-2013	Annual	06/01/12	11.3	8.43	571,703	155,026	21,792	54.0	154,575	12.3
									NA	12.8
2011-2012	Annual	06/01/11	11.3	8.96	501,035	140,507	20,227	57.4	154,575	12.3
									NA	12.8

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Commonwealth Edison Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.5	8.21	3,737,904	701,323	33,009	55.0	257,106	13.0
2018-2019	Annual	06/01/18	11.5	8.32	3,603,685	689,243	34,401	54.8	257,106	13.0
2017-2018	Annual	06/01/17	11.5	8.43	3,512,042	723,959	34,286	54.5	257,106	13.0
2016-2017	Annual	06/01/16	11.5	8.47	3,253,448	679,628	35,451	55.0	257,106	13.0
2015-2016	Annual	06/01/15	11.5	8.61	2,794,752	595,137	31,761	55.0	258,868	13.0
2014-2015	Annual	06/01/14	11.5	8.62	2,358,496	522,129	24,025	55.0	257,106	13.0
2013-2014	Annual	06/01/13	11.5	8.70	2,184,055	484,980	21,732	55.0	257,106	13.0
2012-2013	Annual	06/01/12	11.5	8.91	2,104,425	447,274	18,730	54.6	257,110	13.0
2011-2012	Annual	06/01/11	11.5	9.10	2,053,605	434,935	19,275	55.0	257,095	13.0

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Delmarva Power & Light Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.5	7.14	912,738	161,826	43,744	50.12	56,187	12.0
2018-2019	Annual	06/01/18	10.5	7.29	808,736	144,679	41,619	50.56	56,188	12.0
2017-2018	Annual	06/01/17	10.5	7.16	661,661	130,247	31,798	49.61	72,560	12.0
2016-2017	Annual	06/01/16	10.5	7.21	662,609	124,235	28,558	49.26	72,560	12.0
2015-2016	Annual	06/01/15	11.3	7.80	630,847	116,381	34,074	50.10	72,560	12.8
2014-2015	Annual	06/01/14	11.3	8.05	538,342	101,811	30,141	49.30	72,560	12.8
2013-2014	Annual	06/01/13	11.3	8.00	490,344	97,776	23,375	49.00	108,700	12.8
2012-2013	Annual	06/01/12	11.3	8.30	421,920	83,444	19,978	49.30	110,503	12.8
2011-2012	Annual	06/01/11	11.3	8.23	372,385	77,187	19,090	48.98	96,160	12.8

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Potomac Electric Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.5	7.75	866,691	183,688	31,209	50.0	154,700	12.0
2018-2019	Annual	06/01/18	10.5	7.82	823,989	168,624	28,502	50.0	125,155	12.0
2017-2018	Annual	06/01/17	10.5	7.92	674,070	162,791	25,229	50.0	154,699	12.0
2016-2017	Annual	06/01/16	10.5	7.88	688,327	157,686	23,232	49.0	154,699	12.0
2015-2016	Annual	06/01/15	11.3	8.36	678,289	155,333	26,521	49.0	154,699	12.8
2014-2015	Annual	06/01/14	11.3	8.60	608,441	145,155	24,949	50.0	154,699	12.8
2013-2014	Annual	06/01/13	11.3	8.66	631,202	153,897	23,265	49.0	201,612	12.8
2012-2013	Annual	06/01/12	11.3	8.90	543,628	135,080	20,777	50.0	150,559	12.8
2011-2012	Annual	06/01/11	11.3	8.84	443,251	112,189	16,796	48.0	144,497	12.8

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

PECO Energy

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.35	7.82	970,462	195,907	18,922	53.61	None	NA
2018-2019	Annual	06/01/19	11.00	8.01	915,538	197,292	19,093	54.92	None	NA
2017-2018	Annual	06/01/17	11.00	7.98	851,477	194,315	19,587	54.44	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

ComEd owns 75% of the portion of the project located within Illinois; Exelon owns 12.5% of the Indiana portion of the project. In 2011, FERC approved incentive ratemaking treatment for the line, including a total ROE of 11.43% consisting of a base ROE of 9.93% plus a 50 basis point adder for PJM membership and a 100 basis point ROE adder for the risks and challenges of the project. The incentives are conditioned upon the project eventually being included in the PJM RTEP.

FirstEnergy Corp.

FirstEnergy's transmission system consists of over 24,000 transmission miles. More than 16,300 miles of these lines are owned by FirstEnergy operating utilities. The remaining 7,700 miles are owned by affiliates American Transmission Systems Inc., or ATSI, within the service territories of FirstEnergy subsidiaries Cleveland Electric Illuminating Co., Ohio Edison Co. and Toledo Edison Co. in Ohio, and Trans-Allegheny Interstate Line Co., or TrAILCo, located in Pennsylvania, Virginia and West Virginia.

ATSI and TrAILCo have employed formula rates for transmission since at least 2011. FirstEnergy subsidiaries Pennsylvania Power Co., Potomac Edison Co., Monongahela Power Co. and West Penn Power Co. do not currently have formula transmission rates.

In 2016, FERC approved FirstEnergy's plan to spin off certain transmission assets in PJM owned by subsidiaries Metropolitan Edison Co., or Met-Ed, and Pennsylvania Electric Co. to a separate new entity called Mid-Atlantic Interstate Transmission LLC, or MAIT. In 2016, MAIT and FirstEnergy subsidiary Jersey Central Power & Light Co. filed with FERC to transition from stated transmission rates to formula rates.

American Transmission Systems, Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	01/01/19	10.38	8.15	2,922,890	706,371	55,074	60.0	None	NA
2018	Annual	01/01/18	10.38	8.20	2,634,976	659,095	54,689	60.0	None	NA
2017	Annual	01/01/17	10.38	8.24	2,417,557	574,584	45,058	60.0	None	NA
2016	Annual	01/01/16	10.38	8.22	2,075,262	536,158	43,391	60.0	None	NA
2015**	Annual	01/01/15	12.38/ 11.06	8.78	1,496,882	342,887	27,737	60.0	None	NA
2014-2015	Annual	06/01/14	12.38	9.71	922,578	251,592	14,894	60.0	None	NA
2013-2014	Annual	06/01/13	12.38	9.06	683,237	210,093	9,921	51.0	None	NA
2012-2013	Annual	06/01/12	12.38	9.11	629,845	197,371	9,264	51.0	None	NA
2011-2012	Annual	06/01/11	12.38	9.02	629,837	203,254	10,756	52.0	None	NA

* Including 50 basis point adder for RTO membership.
** Base ROE of 12.38% effective 1/1/2015 through 6/30/2015; base ROE of 11.06% effective 7/1/2015 through 12/31/2015.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Mid-Atlantic Interstate Transmission

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	10.3	7.81	1,020,420	173,323	28,796	59.0	None	NA
2018-2019	Annual	06/01/18	10.3	7.75	675,790	150,859	26,069	50.0	None	NA
2017-2018	Annual	07/01/17	10.3	7.74	538,400	132,436	22,612	50.0	None	NA

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Trans-Allegheny Interstate Line Company (TrAILCo)

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.7	8.60	1,490,702	236,436	NA	60.00	945,590	12.7
2018-2019	Annual	06/01/18	11.7	8.57	1,492,892	226,652	NA	59.72	969,650	12.7
2017-2018	Annual	06/01/17	11.7	8.58	1,623,012	267,803	NA	59.76	988,681	12.7
2016-2017	Annual	06/01/16	11.7	8.59	1,481,741	244,055	NA	59.87	1,007,415	12.7
2015-2016	Annual	06/01/15	11.7	8.59	1,337,562	218,394	NA	59.89	1,026,266	12.7
2014-2015	Annual	06/01/14	11.7	8.97	1,168,843	200,325	NA	59.42	1,036,046	12.7
2013-2014	Annual	06/01/13	11.7	8.93	1,082,610	181,544	NA	59.42	1,058,915	12.7
2012-2013	Annual	06/01/12	11.7	8.96	1,118,296	182,232	NA	59.82	1,069,935	12.7
2011-2012	Annual	06/01/11	11.7	9.71	1,129,674	174,275	NA	56.15	1,056,324	12.7

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

MAIT's formula rate filing included a proposed 10.5% base ROE plus a 50 basis point ROE adder for participation in PJM. Protests against MAIT's requested ROE were filed by the Pennsylvania Public Utility Commission, the Pennsylvania Office of Consumer Advocate, the Met-Ed Industrial Users Group and Penelec Industrial Customer Alliance, or Industrial Customers, and AMP. The Industrial Customers recommended that MAIT's base ROE be set at 8.22%, while AMP recommended it be set at 8.15%.

In 2017, FERC set MAIT's proposed formula rate for hearing and settlement procedures. In May 2018, FERC approved a settlement, thereby authorizing MAIT a 9.8% base ROE plus the 50 basis point ROE adder for participation in PJM, for a total ROE of 10.3%.

In 2015, FERC approved a settlement that allowed ATSI to transition to a forward-looking formula rate while also incrementally reducing ATSI's authorized ROE through the end of 2017. The settlement specified ROEs, including any incentives, to be applied for different periods as follows: (1) 12.38% from Jan. 1, 2015, through June 30, 2015; (2) 11.06% from July 1, 2015, through Dec. 31, 2015; and (3) 10.38% beginning Jan. 1, 2016.

With respect to ATSI's ROE, FERC noted in the order that the 12.38% ROE was originally established in the context of a systemwide ROE for MISO transmission owners. FERC also noted that since it approved the current ROE for ATSI, circumstances have changed: ATSI is no longer a MISO member and FERC had previously allowed parties to challenge the justness and reasonableness of maintaining the MISO systemwide ROE of 12.38% for Duke Energy Ohio when Duke withdrew from MISO and integrated into PJM in 2012. ATSI withdrew from MISO and joined PJM in 2009.

In 2011, TrAILCo completed and placed into commercial operation a 150-mile transmission line, extending from southwest Pennsylvania to northern Virginia. The company is authorized a formula rate that currently reflects a base ROE of 11.7%. Approximately $946 million of TrAILCo's total rate base of $1.49 billion is accorded an additional 100 basis point ROE incentive adder, or an ROE of 12.7%.

PPL Corp.

PPL subsidiary PPL Electric Utilities LLC's formula-based rates reflect a base ROE of 11.68%, which includes the 50 basis point adder for participation in an RTO; $634 million of PPL's total rate base of $4.076 billion is accorded an incentive ROE of 12.93%. The incentive ROE is primarily related to the approximately $1.35 billion 500-kV Susquehanna-Roseland transmission line that PPL and PSEG jointly constructed and placed into service in May 2015.

PPL Electric Utilities

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	06/01/19	11.68	8.32	4,076,470	509,329	66,721	54.5	633,941	12.93
2018-2019	Annual	06/01/18	11.68	8.36	3,581,503	437,358	57,422	54.7	633,942	12.93
2017-2018	Annual	06/01/17	11.68	8.52	3,095,809	428,804	60,675	54.5	618,970	12.93
2016-2017	Annual	06/01/16	11.68	8.36	2,648,059	353,534	40,689	52.5	635,535	12.93
2015-2016	Annual	06/01/15	11.68	8.35	2,381,458	318,398	32,900	51.3	752,343	12.93
2014-2015	Annual	06/01/14	11.68	8.32	1,924,908	304,139	37,318	50.8	618,661	12.93
2013-2014	Annual	06/01/13	11.68	8.59	1,323,312	252,536	35,472	51.8	234,572	12.93
2012-2013	Annual	06/01/12	11.68	8.84	929,929	185,873	22,870	56.3	51,130	12.93
2011-2012	Annual	06/01/11	11.68	9.17	834,989	176,519	23,755	57.3	49,183	12.93

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

In 2016, PPL completed a $350 million transmission project to improve reliability in the Pocono region; this project, known as the Northeast/Pocono Reliability Project, is accorded an 11.68% ROE, inclusive of a 50 basis point RTO adder, as FERC rejected PPL's request for an additional 100 basis point incentive ROE adder for the project. FERC found that PPL had not identified risks and challenges of the project sufficient to support its request for an additional ROE adder.

PPL is proposing to build a major new regional transmission line and submitted "Project Compass" to PJM as part of a competitive solicitation process. As proposed, the 500-kV Project Compass line would run about 725 miles from western Pennsylvania into New York and New Jersey. According to preliminary estimates, the cost of the project would be between $4 billion and $6 billion. The preliminary timeline contemplates completion of the project between 2023 and 2025.

PPL subsidiaries Louisville Gas and Electric LLC and Kentucky Utilities LLC do not employ formula rates for transmission and are not included in this report.

Public Service Enterprise Group

Formula-based transmission rates for PSE&G reflect a base ROE of 11.68%, with incentives established for certain projects. Of PSE&G's total $8.61 billion in rate base, approximately $979 million earns an incentive ROE of 11.93%, and approximately $768 million of rate base earns an incentive ROE of 12.93%.

The company's rate base growth has been largely driven by a number of major transmission projects, including: the 500-kV Susquehanna-Roseland line developed jointly with PPL, at an estimated cost to PSE&G of $790 million and which was placed in service in May 2015; the North East Grid reliability transmission project, at an estimated cost of $907 million, extending from Hudson County to Roseland in Essex County and completed in July 2016; and the Mickleton-Gloucester-Camden project, at an estimated cost of $435 million, a 230-kV upgrade project in southern New Jersey.

Public Service Electric & Gas Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Total rate base ($000)	Ann. rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	01/01/19	11.68	8.06	8,613,744	1,160,921	119,736	53.31	976,119	11.93
									768,277	12.93
2018	Annual	01/01/18	11.68	8.12	7,917,998	1,230,438	130,535	52.96	625,390	11.93
									767,017	12.93
2017	Annual	01/01/17	11.68	8.14	6,975,697	1,214,229	120,931	52.65	977,782	11.93
									769,266	12.93
2016	Annual	01/01/16	11.68	8.16	6,130,071	1,076,464	110,916	52.19	916,711	11.93
									769,899	12.93
2015	Annual	01/01/15	11.68	8.47	5,026,648	904,982	96,521	52.27	898,976	11.93
									790,589	12.93
2014	Annual	01/01/14	11.68	8.69	3,991,256	729,772	70,697	52.69	586,909	11.93
									770,120	12.93
2013	Annual	01/01/13	11.68	8.47	3,020,046	570,515	54,475	52.27	262,717	11.93
									551,566	12.93
2012	Annual	01/01/12	11.68	8.69	1,879,813	389,040	35,698	52.69	0	11.93
									250,638	12.93
2011	Annual	01/01/11	11.68	8.73	1,362,886	286,697	27,126	52.24	0	11.93
									173,485	12.93

* Including 50 basis point adder for RTO membership.
ROE = return on equity; ROR = rate of return; NISR = network integration service rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Transmission rate base values for PJM utilities with formula rates ($000)

Ticker	Parent company	Filing company	2011	2012	2013	2014	2015	2016	2017	2018	2019	2011-2019 CAGR (%)
AEP	American Electric Power Co.	Appalachian Transmission Co.	NA	17	147	117	40	72	6	3,427	29,318	NA
AEP	American Electric Power Co.	Indiana Michigan Transmission Co.	NA	20,378	136,393	211,623	311,082	757,006	720,340	1,219,216	1,724,392	NA
AEP	American Electric Power Co.	Kentucky Transmission Co.	NA	NA	NA	1,230	26,465	59,005	55,059	80,519	99,470	NA
AEP	American Electric Power Co.	Ohio Transmission Co.	NA	222,253	415,820	879,928	1,299,306	1,503,860	1,452,176	1,983,985	2,416,084	NA
AEP	American Electric Power Co.	West Virginia Transmission Co.	NA	9	129	65,835	281,054	459,222	443,818	623,627	857,200	NA
AEP	American Electric Power Co.	Appalachian Power Co.	1,081,169	1,202,875	1,237,984	1,226,158	1,373,465	1,658,135	1,633,809	1,822,868	2,101,335	8.66
AEP	American Electric Power Co.	Indiana Michigan Power Co.	539,738	569,934	590,308	611,623	647,973	692,759	690,054	747,314	770,863	4.56
AEP	American Electric Power Co.	Kentucky Power Co.	253,538	266,844	292,301	315,864	320,431	312,148	304,612	300,309	342,717	3.84
AEP	American Electric Power Co.	Kingsport Power Co.	8,095	10,864	14,948	13,791	14,808	15,765	14,412	21,179	21,683	13.11
AEP	American Electric Power Co.	Ohio Power Co.	953,959	997,539	1,075,078	1,063,852	1,181,403	1,209,515	1,219,826	1,368,524	1,355,197	4.49
AEP	American Electric Power Co.	Wheeling Power Co.	16,983	57,990	70,339	77,983	83,748	83,380	81,734	77,860	79,048	21.19
D	Dominion Energy Inc.	Virginia Electric and Power Co.	2,099,058	2,416,341	2,754,969	3,343,567	4,075,586	4,655,808	5,083,699	5,350,060	5,995,871	14.02
DUK	Duke Energy Corp.	Duke Energy Kentucky	NA	22,449	8,876	14,167	15,939	19,546	18,302	20,589	21,346	NA
DUK	Duke Energy Corp.	Duke Energy Ohio	NA	359,899	327,499	345,845	349,981	388,252	431,213	464,965	589,691	NA
NA	Duquesne Light Holdings	Duquesne Light Company	461,309	488,684	490,443	NA	525,519	559,683	569,262	570,454	586,143	3.04
EXC	Exelon Corp.	Atlantic City Electric Co.	376,197	370,124	392,758	422,072	476,688	544,622	629,136	714,619	822,316	10.27
EXC	Exelon Corp.	Baltimore Gas & Electric Co.	501,035	571,703	564,419	600,119	646,901	705,211	887,350	1,039,327	1,175,192	11.24
EXC	Exelon Corp.	Commonwealth Edison Co.	2,053,605	2,104,425	2,184,055	2,358,496	2,794,752	3,253,448	3,512,042	3,603,685	3,737,904	7.77
EXC	Exelon Corp.	Delmarva Power & Light Co.	372,385	421,920	490,344	538,342	630,847	662,609	661,661	808,736	912,738	11.86
EXC	Exelon Corp.	PECO Energy*	NA	NA	NA	NA	NA	NA	851,477	915,538	970,462	NA
EXC	Exelon Corp.	Potomac Electric Power Co.	443,251	543,628	631,202	608,441	678,289	688,327	674,070	823,989	866,691	8.74
FE	FirstEnergy Corp.	American Transmission Systems Inc.	629,837	629,845	683,237	922,578	1,496,882	2,075,262	2,417,557	2,634,976	2,922,890	21.15
FE	FirstEnergy Corp.	Mid-Atlantic Interstate Transmission*	NA	NA	NA	NA	NA	NA	538,400	675,790	1,020,420	NA
FE	FirstEnergy Corp.	Trans-Allegheny Interstate (TrAILCo)	1,129,674	1,118,296	1,082,610	1,168,843	1,337,562	1,481,741	1,623,012	1,492,892	1,490,702	3.53
PPL	PPL Corp.	PPL Electric Utilities	834,989	929,929	1,323,312	1,924,908	2,381,458	2,648,059	3,095,809	3,581,503	4,076,470	21.92
PEG	Public Service Enterprise Group	Public Service Electric and Gas	1,362,886	1,879,813	3,020,046	3,991,256	5,026,648	6,130,071	6,975,697	7,917,998	8,613,744	25.92

* PECO Energy and Mid-Atlantic Interstate Transmission transitioned from stated rate to formula rate for 2017 rate year. A settlement in PECO Energy's 2019 update is pending at FERC as of Aug. 25, 2019.
CAGR = compound annual growth rate; NA = not applicable or not available
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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RRA Regulatory Focus

An Overview of Transmission Ratemaking in the Midcontinent Independent System Operator – 2019 Update

Overview

Double-digit transmission rate base growth at each of Entergy Corp.'s five operating companies drove an overall 11% increase in the aggregate transmission rate base for a group of 22 utilities in the Midcontinent Independent System Operator, or MISO, between 2018 and 2019. Of these 22 companies that operate in MISO and employ formula transmission rates followed by Regulatory Research Associates, a group within S&P Global Market Intelligence, only four non-Entergy companies reported a year-over-year increase in transmission rate base greater than 10%.

Midcontinent Independent System Operator footprint

Source: FERC

Led by Entergy Mississippi Inc., with an increase of 31.7%, and Entergy Arkansas Inc., with an increase of 30.1%, the aggregate transmission rate base for the five Entergy operating companies rose from $5.82 billion in 2018 to $6.93 billion in 2019, or by 19.1%. The aggregate transmission rate base for all 22 companies in MISO grew to $29.15 billion in 2019 from $26.25 billion in 2018, an increase of 11%.

The transmission rate base data is sourced from newly available transmission formula rate filings with the Federal Energy Regulatory Commission, which shows that the Entergy operating companies accounted for more than 38% of the overall increase in aggregate transmission rate base for the group of 22 utilities in MISO between 2018 and 2019.

At the individual company level, American Transmission Company, or ATC, remained the largest company in MISO as measured by transmission rate base, with $3.9 billion. ATC was followed by Entergy Louisiana Inc., with $2.9 billion, and by Xcel Corp. subsidiaries Northern States Power-Minnesota and Northern States Power-Wisconsin, which are combined for formula rate filing purposes, with $2.89 billion.

For 2019, Entergy continues to rank first among holding companies in MISO as measured by transmission rate base, with $6.93 billion, followed by Fortis Inc.,

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with $6.16 billion and ATC with $3.90 billion. Ameren Corp. is a close fourth place in the parent company rankings, with an aggregate transmission rate base of $3.89 billion for operating companies Ameren Illinois, American Missouri and Ameren Transmission of Illinois, or ATXI.

Among the companies in the sample that employed formula transmission rates for the years 2011 through 2019, ATXI demonstrated the largest growth in transmission rate base, with a CAGR of 50.23% that brought the company's transmission rate base to $1.33 billion in 2019 from only $50 million in 2011. ATXI was followed by Ameren Illinois, with a 2011-2019 CAGR of 20.39%, and Otter Tail Corp. subsidiary Otter Tail Power Company, with a CAGR of 15.79%

The authorized transmission return on equity for all companies in MISO, including a 50 basis point incentive adder for membership in a regional transmission organization, or RTO, remains unchanged from last year, at 10.82%. The 10.82% ROE was established by FERC in 2016 and is the subject of continuing litigation at the commission. See FERC and Electric Transmission ROEs – 2019 Update, published May 21, 2019.

Apart from this adder, FERC has authorized additional ROE incentive adders on a company-by-company or project-specific basis only for three Fortis Inc. transmission-only companies in MISO. Details on these ROE incentive adders are included in the Fortis section below.

Background

RRA first published this survey of transmission rate bases for utilities with formula rates in MISO in 2015. The first report compiled five years of data for each of the companies — 2015 data and four years of historical data. RRA has

MISO transmission formula rate summary

Ticker	Transmission owner	Filing entity	2018 transmission rate base ($000)	2019 transmission rate base ($000)	Rate base growth 2018-2019 (%)	ROE* (%)	Rate base authorized ROE adder ($000)	ROE including adder* (%)
AEE	Ameren Corp.	Ameren Illinois	1,590,890	1,882,168	18.31	10.82	None	NA
AEE	Ameren Corp.	Ameren Missouri	635,439	686,549	8.04	10.82	None	NA
AEE	Ameren Corp.	Ameren Transmission of Illinois	1,267,454	1,325,931	4.61	10.82	None	NA
AES	IPALCO Enterprises	Indianapolis Power & Light Co.	194,604	210,949	8.40	10.82	None	NA
ALE	ALLETE Inc.	Minnesota Power Co.	564,715	692,704	22.66	10.82	None	NA
BRK	Berkshire Hathaway Energy	MidAmerican Energy Co.	1,157,122	1,207,813	4.38	10.82	None	NA
DUK	Duke Energy Corp.	Duke Energy Indiana	864,670	939,991	8.71	10.82	None	NA
ETR	Entergy Corp.	Entergy Arkansas Inc.	1,458,682	1,898,099	30.12	10.82	None	NA
ETR	Entergy Corp.	Entergy Louisiana Inc.	2,618,077	2,895,429	10.59	10.82	None	NA
ETR	Entergy Corp.	Entergy Mississippi Inc.	812,147	1,069,255	31.66	10.82	None	NA
ETR	Entergy Corp.	Entergy New Orleans Inc.	94,774	105,164	10.96	10.82	None	NA
ETR	Entergy Corp.	Entergy Texas Inc.	839,025	966,003	15.13	10.82	None	NA
FTS	Fortis Inc.	ITC Midwest	2,411,250	2,716,629	12.66	10.82	2,716,629	11.07
FTS	Fortis Inc.	ITC Transmission	1,739,118	1,947,137	11.96	10.82	1,947,137	11.07
FTS	Fortis Inc.	Michigan Electric Transmission Co.	1,363,673	1,497,827	9.84	10.82	1,497,827	11.07
MDU	MDU Resources	Montana-Dakota Utilities	288,969	274,213	-5.11	10.82	None	NA
NI	NiSource	Northern Indiana Public Service Co.	926,917	968,156	4.45	10.82	None	NA
OTTR	Otter Tail Corp.	Otter Tail Power Company	415,044	422,829	1.88	10.82	None	NA
VVC	Vectren Corp.	Southern Indiana Gas & Electric Co.	284,443	309,265	8.73	10.82	None	NA
XEL	Xcel Energy Inc.	Northern States Power MN WI	2,678,599	2,891,643	7.95	10.82	None	NA
na	American Transmission Co.	American Transmission Co.	3,703,663	3,899,703	5.29	10.82	None	NA
na	Cleco Corporate Holdings	Cleco Power	342,815	342,480	-0.01	10.82	None	NA

NA = not applicable or not available; ROE = return on equity
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

published annual updates to that first report, for a total historical data set covering nine full years from 2011 through 2019. This report is an update of An Overview of Transmission Ratemaking in MISO — 2018 update, a report published on Aug. 27, 2018.

For this report, RRA analyzed the transmission formula rate updates filed by a group of 22 companies in MISO for each company's latest rate year. The formula rate updates may not reflect subsequent revisions filed by individual companies to incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

The accompanying table lists the MISO companies in this report that employ formula based transmission rates, their reported transmission rate base for 2018 and 2019, where available, their base ROE, and any additional ROE incentive adders where applicable. The appendix includes the same companies with rate base values for the years 2011 through 2019, where available.

Formula rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach with annual updates based on cost of service data, generally drawn from the same data provided in annual FERC Form 1 filings. Approximately 100 utilities nationwide employ FERC-approved formula rate frameworks for transmission. A "stated" transmission rate is also based on traditional cost of service data, but the rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward-looking projected costs, subject to a true-up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation includes transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base.

Given the complexities inherent in determining a company's transmission rate base from an outside perspective, the RRA reports, with very limited exceptions, only include transmission rate base reported in annual updates. For additional information on the complex issues associated with determining a utility's rate base, see RRA's July 2, 2019 report Rate base: How would you rate your knowledge of this utility industry fundamental?

Individual company details

The sections that follow provide a closer look at transmission ratemaking and investment for each holding company with operations in MISO that are subject to formula-based rates. For each, there is a brief description followed by a table or tables that provide detail for their individual operating companies regarding authorized base ROE, ROR, rate base, net annual revenue requirement, network integration service rate, equity ratio, any additional ROE incentives that apply to the company's rate base, and the portion of total rate base that is accorded incentive ROEs.

AES Corp.

AES Corp.'s Indianapolis Power & Light Co. is a vertically integrated utility serving 470,000 customers in and around Indianapolis.

Indianapolis Power & Light Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE (%)
2019-2020	Annual	6/1/2019	10.82	7.47	210,949	42,871	17,772	45.0	None	NA
2018-2019	Annual	6/1/2018	10.82	7.57	194,604	42,172	18,527	46.0	None	NA
2017-2018	Annual	6/1/2017	10.82	7.32	187,354	42,253	17,922	45.0	None	NA
2016-2017	Annual	6/1/2016	12.88	8.23	114,485	30,207	13,006	46.0	None	NA
2015-2016	Annual	6/1/2015	12.88	8.39	97,242	29,746	12,233	46.0	None	NA
2014-2015	Annual	6/1/2014	12.88	8.59	99,678	22,236	9,034	46.0	None	NA
2013-2014	Annual	6/1/2013	12.88	8.70	95,732	18,365	7,724	47.0	None	NA
2012-2103	Annual	6/1/2012	12.88	8.74	90,232	20,125	8,152	46.0	None	NA
2011-2012	Annual	6/1/2011	12.88	8.80	94,717	19,631	7,982	46.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

ALLETE Corp.

ALLETE Corp. subsidiary Minnesota Power Co., or MP, owns and operates 8,472 miles of electric transmission and distribution lines and 164 substations in northeastern Minnesota.

MP is a participant in the CapX2020 initiative, a joint undertaking of 11 transmission-owning utilities in Minnesota, North Dakota, South Dakota and Wisconsin. CapX2020 was formed to upgrade and expand the electric transmission grid to ensure continued reliability in the upper Midwest. CapX2020 projects provide transmission capacity to support new generation resources, including renewable energy. The projects include four 345-kV transmission lines and one 230-kV line. CapX2020 has been reported to be the largest development of new transmission in the upper Midwest in nearly 40 years, and the five CapX2020 lines are projected to cost more than $2 billion and cover nearly 800 miles.

MP is a participant in three CapX2020 transmission line projects: the Monticello-St. Cloud line, the extension of that line to Fargo, ND, and a new 230-kV line between Bemidji, Minn., and the Boswell Energy Center near Grand Rapids, Minn. The Bemidji-Grand Rapids line and the Monticello-St. Cloud line were both completed in 2012, and the extension of the line to Fargo was completed in 2015.

Minnesota Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.15	692,704	83,615	NA	59.0	None	NA
2018	Annual	1/1/2018	10.82	8.11	564,715	86,790	NA	58.0	None	NA
2017	Annual	1/1/2017	10.82	8.13	486,307	80,115	NA	58.0	None	NA
2016	Annual	1/1/2016	12.88	8.98	386,593	59,565	NA	57.0	None	NA
2015	Annual	1/1/2015	12.88	8.74	313,445	58,413	28,445	54.0	None	NA
2014	Annual	1/1/2014	12.88	8.71	293,361	50,600	23,947	54.0	None	NA
2013	Annual	1/1/2013	12.88	8.89	233,634	48,263	17,860	55.0	None	NA
2012	Annual	1/1/2012	12.88	8.82	217,218	50,805	22,662	54.0	None	NA
2011	Annual	1/1/2011	12.88	9.15	221,642	53,144	23,905	56.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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Ameren Corp.

Ameren Corp. operates three regulated subsidiaries, Ameren Illinois, or AI, Ameren Missouri, or AM, and ATXI. AI serves electric and gas customers in Illinois, and AM serves electric and gas customers in Missouri. ATXI does not serve retail customers but invests in MISO Multi Value Projects, which are designated by MISO after comprehensive transmission expansion planning with stakeholders to meet reliability needs and economic and public policy goals in the region.

Ameren Illinois

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.75	1,882,168	270,333	38,940	52.87	None	NA
2018	Annual	1/1/2018	10.82	8.06	1,590,890	261,013	36,371	53.0	None	NA
2017	Annual	1/1/2017	10.82	8.24	1,358,324	223,585	30,562	53.0	None	NA
2016	Annual	1/1/2016	12.88	9.16	1,158,351	207,876	29,203	53.0	None	NA
2015	Annual	1/1/2015	12.88	9.39	890,188	159,124	22,427	55.0	None	NA
2014	Annual	1/1/2014	12.88	9.57	669,427	143,001	20,298	56.0	None	NA
2013	Annual	1/1/2013	12.88	10.06	581,596	133,058	18,345	55.0	None	NA
2012	Annual	1/1/2012	12.88	NA	NA	NA	NA	NA	None	NA
2011	Annual	1/1/2011	12.88	10.44	426,442	104,577	14,412	60.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Ameren Missouri

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	7.97	686,549	120,226	18,541	53.0	None	NA
2018-2019	Annual	6/1/2018	10.82	8.03	635,439	118,110	19,029	52.0	None	NA
2017-2018	Annual	6/1/2017	10.82	8.08	612,873	121,790	19,277	52.0	None	NA
2016-2017	Annual	6/1/2016	12.88	8.85	505,365	116,493	17,873	51.0	None	NA
2015-2016	Annual	6/1/2015	12.88	8.95	501,156	108,618	15,524	52.0	None	NA
2014-2015	Annual	6/1/2014	12.88	9.27	419,280	88,686	12,852	53.0	None	NA
2013-2014	Annual	6/1/2013	12.88	9.09	379,852	81,433	11,892	52.0	None	NA
2012-2013	Annual	6/1/2012	12.88	9.17	391,949	80,833	11,608	52.0	None	NA
2011-2012	Annual	6/1/2011	12.88	9.28	366,460	78,240	11,123	53.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Ameren Transmission of Illinois

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.60	1,325,931	NA	NA	56.1	None	NA
2018	Annual	1/1/2018	10.82	7.58	1,267,454	197,354	NA	56.0	None	NA
2017	Annual	1/1/2017	10.82	7.99	1,135,362	161,413	NA	56.0	None	NA
2016	Annual	1/1/2016	12.88	8.66	906,970	130,383	NA	56.0	None	NA
2015	Annual	1/1/2015	12.88	8.83	535,608	71,386	NA	56.0	None	NA
2014	Annual	1/1/2014	12.88	8.73	221,851	25,755	NA	57.0	None	NA
2013	Annual	1/1/2013	12.88	8.49	86,371	5,637	NA	56.0	None	NA
2012	Annual	1/1/2012	12.88	9.43	52,787	1,143	NA	56.0	None	NA
2011	Annual	1/1/2011	12.88	10.01	50,960	NA	NA	56.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

American Transmission Company

ATC, founded in 2001, was the first multistate, transmission-only utility established in the U.S. ATC owns and operates more than 9,530 miles of transmission lines and 530 substations in an area from the Upper Peninsula of Michigan, throughout the eastern half of Wisconsin, and into portions of Illinois. ATC is a privately owned company, and investor-owned utilities, municipalities, municipal electric companies and electric cooperatives from Wisconsin, Michigan, Minnesota and Illinois have ownership stakes in ATC.

American Transmission Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.69	3,899,703	565,738	56,154	50.0	None	NA
2018	Annual	1/1/2018	10.82	7.69	3,703,663	592,092	60,931	50.0	None	NA
2017	Annual	1/1/2017	10.82	7.67	3,526,665	571,471	58,338	50.0	None	NA
2016	Annual	1/1/2016	12.20	8.42	3,298,732	582,865	60,431	50.0	None	NA
2015	Annual	1/1/2015	12.20	8.50	3,050,028	555,124	55,542	50.0	None	NA
2014	Annual	1/1/2014	12.20	8.44	2,912,618	538,344	54,074	50.0	None	NA
2013	Annual	1/1/2013	12.20	8.50	2,811,456	531,152	53,299	50.0	None	NA
2012	Annual	1/1/2012	12.20	8.59	2,686,671	508,873	50,812	50.0	None	NA
2011	Annual	1/1/2011	12.20	8.72	2,563,825	506,205	51,720	50.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Berkshire Hathaway Energy

Berkshire Hathaway Energy subsidiary MidAmerican Energy Co. serves 700,000 retail electric customers in portions of Iowa, Illinois and South Dakota.

MidAmerican Energy Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.57	1,207,813	105,077	25,630	52.0	None	NA
2018	Annual	1/1/2018	10.82	7.60	1,157,122	111,182	27,706	52.0	None	NA
2017	Annual	1/1/2017	10.82	9.07	1,093,353	120,085	30,140	55.0	None	NA
2016	Annual	1/1/2016	12.88	8.71	1,078,584	114,413	28,322	53.0	None	NA
2015	Annual	1/1/2015	12.88	8.18	883,262	105,582	26,424	50.0	None	NA
2014	Annual	1/1/2014	12.88	8.41	632,482	112,214	29,209	50.0	None	NA
2013	Annual	1/1/2013	12.88	8.61	494,335	92,955	24,371	53.0	None	NA
2012	Annual	1/1/2012	12.88	9.06	381,686	72,151	19,058	53.0	None	NA
2011	Annual	1/1/2011	12.88	NA	NA	NA	NA	NA	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Cleco Corporate Holdings

Cleco Corporate Holdings' subsidiary Cleco Power owns and operates a transmission system consisting of approximately 1,300 miles of transmission lines and 81 transmission substations in Louisiana. In 2015, FERC approved the sale of Cleco Corp. to a North American investor group named Cleco Partners for approximately $4.9 billion. Cleco Partners consists of infrastructure investment organizations, including Macquarie Infrastructure and Real Assets and British Columbia Investment Management, together with John Hancock Financial and other infrastructure investors. The transaction closed in 2016.

Cleco Power

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	8.15	342,480	47,489	17,852	53.0	None	NA
2018-2019	Annual	6/1/2018	10.82	8.06	342,815	47,302	19,283	NA	None	NA
2017-2018	Annual	6/1/2017	10.82	8.55	298,824	51,875	20,342	55.0	None	NA
2016-2017	Annual	6/1/2016	12.88	9.46	277,997	49,624	19,089	55.0	None	NA
2015-2016	Annual	6/1/2015	12.88	8.23	324,688	57,039	NA	53.0	None	NA
2014-2015	Annual	6/1/2014	12.88	9.35	322,465	59,114	19,429	54.0	None	NA
2013-2014	Annual	6/1/2013	12.88	8.50	266,292	52,110	17,468	NA	None	NA
2012-2013	Annual	6/1/2012	NA	9.29	232,098	42,868	NA	50.0	None	NA
2011-2012	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Duke Energy Corp.

Duke Energy subsidiary Duke Energy Indiana is the only Duke subsidiary in MISO and serves approximately 820,000 customers in Indiana.

Duke Energy Indiana

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	8.07	939,991	162,289	29,429	53.0	None	NA
2018-2019	Annual	6/1/2018	10.82	7.90	864,670	152,656	29,359	52.0	None	NA
2017-2018	Annual	6/1/2017	10.82	7.88	761,646	150,649	28,056	52.0	None	NA
2016-2017	Annual	6/1/2016	12.88	8.52	722,955	150,155	28,809	50.0	None	NA
2015-2016	Annual	6/1/2015	12.88	8.49	684,472	138,002	25,625	50.0	None	NA
2014-2015	Annual	6/1/2014	12.88	8.59	618,613	130,453	24,924	51.0	None	NA
2013-2014	Annual	6/1/2013	12.88	8.52	506,630	116,219	23,062	50.0	None	NA
2012-2013	Annual	6/1/2012	12.88	8.72	498,343	110,905	24,309	52.0	None	NA
2011-2012	Annual	6/1/2011	12.88	8.45	485,732	114,907	NA	NA	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Entergy Corp.

Entergy Corp. employed a system-wide open-access transmission tariff and transmission rate until it transitioned into MISO in 2013. For the rate years 2011-2012 and 2012-2013, Entergy Services filed system-wide transmission data in annual formula rate updates for Entergy's operating companies, Entergy Arkansas Inc., Entergy Gulf States Louisiana Inc., Entergy Louisiana Inc., Entergy Mississippi Inc., Entergy New Orleans Inc. and Entergy Texas Inc. During those two rate years, Entergy's system-wide, consolidated transmission rate base declined slightly from $2.3 billion to approximately $2.2 billion.

Upon Entergy's integration into MISO in 2013, a transmission rate was calculated separately for each Entergy operating company based on a 2012 historical test year and applied through May 2014. Beginning June 1, 2014, the transmission rates were updated with 2013 calendar-year data. Data for the individual Entergy operating companies is only available for the six rate years 2013-2014 through 2018-2019. In addition, in 2015, the Louisiana operations of Entergy Gulf States were rolled into Entergy Louisiana; the Texas operations became Entergy Texas.

Entergy Arkansas Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	7.42	1,898,099	250,178	39,650	47.89	None	NA
2018-2019	Annual	6/1/2018	10.82	7.15	1,458,682	209,340	NA	46.38	None	NA
2017-2018	Annual	6/1/2017	10.82	7.31	1,333,909	210,504	NA	46.61	None	NA
2016-2017	Annual	6/1/2016	12.88	7.87	1,083,494	229,811	41,180	45.70	None	NA
2015-2016	Annual	6/1/2015	12.88	7.52	1,034,426	184,067	31,500	44.83	None	NA
2014-2015	Annual	6/1/2014	12.88	7.74	670,884	135,452	23,628	46.00	None	NA
2013-2014	Annual	6/1/2013	12.88	8.01	638,321	142,620	22,197	48.00	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Entergy Louisiana Inc.*

Rate year	Adjustment frequency	Adjustment date	Base ROE** (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE** (%)
2019-2020	Annual	6/1/2019	10.82	7.37	2,895,429	369,828	29,910	47.00	None	NA
2018-2019	Annual	6/1/2018	10.82	7.51	2,618,077	336,379	NA	47.75	None	NA
2017-2018	Annual	6/1/2017	10.82	7.64	2,121,951	312,598	NA	48.21	None	NA
2016-2017	Annual	6/1/2016	12.88	9.24	1,560,300	369,895	34,600	51.42	None	NA
2015-2016	Annual	6/1/2015	12.88	8.54	790,822	170,091	14,600	48.44	None	NA
2014-2015	Annual	6/1/2014	12.88	8.53	632,204	136,428	20,791	50.00	None	NA
2013-2014	Annual	6/1/2013	12.88	8.90	606,291	134,816	22,444	55.00	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Effective October 1, 2015, the Louisiana operations of Entergy Gulf States were rolled into Entergy Louisiana.
** Includes 50-basis-point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Entergy Mississippi Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	7.35	1,069,255	161,888	52,340	49.38	None	NA
2018-2019	Annual	6/1/2018	10.82	7.15	812,147	91,490	NA	48.25	None	NA
2017-2018	Annual	6/1/2017	10.82	7.79	638,309	129,943	NA	49.56	None	NA
2016-2017	Annual	6/1/2016	12.88	8.65	535,167	117,688	36,710	50.06	None	NA
2015-2016	Annual	6/1/2015	12.88	8.61	483,008	108,784	35,800	48.86	None	NA
2014-2015	Annual	6/1/2014	12.88	8.59	475,243	115,237	44,743	48.00	None	NA
2013-2014	Annual	6/1/2013	12.88	7.87	442,074	107,679	37,009	44.00	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Entergy New Orleans Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	7.74	105,164	19,285	NA	53.89	None	NA
2018-2019	Annual	6/1/2018	10.82	8.14	94,774	19,585	NA	54.27	None	NA
2017-2018	Annual	6/1/2017	10.82	8.03	79,699	15,436	NA	56.07	None	NA
2016-2017	Annual	6/1/2016	12.88	9.43	64,496	25,725	21,560	62.06	None	NA
2015-2016	Annual	6/1/2015	12.88	8.67	37,283	13,620	NA	52.28	None	NA
2014-2015	Annual	6/1/2014	12.88	8.52	26,011	13,577	16,685	50.00	None	NA
2013-2014	Annual	6/1/2013	12.88	8.57	22,373	13,090	15,306	53.00	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Entergy Texas Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019-2020	Annual	6/1/2019	10.82	8.47	966,003	152,390	43,080	52.15	None	NA
2018-2019	Annual	6/1/2018	10.82	8.13	839,025	86,771	NA	50.91	None	NA
2017-2018	Annual	6/1/2017	10.82	8.40	747,653	132,148	NA	50.14	None	NA
2016-2017	Annual	6/1/2016	12.88	9.39	674,402	142,202	42,930	50.57	None	NA
2015-2016	Annual	6/1/2015	12.88	9.50	535,922	128,384	36,030	50.03	None	NA
2014-2015	Annual	6/1/2014	12.88	9.44	416,101	109,531	31,464	49.00	None	NA
2013-2014	Annual	6/1/2013	12.88	9.36	384,601	99,337	26,466	48.00	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Fortis Inc.

In 2016, FERC approved the acquisition of ITC Holdings by Canadian company Fortis Inc. ITC was the largest independent electric transmission company in the U.S. Through its three regulated operating subsidiaries in MISO, ITC Transmission, or ITCT, Michigan Electric Transmission, or METC, and ITC Midwest, or ITCM, ITC owns and operates high-voltage transmission facilities in Illinois, Iowa, Kansas, Michigan, Minnesota, Missouri and Oklahoma.

FERC granted ITCT and METC 100-basis-point ROE adders in 2003 and 2006, respectively, based on their independent transmission owner business model. In 2015, FERC approved an ROE incentive adder of 50 basis points for ITCM.

On Oct. 18, 2018, FERC determined that the acquisition by Fortis has "reduced, but not eliminated, the ITC Companies' independence from market participants," and as a result, FERC reduced the ROE incentive adder for each of the three companies to 25 basis points.

ITC Transmission Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.48	1,947,137	269,242	31,574	60.0	1,947,137	11.07
2018	Annual	1/1/2018	10.82	8.73	1,739,118	258,170	30,226	60.0	1,739,118	11.35
2017	Annual	1/1/2017	10.82	8.71	1,688,571	264,043	30,883	60.0	1,688,571	11.35
2016	Annual	1/1/2016	12.88	10.21	1,663,171	262,798	30,605	60.0	1,663,171	13.88
2015	Annual	1/1/2015	12.88	10.30	1,510,408	248,332	28,943	60.0	1,510,408	13.88
2014	Annual	1/1/2014	12.88	10.30	1,379,630	237,157	27,663	60.0	1,379,630	13.88
2013	Annual	1/1/2013	12.88	10.25	1,162,323	220,690	25,761	60.0	1,162,323	13.88
2012	Annual	1/1/2012	12.88	10.40	1,028,301	217,792	26,256	60.0	1,028,301	13.88
2011	Annual	1/1/2011	12.88	10.50	987,390	244,134	29,940	60.0	987,390	13.88

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

ITC Midwest

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.47	2,716,629	333,421	113,523	60.0	2,716,629	11.07
2018	Annual	1/1/2018	10.82	8.57	2,411,250	356,462	121,651	60.0	2,411,250	11.32
2017	Annual	1/1/2017	10.82	8.67	2,196,261	349,142	119,324	60.0	2,196,261	11.32
2016	Annual	1/1/2016	12.88	9.14	2,017,999	350,578	119,042	60.0	2,017,999	12.88
2015	Annual	1/1/2015	12.88	9.26	1,791,523	326,332	112,606	60.0	1,791,523	12.88
2014	Annual	1/1/2014	12.88	9.21	1,619,425	312,326	107,071	60.0	1,619,425	12.88
2013	Annual	1/1/2013	12.88	9.41	1,415,986	276,758	95,073	60.0	1,415,986	12.88
2012	Annual	1/1/2012	12.88	9.62	1,124,854	238,287	82,998	60.0	1,124,854	12.88
2011	Annual	1/1/2011	12.88	9.74	899,855	240,101	83,863	60.0	899,855	12.88

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Michigan Electric Transmission Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/ MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.33	1,497,827	245,013	37,247	60.0	1,497,827	11.07
2018	Annual	1/1/2018	10.82	8.44	1,363,673	231,840	35,127	60.0	1,363,673	11.35
2017	Annual	1/1/2017	10.82	8.45	1,335,636	227,639	34,485	60.0	1,335,636	11.35
2016	Annual	1/1/2016	12.88	9.87	1,233,107	221,386	33,396	60.0	1,233,107	13.38
2015	Annual	1/1/2015	12.88	10.14	1,158,755	216,873	32,861	60.0	1,158,755	13.38
2014	Annual	1/1/2014	12.88	10.09	1,115,132	220,483	33,366	60.0	1,115,132	13.38
2013	Annual	1/1/2013	12.88	10.21	976,663	199,660	30,316	60.0	976,663	13.38
2012	Annual	1/1/2012	12.88	10.34	844,264	189,437	28,913	60.0	844,264	13.38
2011	Annual	1/1/2011	12.88	10.38	725,223	181,296	28,051	60.0	725,223	13.38

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

MDU Resources Group

MDU Resources Group's Montana-Dakota Utilities division serves approximately 130,000 electric customers and 245,000 natural gas customers in North Dakota, South Dakota, Montana and Wyoming.

Montana-Dakota Utilities Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.60	274,213	19,343	31,349	50.0	None	NA
2018	Annual	1/1/2018	10.82	7.82	288,969	21,295	35,058	50.0	None	NA
2017	Annual	1/1/2017	10.82	7.79	242,963	22,252	36,571	50.0	None	NA
2016	Annual	1/1/2016	12.88	8.53	166,536	18,176	33,615	51.0	None	NA
2015	Annual	1/1/2015	12.88	8.61	122,642	20,225	39,312	50.0	None	NA
2014	Annual	1/1/2014	12.88	9.15	105,578	24,014	46,709	55.0	None	NA
2013	Annual	1/1/2013	12.88	10.06	114,130	26,271	35,561	59.0	None	NA
2012	Annual	1/1/2012	12.88	NA	NA	NA	NA	NA	None	NA
2011	Annual	1/1/2011	12.88	NA	NA	NA	NA	NA	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

NiSource Inc.

NiSource subsidiary Northern Indiana Public Service Company serves approximately 461,000 customers in 20 counties in the northern part of Indiana.

Northern Indiana Public Service Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.23	968,156	95,756	33,989	55.0	None	NA
2018	Annual	1/1/2018	10.82	8.49	926,917	108,496	38,701	58.0	None	NA
2017	Annual	1/1/2017	10.82	8.47	850,261	132,320	45,783	58.0	None	NA
2016	Annual	1/1/2016	12.88	9.42	643,368	125,529	42,004	58.0	None	NA
2015	Annual	1/1/2015	12.88	9.53	500,453	121,619	41,317	58.0	None	NA
2014	Annual	1/1/2014	12.88	9.64	393,305	118,658	41,941	58.0	None	NA
2013	Annual	1/1/2013	12.88	9.99	378,412	117,441	41,388	59.0	None	NA
2012	Annual	NA	12.88	NA	NA	NA	NA	NA	None	NA
2011-2012	Annual	6/1/2011	12.88	9.08	357,762	102,599	36,630	59.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Otter Tail Corporation

Otter Tail Corp. subsidiary Otter Tail Power Co. serves approximately 130,000 customers in a 70,000 square-mile area of northeastern South Dakota, eastern North Dakota and west-central Minnesota.

Otter Tail Power Company

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.31	422,829	30,228	33,799	55.0	None	NA
2018	Annual	1/1/2018	10.82	8.31	415,044	27,419	31,600	54.0	None	NA
2017	Annual	1/1/2017	10.82	8.53	396,068	29,571	40,483	57.0	None	NA
2016	Annual	1/1/2016	12.88	9.19	325,508	28,776	39,402	53.0	None	NA
2015	Annual	1/1/2015	12.88	9.08	258,574	25,310	35,902	52.0	None	NA
2014	Annual	1/1/2014	12.88	8.90	231,868	20,343	30,845	49.0	None	NA
2013	Annual	1/1/2013	12.88	9.31	200,251	22,441	33,479	54.0	None	NA
2012	Annual	1/1/2012	12.88	9.24	174,155	24,703	38,796	52.0	None	NA
2011	Annual	1/1/2011	12.88	9.64	130,863	25,747	38,410	53.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Vectren Corporation

Vectren subsidiary Southern Indiana Gas and Electric Co. provides energy delivery services to approximately 145,200 electric customers and approximately 111,500 gas customers located near Evansville in southwestern Indiana.

Southern Indiana Gas and Electric Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	8.05	309,265	34,962	34,538	58.0	None	NA
2018	Annual	1/1/2018	10.82	8.25	284,443	35,766	38,139	60.0	None	NA
2017	Annual	1/1/2017	10.82	8.11	272,467	32,125	31,005	56.0	None	NA
2016	Annual	1/1/2016	12.88	8.86	275,135	31,902	31,393	54.0	None	NA
2015	Annual	1/1/2015	12.88	9.00	275,532	29,128	29,057	55.0	None	NA
2014	Annual	1/1/2014	12.88	9.02	270,409	28,061	27,863	54.0	None	NA
2013	Annual	1/1/2013	12.88	9.15	271,604	25,553	24,814	54.0	None	NA
2012	Annual	1/1/2012	12.88	9.48	260,883	26,391	25,818	55.0	None	NA
2011	Annual	1/1/2011	12.88	9.78	245,067	27,069	28,022	54.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Xcel Energy Inc.

Xcel Energy subsidiaries Northern States Power-Minnesota, or NSP-M, and Northern States Power-Wisconsin, or NSP-W, are transmission-owning members of MISO and are combined for transmission reporting purposes. NSP-M serves portions of Minnesota, North Dakota and South Dakota and provides electric utility service to approximately 1.4 million customers. NSP-W serves approximately 255,000 customers in Wisconsin and Michigan.

In 2014, Xcel submitted and received approval from MISO for its subsidiary Xcel Energy Transmission Development Company to compete for a set of transmission projects that are expected to be proposed in the MISO region resulting from FERC Order 1000. The order, issued in 2011, reformed FERC's electric transmission planning and cost allocation requirements for utility transmission providers. Order 1000 also, for the first time, allowed RTO/ISOs to utilize competitive bidding for certain new transmission projects in their respective regions. Previously, incumbent transmission providers enjoyed a right-of-first-refusal to build new transmission projects in their service territories.

Northern States Power-Minnesota and Northern States Power-Wisconsin

Rate year	Adjustment frequency	Adjustment date	Base ROE* (%)	ROR (%)	Rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Rate base subject to incentive ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.82	7.85	2,891,643	370,656	44,133	53.0	None	NA
2018	Annual	1/1/2018	10.82	7.92	2,678,599	370,587	44,230	54.0	None	NA
2017	Annual	1/1/2017	10.82	7.91	2,609,590	355,016	42,744	52.0	None	NA
2016	Annual	1/1/2016	12.88	8.83	2,619,524	402,420	55,483	53.0	None	NA
2015	Annual	1/1/2015	12.88	8.96	2,469,599	359,232	48,775	53.0	None	NA
2014	Annual	1/1/2014	12.88	8.91	2,114,299	322,308	44,026	53.0	None	NA
2013	Annual	1/1/2013	12.88	9.03	1,800,662	322,943	44,846	54.0	None	NA
2012	Annual	1/1/2012	12.88	9.32	1,465,720	327,994	44,339	54.0	None	NA
2011	Annual	1/1/2011	12.88	9.61	1,240,525	270,341	36,309	55.0	None	NA

NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Appendix: rate base values for MISO utilities with formula rates ($000)

Ticker	Transmission owner	Filing entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2016-2019 CAGR (%)	2011-2019 CAGR (%)
AEE	Ameren Corp.	Ameren Illinois	426,442	NA	581,596	669,427	890,188	1,158,351	1,358,324	1,590,890	1,882,168	17.56	20.39
AEE	Ameren Corp.	Ameren Missouri	366,460	391,949	379,852	419,280	501,156	505,365	612,873	635,439	686,549	10.75	8.16
AEE	Ameren Corp.	Ameren Transmission of Illinois	50,960	52,787	86,371	221,851	535,608	906,970	1,135,362	1,267,454	1,325,931	13.49	50.28
AES	IPALCO Enterprises	Indianapolis Power & Light Co.	94,717	90,232	95,732	99,678	97,242	114,485	187,354	194,604	210,949	22.60	10.53
ALE	ALLETE Inc.	Minnesota Power Co.	221,642	217,218	233,634	293,361	313,445	386,593	486,307	564,715	692,704	21.46	15.31
BRK	Berkshire Hathaway Energy	MidAmerican Energy Co.	NA	381,686	494,335	632,482	883,262	1,078,584	1,093,353	1,157,122	1,207,813	3.84	NA
DUK	Duke Energy Corp.	Duke Energy Indiana	485,732	498,343	506,630	618,613	684,472	722,955	761,646	864,670	939,991	9.15	8.60
ETR	Entergy Corp.	Entergy Services Inc.*	2,295,749	2,197,559	NA	NA	NA	NA	NA	NA	NA	NA	NA
ETR	Entergy Corp.	Entergy Arkansas Inc.	NA	NA	638,321	670,884	1,034,426	1,083,494	1,333,909	1,458,682	1,898,099	20.55	NA
ETR	Entergy Corp.	Entergy Gulf States Inc.	NA	NA	361,158	389,671	581,355	NA	NA	NA	NA	NA	NA
ETR	Entergy Corp.	Entergy Louisiana Inc.**	NA	NA	606,291	632,204	790,822	1,560,300	2,121,951	2,618,077	2,895,429	NA	NA
ETR	Entergy Corp.	Entergy Mississippi Inc.	NA	NA	442,074	475,243	483,008	535,167	638,309	812,147	1,069,255	25.95	NA
ETR	Entergy Corp.	Entergy New Orleans Inc.	NA	NA	22,373	26,011	37,283	62,894	79,699	94,774	105,164	18.69	NA
ETR	Entergy Corp.	Entergy Texas Inc.	NA	NA	384,601	416,101	535,922	618,894	747,653	839,025	966,003	16.00	NA
FTS	Fortis Inc.	ITC Midwest	899,855	1,124,854	1,415,986	1,619,425	1,791,523	2,017,999	2,196,261	2,411,250	2,716,629	10.42	14.81
FTS	Fortis Inc.	ITC Transmission	987,390	1,028,301	1,162,323	1,379,630	1,510,408	1,663,171	1,688,571	1,739,118	1,947,137	5.39	8.86
FTS	Fortis Inc.	Michigan Electric Transmission Co.	725,223	844,264	976,663	1,115,132	1,158,755	1,233,107	1,335,636	1,363,673	1,497,827	6.70	9.49
MDU	MDU Resources	Montana-Dakota Utilities Co.	NA	NA	114,130	105,578	122,642	166,536	242,963	288,969	274,213	18.08	NA
NI	NiSource	Northern Indiana Public Service Co.	357,762	NA	378,412	393,305	500,453	643,368	850,261	926,917	968,156	14.59	13.25
OTTR	Otter Tail Corp.	Otter Tail Power Company	130,863	174,155	200,251	231,868	258,574	325,508	396,068	415,044	422,829	9.11	15.79
VVC	Vectren Corp.	Southern Indiana Gas & Electric Co.	245,067	260,883	271,604	270,409	275,532	275,135	272,467	284,443	309,265	3.97	2.95
XEL	Xcel Energy Inc.	Northern States Power MN WI	1,240,525	1,465,720	1,800,662	2,114,299	2,469,599	2,619,524	2,609,590	2,678,599	2,891,643	3.35	11.16
NA	American Transmission Co.	American Transmission Co.	2,563,825	2,686,671	2,811,456	2,912,618	3,050,028	3,298,732	3,526,665	3,703,663	3,899,703	5.74	5.38
NA	Cleco Corporate Holdings	Cleco Power	NA	232,098	266,292	322,465	324,688	277,997	298,824	342,815	342,480	7.20	NA

NA = not available or not applicable
* Entergy Services filed consolidated formula rate updates on behalf of all Entergy operating utilities prior to 2013.
** Represents the combined rate base of Entergy Gulf States and Entergy Louisiana beginning in 2016. Effective October 1, 2015, the Louisiana operations of Entergy Gulf States were rolled into Entergy Louisiana.
Source: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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RRA Regulatory Focus
An Overview of Transmission Ratemaking in ISO New England – 2019 Update

Overview

Transmission rate base growth in ISO New England, or ISO-NE, accelerated for the second consecutive year, reaching $9.88 billion in 2019 from $9.08 billion in 2018, an increase of 8.8%. This follows growth of 7.2% from 2017 to 2018 and of only 6.3% from 2016 to 2017.

ISO New England

Source: FERC

The transmission rate base data, which is sourced from 2019 transmission formula rate filings with the Federal Energy Regulatory Commission, demonstrates that the increasing growth rate observed in ISO-NE is led by Eversource Energy, which reported an 11.8% increase in transmission rate base to $5.76 billion in 2019 from $5.15 billion in 2018.

Regulatory Research Associates, a group within S&P Global Market Intelligence, follows 11 companies that operate in ISO-NE with formula transmission rates. In 2019, transmission rate base for these companies ranged from a low of $3.1 million for Unitil Corp.'s Fitchburg Gas and Electric Co. to $2.78 billion for Eversource Energy subsidiary Connecticut Light & Power Co., or CL&P.

At the individual operating company level, Eversource subsidiary Public Service Company of New Hampshire reported the sharpest year-over-year transmission rate base increase among these 11 companies, growing 20.8% to $864 million in 2019 from $715 million in 2018.

United Illuminating Co., a subsidiary of Avangrid Inc., reported the second largest year-over-year growth, from $539 million in 2018 to $620 million in 2019, or 14.9%. CL&P reported the next largest growth, from $2.46 billion in 2018 to $2.78 billion in 2019, or 13.1%.

The return on equity for all transmission owners in ISO-NE remained unchanged in 2019 at 11.07%, including a 50 basis point incentive adder for participation in a regional transmission organization or independent system operator. The ROE in ISO-NE is the subject of ongoing litigation at FERC that began in 2011, and the commission is currently considering stakeholder comments on a proposal to fundamentally revise the methodology used to establish ROEs for electric utilities. See the ISO-NE return on equity section below for more information.

FERC has granted additional transmission ROE incentive adders of up to 125 basis points for certain investments by utilities in ISO-NE. FERC orders in 2014, however, have capped the total ROE for ISO-NE companies at 11.74% including all incentives. See the individual company sections below for additional details on these incentive adders.

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Regulatory Focus: Topical Special Report

Evolution of ISO-NE

In 1966, the Northeast Power Coordinating Council was formed to improve system reliability after the 1965 Northeast Blackout shut down power for 30 million customers in New England, New York, New Jersey, Pennsylvania and part of Ontario, Canada.

In 1971, the New England Power Pool, or NEPOOL, was formed by the region's private and municipal utilities and was intended to foster cooperation and coordination among utilities in the six-state region of Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont and most of Maine. Initially, NEPOOL operated as a "tight power pool," a single, unified regional network with coordinated operations covering the bulk power facilities subject to its control, including a centralized control center to provide central dispatch services.

Following the issuance of FERC's transmission open-access mandate in Order No. 888 in 1996, NEPOOL was required to revise its operational and organizational structure to satisfy the requirements for an RTO or ISO. To meet those requirements, NEPOOL elected to contract with an independent entity, ISO-NE, to perform those functions.

Subsequently, ISO-NE, with FERC's approval, was authorized to fulfill the obligations of an ISO beginning in 1997. Also in 1997, ISO-NE created a management system for the region's bulk power system and new wholesale markets to ensure open access to the region's transmission system.

In 2004, FERC conditionally recognized ISO-NE as an RTO and, in 2005, designated ISO-NE as the RTO for the six-state New England region.

Background

RRA first published this survey of transmission rate bases for utilities with formula rates in ISO-NE in 2015. The first report compiled five years of data for each of the companies — 2015 data and four years of historical data. RRA has published annual updates to that first report, for a total historical data set covering nine full years from 2011 through 2019. This report is an update of *An Overview of Transmission Ratemaking in ISO New England — 2018 Update*, a report published on Oct. 25, 2018.

ISO-NE transmission formula rate summary

Ticker	Parent company	Filing entity	Transmission investment base 2018-2019 ($000)	Transmission investment base 2019-2020 ($000)	Investment base growth 2018-2019 to 2019-2020 (%)	Base ROE (%)*	Investment base subject to incentive ROE ($000)	Incentive ROE (%)*
AGR	Avangrid Inc.	Central Maine Power Co.	1,104,754	1,126,724	1.99	11.07	911,629	11.74
AGR	Avangrid Inc.	The United Illuminating Company	539,112	619,711	14.95	11.07	354,103	11.74
EMA	Emera Inc.	Emera Maine	228,831	226,099	-1.19	11.07	NA	NA
ES	Eversource Energy	Connecticut Light & Power Co.	2,456,226	2,777,860	13.09	11.07	1,221,162	11.74
ES	Eversource Energy	NSTAR Electric Co.	1,293,099	1,384,529	7.07	11.07	194,681	11.74
ES	Eversource Energy	Public Service Co. of New Hampshire	715,270	864,243	20.83	11.07	75,496	11.74
ES	Eversource Energy	Western Massachusetts Electric Co.	687,987	736,171	7.00	11.07	376,922	11.74
NEE	NextEra Energy Inc.	New Hampshire Transmission LLC	43,487	46,067	5.93	11.07	NA	NA
UTL	Unitil Corp.	Fitchburg Gas and Electric Co.	2,795	3,148	12.63	11.07	NA	NA
na	National Grid USA	New England Power Co.	1,186,573	1,198,264	0.98	11.07	247,625	11.74
na	na	Vermont Transco LLC	818,484	895,913	9.46	11.07	177,351	11.74

*Inclusive of 50 basis point incentive adder for membership in ISO-NE. Total ROE capped at 11.74% inclusive of all incentive adders pursuant to FERC Opinion 531.
NA = not applicable or not available; ROE = return on equity
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

For this report, RRA analyzed the transmission formula rate updates filed by a group of 11 companies in ISO-NE for the latest rate year. The formula rate updates may not reflect subsequent revisions filed by individual companies to incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

The accompanying summary table lists the ISO-NE companies in this report that employ formula-based transmission rates, their reported transmission rate base for 2018 and 2019, where available, their base ROE, and any additional ROE incentive adders where applicable. The appendix includes the same companies with rate base values for the years 2011 through 2019, where available.

Formula transmission rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that adjusts rates annually based on updated cost of service data, generally drawn from the same data filed by a company in its annual FERC Form 1. Approximately 100 utilities nationwide employ FERC-approved formula rate frameworks for transmission. A "stated" transmission rate is also based on traditional cost of service data, but the rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward-looking projected costs, subject to a true-up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation in each utility's annual update includes, among other things, transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base.

Given the complexities inherent in determining a company's transmission rate base from an outside perspective, the RRA reports, with very limited exceptions, include transmission rate base only for those companies that report such data in their annual updates under a formula-based rate framework. For additional information on the complex issues associated with determining a utility's rate base, see RRA's July 2, 2019, Topical Special Report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Transmission ratemaking in ISO-NE

The annual updates filed by utilities in New England report transmission "investment base," and that term is used in lieu of the term "rate base." Wherever possible, the investment base data included in this report does not include construction work in progress, or CWIP.

In New England, transmission owners recover transmission revenue requirements through a combination of local and regional open access transmission tariff, or OATT, rates. The transmission owners provide regional network service, or RNS, over their regional high-voltage lines pursuant to ISO-NE's OATT, and the rate for RNS is calculated annually using a formula rate for all pool transmission facilities, or PTF, in New England. The RNS formula rate applies only to PTF, i.e., those assets that have been turned over to the operational control of ISO-NE by transmission owners in New England.

The ISO-NE formula rate for RNS was established by settlement and accepted by FERC in 1999. The formula rate defines the inputs and factors to be used by every transmission owner in ISO-NE for calculating its annual revenue requirement. All ISO-NE transmission owners are required to jointly submit to FERC an informational filing that updates the RNS rates under ISO-NE's OATT. The total of the transmission owners' revenue requirements, including adjustments for an annual true-up and other items, is used to establish the rate for RNS in effect from June 1 through May 31 of each rate year.

ISO-NE return on equity

In 2004, in conjunction with conditionally approving the formation of ISO-NE, FERC approved a base ROE of 10.2% for members of ISO-NE, as well as a 74 basis point ROE adder to reflect interest rate data at that time and a 50 basis point incentive ROE adder for RTO/ISO participation, resulting in a total authorized ROE of 11.44%. In 2006, FERC revised the base ROE upward from 10.2% to 10.4%, resulting in an overall ROE of 11.64%, inclusive of the 50 basis point RTO/ISO incentive.

In response to a complaint filed in 2011, FERC issued in 2014 an order finding that ISO-NE's then-existing base ROE of 11.14%, excluding any incentives, was unjust and unreasonable. FERC reduced ISO-NE's base ROE to 10.57% and determined that ISO-NE's maximum ROE, including all incentives, cannot exceed 11.74%, which was the top of the "zone of reasonableness" determined in the proceeding. Both ISO-NE transmission owners and New England stakeholders appealed FERC's order to the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit.

In 2012, a second complaint was filed against ISO-NE, arguing that the base ROE should be reduced to 8.7%; in 2014, a third complaint was filed, arguing that ISO-NE's base ROE should be reduced to 8.84%.

In 2016, the administrative law judge in the second and third complaint cases issued an initial decision recommending that the base ROE going forward for transmission owners in ISO-NE be increased from 10.57% to 10.9%, with an overall ROE ceiling including all incentives of 12.19%.

Shortly thereafter, a fourth complaint was filed against ISO-NE by a group of utilities known as Eastern Massachusetts Consumer-Owned Systems, or EMCOS. In its complaint, EMCOS argued that the base ROE for ISO-NE transmission owners should be reduced from 10.57% to 8.61% and the overall ROE ceiling, which was set at 11.74% by FERC's order in 2014, should be reduced to 11.24%.

Later that year, FERC set the fourth complaint for hearing, while also acknowledging concerns raised by the Edison Electric Institute over the "pancaking" of multiple complaint proceedings by reiterating a previous explanation that the Regulatory Fairness Act allows successive requests for rate changes so long as each is based on "new, more current data."

The commission acknowledged that "[u]tilities are free to file for successively higher rate increases based on later common equity cost data without regard to the status of their prior requests, and a fair symmetry requires that complainants also be free to file complaints requesting further rate decreases based on later common equity cost data without regard to the status of their prior complaints."

In 2017, in response to the appeals of FERC's 2014 order on the first complaint, the D.C. Circuit issued an opinion vacating and remanding the FERC orders that reduced the authorized base ROE for transmission owners in ISO-NE from 11.14% to 10.57%.

In October 2018, FERC issued an order in response to the D.C Circuit's remand and addressed all four complaints against ISO-NE. FERC proposed a fundamental change to the commission's policies for determining an appropriate ROE for electric utilities by giving equal weight to the results of four financial models instead of primarily relying on the discounted cash flow model that the commission has historically used.

FERC directed the parties in the ISO-NE cases to submit briefs and reply briefs regarding the proposed new ROE approach and how to apply it to the four pending complaints involving transmission owners in New England. FERC action in the cases is pending.

Individual company details

The sections that follow provide a closer look at transmission ratemaking and investment for each holding company with operations in ISO-NE that is covered by RRA. For each there is a summary description, followed by a table or tables that provide detail for each operating company regarding authorized base ROE, ROR, investment base, net annual revenue requirement, network integration service rate, equity ratio, any additional ROE incentives that apply to the company's investment base, and the portion of total investment base that is accorded incentive ROEs, where applicable. The Appendix tracks the transmission investment base for companies in ISO-NE for rate years 2011-12 through 2018-19.

S&P Global
Market Intelligence

Regulatory Focus: Topical Special Report

Avangrid Inc.

Avangrid Inc. subsidiary Central Maine Power Co., or CMP, conducts regulated electric transmission and distribution operations in Maine. CMP serves approximately 612,000 customers in a service territory of approximately 11,000 square miles with a population of approximately 1 million. CMP's service territory is located in the southern and central areas of Maine and contains most of Maine's industrial and commercial centers, including the city of Portland and the Lewiston-Auburn, Augusta-Waterville, Saco-Biddeford and Bath-Brunswick areas.

Central Maine Power Company

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.55	1,126,724	223,775	111,940	59.13	911,629	11.74
2018-2019	Annual	6/1/2018	11.07	8.60	1,104,754	219,997	110,430	59.64	968,238	11.74
2017-2018	Annual	6/1/2017	11.07	8.49	1,143,917	247,631	111,958	62.40	1,001,555	11.74
2016-2017	Annual	6/1/2016	11.07	8.65	1,136,321	245,428	103,296	60.26	945,107	11.74
2015-2016	Annual	6/1/2015	11.07	8.73	855,355	244,434	98,700	62.10	721,940	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	9.04	651,428	251,563	89,796	60.65	456,199	12.89/ 11.74
									53,384	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	9.27	418,034	220,574	86,947	61.84	203,759	12.89
									55,413	12.64
2012-2013	Annual	6/1/2012	11.64	9.69	533,684	147,223	75,255	65.77	37,936	12.89
									53,086	12.64
2011-2012	Annual	6/1/2011	11.64	10.01	177,457	158,933	63,884	67.60	21,185	12.89
									55,606	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

United Illuminating Company

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.64	619,711	166,094	111,940	56.63	354,103	11.74
2018-2019	Annual	6/1/2018	11.07	8.66	539,112	158,462	110,430	56.15	370,397	11.74
2017-2018	Annual	6/1/2017	11.07	8.42	535,456	146,226	111,958	54.42	382,770	11.74
2016-2017	Annual	6/1/2016	11.07	8.13	480,546	133,961	103,296	50.03	302,434	11.74
2015-2016	Annual	6/1/2015	11.07	8.18	458,700	145,891	98,700	50.63	201,817	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	8.32	449,635	116,209	89,796	48.31	190,507	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.63	409,285	130,586	86,947	51.74	219,387	12.64
2012-2013	Annual	6/1/2012	11.64	8.91	377,520	114,354	75,255	50.37	246,067	12.64
2011-2012	Annual	6/1/2011	11.64	8.74	386,705	85,388	63,884	48.07	295,072	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

CMP owns 78.3% of Maine Electric Power Co.'s, or MEPCO's, common stock. The remaining 21.7% is held by Emera Maine. MEPCO owns and operates a 345-kV transmission interconnection between Wiscasset, Maine, and the Maine-New Brunswick international border at Orient, Maine, where it interconnects with New Brunswick Power's facilities in the province of New Brunswick, Canada.

In 2010, CMP launched the Maine Power Reliability Program, or MPRP, a five-year project to support the development of new renewable energy resources and help ensure long-term reliability by increasing the capacity and efficiency of the New England transmission grid. The MPRP included the construction of five new 345-kV substations and related facilities linked by approximately 450 miles of new or rebuilt transmission lines. The MPRP was completed in 2015 at a final cost of $1.36 billion.

CMP was granted a 125 basis point incentive ROE adder for the MPRP by FERC in 2008. The commission found that an ROE incentive was justified because the MPRP was not routine and faced significant siting, construction, regulatory, environmental and financial risks and challenges. Considering the other incentives FERC approved for the MPRP, such as inclusion of CWIP in investment base and the ability to recover sunk costs if the project was abandoned, the commission determined that the MPRP warranted a 125 basis point ROE adder, rather than the 150 basis point ROE adder that CMP requested.

AVANGRID subsidiary United Illuminating Co., or UI, serves approximately 325,000 customers in the Greater New Haven and Bridgeport areas of Connecticut.

Pursuant to an agreement with Eversource Inc. subsidiary CL&P, UI has the right to invest in and own transmission assets associated with the Connecticut portion of the New England East-West Solution, or NEEWS, projects. See the Eversource section below for more information on the NEEWS projects.

In 2007, FERC granted UI a 50 basis point incentive ROE adder for employing advanced technology for the $1.3 billion Middletown-Norwalk transmission project. See the Eversource section below for additional details.

Emera Inc.

Emera Inc. subsidiary Emera Maine is the consolidated operations of Bangor Hydro Electric and Maine Public Service, which officially became one utility in 2014. Emera Maine serves 154,000 customers, and its two service districts encompass almost 9,000 square miles and approximately 1,265 miles of transmission lines in eastern Maine. Emera's Bangor Hydro District is a member of ISO-NE, and its rates are regulated through ISO-NE's open access transmission tariff.

Emera's Maine Public District service territory, in far northern Maine, is not connected to the New England bulk power system and is not a member of ISO-NE.

Emera Maine

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.15	226,099	38,419	111,940	54.13	NA	NA
2018-2019	Annual	6/1/2018	11.07	8.25	228,831	39,469	110,430	56.03	NA	NA
2017-2018	Annual	6/1/2017	11.07	8.66	247,793	47,600	111,958	59.26	NA	NA
2016-2017	Annual	6/1/2016	11.07	8.96	248,108	50,753	103,296	64.25	NA	NA
2015-2016	Annual	6/1/2015	11.07	8.60	236,690	47,940	98,700	63.51	NA	NA
2014-2015	Annual	6/1/2014	11.64/ 11.07	9.89	241,376	51,267	89,796	67.51	NA	NA
2013-2014	Annual	6/1/2013	11.64	9.87	229,237	47,745	86,947	64.10	NA	NA
2012-2013	Annual	6/1/2012	11.64	10.30	178,451	47,773	75,255	68.43	NA	NA
2011-2012	Annual	6/1/2011	11.64	10.21	161,822	40,463	63,884	66.89	NA	NA

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
NA = not applicable or not available
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Eversource Energy

In 2015, Northeast Utilities, or NU, and its wholly owned utility subsidiaries CL&P, NSTAR Electric, Public Service Company of New Hampshire, or PSNH, and Western Massachusetts Electric Company, or WMECO, commenced doing business as Eversource Energy. CL&P serves customers in Connecticut; NSTAR serves customers in eastern Massachusetts; PSNH serves customers in New Hampshire; and WMECO serves customers in western Massachusetts.

Connecticut Light & Power Co.

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.27	2,777,860	536,291	111,940	55.47	1,221,162	11.74
2018-2019	Annual	6/1/2018	11.07	8.21	2,456,226	491,369	110,430	54.75	1,273,540	11.74
2017-2018	Annual	6/1/2017	11.07	8.39	2,274,460	497,306	111,958	56.46	1,654,815	11.74
2016-2017	Annual	6/1/2016	11.07	8.23	2,172,418	454,550	103,296	54.10	1,396,927	11.74
2015-2016	Annual	6/1/2015	11.07	8.62	2,003,982	456,421	98,700	54.22	1,311,433	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	8.67	1,915,735	426,297	89,796	53.20	117,933	12.89/ 11.74
									1,211,706	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.74	1,778,523	418,244	86,947	54.61	24,816	12.89
									1,257,642	12.64
2012-2013	Annual	6/1/2012	11.64	8.68	1,756,033	399,857	75,255	52.09	9,265	12.89
									1,308,113	12.64
2011-2012	Annual	6/1/2011	11.64	8.73	1,849,211	399,705	63,884	52.01	9,850	12.89
									1,393,254	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

NSTAR Electric Co.

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	7.80	1,384,529	251,621	111,940	55.25	194,681	11.74
2018-2019	Annual	6/1/2018	11.07	7.66	1,293,099	244,750	110,430	54.22	202,708	11.74
2017-2018	Annual	6/1/2017	11.07	8.09	1,228,858	256,744	111,958	56.41	212,527	11.74
2016-2017	Annual	6/1/2016	11.07	7.97	1,055,830	224,324	103,296	56.51	222,125	11.74
2015-2016	Annual	6/1/2015	11.07	8.47	981,869	234,176	98,700	58.26	232,134	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	8.47	952,774	240,491	89,796	57.78	245,138	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.70	731,334	200,907	86,947	58.48	251,504	12.64
2012-2013	Annual	6/1/2012	11.64	8.98	601,519	172,933	75,255	58.77	286,377	12.64
2011-2012	Annual	6/1/2011	11.64	8.91	605,881	162,054	63,884	57.68	298,831	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Public Service Company of New Hampshire

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.46	864,243	173,049	111,940	61.80	75,496	11.74
2018-2019	Annual	6/1/2018	11.07	8.19	715,270	149,981	110,430	57.40	77,711	11.74
2017-2018	Annual	6/1/2017	11.07	8.09	651,299	142,834	111,958	56.41	80,902	11.74
2016-2017	Annual	6/1/2016	11.07	7.88	554,245	119,371	103,296	53.60	84,212	11.74
2015-2016	Annual	6/1/2015	11.07	8.15	493,064	109,897	98,700	53.44	90,210	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	8.04	448,019	98,592	89,796	52.06	93,438	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.25	385,327	89,912	86,947	52.31	97,126	12.64
2012-2013	Annual	6/1/2012	11.64	8.29	360,700	82,838	75,255	52.15	101,001	12.64
2011-2012	Annual	6/1/2011	11.64	8.52	313,650	75,811	63,884	52.78	104,998	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Western Massachusetts Electric Company

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.06	736,171	138,897	111,940	56.00	376,922	11.74
2018-2019	Annual	6/1/2018	11.07	7.89	687,987	126,244	110,430	53.53	370,442	11.74
2017-2018	Annual	6/1/2017	11.07	7.96	615,517	127,312	111,958	54.22	371,442	11.74
2016-2017	Annual	6/1/2016	11.07	7.98	583,847	119,122	103,296	53.60	385,286	11.74
2015-2016	Annual	6/1/2015	11.07	8.01	553,658	110,445	98,700	50.45	399,554	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	7.96	564,089	104,257	89,796	50.47	391,487	12.89/ 11.74
									8,338	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.24	443,479	99,397	86,947	50.63	251,403	12.89
									8,541	12.64
2012-2013	Annual	6/1/2012	11.64	8.52	185,550	71,312	75,255	51.29	20,686	12.89
									9,109	12.64
2011-2012	Annual	6/1/2011	11.64	9.02	139,478	31,862	63,884	51.23	9,581	12.89
									9,584	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Eversource is a major participant in the NEEWS transmission projects developed by system planners from ISO-NE, CL&P, WMECO and National Grid. The projects were identified by ISO-NE in its regional planning process to address reliability issues in New England.

The main components of the NEEWS projects are 345-kV high-voltage lines. The projects also include upgrades to substations and improvements to the region's 115-kV electric system. The NEEWS projects are estimated to cost $2.1 billion and include the projects summarized below.

- The **Greater Springfield Reliability Project**, or GSRP, was the first and largest project within the NEEWS family of projects. At an approximate cost of $718 million, the GSRP was fully energized in 2013. The project was designed to improve transmission system reliability, ease transmission bottlenecks in the greater Springfield and north central Connecticut areas and meet more stringent federal and regional reliability standards.
- The **Interstate Reliability Project**, or IRP, is the second major NEEWS project. It includes CL&P's construction of an approximately 40-mile, 345-kV overhead line from Lebanon, Conn., to the Connecticut-Rhode Island border in Thompson, Conn., where it connects to transmission enhancements being constructed by National Grid in Rhode Island and Massachusetts. Eversource's portion of the project cost was $218 million. Construction was completed and the project placed in service in 2015.
- The **Greater Boston and New Hampshire Solution**, or Greater Boston, proposed by NU and National Grid, was selected in 2015 by ISO-NE to enhance the region's system reliability. Greater Boston consists of a portfolio of electric transmission upgrades encompassing the Merrimack Valley and metropolitan Boston areas of southern New Hampshire and eastern Massachusetts.

Transmission owners participating in NEEWS projects were authorized a 125 basis point incentive ROE adder by FERC in 2008. FERC found the transmission owners demonstrated the projects are non-routine and the significant risks and challenges faced by the projects warranted the granting of an ROE incentive.

In 2008, FERC authorized CL&P a 50 basis point incentive ROE adder for advanced technology for the $1.3 billion Middletown to Norwalk transmission project. CL&P's share of the project was estimated to be $1 billion. The project was a joint undertaking between UI and CL&P to build a new 345-kV transmission line from Middletown to Norwalk, Conn., and to rebuild and modify portions of the existing 115-kV transmission system.

National Grid US

New England Power Co., or NEP, holds the New England transmission assets of parent National Grid US, a subsidiary of the UK-based National Grid PLC. NEP provides services to National Grid utility affiliates Massachusetts Electric, Nantucket Electric and Narragansett Electric and maintains and operates a 9,000-mile transmission system serving parts of Massachusetts, New Hampshire, Rhode Island, Maine and Vermont.

National Grid is also a participant in the NEEWS projects. See the Eversource section for more details on NEEWS.

New England Power Co.

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.14	1,198,264	393,845	111,940	63.46	247,625	11.74
2018-2019	Annual	6/1/2018	11.07	7.20	1,186,573	391,929	110,430	62.58	253,206	11.74
2017-2018	Annual	6/1/2017	11.07	7.50	1,030,976	411,746	111,958	64.51	216,573	11.74
2016-2017	Annual	6/1/2016	11.07	7.35	1,013,188	378,391	103,296	64.46	211,609	11.74
2015-2016	Annual	6/1/2015	11.07	7.76	963,081	373,071	98,700	68.45	163,079	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	7.70	857,265	346,484	89,796	64.18	36,667	12.89/ 11.74
									126,412	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	7.87	729,866	307,127	86,947	64.25	33,641	12.89
									192,796	12.64
2012-2013	Annual	6/1/2012	11.64	7.93	696,437	273,521	75,255	64.55	31,094	12.89
									184,864	12.64
2011-2012	Annual	6/1/2011	11.64	7.91	643,133	197,600	63,884	64.07	9,003	12.89
									186,437	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

NextEra Energy Inc.

NextEra Energy subsidiary New Hampshire Transmission, or NHT, owns the Seabrook Substation, a 345-kV facility located in Seabrook, N.H. The Seabrook Substation connects the Seabrook Nuclear Generating Station to the New England transmission grid and interconnects three 345-kV transmission lines in New England. Operational control of the Seabrook Substation is under the authority of ISO-NE.

New Hampshire Transmission LLC

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.94	46,067	13,681	111,940	60.00	NA	NA
2018-2019	Annual	6/1/2018	11.07	8.94	43,487	12,623	110,430	59.60	NA	NA
2017-2018	Annual	6/1/2017	11.07	9.04	35,716	10,493	111,958	60.00	NA	NA
2016-2017	Annual	6/1/2016	11.07	9.03	40,007	12,806	103,296	59.60	NA	NA
2015-2016	Annual	6/1/2015	11.07	9.08	37,130	15,735	98,700	60.00	NA	NA
2014-2015	Annual	6/1/2014	11.64/ 11.07	9.38	37,934	19,079	89,796	59.96	NA	NA
2013-2014	Annual	6/1/2013	11.64	8.48	37,493	14,080	86,947	60.00	NA	NA
2012-2013	Annual	6/1/2012	11.64	8.58	36,799	10,179	75,255	59.98	NA	NA
2011-2012	Annual	6/1/2011	11.64	8.62	39,302	13,700	63,884	59.27	NA	NA

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Unitil Corp.

Unitil Corp.'s principal business is the distribution of electricity and natural gas to approximately 180,600 customers throughout its service territories in the states of New Hampshire, Massachusetts and Maine. Unitil is the parent company of three wholly-owned distribution utilities: Unitil Energy, which provides electric service in the southeastern

Fitchburg Gas and Electric Company

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.58	3,148	874	111,940	48.10	NA	NA
2018-2019	Annual	6/1/2018	11.07	8.01	2,795	790	110,430	47.15	NA	NA
2017-2018	Annual	6/1/2017	11.07	9.33	3,011	932	111,958	54.94	NA	NA
2016-2017	Annual	6/1/2016	11.07	9.35	2,676	905	103,296	53.28	NA	NA
2015-2016	Annual	6/1/2015	11.07	9.15	2,666	778	98,700	50.32	NA	NA
2014-2015	Annual	6/1/2014	11.64/ 11.07	9.26	2,583	544	89,796	48.81	NA	NA
2013-2014	Annual	6/1/2013	11.64	9.21	865	430	86,947	47.78	NA	NA
2012-2013	Annual	6/1/2012	11.64	8.96	741	843	75,255	43.67	NA	NA
2011-2012	Annual	6/1/2011	11.64	8.94	471	294	63,884	43.40	NA	NA

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

and state capital regions of New Hampshire, including the capital city of Concord; Fitchburg Gas and Electric Co., which provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and Northern Utilities, which provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland.

Vermont Electric Power and Vermont Transco LLC

Vermont Electric Power Co., or VELCO, was formed in 1956 when Vermont's local utilities joined to establish a statewide, transmission-only company in order to create and maintain an interconnected electric transmission grid capable of sharing access to hydro power. VELCO currently manages a system that includes 738 miles of transmission lines, 55 substations, equipment that enables interconnected operations with Hydro-Québec, and a 52-mile, 450-kV direct-current line through the northeast corner of Vermont owned by Vermont Electric Transmission Co.

Vermont Transco LLC

Rate year	Adjustment frequency	Adjustment date	ROE (%)*	ROR (%)	Investment base ($000)	Annual rev. req. ($000)	RNS rate ($/MW-Yr)	Equity (%)	Incentive investment base ($000)	Incentive ROE (%)*
2019-2010	Annual	6/1/2019	11.07	8.16	895,913	162,415	111,940	56.84	177,351	11.74
2018-2019	Annual	6/1/2018	11.07	8.44	818,484	155,246	110,430	59.29	179,121	11.74
2017-2018	Annual	6/1/2017	11.07	8.64	699,917	145,448	111,958	49.61	177,477	11.74
2016-2017	Annual	6/1/2016	11.07	8.19	681,108	141,675	103,296	54.61	185,043	11.74
2015-2016	Annual	6/1/2015	11.07	8.35	654,862	143,784	98,700	55.46	189,289	11.74
2014-2015	Annual	6/1/2014	11.64/ 11.07	8.50	644,134	150,483	89,796	52.97	196,539	12.64/ 11.74
2013-2014	Annual	6/1/2013	11.64	8.34	598,384	123,385	86,947	50.48	222,454	12.64
2012-2013	Annual	6/1/2012	11.64	8.69	543,575	127,176	75,255	53.45	228,499	12.64
2011-2012	Annual	6/1/2011	11.64	8.79	540,985	100,194	63,884	53.42	232,362	12.64

ROE = return on equity; ROR = return on rate base; RNS = Regional Network Service
* Inclusive of 50 basis point incentive adder for membership in ISO-NE.
Note: In October 2014 FERC reduced the authorized base ROE for ISO-NE transmission owners from 11.14% to 10.57% and capped the total allowable ROE at 11.74%, inclusive of all incentive adders.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

In 2006, VELCO and Vermont's electric distribution companies formed Vermont Transco LLC, a limited liability corporation. Vermont Transco owns Vermont's high-voltage, 115-kV-and-above electric transmission system and provides service under applicable tariffs to: Vermont's 17 electric distribution utilities; two small distribution utility loads in New Hampshire; and, loads throughout New England through ISO-NE. VELCO manages the Vermont Transco system and, in that capacity, operates and maintains Vermont's electric transmission system.

For a complete, searchable listing of RRA's in-depth research and analysis please go to the S&P Global Market Intelligence Energy Research Library.

Appendix: ISO-NE transmission investment base values ($000)

Ticker	Parent Co.	Filing entity	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	'16-'17 to '19 '20 CAGR (%)	'11-'12 to '19-'20 CAGR (%)
AGR	Avangrid Inc.	Central Maine Power Co.	177,457	533,684	418,034	651,428	855,355	1,136,321	1,143,917	1,104,754	1,126,724	-0.28	25.99
AGR	Avangrid Inc.	The United Illuminating Co.	386,705	377,520	409,285	449,635	458,700	480,546	535,456	539,112	619,711	8.85	6.07
EMA	Emera Inc.	Emera Maine	161,822	178,451	229,237	241,376	236,690	248,108	247,793	228,831	226,099	-3.05	4.27
ES	Eversource Energy	Connecticut Light & Power Co.	1,849,211	1,756,033	1,778,523	1,915,735	2,003,982	2,172,418	2,274,460	2,456,226	2,777,860	8.54	5.22
ES	Eversource Energy	NSTAR Electric Co.	605,881	601,519	731,334	952,774	981,869	1,055,830	1,228,858	1,293,099	1,384,529	9.46	10.88
ES	Eversource Energy	Public Service Co. of New Hampshire	313,650	360,700	385,327	448,019	493,064	554,245	651,299	715,270	864,243	15.96	13.51
ES	Eversource Energy	Western Massachusetts Electric Co.	139,478	185,550	443,479	564,089	553,658	583,847	615,517	687,987	736,171	8.03	23.11
NEE	NextEra Energy Inc.	New Hampshire Transmission LLC	39,302	36,799	37,493	37,934	37,130	40,007	35,716	43,487	46,067	4.81	2.01
UTL	Unitil Corp.	Fitchburg Gas and Electric Co.	471	741	865	2,583	2,666	2,676	3,011	2,795	3,148	5.56	26.80
na	National Grid USA	New England Power Co.	643,133	696,437	729,866	857,265	963,081	1,013,188	1,030,976	1,186,573	1,198,264	5.75	8.09
na	na	Vermont Transco LLC	540,985	543,575	598,384	644,134	654,862	681,108	699,917	818,484	895,913	9.57	6.51

Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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RRA Regulatory Focus
An Overview of Transmission Ratemaking in the Southwest Power Pool — 2019 Update

Overview

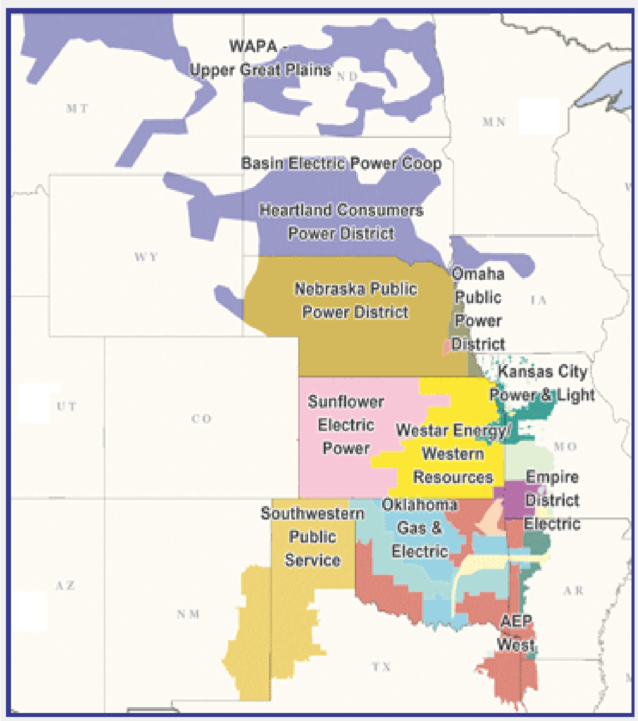
Transmission rate base growth in the Southwest Power Pool slowed for the second consecutive year in 2019, based on newly available transmission formula rate data from the Federal Energy Regulatory Commission. The aggregate transmission rate base in a survey of 14 companies in SPP grew to $10.59 billion in 2019 from $10.09 billion in 2018, an increase of only 4.97%. This compares to growth for those same companies of 7.51% from 2017 to 2018 and average growth of approximately 9.5% for each of the three years prior to 2017.

Of these 14 companies examined in SPP with formula rates for transmission, only eight reported positive growth in transmission rate base from 2018 to 2019, while the other six reported a decline. The highest year-over-year growths were reported by American Electric Power Co., or AEP, subsidiaries.

AEP Oklahoma Transmission, or AEPOKT, reported an increase in transmission rate base to $750.1 million in 2019 from $640.9 million in 2018, or 17.03%. AEP's Southwestern Electric Power Co., or SWEPCO, reported an increase in transmission rate base to $1.05 billion in 2019 from $928.9 million in 2018, or 13.41%.

Authorized base ROEs, a 50 basis point ROE adder for participation in a regional transmission organization, and any additional ROE incentives for SPP transmission owners have been authorized by FERC on a company-by-company basis. Just three of the 14 companies surveyed have received additional incentive ROE adders, ITC Great Plains, Prairie Wind Transmission LLC and Transource Missouri LLC. See the company sections in the following pages for additional information.

Southwest Power Pool



Source: FERC

The average authorized base ROE for the 14 SPP companies in this report with formula transmission rates was 10.57% in 2019, a decline from 10.85% in 2018, including the 50 basis point ROE incentive adder for membership in an RTO. The decline in average ROE is attributable to the reduction in authorized ROEs upon the resolution of complaint cases at FERC involving OGE Energy Corp. subsidiary Oklahoma Gas & Electric Co., or OG&E, and the four AEP operating companies in SPP.

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S&P Global
Market Intelligence

RRA Regulatory Focus: Topical Special Report

Background

Regulatory Research Associates, a group within S&P Global Market Intelligence, first published this survey of transmission rate bases for utilities with formula rates in SPP in 2015. The first report compiled five years of data for each of the companies — 2015 data and four years of historical data. RRA has published annual updates to that first report, for a total historical data set covering nine full years from 2011 through 2019. This report is an update of *An Overview of Transmission Ratemaking in the Southwest Power Pool — 2018 update*, a report published on Sept. 18, 2018.

For this report, RRA analyzed the transmission formula rate updates filed by a group of 14 companies in SPP for each company's latest rate year. The formula rate updates may not reflect subsequent revisions filed by individual companies to incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

The accompanying summary table lists the SPP companies in this report that employ formula-based transmission rates, their reported transmission rate base for 2018 and 2019, where available, their base ROE, and any additional ROE incentive adders where applicable. The appendix includes the same companies with rate base values for the years 2011 through 2019, where available.

Transmission summary for SPP utilities with formula rates

Ticker	Parent company(ies)	Filing entity	2018 transmission rate base ($000)	2019 transmission rate base ($000)	Rate base growth 2018-2019 (%)	Base ROE (%)*	Rate base eligible for incentive ($000)	Incentive ROE* (%)
AEP	American Electric Power Co.	Public Service Co. of Oklahoma	477,207	490,471	2.78	10.50	None	NA
AEP	American Electric Power Co.	Southwestern Electric Power Co.	928,917	1,053,463	13.41	10.50	None	NA
AEP	American Electric Power Co.	AEP Oklahoma Transmission	640,941	750,079	17.03	10.50	None	NA
AEP	American Electric Power Co.	AEP Southwestern Transmission	4	11	175.00	10.50	None	NA
AQN	Algonquin Power & Utilities	Empire District Electric Co.	237,101	238,839	0.73	10.00	None	NA
EVRG	Evergy Inc.	Kansas City Power & Light Co.	206,225	190,629	-7.56	11.10	None	NA
EVRG	Evergy Inc.	KCP&L Greater Missouri Operations	210,447	195,748	-6.98	11.10	None	NA
EVRG	Evergy Inc.	Westar Energy Inc.	1,622,268	1,609,867	-0.76	10.30	None	NA
FTS	Fortis Inc.	ITC Great Plains	461,924	448,314	-2.95	11.16	448,314	12.16
OGE	OGE Energy Corp.	Oklahoma Gas & Electric Co.	1,628,779	1,646,316	1.08	10.5**	None	NA
XEL	Xcel Energy Inc.	Public Service Co. of Colorado	1,313,799	1,445,653	10.04	9.72	None	NA
XEL	Xcel Energy Inc.	Southwestern Public Service Co.	1,952,973	2,144,278	9.80	10.50	None	NA
NA	Westar, AEP, Berkshire	Prairie Wind Transmission LLC	141,635	119,840	-15.39	11.30	119,840	12.80
NA	AEP, Great Plains Energy	Transource Missouri LLC	270,373	260,935	-3.49	10.30	NA	11.30
Totals			**10,092,593**	**10,594,443**	**4.97**	**-**	**-**	**-**

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity
* Includes 50 basis point adder for RTO participation.
** Pending settlement at FERC as of Oct. 15, 2019.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Formula transmission rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that updates rates annually based on updated cost of service data, generally drawn from the same data filed by a company in its annual FERC Form 1. Approximately 100 utilities nationwide employ FERC-approved formula rate frameworks for transmission. A "stated" transmission rate is also based on traditional cost of service data, but the rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward-looking projected costs, subject to a true-up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation in each utility's annual update includes transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base.

Given the complexities inherent in determining a company's transmission rate base from an outside perspective, the RRA reports, with very limited exceptions, include transmission rate base only for those companies that report such data in their annual updates under a formula-based rate framework. For additional information on the complex issues associated with determining a utility's rate base, see RRA's July 2, 2019, Topical Special Report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Individual company details

The sections that follow provide a closer look at transmission ratemaking and rate base for 14 companies with operations in SPP that employ formula-based rates. For each there is a brief description, followed by a table or tables that provide detail regarding authorized base ROE, rate of return, rate base, net annual revenue requirement, network integration service rate, equity ratio, any additional ROE incentives that apply to the company's rate base, and the portion of total rate base that is accorded incentive ROEs.

American Electric Power Inc.

AEP has four subsidiaries that are members of SPP: Public Service Company of Oklahoma, or PSO, SWEPCO, AEPOKT and AEP Southwestern Transmission, or AEPSWT. PSO serves approximately 542,000 retail customers in eastern and southwestern Oklahoma. SWEPCO serves approximately 528,000 retail customers in northeastern and the panhandle areas of Texas, northwestern Louisiana and western Arkansas.

AEPOKT and AEPSWT are transmission-only, or transco, subsidiaries of AEP and do not serve retail customers.

PSO and SWEPCO filed an application with FERC to transition from stated rates to formula-based rates for transmission in 2007 and requested that FERC approve a base ROE of 11.9%, inclusive of a 50 basis point ROE adder for participation in an RTO. The application was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.2%, inclusive of the 50 basis point ROE adder.

Public Service Company of Oklahoma

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	7/1/2019	10.5	7.78	490,471	87,779	9,706	49.00	None	NA
2018-2019	Annual	7/1/2018	11.2	7.78	477,207	97,991	11,085	47.24	None	NA
2017-2018	Annual	7/1/2017	11.2	7.69	471,016	90,526	10,260	48.36	None	NA
2016-2017	Annual	7/1/2016	11.2	7.73	442,224	84,778	9,499	46.31	None	NA
2015-2016	Annual	7/1/2015	11.2	8.15	429,462	86,135	9,429	49.50	None	NA
2014-2015	Annual	7/1/2014	11.2	8.17	431,508	83,264	NA	48.28	None	NA
2013-2014	Annual	7/1/2013	11.2	8.35	389,417	76,280	NA	48.83	None	NA
2012-2013	Annual	7/1/2012	11.2	8.32	355,103	70,223	NA	48.21	None	NA
2011-2012	Annual	7/1/2011	11.2	8.53	336,165	71,490	NA	46.28	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Southwestern Electric Power Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	7/1/2019	10.5	7.35	1,053,463	167,740	10,995	46.68	None	NA
2018-2019	Annual	7/1/2018	11.2	7.90	928,917	182,008	10,725	48.09	None	NA
2017-2018	Annual	7/1/2017	11.2	7.78	869,509	161,976	9,557	45.61	None	NA
2016-2017	Annual	7/1/2016	11.2	8.25	734,624	145,740	9,985	49.32	None	NA
2015-2016	Annual	7/1/2015	11.2	8.40	650,571	135,262	9,371	50.25	None	NA
2014-2015	Annual	7/1/2014	11.2	8.56	601,198	122,795	NA	51.03	None	NA
2013-2014	Annual	7/1/2013	11.2	8.54	628,926	119,435	NA	50.75	None	NA
2012-2013	Annual	7/1/2012	11.2	8.74	531,652	109,060	NA	51.97	None	NA
2011-2012	Annual	7/1/2011	11.2	8.56	494,143	102,313	NA	49.18	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Oklahoma Transmission Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	7/1/2019	10.5	NA	750,079	117,137	NA	NA	None	NA
2018-2019	Annual	7/1/2018	11.2	7.37	640,941	102,914	NA	50.69	None	NA
2017-2018	Annual	7/1/2017	11.2	7.66	680,649	96,376	8,379	50.05	None	NA
2016-2017	Annual	7/1/2016	11.2	7.57	433,460	63,676	6,114	51.02	None	NA
2015-2016	Annual	7/1/2015	11.2	NA	339,186	46,664	4,152	NA	None	NA
2014-2015	Annual	7/1/2014	11.2	NA	289,268	38,134	NA	NA	None	NA
2013-2014	Annual	7/1/2013	11.2	NA	223,948	28,072	NA	NA	None	NA
2012-2013	Annual	7/1/2012	11.2	NA	40,738	5,430	NA	NA	None	NA
2011-2012	Annual	7/1/2011	11.2	NA	16,345	2,317	NA	NA	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEP Southwestern Transmission Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	7/1/2019	10.5	7.70	11	66	8.28	48.95	None	NA
2018-2019	Annual	7/1/2018	11.2	7.90	4	73	NA	48.17	None	NA
2017-2018	Annual	7/1/2017	11.2	7.78	4	125	NA	45.61	None	NA
2016-2017	Annual	7/1/2016	11.2	8.25	6	131	NA	49.32	None	NA
2015-2016	Annual	7/1/2015	11.2	NA	2	144	NA	NA	None	NA
2014-2015	Annual	7/1/2014	11.2	NA	74	224	NA	NA	None	NA
2013-2014	Annual	7/1/2013	11.2	NA	3	189	NA	NA	None	NA
2012-2013	Annual	7/1/2012	11.2	NA	<1	114	NA	NA	None	NA
2011-2012	Annual	7/1/2011	11.2	NA	NA	139	NA	NA	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

AEPOKT and AEPSWT filed an application with FERC in 2009 to establish formula-based rates for transmission and requested that FERC approve a base ROE of 11.9%, inclusive of the 50 basis point adder for RTO participation. FERC approved a settlement in the AEPOKT/AEPSWT case in 2011 that also incorporated an ROE of 11.2%, inclusive of the 50 basis point RTO adder, for both companies.

In 2017, East Texas Electric Cooperative filed a complaint at FERC against AEP's four operating and transmission companies in SPP, asserting that the AEP companies' authorized base ROE of 10.7%, exclusive of the 50 basis point RTO adder, adopted in 2009 and 2011 is excessive and should be reduced to 8.36%.

On March 21, 2019, the parties filed a settlement of all issues in the East Texas complaint case. The settlement provides that the AEP companies in SPP will reduce the base ROE in their formula rates for transmission to 10% from 10.7%, plus an additional 50 basis point ROE adder for membership in SPP. On June 28, FERC approved the settlement as filed.

Empire District Electric Co.

Empire District Electric Co., or EDE, is a vertically integrated electric and gas utility. The territory served by EDE's electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri and including smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas.

In 2016, Algonquin Power & Utilities and EDE announced that they had entered into an agreement whereby Algonquin was to acquire EDE for $2.4 billion, or C$3.4 billion, including $900 million of assumed debt. FERC approved the proposed transaction in 2016, and after state commissions in Arkansas, Kansas, Missouri and Oklahoma subsequently approved the proposed transaction, it was completed in 2017.

EDE received FERC approval in 2012 to transition from a fixed transmission rate to a formula rate. FERC simultaneously authorized EDE a base ROE of 10%, inclusive of the 50 basis point RTO adder.

Empire District Electric Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019-2020	Annual	7/1/2019	10.0	7.49	238,839	32,932	29,727	49.15	None	NA
2018-2019	Annual	7/1/2018	10.0	7.54	237,101	50,155	50,550	48.92	None	NA
2017-2018	Annual	7/1/2017	10.0	7.58	211,527	40,924	39,280	48.32	None	NA
2016-2017	Annual	7/1/2016	10.0	7.55	197,531	36,613	35,117	48.16	None	NA
2015-2016	Annual	7/1/2015	10.0	7.60	171,333	34,388	30,131	49.26	None	NA
2014-2015	Annual	7/1/2014	10.0	7.83	151,930	31,828	27,965	50.04	None	NA
2013-2014	Annual	7/1/2013	10.0	7.92	146,133	29,426	25,315	49.92	None	NA
2012-2013	Annual	7/1/2012	10.5	8.57	134,333	28,095	23,256	49.49	None	NA
2011-2012	Annual	7/1/2011	NA	NA	NA	NA	NA	NA	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Evergy Inc.

Evergy subsidiaries Kansas City Power & Light Co., or KCP&L, and Kansas City Power & Light Greater Missouri Operations, or KCP&L GMO, provide electric utility service to customers in Missouri and Kansas. The two utilities combined serve approximately 838,400 customers.

KCP&L and KCP&L GMO filed an application with FERC to transition from stated transmission rates to formula-based rates in 2009 and requested that FERC approve a base ROE of 12.3%, inclusive of a 50 basis point ROE adder for participation in an RTO. The KCP&L/KCP&L GMO application was ultimately resolved through a settlement approved by FERC in 2010 that incorporated an ROE of 11.1% for both companies, inclusive of the 50 basis point RTO adder.

Kansas City Power & Light Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	11.1	8.18	190,629	38,047	NA	50.59	None	NA
2018	Annual	1/1/2018	11.1	7.63	206,225	46,238	NA	51.97	None	NA
2017	Annual	1/1/2017	11.1	8.26	198,795	38,175	14,412	50.29	None	NA
2016	Annual	1/1/2016	11.1	8.36	177,179	33,151	12,234	50.44	None	NA
2015	Annual	1/1/2015	11.1	8.55	169,896	35,263	NA	50.80	None	NA
2014	Annual	1/1/2014	11.1	9.07	154,548	29,237	NA	49.64	None	NA
2013	Annual	1/1/2013	11.1	9.32	144,106	30,145	NA	47.16	None	NA
2012	Annual	1/1/2012	11.1	9.47	140,888	30,441	NA	47.76	None	NA
2011	Annual	1/1/2011	11.1	9.49	140,647	29,348	NA	48.23	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

KCP&L Greater Missouri Operations

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	11.1	8.18	195,748	38,825	NA	50.59	None	NA
2018	Annual	1/1/2018	11.1	7.63	210,447	39,542	NA	51.97	None	NA
2017	Annual	1/1/2017	11.1	8.26	210,004	39,246	NA	50.29	None	NA
2016	Annual	1/1/2016	11.1	8.36	198,084	33,086	NA	50.44	None	NA
2015	Annual	1/1/2015	11.1	8.55	206,040	30,884	NA	50.80	None	NA
2014	Annual	1/1/2014	11.1	9.07	204,224	36,472	NA	49.64	None	NA
2013	Annual	1/1/2013	11.1	9.32	182,824	38,505	NA	47.16	None	NA
2012	Annual	1/1/2012	11.1	9.47	174,431	36,406	NA	47.76	None	NA
2011	Annual	1/1/2011	11.1	9.49	155,623	29,026	NA	48.23	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Westar Energy Inc.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.3	7.47	1,609,867	255,278	63,841	51.19	None	NA
2018	Annual	1/1/2018	10.3	7.54	1,622,268	289,696	70,764	51.73	None	NA
2017	Annual	1/1/2017	10.3	7.91	1,391,387	264,137	66,155	53.32	None	NA
2016	Annual	1/1/2016	10.3	7.98	1,330,311	234,569	56,230	50.52	None	NA
2015	Annual	1/1/2015	11.3	8.32	1,187,333	237,922	56,840	48.71	None	NA
2014	Annual	1/1/2014	11.3	8.63	1,126,684	242,538	60,408	50.63	None	NA
2013	Annual	1/1/2013	11.3	8.92	996,620	198,249	48,369	52.80	None	NA
2012	Annual	1/1/2012	11.3	8.73	900,564	186,059	44,309	49.11	None	NA
2011	Annual	1/1/2011	11.3	8.56	812,270	132,057	34,856	47.62	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Evergy's Westar Energy subsidiary is a vertically integrated electric utility and the largest electric company in Kansas, serving 690,000 residential, commercial and industrial customers in the eastern third of the state. Kansas Gas and Electric Company, or KG&E, Westar Energy's wholly owned subsidiary, provides service in south-central and southeastern Kansas, including the city of Wichita. Both Westar and KG&E conduct business using the name Westar Energy.

FERC authorized a base ROE of 11.3% for Westar in 2008, inclusive of the 50 basis point RTO adder. In 2014, the Kansas Corporation Commission, or KCC, filed a complaint with FERC alleging that the 11.3% ROE was unjust, unreasonable and unduly discriminatory and that a just and reasonable ROE for Westar's transmission formula rate would be 9.37%. In 2015, Westar filed a settlement in the complaint proceeding proposing to reduce its authorized ROE from 11.3% to 10.3%, inclusive of the 50 basis point RTO adder, and FERC approved the settlement in 2016.

Westar owns a 50% interest in Prairie Wind Transmission, which is a joint venture between it and Electric Transmission America, which itself is a joint venture between affiliates of AEP and Berkshire Hathaway Energy. In 2014, Prairie Wind completed construction of a 108-mile, 345-kV double-circuit transmission line that is now being used to provide transmission service in SPP. The final cost of the line was $161.5 million. See the Prairie Wind Transmission section below for more information.

Fortis Inc.

Fortis Inc. subsidiary ITC Great Plains is a member of SPP. In 2016, FERC approved the acquisition of ITC Holdings, the parent company of ITC Great Plains, by Fortis and the transaction was completed in October 2016.

In 2009, FERC approved ITC Great Plains' request for transmission rate incentives for its proposed Kansas V-Plan transmission project. Specifically, FERC approved an incentive ROE of 12.16% for the planned high-voltage transmission project as well as for two existing substations the company planned to purchase.

The overall ROE approved by FERC represents a base ROE of 10.66%, plus a 50 basis point incentive adder for participation in SPP and a 100 basis point incentive adder based on the company's status as an independent transmission company. The 122-mile, $300 million Kansas V-Plan was designed to connect eastern and western Kansas to Nebraska and Oklahoma, and the project was completed in 2014.

On June 11, 2019, the KCC filed a formal complaint against ITC Great Plains' 100 basis point incentive adder to its authorized base ROE.

ITC Great Plains LLC

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	11.16	8.96	448,314	76,284	NA	60.0	448,314	12.16
2018	Annual	1/1/2018	11.16	8.89	461,924	88,298	NA	60.0	461,924	12.16
2017	Annual	1/1/2017	11.16	8.76	481,235	88,258	NA	60.0	481,235	12.16
2016	Annual	1/1/2016	11.16	8.69	482,290	83,123	NA	60.0	482,290	12.16
2015	Annual	1/1/2015	11.16	9.20	465,119	80,421	NA	60.0	465,119	12.16
2014	Annual	1/1/2014	11.16	7.97	416,019	65,034	NA	60.0	416,019	12.16
2013	Annual	1/1/2013	11.16	8.72	298,176	46,199	NA	60.0	298,176	12.16
2012	Annual	1/1/2012	11.16	8.87	202,100	31,196	NA	60.0	202,100	12.16
2011	Annual	1/1/2011	11.16	9.53	74,237	10,681	NA	60.0	74,237	12.16

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

The KCC argued in its complaint that to be consistent with FERC's Oct. 18, 2018, order in a case involving three other subsidiaries of ITC Holdings in the Midcontinent Independent System Operator, the commission should "either eliminate ITC Great Plains' transco adder entirely or reduce it from 100 basis points to no more than 25 basis points."

In its October 2018 order, in response to a complaint filed by Consumers Energy and others, FERC agreed to reduce the ROE incentive adders to 25 basis points for the three MISO subsidiaries of ITC Holdings: International Transmission Company, ITC Midwest and Michigan Electric Transmission Company.

OGE Energy Corp.

OGE Energy Corp. subsidiary Oklahoma Gas & Electric Co., or OG&E, serves 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City and Fort Smith, Ark., the second largest city in that state.

OG&E filed an application with FERC to switch from a stated transmission rate to a formula-based rate in 2008 and requested that FERC approve a base ROE of 12.7%, inclusive of a 50 basis point ROE adder for participation in an RTO. The OG&E case was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.1%, inclusive of the 50 basis point RTO adder.

In 2016, OG&E announced it was moving up the construction timeline of a $190 million transmission line to help connect wind farms in northwestern Oklahoma. The utility said it would begin building the 126-mile Windspeed II line from Woodward to its Cimarron substation northwest of Oklahoma City in 2017 and expects to complete the line in 2018.

Oklahoma Gas & Electric Co.

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.5**	8.04	1,646,316	230,947	NA	53.47	None	NA
2018	Annual	1/1/2018	11.1	8.62	1,628,779	297,787	23,334	55.52	None	NA
2017	Annual	1/1/2017	11.1	8.50	1,481,276	263,096	19,385	53.53	None	NA
2016	Annual	1/1/2016	11.1	8.61	1,475,275	252,102	17,509	54.10	None	NA
2015	Annual	1/1/2015	11.1	8.79	1,492,662	247,998	15,544	55.53	None	NA
2014	Annual	1/1/2014	11.1	8.88	1,445,542	242,387	14,056	55.92	None	NA
2013	Annual	1/1/2013	11.1	8.82	1,223,612	209,874	15,700	54.41	None	NA
2012	Annual	1/1/2012	11.1	8.93	990,206	170,742	16,352	55.45	None	NA
2011	Annual	1/1/2011	11.1	9.00	608,626	111,626	17,591	55.28	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
** Pending settlement at FERC as of Oct. 15, 2019.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

In January 2018, the Oklahoma Municipal Power Authority, or OMPA, filed a complaint at FERC against OG&E, arguing that the 10.6% base ROE established in 2009 in the utility's initial formula transmission rate proceeding, exclusive of a 50 basis point RTO adder, is no longer just and reasonable.

On May 21, 2019, the parties filed a settlement in the OMPA complaint case that incorporates a 10.5% ROE, inclusive of a 50 basis point RTO adder. The settlement is pending FERC action.

Xcel Energy Inc.

Xcel Energy Inc. subsidiaries Public Service Company of Colorado, or PSCO, and Southwestern Public Service Company, or SPS, are members of SPP. PSCO provides electric utility service to approximately 1.4 million customers in Colorado. SPS serves about 267,000 customers in Texas and more than 118,000 customers in New Mexico in a territory that includes the cities of Roswell, NM, and Amarillo and Lubbock, Texas.

PSCO filed an application with FERC to switch from a stated transmission rate to a formula-based rate in 2012 and requested that FERC approve a base ROE of 10.25%, inclusive of a 50 basis point ROE adder for participation in an RTO. The PSCO case was ultimately resolved through a settlement approved by FERC in 2014 that incorporated an ROE of 9.72%, inclusive of the 50 basis point RTO adder.

SPS filed an application with FERC to switch to formula-based rates for transmission in 2008 and requested that FERC approve a base ROE of 12.7%, inclusive of a 50 basis point ROE adder for participation in an RTO. The SPS case was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.27%, inclusive of the 50 basis point RTO adder.

Public Service Company of Colorado

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	9.72	7.34	1,445,653	248,374	41,975	56.28	None	NA
2018	Annual	1/1/2018	9.72	7.35	1,313,799	254,445	43,299	55.44	None	NA
2017	Annual	1/1/2017	9.72	7.43	1,281,665	249,559	42,053	56.38	None	NA
2016	Annual	1/1/2016	9.72	7.46	1,231,153	245,920	40,338	56.46	None	NA
2015	Annual	1/1/2015	9.72	7.50	1,158,038	230,012	38,168	56.34	None	NA
2014	Annual	1/1/2014	9.72	7.50	1,120,089	225,358	36,960	56.36	None	NA
2013	Annual	1/1/2013	10.25	7.87	1,038,986	215,056	35,564	56.97	None	NA
2012	Annual	1/1/2012	10.25	8.22	909,572	182,492	30,344	56.30	None	NA
2011	Annual	1/1/2011	10.50	NA	NA	NA	NA	NA	None	NA

Data compiled Oct. 15, 2019.
NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Southwestern Public Service Company

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.50	7.73	2,144,278	316,794	25,470	54.47	None	NA
2018	Annual	1/1/2018	10.50	7.71	1,952,973	311,420	26,996	54.41	None	NA
2017	Annual	1/1/2017	10.50	8.18	1,701,994	282,070	25,779	53.78	None	NA
2016	Annual	1/1/2016	10.50	8.22	1,649,620	266,501	27,055	53.62	None	NA
2015	Annual	1/1/2015	11.27	8.78	1,375,467	237,688	26,629	53.52	None	NA
2014	Annual	1/1/2014	11.27	9.02	1,035,469	194,447	23,968	53.89	None	NA
2013	Annual	1/1/2013	11.27	8.93	786,909	154,249	21,684	52.56	None	NA
2012	Annual	1/1/2012	11.27	8.98	660,586	130,735	NA	50.90	None	NA
2011	Annual	1/1/2011	11.27	9.14	591,360	112,194	22,876	51.16	None	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

In 2015, FERC approved a settlement resolving a series of complaints filed against SPS's 11.27% ROE. Five cooperative utilities and a group representing four West Texas municipalities asserted that a new analysis indicated that the base ROE for SPS should be lowered to 9.11%. The approved settlement reduced SPS's transmission ROE from 11.27% to 10.5%, inclusive of the 50 basis point RTO adder.

Prairie Wind Transmission LLC

Prairie Wind Transmission LLC is a joint venture formed by Westar and Electric Transmission America, or ETA. ETA is in turn a joint venture of subsidiaries of AEP and Berkshire Hathaway Energy that was formed to build and own new electric transmission assets in Kansas.

In 2014, Prairie Wind completed a 108-mile, 345-kV double-circuit transmission line linking an existing 345-kV substation near Wichita, Kan., to a new 345-kV substation northeast of Medicine Lodge, Kan., near the Flat Ridge I Wind Farm, and then south to the Kansas/Oklahoma border. Westar provided project management services to Prairie Wind, which included coordination of the engineering and construction of the new transmission lines and facilities. The total estimated investment for the 345-kV line was $170 million.

Prairie Wind Transmission LLC

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	11.3	7.9	119,840	14,843	NA	45.66	119,840	12.8
2018	Annual	1/1/2018	11.3	8.0	141,635	20,928	NA	47.21	141,635	12.8
2017	Annual	1/1/2017	11.3	7.8	134,513	18,216	NA	44.80	134,513	12.8
2016	Annual	1/1/2016	11.3	8.3	144,101	21,052	NA	50.49	144,101	12.8
2015	Annual	1/1/2015	11.3	9.0	135,129	15,536	NA	48.29	135,129	12.8
2014	Annual	1/1/2014	11.3	7.9	158,632	15,952	NA	50.00	158,632	12.8
2013	Annual	1/1/2013	11.3	9.0	100,816	14,491	NA	50.00	100,816	12.8
2012	Annual	1/1/2012	11.3	11.2	21,993	4,964	NA	50.00	21,993	12.8
2011	Annual	1/1/2011	11.3	11.2	5,532	1,924	NA	50.00	5,532	12.8

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

FERC approved Prairie Wind's request for incentive rate treatment for the project in 2008, including a 150 basis point ROE adder given the size, scope, benefits and risks of the project. FERC also granted Prairie Wind a 50 basis point ROE incentive for participation in SPP, resulting in a total ROE of 12.8%.

Transource Energy LLC

Transource Energy LLC is a partnership between AEP and Great Plains Energy focused on the development of competitive electric transmission projects. AEP owns 86.5% of Transource, and Great Plains owns 13.5%. Transource Missouri LLC, a subsidiary of Transource Energy, began filing annual formula rate updates in 2014.

In 2011, the Missouri Public Service Commission authorized Transource subsidiary Transource Missouri to construct two new 345-kV transmission lines in the northwest part of the state. The Iatan-Nashua line will run 30 miles in Platte County, Missouri, in an arc around Kansas City International Airport. The Sibley-Nebraska City line runs 175 miles from a substation owned by Omaha Public Power District. The Sibley-Nebraska City line was completed in December 2016.

Transource Missouri received FERC approval for incentive rate treatment for the Sibley-Nebraska City line in October 2012. In approving the incentives for the Sibley-Nebraska City line, FERC stated that it would grant a 100 basis point ROE adder for the risks and challenges of the project, including the construction challenges associated with two crossings of the Missouri River and obtaining rights-of-way in two states. In addition, FERC noted the length and cost of the project and the increased power transfer capability it would provide between Kansas and Nebraska, as well as between the SPP and the MISO regions.

Transource Missouri LLC

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2019	Annual	1/1/2019	10.30	7.40	260,935	36,145	NA	55.0	NA	11.30
2018	Annual	1/1/2018	10.30	7.03	270,373	38,804	NA	54.8	NA	11.30
2017	Annual	1/1/2017	10.30	7.51	274,489	33,200	NA	55.0	NA	11.30
2016	Annual	1/1/2016	10.30	7.45	80,168	32,150	NA	55.0	NA	11.30
2015	Annual	1/1/2015	10.30	7.60	42,078	23,504	NA	60.0	NA	11.30
2014	Annual	1/1/2014	10.30	7.70	2,744	10,647	NA	60.0	NA	NA
2013	Annual	1/1/2013	NA	NA	NA	NA	NA	NA	NA	NA
2012	Annual	1/1/2012	NA	NA	NA	NA	NA	NA	NA	NA
2011	Annual	1/1/2011	NA	NA	NA	NA	NA	NA	NA	NA

Data compiled Oct. 15, 2019.
NA = not applicable or not available; ROE = return on equity; ROR = rate of return; NISR = network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

Appendix: Transmission rate base values for SPP utilities with formula rates ($000)

Ticker	Parent company	Filing entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR 2016-19 (%)	CAGR 2011-19 (%)
AEP	American Electric Power Co.	Public Service Co. of Oklahoma	336,165	355,103	389,417	431,508	429,462	442,224	471,016	477,207	490,471	3.51	4.84
AEP	American Electric Power Co.	Southwestern Electric Power Co.	494,143	531,652	628,926	601,198	650,571	734,624	869,509	928,917	1,053,463	12.77	9.92
AEP	American Electric Power Co.	AEP Oklahoma Transmission	16,345	40,738	223,948	289,268	339,186	433,460	680,649	640,941	750,079	20.06	61.33
AEP	American Electric Power Co.	AEP Southwestern Transmission	NA	<1	3	74	2	6	4	4	11	22.39	NA
AQN	Algonquin Power & Utilities	Empire District Electric Co.	NA	134,333	146,133	151,930	171,333	197,531	211,527	237,101	238,839	6.53	NA
EVRG	Evergy Inc.	Kansas City Power & Light Co.	140,647	140,888	144,106	154,548	169,896	177,179	198,795	206,225	190,629	2.47	3.87
EVRG	Evergy Inc.	KCP&L Greater Missouri Operations	155,623	174,431	182,824	204,224	206,040	198,084	210,004	210,447	195,748	-0.39	2.91
EVRG	Evergy Inc.	Westar Energy	812,270	900,564	996,620	1,126,684	1,187,333	1,330,311	1,391,387	1,622,268	1,609,867	6.56	8.93
FTS	Fortis Inc.	ITC Great Plains	74,237	202,100	298,176	416,019	465,119	482,290	481,235	461,924	448,314	-2.41	25.20
OGE	OGE Energy Corp.	Oklahoma Gas & Electric Co.	608,626	990,206	1,223,612	1,445,542	1,492,662	1,475,275	1,481,276	1,628,779	1,646,316	3.72	13.25
XEL	Xcel Energy Inc.	Public Service Co. of Colorado	NA	909,572	1,038,986	1,120,089	1,158,038	1,231,153	1,281,665	1,313,799	1,445,653	5.50	NA
XEL	Xcel Energy Inc.	Southwestern Public Service Co.	591,360	660,586	786,909	1,035,469	1,375,467	1,649,620	1,701,994	1,952,973	2,144,278	9.14	17.47
na	AEP, Berkshire, Westar	Prairie Wind Transmission LLC	5,532	21,993	100,816	158,632	135,129	144,101	134,513	141,635	119,840	-5.96	46.88
na	AEP, Great Plains Energy	Transource Missouri LLC	NA	NA	NA	2,744	42,078	80,168	274,489	270,373	260,935	48.20	NA
Totals			**3,234,948**	**5,062,166**	**6,160,476**	**7,137,929**	**7,822,316**	**8,576,026**	**9,388,063**	**10,092,593**	**10,594,443**	**7.30**	**NA**

Data compiled Oct. 15, 2019.
NA = Not applicable or not available; CAGR = Compound annual growth rate
Sources: FERC; Regulatory Research Associates, a group within S&P Global Market Intelligence

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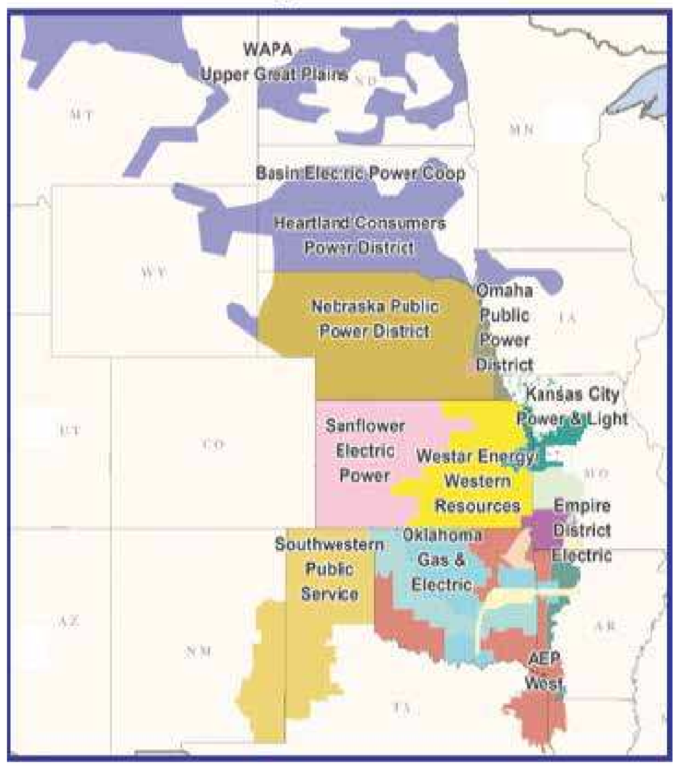
RRA Regulatory Focus
Topical Special Report

An Overview of Transmission Ratemaking in the Southwest Power Pool - 2018 Update

Overview and summary

Transmission rate base in the Southwest Power Pool, or SPP, demonstrated slowing and very mixed growth from 2017 to 2018 based on newly available data from the Federal Energy Regulatory Commission. The aggregate transmission rate base in a survey of 14 companies in SPP grew to $10.09 billion in 2018 from $9.39 billion in 2017, an increase of 7.5%. This compares to remarkably consistent and higher aggregate rate base growth for those same 14 companies of 9.47% from 2016 to 2017, 9.63% from 2015 to 2016 and 9.59% from 2014 to 2015.

Southwest Power Pool footprint



Source: FERC

Of the 14 companies examined in SPP with formula rates, transmission rate base growth from 2017 to 2018 ranged from a low of -5.83% for AEP Oklahoma Transmission Co., or AEPOKT, to a high of 16.59% for Evergy Inc. subsidiary Westar Energy. Seven of the 14 companies reported year on year growth of less than 5%, and only three companies reported year on year growth exceeding 10%.

For the 10 companies in our SPP survey with data available for every year from 2011 through 2018, the aggregate compound annual growth rate, or CAGR, was 17.65%. Complete data for four companies was not available for the entire 2011 to 2018 period, including AEP Southwestern Transmission, or AEPSWT, Algonquin Power & Utilities subsidiary Empire District Electric, Xcel Energy subsidiary Public Service Company of Colorado, and Transource Missouri, a joint venture between American Electric Power Co. and Great Plains Energy. On June 4, 2018, Great Plains Energy and Westar Energy completed a merger to form Evergy Inc.

The average authorized base ROE for the SPP companies in this report in 2018 with formula rates for transmission was 10.85%, unchanged from 2017, including the 50 basis point ROE incentive adder for membership in a Regional Transmission Organization, or RTO.

FERC has authorized additional ROE incentive adders on a company by company or project specific basis. In SPP, three transmission-only companies have received incentive ROE adders, ITC Great Plains, Prairie Wind Transmission and Transource Missouri. See company sections below for additional information.

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RRA Regulatory Focus: Topical Special Report

This report is an update of *An Overview of Transmission Ratemaking in the Southwest Power Pool – 2017 Update*, a report published on Sept. 13, 2017 by Regulatory Research Associates, an offering of S&P Global Market Intelligence.

Table 1 lists the SPP companies in this report which employ formula based transmission rates, their reported transmission rate base for 2017 and 2018, where available, their base ROE, and any additional ROE incentive adders where applicable. **Table 2** on page 3 lists the companies with transmission rate base values for the years 2011 through 2018, where available.

Table 1: Transmission summary for SPP utilities with formula rates

Ticker	Parent company(ies)	Filing entity	2017 transmission rate base ($000)	2018 transmission rate base ($000)	Rate base growth 2017-2018 (%)	Base ROE (%)*	Rate base eligible for incentive ($000)	Incentive ROE* (%)
AEP	American Electric Power	Public Service Co. of Oklahoma	471,016	477,207	1.31	11.20	None	NA
AEP	American Electric Power	Southwestern Electric Power	869,509	928,917	6.83	11.20	None	NA
AEP	American Electric Power	AEP Oklahoma Transmission	680,649	640,941	(5.83)	11.20	None	NA
AEP	American Electric Power	AEP Southwestern Transmission	4	4	-	11.20	None	NA
AQN	Algonquin Power & Utilities	Empire District Electric	211,527	237,101	12.09	10.00	None	NA
EVRG	Evergy Inc.	Kansas City Power & Light	198,795	206,225	3.74	11.10	None	NA
EVRG	Evergy Inc.	KCP&L Greater Missouri Operations	210,004	210,447	0.21	11.10	None	NA
EVRG	Evergy Inc.	Westar Energy	1,391,387	1,622,268	16.59	10.30	None	NA
FTS	Fortis Inc.	ITC Great Plains	481,235	461,924	(0.40)	11.16	NA	12.16
OGE	OGE Energy	Oklahoma Gas & Electric	1,481,276	1,628,779	9.96	11.10	None	NA
XEL	Xcel Energy	Public Service Co. of Colorado	1,281,665	1,313,799	2.51	9.72	None	NA
XEL	Xcel Energy	Southwestern Public Service	1,701,994	1,952,973	14.75	10.50	None	NA
na	Westar, AEP, Berkshire	Prairie Wind Transmission	134,513	141,635	5.29	11.30	141,635	12.80
na	AEP, Great Plains	Transource Missouri	274,489	270,373	(1.50)	10.30	NA	11.30
Totals			**9,388,063**	**10,092,593**	**7.50**			

NA = Not applicable or not available; ROE = Return on equity
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

SPP background

In 1968, SPP joined 12 other entities to form what became the North American Electric Reliability Corporation, or NERC. In 1998, SPP began administering regional transmission service, and FERC approved SPP as an RTO in 2004. In 2007, FERC approved SPP as a Regional Entity, or RE. As an RE, SPP is responsible for enforcing the mandatory electric reliability standards of NERC that FERC approves.

In 2014, SPP began operating day-ahead and real-time energy markets and an operating reserve market. In 2015, SPP expanded by incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District. The expansion doubled SPP's footprint, and SPP now administers transmission service in all or parts of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

Formula transmission rates

FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that updates rates and other parameters annually based on updated cost of service data. Approximately 100 companies nationwide employ formula rates for transmission. A "stated" transmission rate is also based on traditional cost of service data, but a stated rate can only be updated through a formal rate case process.

Formula transmission rates can be based on actual historical costs or forward looking projected costs, subject to a true up the following year. FERC requires that utilities employing formula rates share annual updates to their transmission rates, including appropriate supporting documentation, with all interested parties and file such annual updates with the commission on an informational basis.

The supporting documentation in each utility's annual update includes, among other things, transmission plant in service, accumulated depreciation, O&M expenses, return and capitalization calculations, composite income taxes, gross and net revenue requirements, and transmission rates, as well as the filing company's determination of its transmission rate base. The annual updates also include detailed information on any ROE incentive adders that FERC has authorized for any portion of a company's transmission rate base.

For this report, RRA analyzed transmission formula rate updates filed by 14 companies in SPP for rate years beginning on Jan. 1, 2018 or July 1, 2018. The formula rate updates may not reflect subsequent revisions filed by individual companies to incorporate the impact of federal tax reform, which, among other things, reduced the corporate federal income tax rate to 21% from 35% effective Jan. 1, 2018.

Table 2: Transmission rate base values for SPP utilities with formula rates ($000)

Ticker	Parent company	Filing entity	2011	2012	2013	2014	2015	2016	2017	2018	CAGR 2011-'18 (%)
AEP	American Electric Power	Public Service Co. of Oklahoma	336,165	355,103	389,417	431,508	429,462	442,224	471,016	477,207	5.13
AEP	American Electric Power	Southwestern Electric Power	494,143	531,652	628,926	601,198	650,571	734,624	869,509	928,917	9.44
AEP	American Electric Power	AEP Oklahoma Transmission	16,345	40,738	223,948	289,268	339,186	433,460	680,649	640,941	68.90
AEP	American Electric Power	AEP Southwestern Transmission	NA	<1	3	74	2	6	4	4	NA
AQN	Algonquin Power & Utilities	Empire District Electric	NA	134,333	146,133	151,930	171,333	197,531	211,527	237,101	NA
EVRG	Evergy Inc.	Kansas City Power & Light	140,647	140,888	144,106	154,548	169,896	177,179	198,795	206,225	5.62
EVRG	Evergy Inc.	KCP&L Greater Missouri Operations	155,623	174,431	182,824	204,224	206,040	198,084	210,004	210,447	4.41
EVRG	Evergy Inc.	Westar Energy	812,270	900,564	996,620	1,126,684	1,187,333	1,330,311	1,391,387	1,622,268	10.39
FTS	Fortis Inc.	ITC Great Plains	74,237	202,100	298,176	416,019	465,119	482,290	481,235	461,924	29.84
OGE	OGE Energy	Oklahoma Gas & Electric	608,626	990,206	1,223,612	1,445,542	1,492,662	1,475,275	1,481,276	1,628,779	15.10
XEL	Xcel Energy	Public Service Co. of Colorado	NA	909,572	1,038,986	1,120,089	1,158,038	1,231,153	1,281,665	1,313,799	NA
XEL	Xcel Energy	Southwestern Public Service	591,360	660,586	786,909	1,035,469	1,375,467	1,649,620	1,701,994	1,952,973	18.61
na	AEP, Berkshire, Westar	Prairie Wind Transmission	5,532	21,993	100,816	158,632	135,129	144,101	134,513	141,635	58.92
na	AEP, Great Plains	Transource Missouri	NA	NA	NA	2,744	42,078	80,168	274,489	270,373	NA
Totals			**3,234,948**	**5,062,166**	**6,160,476**	**7,137,929**	**7,822,316**	**8,576,026**	**9,388,063**	**10,092,593**	**17.65**

NA = Not applicable or not available; CAGR = Compound annual growth rate
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

Transmission incentives/ROE policy

In 2012, FERC issued a Policy Statement providing guidance and clarity with respect to certain aspects of its transmission incentives policies originally adopted in 2006 in Order 679. Order 679 provided for the following incentive-based rate treatments for specific transmission projects: (1) incentive ROEs for new investment; (2) inclusion in rate base of prudently incurred construction work in progress, or CWIP; (3) full recovery of prudently incurred pre-operations costs; (4) full recovery of prudently incurred costs of abandoned facilities; (5) use of hypothetical capital structures; (6) accumulated deferred income tax accruals; (7) adjustments to book value for sales/purchases; (8) accelerated depreciation for transmission assets; (9) deferred cost recovery for utilities with retail rate freezes; and, (10) an ROE incentive adder of 50 basis points for utilities that join and/or continue to be members of RTOs or independent system operators, or ISOs.

FERC requires companies seeking incentives to demonstrate a connection between the incentives requested and the proposed investment, known as the "nexus" test, and that the incentives requested address the risks and challenges that a project faces. FERC has frequently included a condition when approving incentives that a project must be included in an RTO/ISO Regional Transmission Expansion Plan, or RTEP, to be eligible for incentive rate treatment. RTEPs are typically prepared annually by RTOs and ISOs and identify transmission system additions and improvements needed to ensure reliability and promote economic efficiency.

In its 2012 policy statement, FERC stated it would no longer rely on an analysis of whether a project is considered routine or non-routine as a proxy for the nexus test but instead would rely more directly on applicants' demonstrating how the total package of incentives requested is tailored to address the risks and challenges of a specific project. FERC also stated it would expect that, before seeking an incentive ROE adder based on the risks and challenges of a project, an applicant would take all reasonable steps to mitigate risks, including seeking incentives designed to reduce those risks, such as rate base inclusion of CWIP, pre-commercial cost recovery, and abandoned plant cost recovery. The policy statement provided examples of the types of projects that may merit an incentive ROE, including those using advanced technologies. However, FERC stated that it would no longer consider a separate ROE incentive adder solely for an advanced technology.

With respect to ROE, FERC issued Opinion 531 on June 19, 2014, adopting a two-step discounted cash flow, or DCF, methodology for setting electric utility ROEs that is identical to the methodology historically used by FERC to establish ROEs for natural gas and oil pipelines. The two-step DCF methodology incorporates both short-term and long-term measures of growth in dividends. Prior to Opinion 531, the commission used a one-step DCF for electric utilities.

Opinion 531 applied the new methodology in a then-pending complaint involving the base ROE utilized for transmission owners in ISO-New England, or ISO-NE. On April 14, 2017, the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit, remanded the FERC orders issued in 2014 regarding the authorized ROE for ISO-NE. The D.C. Circuit determined that FERC must use a two-step process to establish a just and reasonable ROE by first finding that an existing rate is unlawful, and second by establishing a new just and reasonable rate. The court found that in the ISO-NE case, FERC had, instead, concluded that the existing 11.14% ROE was unlawful based entirely on its determination that a 10.57% ROE was just and reasonable. The D.C. Circuit's decision may ultimately impact FERC's future determination of the appropriate ROE for transmission owners in SPP.

SPP return on equity

Authorized base ROEs, a 50 basis point ROE adder for RTO participation and any additional ROE incentives for SPP transmission owners have been authorized by FERC on a company-by-company basis. Details are included in the individual company sections.

Individual company details

The sections that follow provide a closer look at transmission ratemaking and rate base for 14 companies with operations in SPP that employ formula based rates. For each there is a brief description, followed by a table or tables that provide detail for each operating company regarding authorized base ROE, rate of return, or ROR, rate base, net annual revenue requirement, network integration service rate, or NISR, equity ratio, any additional ROE incentives that apply to the company's rate base, and the portion of total rate base that is accorded incentive ROEs.

American Electric Power

AEP has four subsidiaries that are members of SPP: Public Service Company of Oklahoma, or PSO; Southwestern Electric Power Co., or SWEPCO; AEPOKT; and, AEPSWT. PSO serves approximately 542,000 retail customers in eastern and southwestern Oklahoma. SWEPCO serves approximately 528,000 retail customers in northeastern and the panhandle areas of Texas, northwestern Louisiana and western Arkansas.

AEPOKT and AEPSWT are transmission-only, or transco, subsidiaries of AEP and do not serve retail customers. The transcos develop, own and operate transmission assets that are physically connected to AEP's existing system. The transcos are independent of, but overlay AEP's existing vertically integrated utility operating companies. AEPOKT currently owns and operates transmission assets or has assets under construction.

Public Service Company of Oklahoma

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018-2019	Annual	7/1/2018	11.2	7.78	477,207	97,991	11,085	47.24	None	NA
2017-2018	Annual	7/1/2017	11.2	7.69	471,016	90,526	10,260	48.36	None	NA
2016-2017	Annual	7/1/2016	11.2	7.73	442,224	84,778	9,499	46.31	None	NA
2015-2016	Annual	7/1/2015	11.2	8.15	429,462	86,135	9,429	49.50	None	NA
2014-2015	Annual	7/1/2014	11.2	8.17	431,508	83,264	NA	48.28	None	NA
2013-2014	Annual	7/1/2013	11.2	8.35	389,417	76,280	NA	48.83	None	NA
2012-2013	Annual	7/1/2012	11.2	8.32	355,103	70,223	NA	48.21	None	NA
2011-2012	Annual	7/1/2011	11.2	8.53	336,165	71,490	NA	46.28	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

Southwestern Electric Power

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018-2019	Annual	7/1/2018	11.2	7.90	928,917	182,008	10,725	48.09	None	NA
2017-2018	Annual	7/1/2017	11.2	7.78	869,509	161,976	9,557	45.61	None	NA
2016-2017	Annual	7/1/2016	11.2	8.25	734,624	145,740	9,985	49.32	None	NA
2015-2016	Annual	7/1/2015	11.2	8.40	650,571	135,262	9,371	50.25	None	NA
2014-2015	Annual	7/1/2014	11.2	8.56	601,198	122,795	NA	51.03	None	NA
2013-2014	Annual	7/1/2013	11.2	8.54	628,926	119,435	NA	50.75	None	NA
2012-2013	Annual	7/1/2012	11.2	8.74	531,652	109,060	NA	51.97	None	NA
2011-2012	Annual	7/1/2011	11.2	8.56	494,143	102,313	NA	49.18	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

PSO and SWEPCO filed an application with FERC to switch from stated rates to formula based rates for transmission in 2007 and requested that FERC approve a base ROE of 11.9%, inclusive of a 50 basis point ROE adder for participation in an RTO. The application was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.2%, inclusive of the 50 basis point ROE adder. AEPOKT and AEPSWT filed an application with FERC in 2009 to establish formula-based rates for transmission, and requested that FERC approve a base ROE of 11.9%, inclusive of the 50 basis point adder for RTO participation. FERC approved a settlement in the AEPOKT/AEPSWT case in 2011 that also incorporated an ROE of 11.2%, inclusive of the 50 basis point RTO adder, for both companies.

In 2017, East Texas Electric Cooperative, or East Texas, filed a complaint at FERC against AEP's four operating and transmission companies in SPP, asserting that the AEP companies' authorized base ROE of 10.7% adopted in 2009 and 2011 is excessive and should be reduced to 8.36%. On Nov. 16, 2017, FERC issued an order establishing hearing and settlement judge proceedings on the complaint. On April 30, 2018, FERC's chief administrative law judge terminated settlement proceedings and ordered formal hearing procedures to commence on the complaint.

AEP Oklahoma Transmission

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018-2019	Annual	7/1/2018	11.2	7.37	640,941	102,914	NA	50.69	None	NA
2017-2018	Annual	7/1/2017	11.2	7.66	680,649	96,376	8,379	50.05	None	NA
2016-2017	Annual	7/1/2016	11.2	7.57	433,460	63,676	6,114	51.02	None	NA
2015-2016	Annual	7/1/2015	11.2	NA	339,186	46,664	4,152	NA	None	NA
2014-2015	Annual	7/1/2014	11.2	NA	289,268	38,134	NA	NA	None	NA
2013-2014	Annual	7/1/2013	11.2	NA	223,948	28,072	NA	NA	None	NA
2012-2013	Annual	7/1/2012	11.2	NA	40,738	5,430	NA	NA	None	NA
2011-2012	Annual	7/1/2011	11.2	NA	16,345	2,317	NA	NA	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

AEP Southwestern Transmission

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018-2019	Annual	7/1/2018	11.2	7.9	4	73	NA	48.17	None	NA
2017-2018	Annual	7/1/2017	11.2	7.78	4	125	NA	45.61	None	NA
2016-2017	Annual	7/1/2016	11.2	8.25	6	131	NA	49.32	None	NA
2015-2016	Annual	7/1/2015	11.2	NA	2	144	NA	NA	None	NA
2014-2015	Annual	7/1/2014	11.2	NA	74	224	NA	NA	None	NA
2013-2014	Annual	7/1/2013	11.2	NA	3	189	NA	NA	None	NA
2012-2013	Annual	7/1/2012	11.2	NA	<1	114	NA	NA	None	NA
2011-2012	Annual	7/1/2011	11.2	NA	NA	139	NA	NA	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

Empire District Electric

Empire District Electric, or EDE, is a vertically integrated electric and gas utility. The territory served by EDE's electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and includes smaller areas in southeastern Kansas, northeastern Oklahoma, and northwestern Arkansas.

Empire District Electric

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018-2019	Annual	7/1/2018	10.0	7.54	237,101	50,155	50,550	48.92	None	NA
2017-2018	Annual	7/1/2017	10.0	7.58	211,527	40,924	39,280	48.32	None	NA
2016-2017	Annual	7/1/2016	10.0	7.55	197,531	36,613	35,117	48.16	None	NA
2015-2016	Annual	7/1/2015	10.0	7.60	171,333	34,388	30,131	49.26	None	NA
2014-2015	Annual	7/1/2014	10.0	7.83	151,930	31,828	27,965	50.04	None	NA
2013-2014	Annual	7/1/2013	10.0	7.92	146,133	29,426	25,315	49.92	None	NA
2012-2013	Annual	7/1/2012	10.5	8.57	134,333	28,095	23,256	49.49	None	NA
2011-2012	Annual	7/1/2011	NA	NA	NA	NA	NA	NA	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

In 2016, Algonquin Power & Utilities and EDE announced that they had entered into an agreement whereby Algonquin was to acquire EDE for $2.4 billion, or C$3.4 billion, including $900 million of assumed debt. FERC approved the proposed transaction in 2016, and after state commissions in Arkansas, Kansas, Missouri and Oklahoma subsequently approved the proposed transaction it was completed in 2017.

EDE received FERC approval in 2012 to transition from a fixed transmission rate to a formula rate. FERC simultaneously authorized EDE a base ROE of 10%, inclusive of the 50 basis point RTO adder.

Evergy Inc.

Evergy subsidiaries Kansas City Power & Light, or KCP&L, and Kansas City Power & Light Greater Missouri Operations, or KCP&L GMO, provide electric utility service to customers in Missouri and Kansas. The two utilities combined serve approximately 838,400 customers.

Kansas City Power & Light

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	11.1	7.63	206,225	46,238	NA	51.97	None	NA
2017	Annual	1/1/2017	11.1	8.26	198,795	38,175	14,412	50.29	None	NA
2016	Annual	1/1/2016	11.1	8.36	177,179	33,151	12,234	50.44	None	NA
2015	Annual	1/1/2015	11.1	8.55	169,896	35,263	NA	50.80	None	NA
2014	Annual	1/1/2014	11.1	9.07	154,548	29,237	NA	49.64	None	NA
2013	Annual	1/1/2013	11.1	9.32	144,106	30,145	NA	47.16	None	NA
2012	Annual	1/1/2012	11.1	9.47	140,888	30,441	NA	47.76	None	NA
2011	Annual	1/1/2011	11.1	9.49	140,647	29,348	NA	48.23	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

KCP&L Greater Missouri Operations

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	11.1	7.63	210,447	39,542	NA	51.97	None	NA
2017	Annual	1/1/2017	11.1	8.26	210,004	39,246	NA	50.29	None	NA
2016	Annual	1/1/2016	11.1	8.36	198,084	33,086	NA	50.44	None	NA
2015	Annual	1/1/2015	11.1	8.55	206,040	30,884	NA	50.80	None	NA
2014	Annual	1/1/2014	11.1	9.07	204,224	36,472	NA	49.64	None	NA
2013	Annual	1/1/2013	11.1	9.32	182,824	38,505	NA	47.16	None	NA
2012	Annual	1/1/2012	11.1	9.47	174,431	36,406	NA	47.76	None	NA
2011	Annual	1/1/2011	11.1	9.49	155,623	29,026	NA	48.23	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

KCP&L and KCP&L GMO filed an application with FERC to switch from stated transmission rates to formula based rates in 2009 and requested that FERC approve a base ROE of 12.3%, inclusive of a 50 basis point ROE adder for participation in an RTO. The KCP&L/KCP&L GMO application was ultimately resolved through a settlement approved by FERC in 2010 that incorporated an ROE of 11.1% for both companies, inclusive of the 50 basis point RTO adder.

Evergy's Westar Energy subsidiary is a vertically integrated electric utility and the largest electric company in Kansas, serving 690,000 residential, commercial and industrial customers in the eastern third of the state. Kansas Gas and Electric Company, or KG&E, Westar Energy's wholly-owned subsidiary, provides service in south-central and southeastern Kansas, including the city of Wichita. Both Westar and KG&E conduct business using the name Westar Energy.

FERC authorized a base ROE of 11.3% for Westar in 2008, inclusive of the 50 basis point RTO adder. In 2014, the Kansas Corporation Commission, or KCC, filed a complaint with FERC alleging that the 11.3% ROE was unjust, unreasonable and unduly discriminatory, and that a just and reasonable ROE for Westar's transmission formula rate would be 9.37%. In 2015, Westar filed a settlement in the complaint proceeding proposing to reduce its authorized ROE from 11.3% to 10.3%, inclusive of the 50 basis point RTO adder, and FERC approved the settlement in 2016.

Westar Energy

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	10.3	7.54	1,622,268	289,696	70,764	51.73	None	NA
2017	Annual	1/1/2017	10.3	7.91	1,391,387	264,137	66,155	53.32	None	NA
2016	Annual	1/1/2016	10.3	7.98	1,330,311	234,569	56,230	50.52	None	NA
2015	Annual	1/1/2015	11.3	8.32	1,187,333	237,922	56,840	48.71	None	NA
2014	Annual	1/1/2014	11.3	8.63	1,126,684	242,538	60,408	50.63	None	NA
2013	Annual	1/1/2013	11.3	8.92	996,620	198,249	48,369	52.80	None	NA
2012	Annual	1/1/2012	11.3	8.73	900,564	186,059	44,309	49.11	None	NA
2011	Annual	1/1/2011	11.3	8.56	812,270	132,057	34,856	47.62	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

In 2015, the KCC approved a request by Westar to build a transmission line from the company's Jeffrey Energy Center Substation, northwest of St. Marys, Kansas, to its East Manhattan Substation near Manhattan, Kansas. The route of the new 25.6 mile line follows the existing 230 kV transmission line right of way. Upon completion, Westar decommissioned the older line. Construction of the new line began in June 2016 and was completed and placed in service in April 2017.

Westar owns a 50% interest in Prairie Wind Transmission, which is a joint venture between it and Electric Transmission America, which itself is a joint venture between affiliates of AEP and Berkshire Hathaway Energy. In 2014, Prairie Wind completed construction of a 108 mile, 345 kV double-circuit transmission line that is now being used to provide transmission service in SPP. The final cost of the line was $161.5 million. See the Prairie Wind Transmission section below for more information.

Fortis Inc./ITC Holdings

Fortis subsidiary ITC Great Plains is a member of SPP. In 2016, FERC approved the acquisition of ITC Holdings, the parent company of ITC Great Plains, by the Canadian company Fortis Inc., and the transaction was completed in October 2016.

In 2009, FERC approved ITC Great Plains' request for transmission rate incentives for its proposed Kansas V-Plan transmission project. Specifically, FERC approved an incentive ROE of 12.16% for the planned high voltage transmission project, as well as for two existing substations the company planned to purchase. The overall ROE approved by FERC represents a base ROE of 10.66%, plus a 50 basis point incentive adder for participation in SPP, and a 100 basis point incentive adder based on the company's status as an independent transmission company. The 122 mile, $300 million Kansas V-Plan was designed to connect eastern and western Kansas to Nebraska and Oklahoma, and the project was completed in 2014.

In 2016, ITC Great Plains, in conjunction with Mid-Kansas Electric Company, or MKEC, placed the Elm Creek-Summit high voltage electric transmission line and the Elm Creek substation into service in central Kansas. The 60 mile, 345 kV, $113 million transmission line links the existing 345kV Summit substation southeast of Salina, Kansas to the new 345 kV Elm Creek substation southeast of Concordia, Kansas.

ITC Great Plains

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	11.16	8.89	461,924	88,298	NA	60.0	NA	12.16
2017	Annual	1/1/2017	11.16	8.76	481,235	88,258	NA	60.0	NA	12.16
2016	Annual	1/1/2016	11.16	8.69	482,290	83,123	NA	60.0	NA	12.16
2015	Annual	1/1/2015	11.16	9.20	465,119	80,421	NA	60.0	NA	12.16
2014	Annual	1/1/2014	11.16	7.97	416,019	65,034	NA	60.0	NA	12.16
2013	Annual	1/1/2013	11.16	8.72	298,176	46,199	NA	60.0	NA	12.16
2012	Annual	1/1/2012	11.16	8.87	202,100	31,196	NA	60.0	NA	12.16
2011	Annual	1/1/2011	11.16	9.53	74,237	10,681	NA	60.0	NA	12.16

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

OGE Energy

OGE Energy subsidiary Oklahoma Gas & Electric, or OG&E, serves 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City and Fort Smith, Arkansas, the second largest city in that state.

OG&E filed an application with FERC to switch from a stated transmission rate to a formula based rate in 2008 and requested that FERC approve a base ROE of 12.7%, inclusive of a 50 basis point ROE adder for participation in an RTO. The OG&E case was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.1%, inclusive of the 50 basis point RTO adder.

In 2016, OG&E announced it was moving up the construction timeline of a $190 million transmission line to help connect wind farms in northwestern Oklahoma. The utility said it would begin building the 126 mile Windspeed II line from Woodward to its Cimarron substation northwest of Oklahoma City in 2017 and expects to complete the line in 2018.

Oklahoma Gas & Electric

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	11.1	8.62	1,628,779	297,787	23,334	55.52	None	NA
2017	Annual	1/1/2017	11.1	8.50	1,481,276	263,096	19,385	53.53	None	NA
2016	Annual	1/1/2016	11.1	8.61	1,475,275	252,102	17,509	54.10	None	NA
2015	Annual	1/1/2015	11.1	8.79	1,492,662	247,998	15,544	55.53	None	NA
2014	Annual	1/1/2014	11.1	8.88	1,445,542	242,387	14,056	55.92	None	NA
2013	Annual	1/1/2013	11.1	8.82	1,223,612	209,874	15,700	54.41	None	NA
2012	Annual	1/1/2012	11.1	8.93	990,206	170,742	16,352	55.45	None	NA
2011	Annual	1/1/2011	11.1	9.00	608,626	111,626	17,591	55.28	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

On Jan. 26, 2018, the Oklahoma Municipal Power Authority, or OMPA, filed a complaint at FERC against OG&E, arguing that the 10.6% base ROE established in 2009 in the utility's initial formula transmission rate proceeding is no longer just and reasonable. On March 8, 2018, OG&E filed a reply to OMPA's complaint. On May 17, 2018, FERC issued an order setting the complaint for hearing.

Xcel Energy

Xcel subsidiaries Public Service Company of Colorado, or PSCO, and Southwestern Public Service Company, or SPS, are members of SPP. PSCO provides electric utility service to approximately 1.4 million customers in Colorado. SPS serves about 267,000 customers in Texas and more than 118,000 customers in New Mexico in a territory that includes the cities of Roswell, New Mexico, and Amarillo and Lubbock, Texas.

PSCO filed an application with FERC to switch from a stated transmission rate to a formula based rate in 2012 and requested that FERC approve a base ROE of 10.25%, inclusive of a 50 basis point ROE adder for participation in an RTO. The PSCO case was ultimately resolved through a settlement approved by FERC in 2014 that incorporated an ROE of 9.72%, inclusive of the 50 basis point RTO adder.

Public Service Company of Colorado

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	9.72	7.35	1,313,799	254,445	43,299	55.44	None	NA
2017	Annual	1/1/2017	9.72	7.43	1,281,665	249,559	42,053	56.38	None	NA
2016	Annual	1/1/2016	9.72	7.46	1,231,153	245,920	40,338	56.46	None	NA
2015	Annual	1/1/2015	9.72	7.50	1,158,038	230,012	38,168	56.34	None	NA
2014	Annual	1/1/2014	9.72	7.50	1,120,089	225,358	36,960	56.36	None	NA
2013	Annual	1/1/2013	10.25	7.87	1,038,986	215,056	35,564	56.97	None	NA
2012	Annual	1/1/2012	10.25	8.22	909,572	182,492	30,344	56.30	None	NA
2011	Annual	1/1/2011	10.50	NA	NA	NA	NA	NA	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Southwestern Public Service Company

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	10.50	7.71	1,952,973	311,420	26,996	54.41	None	NA
2017	Annual	1/1/2017	10.50	8.18	1,701,994	282,070	25,779	53.78	None	NA
2016	Annual	1/1/2016	10.50	8.22	1,649,620	266,501	27,055	53.62	None	NA
2015	Annual	1/1/2015	11.27	8.78	1,375,467	237,688	26,629	53.52	None	NA
2014	Annual	1/1/2014	11.27	9.02	1,035,469	194,447	23,968	53.89	None	NA
2013	Annual	1/1/2013	11.27	8.93	786,909	154,249	21,684	52.56	None	NA
2012	Annual	1/1/2012	11.27	8.98	660,586	130,735	NA	50.90	None	NA
2011	Annual	1/1/2011	11.27	9.14	591,360	112,194	22,876	51.16	None	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

SPS filed an application with FERC to switch to formula based rates for transmission in 2008 and requested that FERC approve a base ROE of 12.7%, inclusive of a 50 basis point ROE adder for participation in an RTO. The SPS case was ultimately resolved through a settlement approved by FERC in 2009 that incorporated an ROE of 11.27%, inclusive of the 50 basis point RTO adder.

In 2015, FERC approved a settlement resolving a series of complaints filed against SPS' 11.27% ROE. Five cooperative utilities and a group representing four West Texas municipalities asserted that a new DCF analysis indicated that the base ROE for SPS should be lowered to 9.11%. The approved settlement reduced SPS's transmission ROE from 11.27% to 10.5%, inclusive of the 50 basis point RTO adder.

SPS and OG&E combined to build two major transmission projects: a $64 million, 345 kV transmission line which runs from northern Hansford County, Texas, to Woodward, Oklahoma; and a $185 million, 345 kV transmission line that extends for almost 200 miles from a substation north of Abernathy, Texas, to Woodward, Oklahoma. The two projects are part of SPS's $1.6 billion "Power for the Plains" transmission enhancement program for Texas, New Mexico and Oklahoma. Power for the Plains was launched after an SPP "High Priority Incremental Load Study" in 2010. The study recommended that SPP build transmission projects and grid upgrades to address load growth from oil and gas exploration in the Permian Basin.

The most expensive Power for the Plains project is the TUCO-Yoakum-Hobbs line, expected to be completed in 2020. At an estimated cost of $242 million, the project consists of about 160 miles of new 345 kV line running between the TUCO substation in Hale County, Texas, and the Hobbs Plant substation in Lea County, New Mexico.

Prairie Wind Transmission

Prairie Wind Transmission is a joint venture formed by Westar and Electric Transmission America, or ETA. ETA is in turn a joint venture of subsidiaries of AEP and Berkshire Hathaway Energy that was formed to build and own new electric transmission assets in Kansas.

Prairie Wind Transmission

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	11.3	8.0	141,635	20,928	NA	47.21	141,635	12.8
2017	Annual	1/1/2017	11.3	7.8	134,513	18,216	NA	44.80	134,513	12.8
2016	Annual	1/1/2016	11.3	8.3	144,101	21,052	NA	50.49	144,101	12.8
2015	Annual	1/1/2015	11.3	9.0	135,129	15,536	NA	48.29	135,129	12.8
2014	Annual	1/1/2014	11.3	7.9	158,632	15,952	NA	50.00	158,632	12.8
2013	Annual	1/1/2013	11.3	9.0	100,816	14,491	NA	50.00	100,816	12.8
2012	Annual	1/1/2012	11.3	11.2	21,993	4,964	NA	50.00	21,993	12.8
2011	Annual	1/1/2011	11.3	11.2	5,532	1,924	NA	50.00	5,532	12.8

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

In 2014, Prairie Wind completed a 108 mile, 345 kV, double circuit transmission line linking an existing 345 kV substation near Wichita, Kansas to a new 345 kV substation northeast of Medicine Lodge, Kansas near the Flat Ridge I Wind Farm, and then south to the Kansas/Oklahoma border. Westar provided project management services to Prairie Wind, which included coordination of the engineering and construction of the new transmission lines and facilities. The total estimated investment for the 345 kV line was $170 million.

FERC approved Prairie Wind's request for incentive rate treatment for the project in 2008, including a 150 basis point ROE adder given the size, scope, benefits, and risks of the project. FERC also granted Prairie Wind a 50 basis point ROE incentive for participation in SPP, resulting in a total ROE of 12.8%.

Transource Energy

Transource Energy is a partnership between AEP and Great Plains focused on the development of competitive electric transmission projects. AEP owns 86.5% of Transource and Great Plains owns 13.5%. Transource Missouri, a subsidiary of Transource Energy, began filing annual formula rate updates in 2014.

In 2011, the Missouri Public Service Commission authorized Transource subsidiary Transource Missouri to construct two new 345 kV transmission lines in the northwest part of the state. The Iatan-Nashua line will run 30 miles in Platte County, Missouri, in an arc around Kansas City International Airport. The Sibley-Nebraska City line runs 175 miles from a substation owned by Omaha Public Power District. The Sibley-Nebraska City line was completed in December 2016.

Transource Missouri received FERC approval for incentive rate treatment for the Sibley-Nebraska City line in October 2012. In approving the incentives for the Sibley-Nebraska City line, FERC stated that it would grant a 100 basis point ROE adder for the risks and challenges of the project, including the construction challenges associated with two crossings of the Missouri River and obtaining rights-of-way in two states. In addition, FERC noted the length and cost of the project, and the increased power transfer capability it would provide between Kansas and Nebraska, as well as between the SPP and the Midcontinent Independent System Operator regions.

Transource Missouri

Rate year	Adjustment frequency	Adjustment date	Base ROE (%)*	ROR (%)	Transmission rate base ($000)	Annual rev. req. ($000)	NISR ($/MW-Yr)	Equity (%)	Incentive rate base ($000)	Incentive ROE* (%)
2018	Annual	1/1/2018	10.30	7.03	270,373	38,804	NA	54.83	NA	11.30
2017	Annual	1/1/2017	10.30	7.51	274,489	33,200	NA	55.0	NA	11.30
2016	Annual	1/1/2016	10.30	7.45	80,168	32,150	NA	55.0	NA	11.30
2015	Annual	1/1/2015	10.30	7.60	42,078	23,504	NA	60.0	27,260	11.30
2014	Annual	1/1/2014	10.30	7.70	2,744	10,647	NA	60.0	0	NA
2013	Annual	1/1/2013	NA	NA	NA	NA	NA	NA	NA	NA
2012	Annual	1/1/2012	NA	NA	NA	NA	NA	NA	NA	NA
2011	Annual	1/1/2011	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not applicable or not available; ROE = Return on equity; ROR = Rate of return; NISR = Network integration service rate
* Includes 50 basis point adder for RTO participation.
Sources: FERC; Regulatory Research Associates, an offering of S&P Global Market Intelligence

Section 1: 10-K (10-K)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2019

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number: 001-32576

ITC HOLDINGS CORP.

(Exact Name of Registrant as Specified in Its Charter)

Michigan	**32-0058047**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

27175 Energy Way
Novi, Michigan 48377
(Address Of Principal Executive Offices, Including Zip Code)
(248) 946-3000
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
None	None	None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☑ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☑ * (Note: the Registrant is a voluntary filer and has not been subject to the filing requirements under Section 13 or 15(d) of the Securities Exchange Act of 1934 for the preceding 12 months.)

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller Reporting Company	Emerging growth company
☐	☐	☑	☐	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock held by non-affiliates on June 30, 2019 was $0.

All shares of outstanding common stock of ITC Holdings Corp. are held by its parent company, ITC Investment Holdings Inc., which is an indirect subsidiary of Fortis Inc. There were 224,203,112 shares of common stock, no par value, outstanding as of February 12, 2020.

DOCUMENTS INCORPORATED BY REFERENCE

None

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ITC Holdings Corp.

Form 10-K for the Fiscal Year Ended December 31, 2019

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- regional economic conditions;
- weather conditions;
- union strikes or labor shortages;
- material and equipment prices and availability;
- variances between estimated and actual costs of construction contracts awarded;
- our ability to obtain financing for such expenditures, if necessary;
- limitations on the amount of construction that can be undertaken on our system or transmission systems owned by others at any one time;
- regulatory requirements relating to our rate construct, including our ability to recover costs;
- the potential for greater competition;
- environmental, siting or regional planning issues; and
- legal proceedings.

Our ability to engage in construction projects resulting from pursuing these initiatives is subject to significant uncertainties, including the factors discussed above, and will depend on obtaining any necessary regulatory and other approvals for the project and for us to initiate construction, our achieving status as the builder of the project in some circumstances and other factors. In addition, projects may be canceled, the scope of planned projects may change, or projects may not be completed on time, any of which may adversely affect our level of investment or cause our projected investments to be inaccurate.

In addition, we expect to incur expenses to pursue strategic development investment opportunities. If these payments or expenses are higher than anticipated, our future results of operations, cash flows and financial condition could be materially and adversely affected.

The regulations to which we are subject may limit our ability to raise capital and/or pursue acquisitions, development opportunities or other transactions or may subject us to liabilities.

Each of our Regulated Operating Subsidiaries is a “public utility” under the FPA and, accordingly, is subject to regulation by the FERC. Approval of the FERC is required under Section 203 of the FPA for a disposition or acquisition of regulated public utility facilities, either directly or indirectly through a holding company. Such approval is also required to acquire a significant interest in securities of a public utility. Section 203 of the FPA also provides

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the FERC with explicit authority over utility holding companies’ purchases or acquisitions of, and mergers or consolidations with, a public utility. Finally, each of our Regulated Operating Subsidiaries must also seek approval by the FERC under Section 204 of the FPA for issuances of its securities (including debt securities). If we are unable to obtain the necessary FERC approvals for potential acquisitions, dispositions or merger activities, or to raise capital, our strategic and growth opportunities may be limited. This could have an adverse impact on our consolidated results of operations, cash flows and financial condition.

We are also pursuing development projects for construction of transmission facilities and interconnections with generating resources. These projects may require regulatory approval by Federal agencies, including the FERC, applicable RTOs and state and local regulatory agencies. Failure to secure such regulatory approval for new strategic development projects could adversely affect our ability to grow our business and increase our revenues. If we fail to obtain these approvals when necessary, we may incur liabilities for such failure.

Changes in energy laws, regulations or policies could impact our business, financial condition, results of operations and cash flows.

Each of our Regulated Operating Subsidiaries is regulated by the FERC as a “public utility” under the FPA and is a TO in MISO, SPP or PJM. We cannot predict whether the approved rate methodologies for any of our Regulated Operating Subsidiaries will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to the FERC, modify provisions of the FPA or provide the FERC or another entity with increased authority to regulate transmission matters. Our Regulated Operating Subsidiaries may be affected by any such changes in federal energy laws, regulations or policies in the future. While our Regulated Operating Subsidiaries are subject to the FERC’s exclusive jurisdiction for purposes of rate regulation, changes in state laws affecting other matters, such as transmission siting and construction, could limit investment opportunities available to us.

Each of our MISO Regulated Operating Subsidiaries depends on its primary customer for a substantial portion of its revenues, and any material failure by those primary customers to make payments for transmission services could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Each of ITCTransmission, METC and ITC Midwest derive a substantial portion of their revenues from the transmission of electricity to the local distribution facilities of DTE Electric, Consumers Energy and IP&L, respectively. Each of these customers is expected to constitute the majority of the revenues of the respective MISO Regulated Operating Subsidiary for the foreseeable future. Any material failure by DTE Electric, Consumers Energy or IP&L to make payments for transmission services could have an adverse effect on our business, financial condition, results of operations and cash flows.

A significant amount of the land on which our assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, we must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact our ability to complete construction projects in a timely manner.

METC does not own the majority of the land on which its electric transmission assets are located. Instead, under the provisions of the Easement Agreement, METC pays an annual rent to Consumers Energy in exchange for rights-of-way, leases, fee interests and licenses which allow METC to use the land on which its transmission lines are located. Under the terms of the Easement Agreement, METC’s easement rights could be eliminated if METC fails to meet certain requirements, such as paying contractual rent to Consumers Energy in a timely manner. Additionally, a significant amount of the land on which our other subsidiaries’ assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, they must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact their ability to complete their construction projects in a timely manner.

We contract with third parties to provide services for certain aspects of our business. If any of these agreements are terminated, we may face a shortage of labor or replacement contractors to provide the services formerly provided by these third parties.

We enter into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of our business, and we utilize the services of contractors to a significant extent. If any of these agreements or arrangements is terminated for any reason, it could result in a

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shortage of a readily available workforce to provide such services and we may face difficulty finding a qualified replacement workforce. In such a situation, if we are unable to find adequate replacements for contractors in a timely manner, it could have an adverse effect on our results of operations and the ability to carry on our business.

Hazards associated with high-voltage electricity transmission may result in suspension of our operations, costly litigation or the imposition of civil or criminal penalties.

Our operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. These hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations, litigation by aggrieved parties and the imposition of civil or criminal penalties which may have a material adverse effect on our business, financial condition and results of operations. We maintain property and casualty insurance, but we are not fully insured against all potential hazards incident to our business, such as damage to poles, towers and lines or losses caused by outages.

We are subject to environmental regulations and to laws that can give rise to substantial liabilities from environmental contamination.

We are subject to federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities relating to investigation and remediation of contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties we currently own or operate. Such liabilities may arise even where the contamination does not result from noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share.

We have incurred expenses in connection with environmental compliance, and we anticipate that we will continue to do so in the future. Failure to comply with the extensive environmental laws and regulations applicable to us could result in significant civil or criminal penalties and remediation costs. Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Some of our facilities and properties are located near environmentally sensitive areas such as wetlands and habitats of endangered or threatened species. In addition, certain properties in which we operate are, or are suspected of being, affected by environmental contamination. Compliance with these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our costs and, therefore, our business, financial condition and results of operations.

If amounts billed for transmission service for our Regulated Operating Subsidiaries' transmission systems are lower than expected, or our actual revenue requirements are higher than expected, the timing of actual collection of our total revenues would be delayed.

If amounts billed for transmission service are lower than expected, the timing of actual collections of our Regulated Operating Subsidiaries' total revenue requirement would likely be delayed until such circumstances are adjusted through the true-up mechanism, which would be settled within a two-year period, in our Regulated Operating Subsidiaries' Formula Rates. Lower than expected amounts collected could result from lower network load or point-to-point transmission service on our Regulated Operating Subsidiaries' transmission systems due to a weak economy, changes in the nature or composition of the transmission assets of our Regulated Operating Subsidiaries and surrounding areas, poor transmission quality of neighboring transmission systems, or for any other reason. In addition, if the revenue requirements of our Regulated Operating Subsidiaries are higher than expected, the timing of actual collection of our Regulated Operating Subsidiaries' total revenue requirements would likely be delayed until such circumstances are reflected through the true-up mechanism, which would be settled within a two-year period, in our Regulated Operating Subsidiaries' Formula Rates. This could be due to higher actual expenditures compared to the forecasted expenditures used to develop their billing rates or for any other reason. The effect of such under-collection would be to reduce the amount of our available cash resources from what we had expected, until such under-collection is corrected through the true-up mechanism in the Formula Rate template, which may require us to increase our outstanding indebtedness, thereby reducing our available

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borrowing capacity, and may require us to pay interest at a rate that exceeds the interest to which we are entitled in connection with the operation of the true-up mechanism.

We are subject to various regulatory requirements, including reliability standards; contract filing requirements; reporting, recordkeeping and accounting requirements; and transaction approval requirements. Violations of these requirements, whether intentional or unintentional, may result in penalties that, under some circumstances, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The various regulatory requirements to which we are subject include reliability standards established by the NERC, which acts as the nation's Electric Reliability Organization approved by the FERC in accordance with Section 215 of the FPA. These standards address operation, planning and security of the bulk power system, including requirements with respect to real-time transmission operations, emergency operations, vegetation management, critical infrastructure protection and personnel training. Failure to comply with these requirements can result in monetary penalties as well as non-monetary sanctions. Monetary penalties vary based on an assigned risk factor for each potential violation, the severity of the violation and various other circumstances, such as whether the violation was intentional or concealed, whether there are repeated violations, the degree of the violator's cooperation in investigating and remediating the violation and the presence of a compliance program, and such penalties can be substantial. Non-monetary sanctions include potential limitations on the violator's activities or operation and placing the violator on a watchlist for major violators. If any of our subsidiaries violate the NERC reliability standards, even unintentionally, in any material way, any penalties or sanctions imposed against us could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Certain of our subsidiaries are also subject to requirements under Sections 203 and 205 of the FPA for approval of transactions; reporting, recordkeeping and accounting requirements; and for filing contracts related to the provision of jurisdictional services. Under the FERC policy, failure to file jurisdictional agreements on a timely basis may result in foregoing the time value of revenues collected under the agreement, but not to the point where a loss would be incurred. The failure to obtain timely approval of transactions subject to FPA Section 203, or to comply with applicable reporting, recordkeeping or accounting requirements under FPA Section 205, could subject us to penalties that could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may negatively affect our business, financial condition and cash flows in unpredictable ways, such as increased security measures and disruptions of markets. Energy related assets, including, for example, our transmission facilities and DTE Electric's, Consumers Energy's and IP&L's generation and distribution facilities that we interconnect with, may be at risk of acts of war and terrorist attacks, as well as natural disasters, severe weather and other catastrophic events. Such events or threats may have a material effect on the economy in general and could result in a decline in energy consumption, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

A cyber-attack or incident could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Various U.S. Government agencies have noted that external threat sources continue to seek to exploit, through cyber attacks, potential vulnerabilities in the U.S. energy infrastructure including electric transmission assets. These cyber threats and attacks are becoming more sophisticated and dynamic. Cyber security incidents could harm our business by limiting our transmission capabilities, delay our development and construction of new facilities or capital improvement projects on existing facilities or expose us to liability. Cyber attacks targeting our information systems could also impair our records, networks, systems and programs, or transmit viruses to other systems. Such events or the threat of such events may increase costs associated with heightened security requirements. In addition, if our major customers or suppliers experience a cyber attack it may reduce their ability to use our transmission facilities or service our transmission assets. If our business or those of our customers and suppliers are subject to a cyber attack, it may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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Changes in tax laws or regulations may negatively affect our results of operations, net income, financial condition, cash flows and credit metrics.

We are subject to taxation by various taxing authorities at the federal, state and local levels. Various representatives of the government, corporations, industry groups and the public continue to pursue changes to tax laws and regulations, and corporate tax reform continues to be a priority in many jurisdictions. Due to unique aspects of the treatment of taxes for regulated utilities, the impacts of changes in tax laws for us and our Regulated Operating Subsidiaries may differ from the impacts to other corporations generally. We cannot predict the timing or impacts of any future modifications or changes in tax laws. Changes in federal, state or local tax rates or other aspects of tax laws could materially and adversely affect our results of operations, net income, financial condition, cash flows, and credit metrics.

Section 1: 10-K (10-K)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(X) Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
for the fiscal year ended December 31, 2018.

OR

( ) Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to .

Commission File Number	Exact name of registrant as specified in its charter; State of Incorporation; Address and Telephone Number	IRS Employer Identification No.
1-14756	**Ameren Corporation** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-1723446
1-2967	**Union Electric Company** (Missouri Corporation) 1901 Chouteau Avenue St. Louis, Missouri 63103 (314) 621-3222	43-0559760
1-3672	**Ameren Illinois Company** (Illinois Corporation) 10 Executive Drive Collinsville, Illinois 62234 (618) 343-8150	37-0211380

Securities Registered Pursuant to Section 12(b) of the Act:

The following security is registered pursuant to Section 12(b) of the Securities Exchange Act of 1934 and is listed on the New York Stock Exchange:

<u>**Registrant**</u>	<u>**Title of each class**</u>

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refueling requirements. Ameren Missouri has inventories and supply contracts sufficient to meet all of its uranium (concentrate and hexafluoride), conversion, and enrichment requirements at least through the 2023 refueling. Ameren Missouri has fuel fabrication service contracts through the 2023 refueling.

RENEWABLE ENERGY CREDITS AND ZERO EMISSION CREDITS

Missouri and Illinois laws require electric utilities to include renewable energy resources in their portfolios. Ameren Missouri and Ameren Illinois satisfied their renewable energy portfolio requirements in 2018.

In Missouri, utilities were required to purchase or generate electricity equal to at least 10% of native load sales from renewable energy sources in 2018. That percentage will increase to at least 15% by 2021, subject to an average 1% annual increase on customer rates over any 10-year period. At least 2% of the annual renewable energy requirement must be derived from solar energy. Ameren Missouri expects to satisfy the nonsolar requirement in 2019 with its Keokuk and Maryland Heights energy centers, a 102-megawatt power purchase agreement with a wind farm operator, and an estimated purchase of approximately $2 million of renewable energy credits in the market. The Keokuk energy center generates electricity using a hydroelectric dam located on the Mississippi River. The Maryland Heights energy center generates electricity by burning methane gas collected from a landfill. Ameren Missouri is meeting the solar energy requirement by purchasing solar-generated renewable energy credits from customer-installed systems and by generating solar energy at its O'Fallon energy center and its headquarters building. In 2018, Ameren Missouri entered into build-transfer agreements to purchase up to 557 megawatts of wind generation. For additional information on these agreements, see Note 2 – Rate and Regulatory Matters under Part II, Item 8 of this report.

Effective June 2017, the FEJA requires the IPA to procure renewable energy credits for all electric distribution customers in Illinois, including those customers supplied by alternative retail electric suppliers. The IPA's initial long-term renewable resources procurement plan was approved by the ICC in 2018. The IPA's plan set forth guidelines by which the IPA should procure 15-year contracts for four million wind renewable energy credits per year and four million solar renewable energy credits per year, allocated among Ameren Illinois, Commonwealth Edison Company, and MidAmerican Energy Company based on load. As a result of the allocation, Ameren Illinois is required to purchase 1.2 million wind renewable energy credits per year and 1.2 million solar renewable energy credits per year. The IPA has completed several procurement events, resulting in contractual commitments of 0.9 million wind renewable energy credits per year and 0.9 million solar renewable energy credits per year for Ameren Illinois. The remaining 0.3 million wind renewable and 0.3 million solar energy credits per year for Ameren Illinois will be obtained through IPA procurement events in 2019. Ameren Illinois will execute additional renewable energy credit contracts after these procurements in 2019. The IPA is expected to file its second long-term renewable resources procurement plan in 2019, which, once approved, will establish the 2020 and 2021 renewable energy credit procurement targets.

The FEJA also required Ameren Illinois to enter into contracts for zero emission credits in an amount equal to approximately 16% of the actual amount of electricity delivered to retail customers during calendar year 2014. This one-time zero emission credit procurement by the IPA, approval by the ICC, and execution of zero emission credit contracts were all completed in 2018. Contracts are for 10 years with quantities allocated among Ameren Illinois, Commonwealth Edison Company, and MidAmerican Energy Company. Both renewable energy credits and zero emission credits have cost recovery tariff mechanisms which fully recover or refund the variance between actual costs incurred from the resulting contracts and the amounts collected from customers.

ENERGY EFFICIENCY

Ameren Missouri and Ameren Illinois have implemented energy-efficiency programs to educate and to help their customers become more efficient energy consumers. In Missouri, the MEEIA established a regulatory recovery mechanism that, among other things, allows electric utilities to recover costs with respect to MoPSC-approved customer energy-efficiency programs. The law requires the MoPSC to ensure that a utility's financial incentives are aligned to help customers use energy more efficiently, to provide timely cost recovery, and to provide earnings opportunities associated with cost-effective energy-efficiency programs. Missouri does not have a law mandating energy-efficiency programs.

In February 2016, the MoPSC issued an order approving Ameren Missouri's MEEIA 2016 plan. That plan included a portfolio of customer energy-efficiency programs, along with a regulatory recovery mechanism. The MoPSC's order included a performance incentive that provides for additional revenues if certain MEEIA 2016 customer energy-efficiency goals are achieved, including $27 million if 100% of the goals are achieved during the three-year period. Ameren Missouri must achieve at least 25% of its energy efficiency-goals to be eligible for a MEEIA 2016 performance incentive and can earn more if its energy savings exceed those goals. Through 2018, Ameren Missouri invested $136 million in MEEIA 2016 customer energy-efficiency programs and recognized $11 million in additional revenue related to performance incentives.

In December 2018, the MoPSC issued an order approving Ameren Missouri's MEEIA 2019 plan. The plan includes a portfolio of customer energy-efficiency programs through December 2021 and low-income customer energy-efficiency programs through December 2024, along with a regulatory recovery mechanism. Ameren Missouri intends to invest $226 million over the life of the plan, including $65

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- the impact and effectiveness of vegetation management programs;
- net metering rules and other changes in existing regulatory frameworks and recovery mechanisms to address the allocation of costs to customers who own generation resources that enable them both to sell power to us and to purchase power from us through the use of our transmission and distribution assets;
- legislation or programs to encourage or mandate energy efficiency and renewable sources of power and the lack of consensus as to who should pay for those programs;
- pressure on customer growth and usage in light of economic conditions, distributed generation, technological advances, and energy-efficiency initiatives;
- changes in the structure of the industry as a result of changes in federal and state laws, including the formation and growth of independent transmission entities;
- changes in the allowed return on common equity on FERC-regulated electric transmission assets;
- the availability of fuel and fluctuations in fuel prices;
- the availability of a skilled work force, including retaining the specialized skills of those who are nearing retirement;
- regulatory lag;
- the influence of macroeconomic factors on yields of United States Treasury securities and on allowed rates of return on equity provided by regulators;
- higher levels of infrastructure and technology investments and adjustments to customer rates associated with the TCJA that are expected to result in negative or decreased free cash flow, which is defined as cash flows from operating activities less cash flows from investing activities and dividends paid;
- public concerns about the siting of new facilities;
- complex new and proposed environmental laws including statutes, regulations, and requirements, such as air and water quality standards, mercury emissions standards, CCR management requirements, and potential CO_2 limitations, which may reduce the frequency at which electric generating units are dispatched based upon their CO_2 emissions;
- public concerns about the potential environmental impacts from the combustion of fossil fuels and some investors' concerns about investing in energy companies that have fossil fuel-fired generation assets;
- aging infrastructure and the need to construct new power generation, transmission, and distribution facilities, which have long time frames for completion, with limited long-term ability to predict power and commodity prices and regulatory requirements;
- public concerns about nuclear generation, decommissioning, and the disposal of nuclear waste; and
- consolidation of electric and natural gas utility companies.

We are monitoring all these issues. Except as otherwise noted in this report, we are unable to predict what impact, if any, these issues will have on our results of operations, financial position, or liquidity. For additional information, see Risk Factors under Part I, Item 1A, Outlook in Management's Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Note 2 – Rate and Regulatory Matters, Note 9 – Callaway Energy Center, and Note 14 – Commitments and Contingencies under Part II, Item 8, of this report.

not allow full or timely recovery of decommissioning costs associated with the retirement of an energy center. Aging transmission and distribution facilities are more prone to failure than new facilities, which results in higher maintenance expense and the need to replace these facilities with new infrastructure. Even if the system is properly maintained, its reliability may ultimately deteriorate and negatively affect our ability to serve our customers, which could result in increased costs associated with regulatory oversight. The frequency and duration of customer outages are among the IEIMA performance standards. Any failure to achieve these standards will result in a reduction in Ameren Illinois' allowed return on equity on electric distribution assets. The higher maintenance costs associated with aging infrastructure and capital expenditures for new or replacement infrastructure could cause additional rate volatility for our customers, resistance by our regulators to allow customer rate increases, and/or regulatory lag in some of our jurisdictions, any of which could adversely affect our results of operations, financial position, and liquidity.

Energy conservation, energy efficiency, distributed generation, energy storage, technological advances, and other factors could reduce energy demand from Ameren Missouri's customers.

Without a regulatory mechanism to ensure recovery, declines in energy usage could result in an under-recovery of Ameren Missouri's revenue requirement, which could adversely affect Ameren and Ameren Missouri's results of operations, financial position, and liquidity. Such declines could occur due to a number of factors:

- *Conservation and energy-efficiency programs*. Missouri allows for conservation and energy-efficiency programs that are designed to reduce energy demand.
- *Distributed generation and other energy-efficiency efforts.* Ameren Missouri is exposed to declining usage from energy-efficiency efforts not related to its energy-efficiency programs, as well as from distributed generation sources, such as solar panels and other technologies. Ameren Missouri generates power at utility-scale energy centers to achieve economies of scale and to produce power at a competitive cost. Some distributed generation technologies have become more cost-competitive, with decreasing costs expected in the future. The costs of these distributed generation technologies may decline over time to a level that is competitive with that of Ameren Missouri's energy centers. Additionally, technological advances in energy storage may be coupled with distributed generation to reduce the demand for our electric utility services. Increased adoption of these technologies by customers could decrease our revenues if customers cease to use our generation, transmission, and distribution services at current levels. Ameren Missouri might incur stranded costs, which ultimately might not be recovered through rates.
- *Macroeconomic factors.* Macroeconomic factors resulting in low economic growth or contraction within Ameren Missouri's service territories could reduce energy demand.

We are subject to employee work force factors that could adversely affect our operations.

Our businesses depend upon our ability to employ and retain key officers and other skilled professional and technical employees. A significant portion of our work force is nearing retirement, including many employees with specialized skills, such as maintaining and servicing our electric and natural gas infrastructure and operating our energy centers. We are also party to collective bargaining agreements that collectively represent about 51% of Ameren's total employees. Any work stoppage experienced in connection with negotiations of collective bargaining agreements could adversely affect our operations.

Our operations are subject to acts of terrorism, cyber attacks, and other intentionally disruptive acts.

Like other electric and natural gas utilities, our energy centers, fuel storage facilities, transmission and distribution facilities, and information systems may be affected by terrorist activities and other intentionally disruptive acts, including cyber attacks, which could disrupt our ability to produce or distribute our energy products. Within our industry, there have been attacks on energy infrastructure, such as substations and related assets, in the past, and there may be more attacks in the future. Any such incident could limit our ability to generate, purchase, or transmit power or natural gas and could have significant regional economic consequences. Any such disruption could result in a significant decrease in revenues, a significant increase in costs including those for repair, or adversely affect economic activity in our service territory which, in turn, could adversely affect our results of operations, financial position, and liquidity.

There has been an increase in the number and sophistication of cyber attacks across all industries worldwide. A security breach at our physical assets or in our information systems could affect the reliability of the transmission and distribution system, disrupt electric generation, including nuclear generation, and/or subject us to financial harm resulting from theft or the inappropriate release of certain types of information, including sensitive customer, employee, financial, and operating system information. Many of our suppliers, vendors, contractors, and information technology providers have access to systems that support our operations and maintain customer and employee data. A breach of these third-party systems could adversely affect our business as if it was a breach of our own system. If a significant breach occurred, our reputation could be adversely affected, customer confidence could be diminished, and/or we could be subject to increased costs associated with regulatory oversight, fines or legal claims, any of which could result in a significant decrease in revenues or significant costs for remedying the impacts of such a breach. Our generation, transmission, and distribution systems are part of an interconnected system. Therefore, a disruption caused by a cyber incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our businesses. Insurance might not be adequate to cover losses that arise in connection with these events. In addition, new

The Brattle Group

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

Presented with:
WIRES

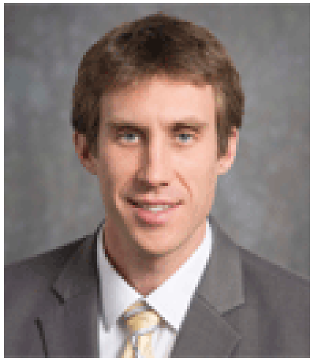
Presented by:
Judy Chang
Johannes Pfeifenberger
Michael Hagerty

July 31, 2013

Introduction – Speakers

Judy Chang

Hannes Pfeifenberger



Mike Hagerty

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This presentation is based on the report with the same title posted here: http://wiresgroup.com/docs/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

Agenda

A. Importance of Considering all Benefits

B. Evolving RTO and non-RTO Experience

C. Checklist of Transmission Benefits

D. Proposed Framework for Incorporating Benefits

E. Comparing Uncertain Benefits and Costs

F. Interregional Planning

Appendix: Details on Benefit Metrics in Checklist

A. Importance of Considering All Benefits

- Not all proposed transmission projects can (or should) be justified economically
- Transmission projects can provide a wide range of benefits—economic, public, and reliability—to a range of market participants and regions
- Narrow or conservative evaluation of transmission benefits risks rejection of valuable projects
  - Transmission benefits in large part are a reduction in system-wide costs
  - Not considering the full economic benefits of transmission investments means not considering all costs and the potentially very-high-cost outcomes that market participants would face without these investments
- Production cost simulations have become a standard tool to assess "economic benefits" of transmission, but only considers short-term dispatch-cost savings under very simplified system conditions (e.g., no transmission outages)
  - Simplified simulations reflect incomplete production cost savings, thus only a smaller portion of the overall economy-wide benefits

B. Evolving RTO and non-RTO Experience

- Planners and regulators increasingly recognize importance of considering the wide range of transmission benefits
- In recent years, some RTOs—in particular the SPP, MISO and CAISO)—gradually expanded transmission planning beyond addressing reliability and load serving concerns to include economic and public-policy drivers.
- Other RTOs and most non-RTO regions still rely primarily on the traditional application of production cost simulations estimate economic value of transmission
- Despite the differences among regions in how they consider transmission benefits in planning, the same set of potential transmission benefits applies in all of them

B. Benefits in RTO Regional Planning

RTO Planning Process	Estimated Benefits	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	• Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits	• Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	• Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction	• Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP's Metrics Task Force	• Reduced energy losses, • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or loss of load probability • Increased wheeling through and out revenues • Value of meeting public policy goals	• Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity

B. Benefits in RTO Regional Planning (cont'd)

RTO Planning Process	Estimated Benefits	Other Benefits Considered (without necessarily estimating their value)
MISO MVP Analysis	• Production cost savings • Reduced operating reserves • Reduced planning reserves • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs	• Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO_2 emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	• Reliability benefits • Production cost savings	• Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	• Reliability benefits • Production cost savings	• Public policy benefits
ERCOT LTS	• Reliability benefits • Production cost savings • Avoided transmission project costs	• Public policy benefits
ISO-NE RSP	• Reliability benefits • Net reduction in total production costs	• Public policy benefits

B. Benefits in Non-RTO Regional Planning

Non-RTO Planning Organization	Benefits Considered in Regional Planning
WECC	• Avoided local transmission project costs • Production cost savings • Reduced generation capital costs
ColumbiaGrid	• Avoided local transmission project costs
NTTG	• Avoided local transmission project costs • Reduced energy losses • Reduced reserve costs
WestConnect	• Avoided local transmission project costs • Production cost savings • Reserve sharing benefits
SERTP	• Avoided local transmission project costs
NCTPC	• Avoided local transmission project costs
Florida Sponsors	• Avoided local transmission project costs

C. "Checklist" of Economic Transmission Benefits

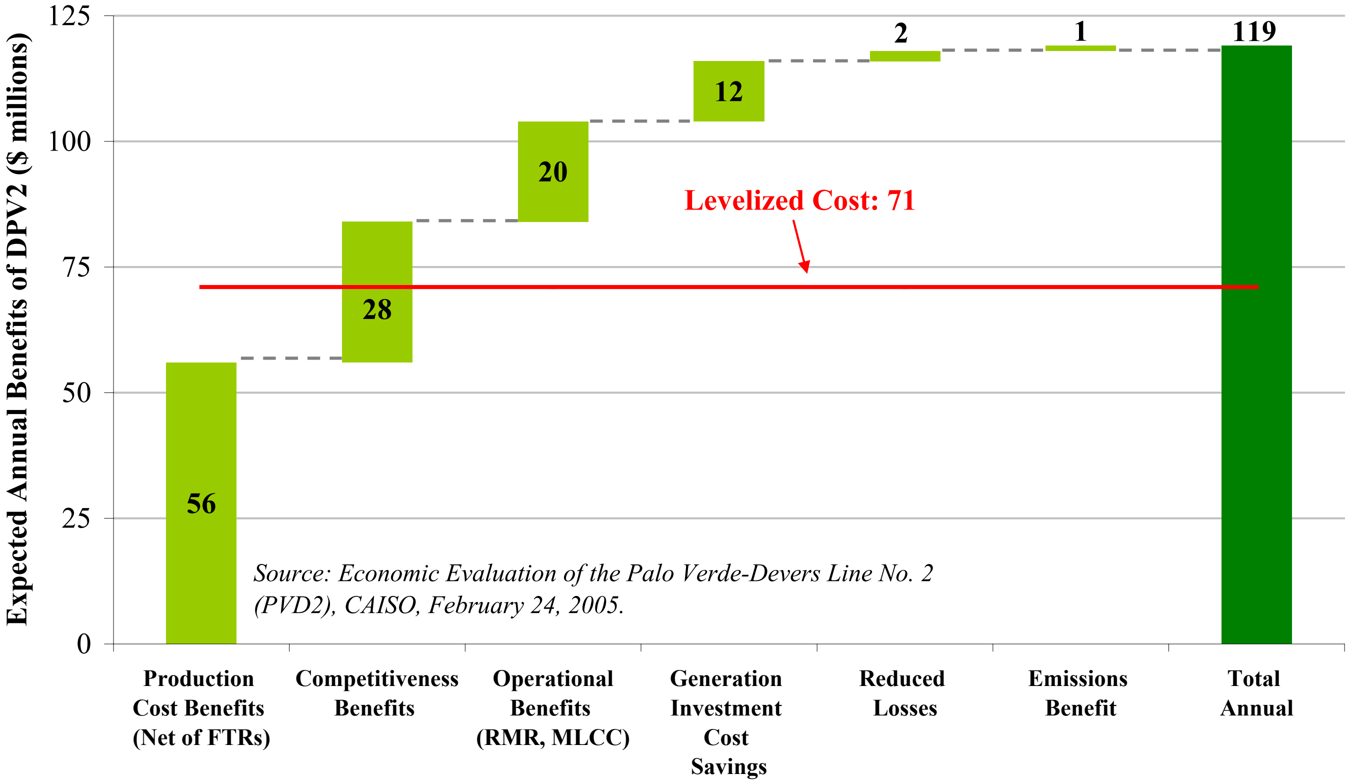
- Compiled a "checklist of economic benefits" from a detailed review of industry practices and our own experience
  - Can be used to help identify the potential benefits of transmission investments
  - Recommend policy makers and planners use this checklist to document, evaluate, and communicate a comprehensive "business case" for transmission projects.
- How to estimate the monetary value of benefits in checklist?
  - Some benefits should be measured routinely with existing tools and metrics (such as "Adjusted Production Cost" savings)
  - Other potentially-significant, but difficult-to-estimate benefits should be analyzed by calculating their likely range and magnitude
  - Omitting consideration of such difficult-to-estimate benefits inherently assigns a zero value and thereby results in a systematic understatement of total project benefits

"Checklist" of Economic Transmission Benefits

Benefit Category	**Transmission Benefit (see Appendix for descriptions and detail)**
Traditional Production Cost Savings	**Production cost savings as currently**
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
	j. More realistic "Day 1" market representation
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, fuel diversity, flexibility, reducing the cost of future transmission needs, wheeling revenues, HVDC operational benefits

Example: Range of Project Benefits vs. Costs

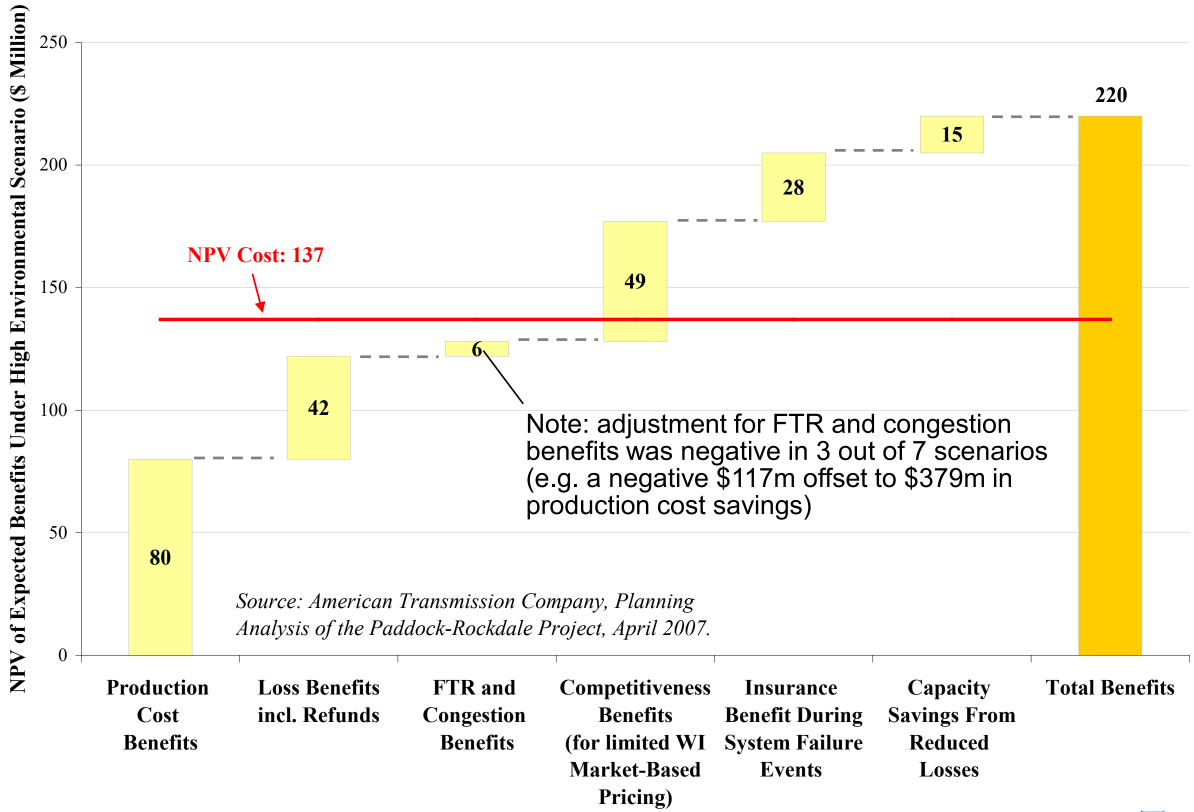
Total electricity market benefits of SCE's DPV2 project in CAISO exceeded project costs by more than 50%



The Brattle Group

Example: Range of Project Benefits vs. Costs

ATC's Paddock-Rockdale study: Significant net benefits (production cost savings alone exceeded costs in some scenarios)



The Brattle Group

D. Proposed Framework for Incorporating Benefits

1. System planners and stakeholders to identify potentially valuable transmission projects and develop a comprehensive list of likely benefits
2. Perform unbiased evaluation of proposed projects to estimate the value of as many of the identified benefits as practical without regard to how the benefits would be distributed
3. Determine whether the projects would be beneficial overall by comparing estimated economy-wide (often referred to as “societal”) benefits with estimates of total project costs
4. Address cost allocation last—and for portfolio of beneficial projects—to reduce incentives to minimize benefits and avoid premature rejection of valuable projects

E. Comparing Uncertain Benefits and Costs

- Long life of assets requires comparison of long-term benefits and costs:
  - Either on a present value or levelized annual basis
  - Over a time period, such as 40 or 50 years, that approaches the useful life of the physical assets
- How benefits and costs accrue over time and across future scenarios will help optimize the timing of investments
- Near- and long-term uncertainties need to be addressed to develop robust plans and least-regret projects:
  - Long-term uncertainties (industry structure, new technologies, fundamental policy changes, and shifts in fuel market fundamentals) can be addressed through scenario-based analyses
  - Near-term uncertainties within long-term scenarios (uncertainties in loads, fuel prices, transmission and generation outages) should be evaluated through sensitivity or "probabilistic" analyses

F. Interregional Planning

- Interregional planning and cost allocation is especially challenging
- Neighboring regions tend to evaluate interregional projects based only on the subset of benefits that are common to the planning processes of both regions
  - Results in the consideration of a narrower set of benefits in interregional projects than are considered for region-internal projects
  - Results in “de-militarized zones” between regions
- To avoid this “least common denominator” outcome, we recommend that each region, at a minimum, evaluate interregional projects based on all benefits that they consider for their regional projects
- Without recognizing all potential benefits, interregional planning will not find many projects that would benefit two or more regions

Additional Reading

Chang, Pfeifenberger, Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments,“ prepared for WIRES, July 2013.

Pfeifenberger "Independent Transmission Companies: Business Models, Opportunities, and Challenges," *American Antitrust Institute's 13th Annual Energy Roundtable*, April 23, 2013.

Pfeifenberger, Chang, Hou "Bridging the Seams: Interregional planning under FERC Order 1000," *Public Utilities Fortnightly*, November 2012.

Pfeifenberger "Transmission Investment Trends and Planning Challenges," *EEI Transmission and Wholesale Markets School*, August 8, 2012

Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning,“ April 2012.

Pfeifenberger and Hou, *Transmission's True Value: Adding up the Benefits of Infrastructure Investments*, Public Utilities Fortnightly, February 2012.

Pfeifenberger and Hou, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, on behalf of WIRES, May 2011.

Pfeifenberger, *Easier Said Than Done: The Continuing Saga of Transmission Cost Allocation*, Harvard Electricity Policy Group meeting, Los Angeles, February 24, 2011.

Pfeifenberger and Newell, *Direct testimony on behalf of The AWC Companies re: the Public Policy, Reliability, Congestion Relief, and Economic Benefits of the Atlantic Wind Connection Project*, filed December 20, 2010 in FERC Docket No. EL11-13.

Pfeifenberger, Chang, Hou, Madjarov, *“Job and Economic Benefits of Transmission and Wind Generation Investments in the SPP Region,” The Brattle Group, Inc.*, March 2010.

“Comments of Peter Fox-Penner, Johannes Pfeifenberger, and Delphine Hou,” in response to FERC's Notice of Request for Comments on Transmission Planning and Cost Allocation (Docket AD09-8).

Pfeifenberger, *"Assessing the Benefits of Transmission Investments,"* presented at the Working Group for Investment in Reliable and Economic Electric Systems (WIRES) meeting, Washington, DC, February 14, 2008.

Pfeifenberger, Direct Testimony on behalf of American Transmission Company re: Transmission Cost-Benefit Analysis Before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008.

Pfeifenberger, Testimony on behalf of Southern California Edison Company re: economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, September and October, 2006.

About *The Brattle Group*

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About *The Brattle Group*

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies around the world.

We combine in-depth industry experience, rigorous analyses, and principled techniques to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
- Cost of Capital & Regulatory Finance
- Demand Forecasting & Weather Normalization
- Demand Response & Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation & Risk Management
- Energy Contract Litigation
- Environmental Compliance
- Fuel & Power Procurement
- Incentive Regulation
- Market Design & Competitive Analysis
- Mergers & Acquisitions
- Rate Design, Cost Allocation, & Rate Structure
- Regulatory Compliance & Enforcement
- Regulatory Strategy & Litigation Support
- Renewables
- Resource Planning
- Retail Access & Restructuring
- Strategic Planning
- Transmission

Appendix

Details on Benefit Metrics in “Checklist”

1. Additional Production Cost Savings

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1a. Reduced impact of generation outages and A/S designations	Consideration of generation outages (and A/S unit designations) will increase impact	Consider both planning and (at least one draw of) forced outages in market simulations. Set aside resources to provide A/S in non-optimized markets.	Outages considered in most RTO's
1b. Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
1c. Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
1d. Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
1e. Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
1f. Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	
1g. Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study

1. Additional Production Cost Savings (cont'd)

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1h. Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
1i. Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)
1j. More realistic "Day 1" market representation	Transmission expansion provide additional benefits in markets where congestion is managed less efficiently	Apply "hurdle rates" between transmission systems and balancing areas (standard approach) plus derate transfer capability for underutilized system during TLR events (e.g., by 5-16%)	DOE and MISO Day-2 market benefit studies

2+3. Resource Adequacy and Generation Capacity Cost Savings

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
2a. Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	All RTOs and non-RTOs ITC-Entergy analysis MISO MVP, ERCOT
2b. Reduced loss of load probability **Or:**	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
2c. Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3a. Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
3b. Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
3c. Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4+5+6+7. Market, Environmental, Public Policy, and Economic Stimulus Benefits

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits	4a. Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
	4b. Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits	5a. Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
	5b. Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	
6. Public Policy Benefits	Reduced cost of meeting public policy goals	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7. Employment and Economic Stimulus Benefits	Increased employment, economic activity, and tax revenues	Increased full-time equivalent (FTE) years of employment and economic activity related to new transmission line	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

8. Other Project-Specific Benefits

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
8a.Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
8b. Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	ITC-Entergy
8c.Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
8d. Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
8e. Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
8f. Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
8g. Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		PJM PATH, AWC analyses

What is Not Addressed in our Report?

- Permitting and siting of new transmission facilities
- Processes and options for cost allocation
- Differences between regulated and merchant transmission
- Differences between the transmission planning and utility IRP processes
- Detailed discussion of iterative transmission planning process itself, including evaluation of transmission and non-transmission alternatives
- Development of decision-analysis tools or frameworks that may be able to streamline the planning process
- Institutional and organizational barriers to creating a credible, unbiased, and comprehensive planning process
- Implications of setting different allowed rates of return on transmission investments and regulatory incentives for such investments
- Broader political economy associated with building transmission, cost allocation, permitting, and regulation

AVANGRID

Marketing

December
/ 2019

AVANGRID

Business Highlights

~$10B in rate base YE ’18 with 9% CAGR through ’22[1]

As of 9/30/2019:

- ~7.3 GW wind & solar installed capacity[2]
- ~562 MW in Construction
- >100% of MW in Long-term Outlook under contract
- ~16.5 GW pipeline[3]

EPS ~12-14% & Adjusted EPS[4] CAGR ~8-10%[1]

Forward 2020+ Mid-Period Assessment Cost Efficiencies:

- $70-$85M (pre-tax) savings in ’19 & $100M (pre-tax) run rate savings

(1) AVANGRID’s Long-Term Outlook ’18–’22 as of February 26, 2019
(2) Installed capacity includes operating capacity plus capacity installed but project not COD
(3) Includes onshore wind, solar and offshore wind (50% ownership of two Vineyard Wind leases & 100% ownership of Kitty Hawk lease)
(4) See Appendix for reconciliation of non-GAAP adjusted EPS to EPS

Financial Highlights

Attractive long term growth outlook

- EPS CAGR 8-10% ('18-'22)[1][2]

Strong balance sheet

- Very low leverage, providing financial flexibility for capital investment projects

Ample Liquidity

- Inter-company lending, external credit facilities, Commercial Paper program, and parent company lending arrangements

Commitment to increase the dividend

- 65%-75% pay out range; future increases expected to be in line with EPS growth[3]

Ability to access 'Green' lending options

- Green bond issued at parent company & execution of green line of credit for operating companies and parent

(1) As of February 26. 2019
(2) See Appendix for calculation of Adjusted EPS and reconciliation to EPS
(3) Subject to authorization by the AVANGRID Board of Directors

Credit Ratings & Dividend Policy

Our credit ratings positioning us well for investments in our clean energy & resiliency projects

Credit Ratings

S&P	Moody's	Fitch
BBB+	Baa1	BBB+

Dividend Policy

DPS	Pay-out	↑
$0.44/share (quarterly)	Target 65-75%	Increases in line with EPS growth & Payout

Results Presentation

Fourth Quarter

February 26 /2020

AVANGRID

Financing & Dividends

We have a Green Financing Strategy…

- $1.35B in Green Bonds Outstanding
- $2.5B Sustainability-Linked credit facility

Stable investment grade ratings…

Fitch	Moody's	S&P
BBB+	Baa1	BBB+

✓ All utilities have A- secured or unsecured ratings from at least 2 of the 3 agencies

And a consistent dividend policy

AVANGRID's Board declared a quarterly dividend of $0.44/Share on 2/19/2020, payable on 4/1/2020

Payout Target 65-75%

Our Customers | Our People
Perform | Invent

BAML Utilities: Power, Utilities and Renewables Conference
Boston, Massachusetts
March 3-4, 2020

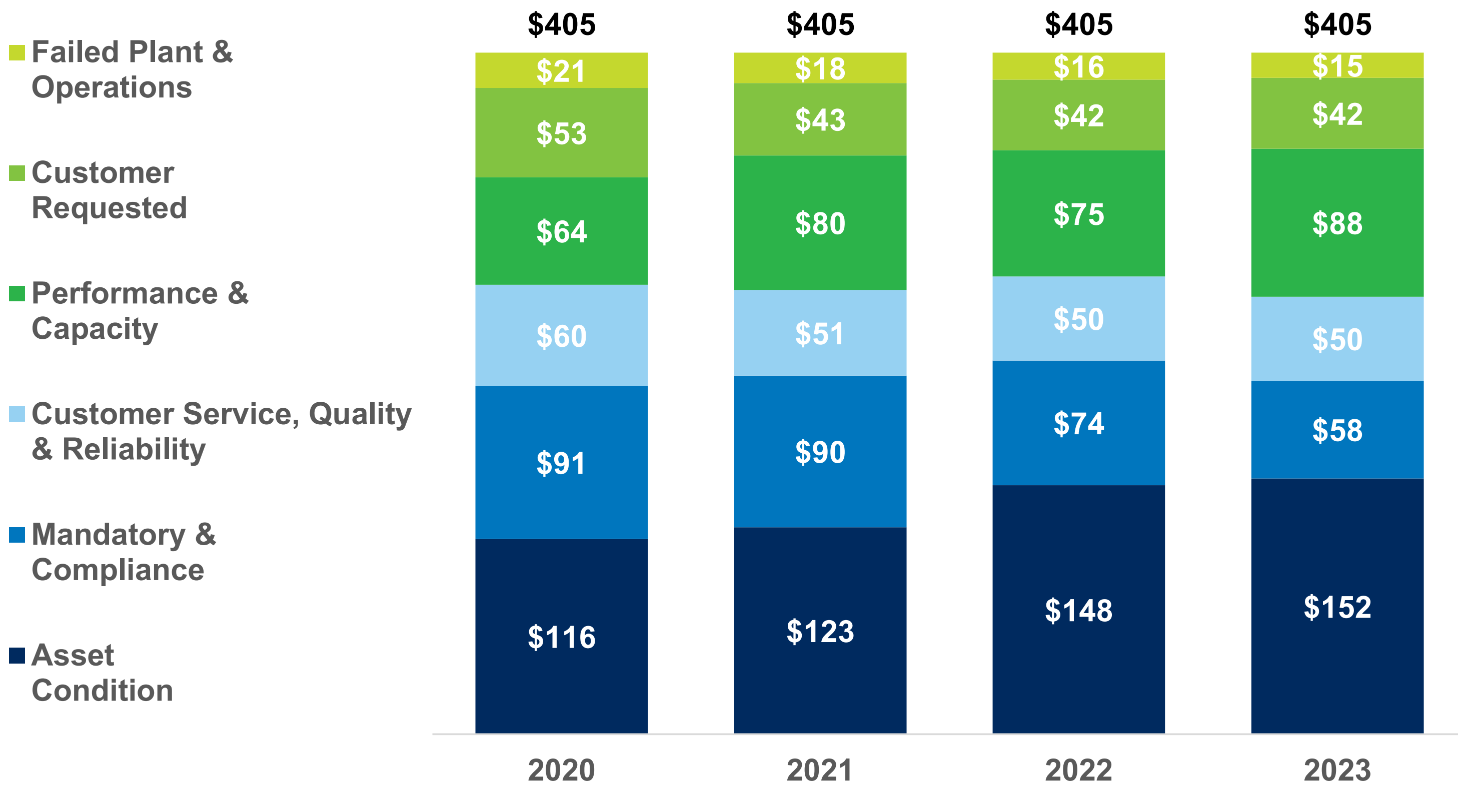
Expectations that drive performance

- General rate cases in 2019:
  - Settlement in Oregon, new rates effective January 15, 2020
  - Settlement in Idaho, new rates effective December 1, 2019
  - Partial settlement in Washington for new rates effective April 1, 2020, expect resolution by the end of Q1 2020
- Plan to file general rate cases in 2020 in Washington, Idaho and Oregon
- Annual earnings growth*
  - Approximately 9% to 10% annually from 2020 to 2022
  - Projecting long-term earnings growth of 4% to 6% following 2022
- 2020 structural costs and regulatory timing lag
  - Structural costs estimated to reduce ROE by approximately 90 basis points
  - Timing lag estimated to reduce ROE by approximately 80 basis points
- Continued dividend growth
  - Increased dividend 4.5% from 2019 to 2020
  - Targeting dividend payout of 65%-75% by 2022

* Assumes adequate and timely rate relief. Calculated off of midpoint of our original 2019 consolidated earnings guidance excluding the termination fee received from Hydro One and the payment of final transaction costs.

Investments to upgrade our systems

5% to 6% rate base growth



Excludes projected capital expenditures at AEL&P of $9 million in 2020 and 2021, $15 million in 2022 and $7 million in 2023.

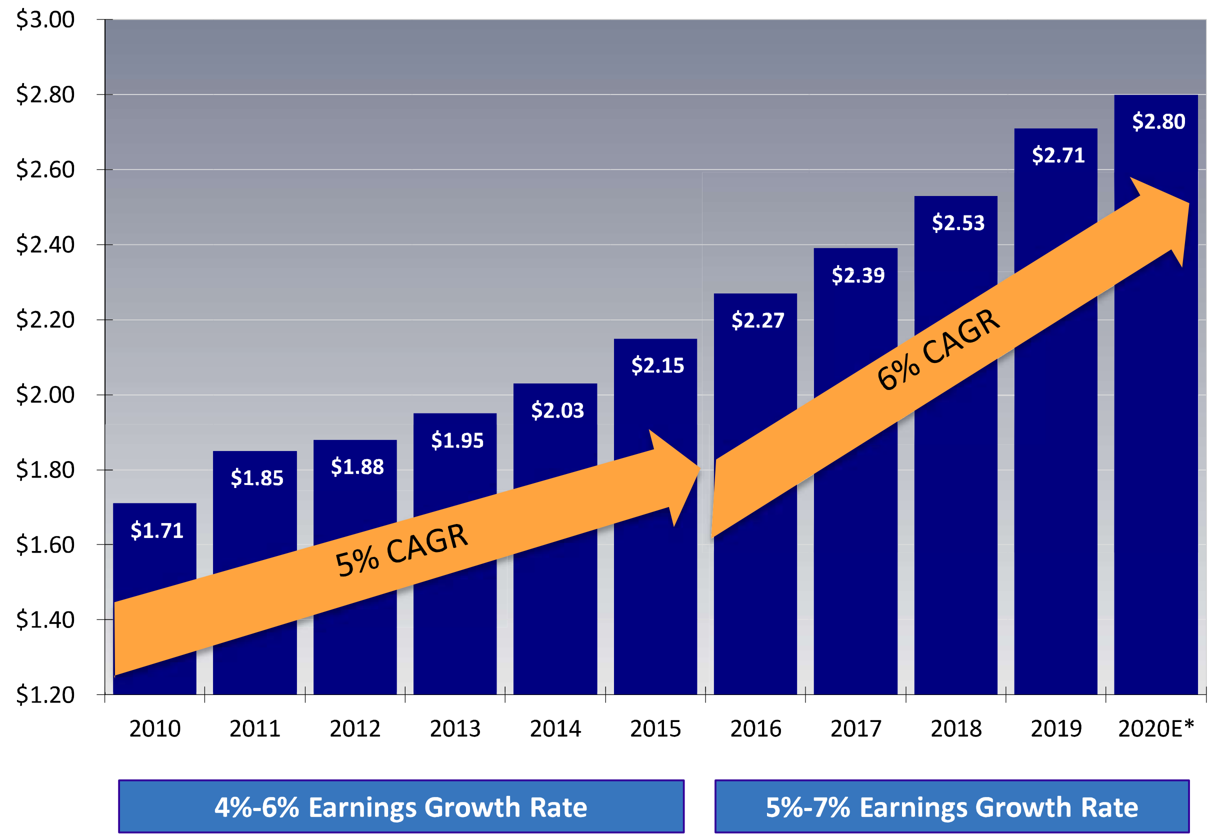

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
Barclays Power & Utility
Credit Corporate Day
New York, NY
March 3, 2020

Strong Dividend Growth

Targeted payout ratio 60-70% of operating earnings

Over 109 years of consecutive quarterly dividends

Targeted dividend growth in line with earnings

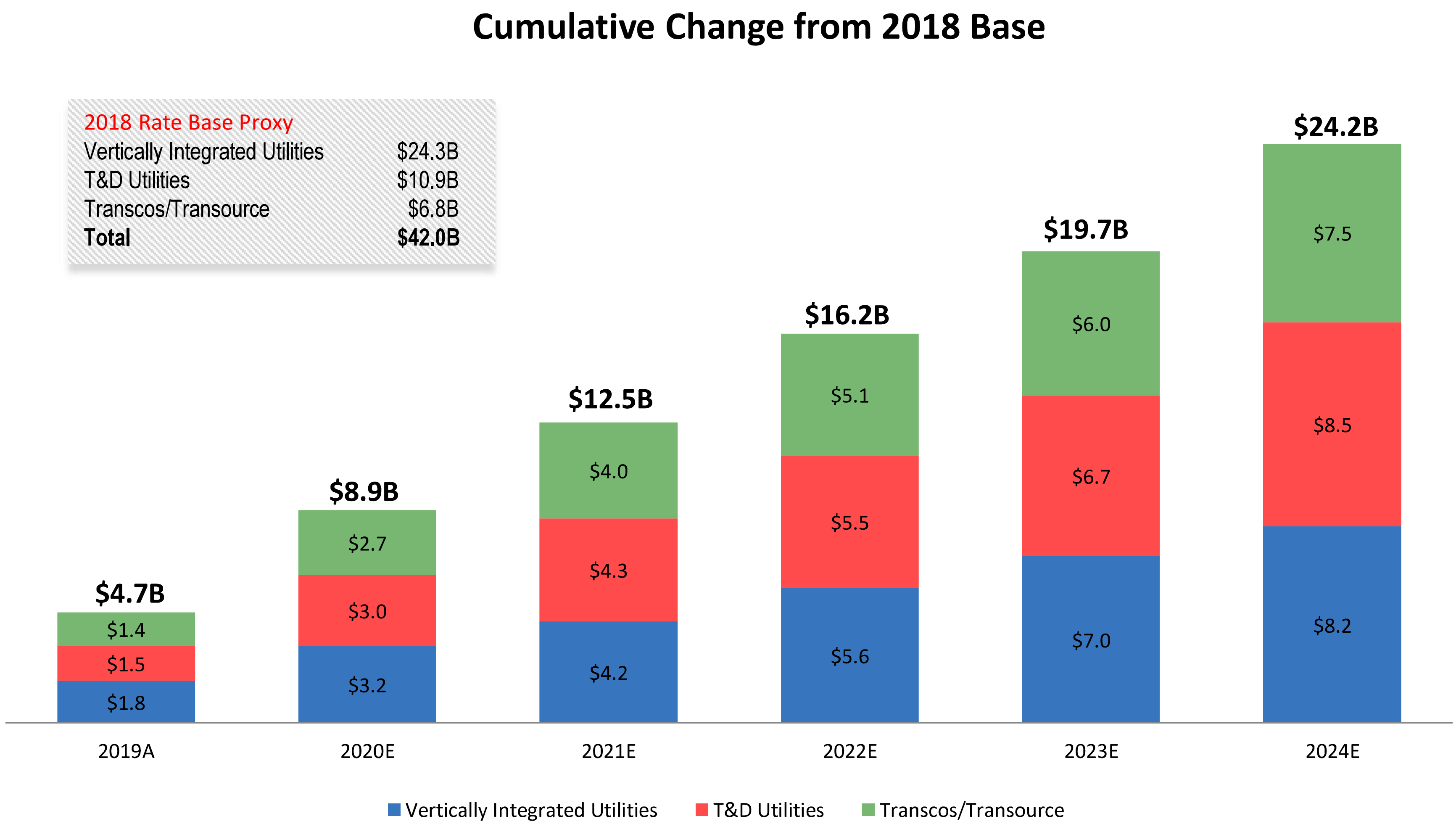


EPS Growth + Dividend Yield = 8% to 10% Annual Return Opportunity

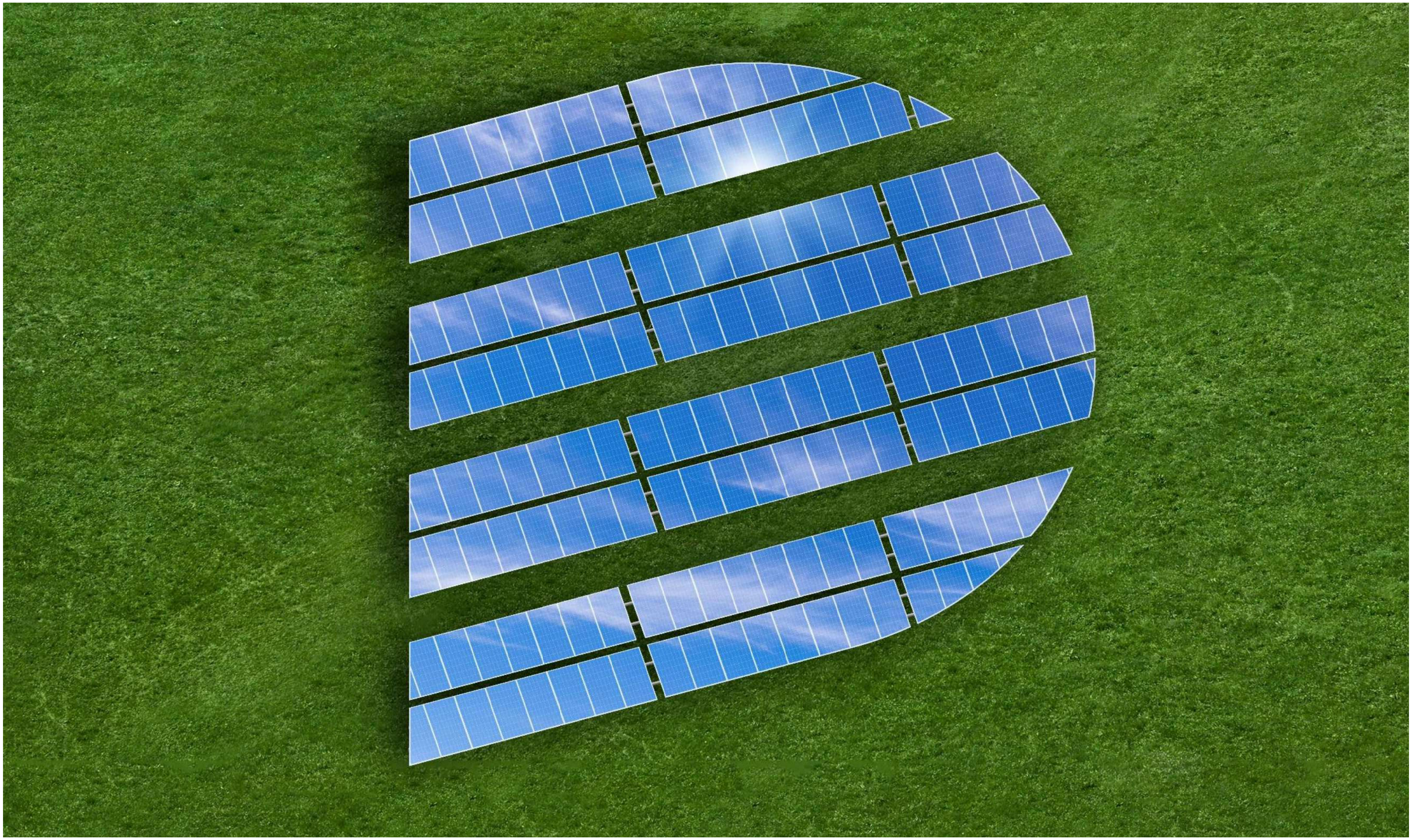
* Subject to Board approval

7.9% CAGR in Rate Base Growth

2018 Rate Base Proxy	
Vertically Integrated Utilities	$24.3B
T&D Utilities	$10.9B
Transcos/Transource	$6.8B
Total	**$42.0B**



5%-7% EPS growth is predicated on regulated rate base growth



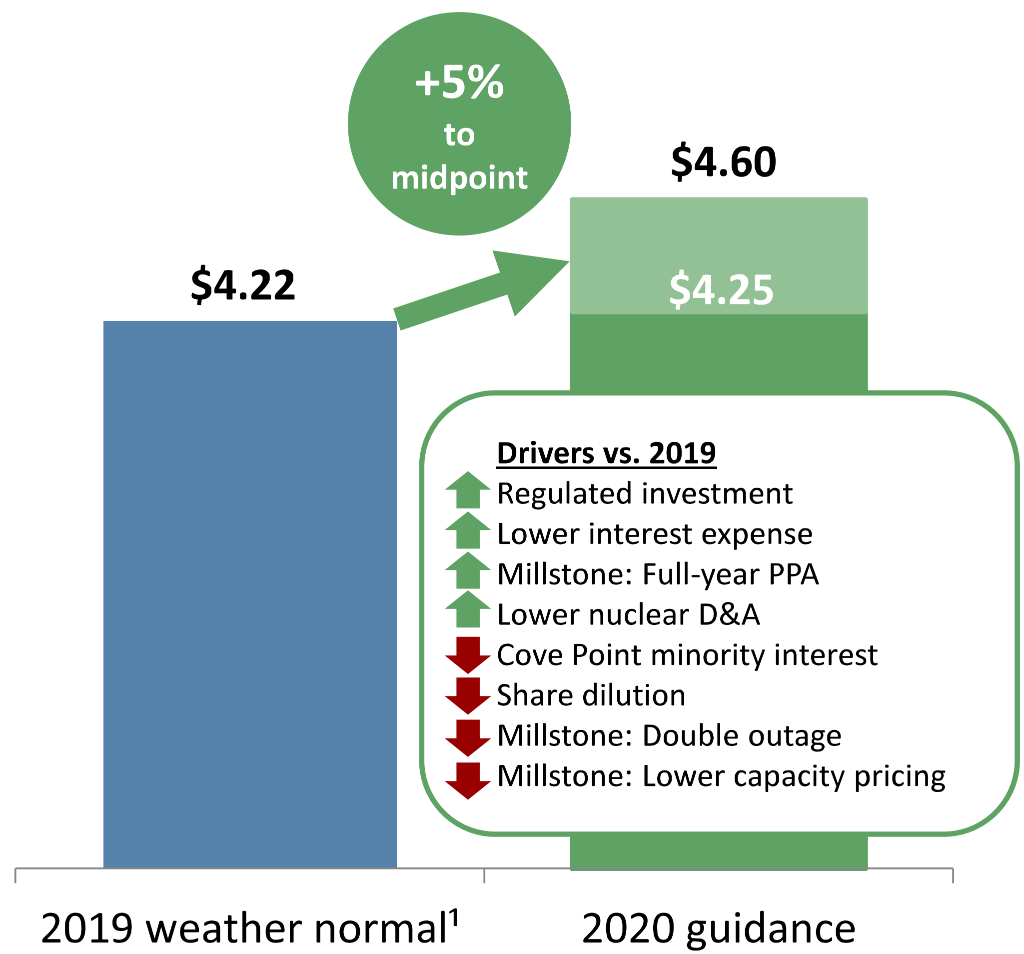
Dominion Energy®

Q4 2019 earnings call

February 11, 2020

Guidance

Operating earnings and dividends per share



- Q1 2020 operating EPS guidance: **$1.05—$1.25**
- 2020+ annual operating EPS growth per year: **5%+**
- Dividends per share growth: **2.5%** per year[2]

[1] See appendix page 42 for detailed weather impact
[2] Subject to Board approval

Key themes

Dominion Energy®

95% — Regulated + "like" earnings

70% / 25% — Earnings from: State-regulated utilities / FERC-regulated assets serving utility customers

~6% — Year-over-year rate base growth

$26B — Five-year growth capital plan (2019—23)

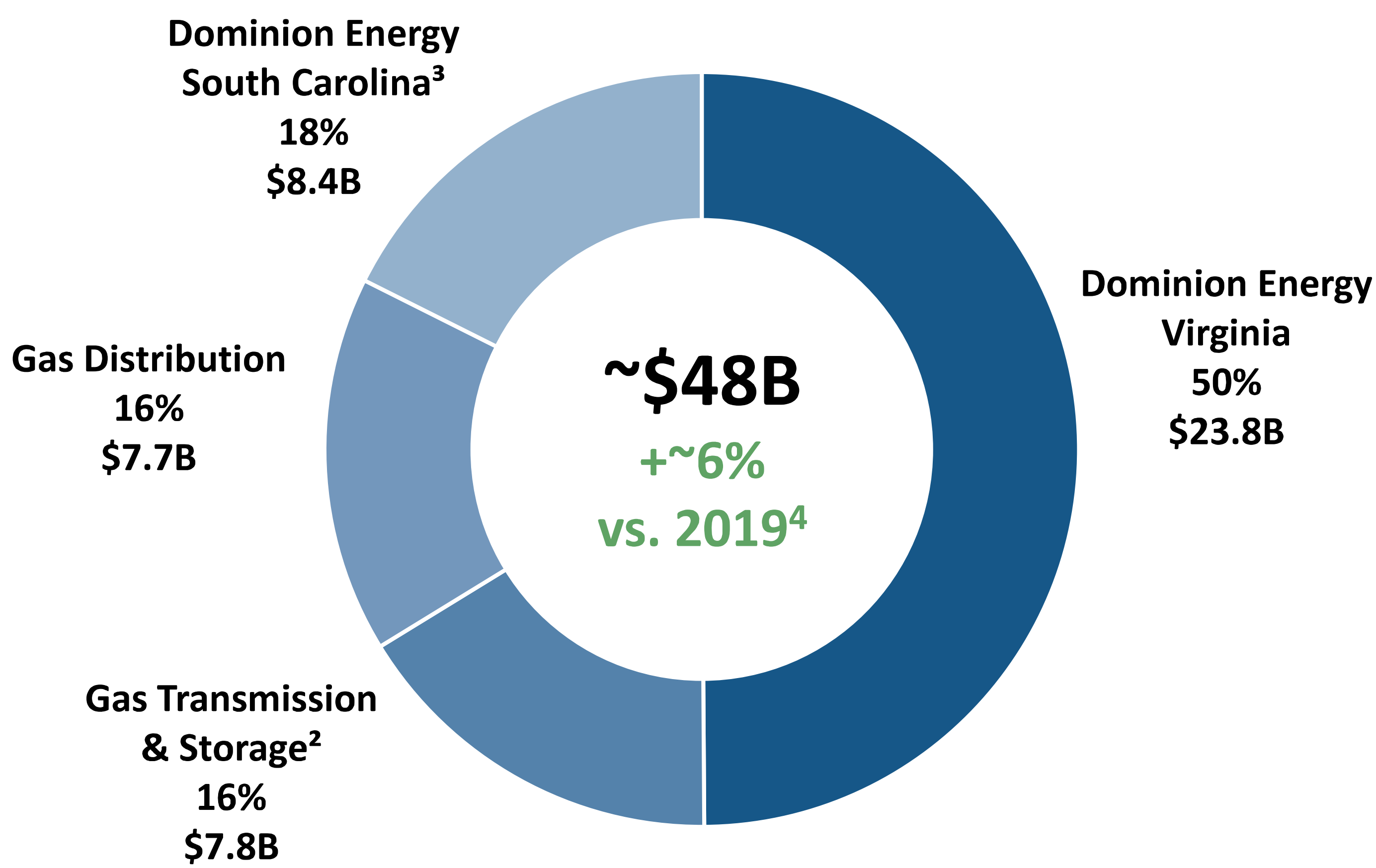
16th — Consecutive quarter of meeting / exceeding midpoint of guidance

Affirmed — 5%+ operating EPS growth post-2020; 2.5% DPS growth[1]

[1] Subject to Board approval

Estimated rate base growth in 2019[1]

$ billions



Note: Gas Distribution and DEV represent estimated rate base as of 12/31/19; DESC and Gas Transmission & Storage represent estimated rate base as of 9/30/2019

[1] See appendix slides 36-40 for details and assumptions

[2] Includes D share of ACP, Supply Header, Iroquois, and jurisdictional Cove Point LNG and Pipeline; excludes Cove Point export and liquefaction

[3] Includes NND

[4] See page 62 of March 25, 2019 investor day materials

2019 Fourth Quarter Review

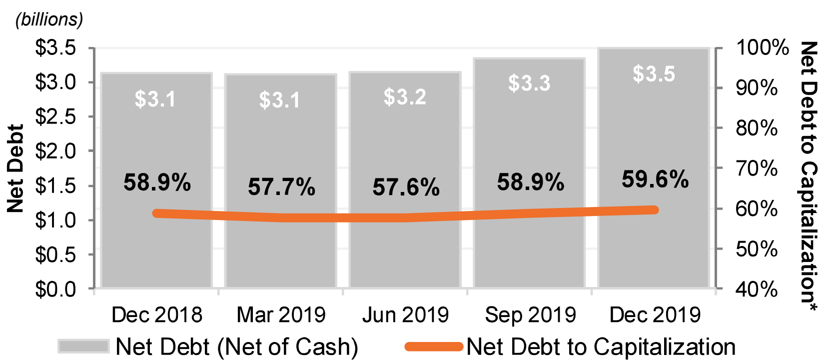
Feb. 7, 2020

Strong Financial Position

Committed to Strong Investment-Grade Credit Ratings

S&P	Moody's	Fitch
BBB+	**Baa2**	**BBB+**
Stable outlook	**Stable outlook**	**Stable outlook**
Affirmed Feb. 28, 2019	Affirmed Dec. 20, 2019	Affirmed Aug. 29, 2019

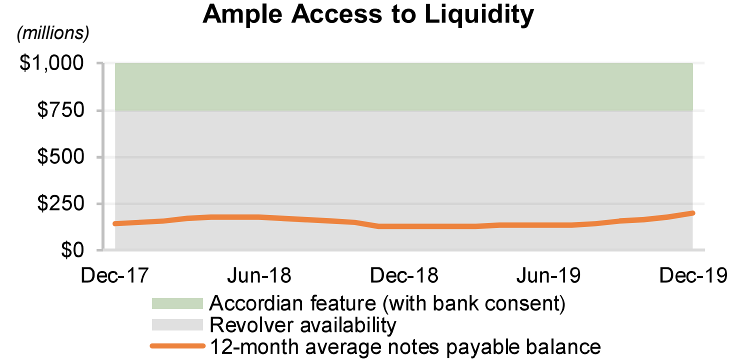
Capital Structure



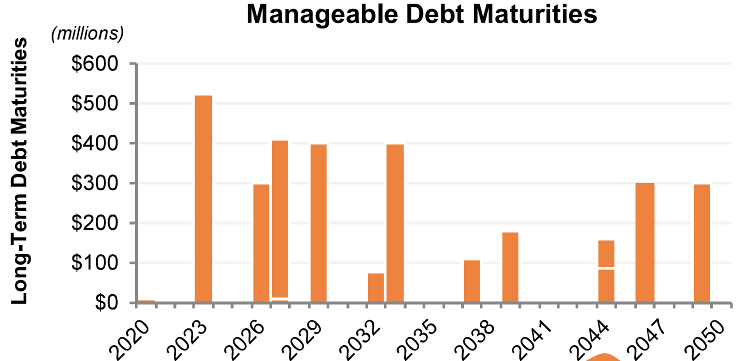
* Excludes noncontrolling interest; see Appendix for detailed capital structure

Strong Liquidity and Debt Profile

Ample Access to Liquidity



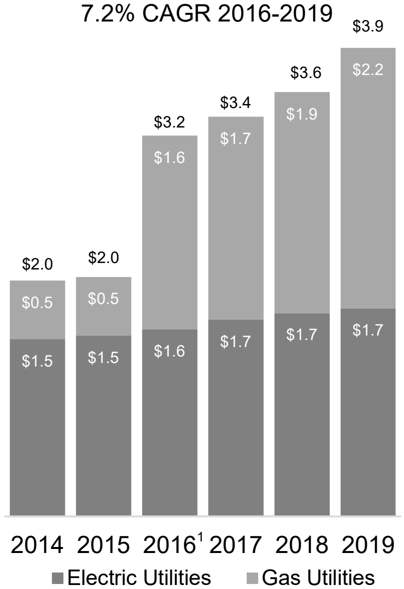
Manageable Debt Maturities



Strategic Execution Delivers Results

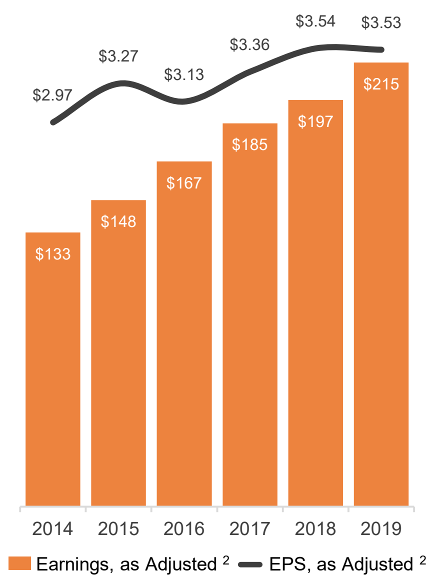
Estimated Rate Base [1]
(in billions as of year-end)

Nearly doubled since 2014
7.2% CAGR 2016-2019



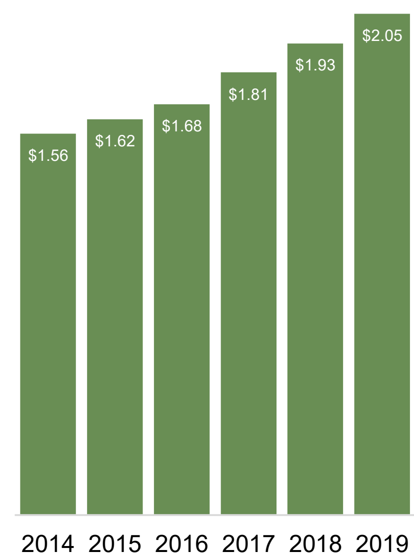
EPS, As Adjusted and Earnings, As Adjusted [2]

3.5% EPS CAGR 2014-2019
10.1% Earnings CAGR 2014-2019

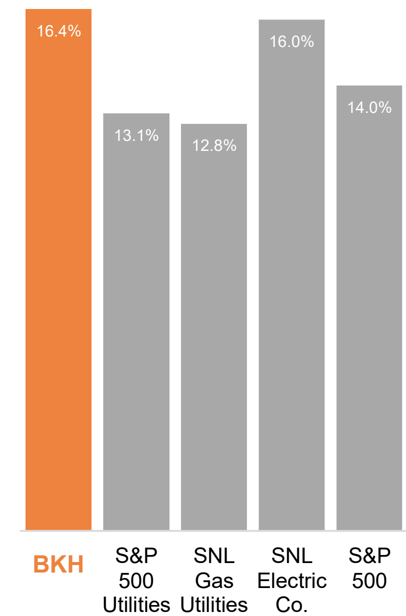


Annual Dividend Per Share

5.6% CAGR 2014-2019



Total Shareholder Return [3]
(10-year annualized return as of Jan. 31, 2020)



Invest for Customer | **Earnings Growth** | **Dividend Growth** | **Strong Long-term TSR**

1 Increase in 2016 rate base primarily driven by February 2016 acquisition of SourceGas
2 Earnings and EPS from continuing operations available for common stock, as adjusted are non-GAAP measures reconciled to GAAP in Appendix
3 10-year annualized total shareholder return as of Jan. 31, 2020, based on data from S&P Global Market Intelligence


ALLETE®
Investor Presentation
March 12, 2020

ALLETE is executing on its multi-faceted strategy; record construction activity in 2019 and 2020

ALLETE

2019 Highlights

- ✓ Achieved earnings growth and guidance objectives
- ✓ Achieved dividend increase objective
- ✓ Clarity on credit headroom
- ✓ First tax equity financing completed
- ✓ Exited U.S. Water and redeployed capital
- ✓ Great Northern Transmission Line completed
- ✓ Minnesota Power retail rate case filing
- ✓ Business rescaled for success
- ✓ Refurbishment of operating wind facilities
- ✓ Glen Ullin wind project completed
- ✓ South Peak wind project nearly completed
- ✓ Diamond Spring wind project announced

ALLETE

2020 Initiatives

- Earnings growth 6%
- Dividend increase 5%
- Successful completion of Minnesota Power retail rate case
- Energize Great Northern Transmission Line
- NTEC approvals / advancement
- SWL&P retail rate case filing
- Nobles 2 completion
- Complete refurbishment projects
- Diamond Spring completion
- Caddo wind project announced – 303 MWs
- Total goal of 500 MWs new wind projects in 2020
- Additional tax equity financing

Over $.5B in new construction activity in 2019 and 2020 sets the stage for incremental earnings in coming years!

ALLETE provides an attractive value proposition

	Financial Targets
Annual total shareholder return*	9 - 10%
Consolidated average annual earnings growth	5 - 7%
Consolidated payout ratio	60 - 65%
Long-term dividend growth	align with earnings

Sustainable energy solutions

Multi-faceted earnings growth potential

Regulated, contracted or recurring energy revenues

Solid balance sheet and credit ratings with growing cash flow from operations

Attractive and growing dividend

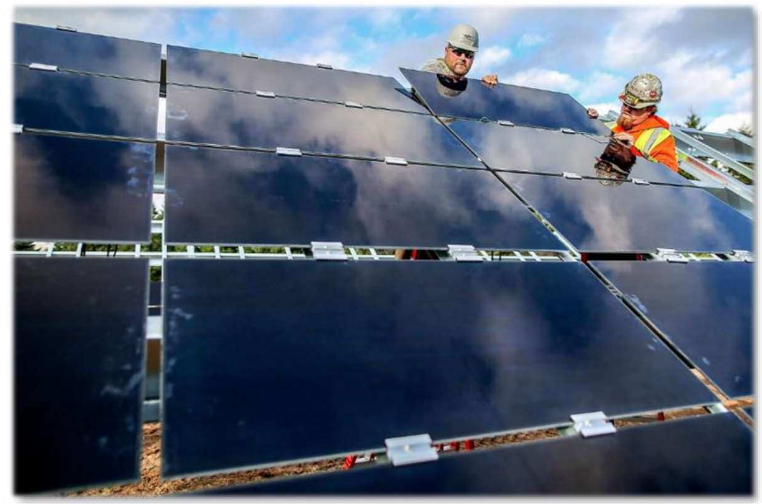
Increased 5% on Jan. 31, 2020

** Defined as earnings growth plus dividend yield*

SWL&P is our regulated electric, natural gas and water distribution company in Wisconsin

Overview

- Wisconsin Public Service Commission regulated
  - Constructive regulatory environment
- Significant rate base investment growth
  - 12/31/2019 YE rate base $84M
  - ~$14M in 2020, ~$50M estimated spend 2020 through 2024
- Rate filing anticipated 2nd quarter 2020
  - New rates anticipated January 1, 2021
  - Current rates based on 55% equity and 10.4% allowed ROE
- Natural gas footprint expansion potential
- Community solar investment proposed



Superior Water, Light & Power will offer a new renewable energy option for customers through a community solar garden that is expected to be generating power by late 2020

SUPERIOR WATER, LIGHT & POWER CUSTOMERS
15,000 electric, 13,000 natural gas, 10,000 water

ALLETE


Customers at the Center
Investor Meetings
Mar. 30 – Apr. 1, 2020
Ameren

Our Value Proposition for Customers, Shareholders and Environment

Ameren

Strong long-term growth outlook

- **Affirm expected 6% to 8% EPS CAGR from 2018-2023[1,2,3]**
- **Expect 6% to 8% EPS CAGR from 2020-2024[1,4]**
- **Expect ~8.7% rate base CAGR from 2019-2024[1]**
- **Constructive frameworks for investment in all jurisdictions**
- **Strong long-term infrastructure investment pipeline**
  - $36+ billion in investment opportunities 2020-2029[1]

Attractive dividend

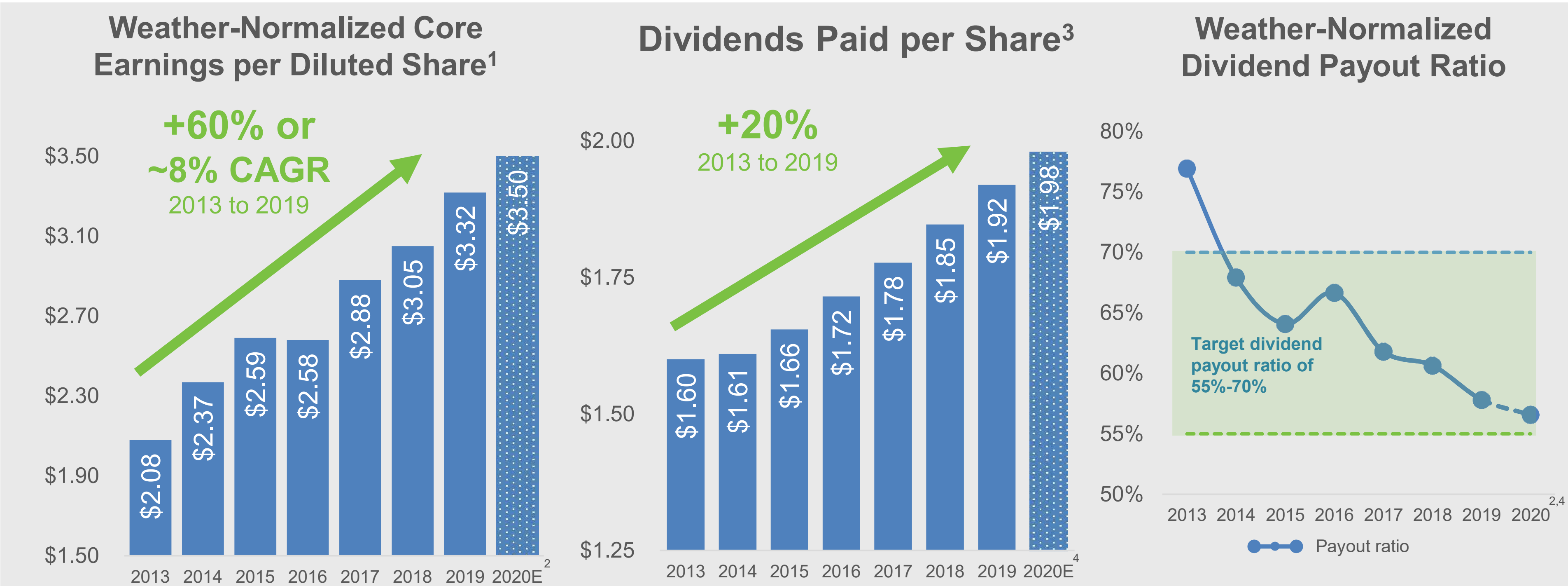
- **Annualized equivalent dividend rate of $1.98 per share provides attractive yield of ~2.7%[5]**
  - Dividend was increased in Oct. 2019 for the sixth consecutive year
- **Expect payout ratio to range between 55% and 70% of annual earnings**
  - 2020 EPS guidance range midpoint of $3.50[1] implies ~57% payout using annualized dividend rate of $1.98 per share

Attractive total return potential

- **Track record of delivering strong results**
  - Core[3] EPS increased ~60% or ~8% CAGR from 2013-2019
- **Attractive combined earnings growth outlook and yield compared to regulated utility peers**
- **We believe execution of our strategy will continue to deliver superior long-term value for customers, shareholders and environment**

[1] Issued and effective as of Feb. 26, 2020 Earnings Conference Call. [2] Using $3.05 as the base, which is 2018 weather-normalized core diluted EPS. [3] See pages 31 and 32 for GAAP to core and weather-normalized reconciliations. [4] Using 2020 EPS guidance range midpoint of $3.50 as the base. [5] Based on Mar. 26, 2020 closing share price.

Strong Track Record of EPS and Dividend Growth



[1] See pages 31 and 32 for GAAP to core and weather-normalized reconciliations. [2] Represents midpoint of 2020 EPS guidance range of $3.40 to $3.60 issued and effective as of Feb. 26, 2020 Earnings Conference Call.
[3] Unrounded dividends 2015-2018 are $1.655, $1.715, $1.7775 and $1.8475. [4] Annualized dividend equivalent rate. Future dividend decisions will be driven by earnings growth, in addition to cash flows and other business conditions, and are at the discretion of Ameren's Board of Directors.

Financial Strategy

- **Strong Liquidity Profile**
  - $2.3 billion of combined credit under facilities maturing in Dec. 2024
    - $1.1 billion Illinois credit facility ($800 million sublimit for Ameren Illinois; $500 million for Ameren Corp.)
    - $1.2 billion Missouri credit facility ($850 million sublimit for Ameren Missouri; $900 million for Ameren Corp.)
    - In December 2019, the facilities were amended and extended by two years to December 2024, with two one-year options to extend the maturity date to December 2026 upon mutual consent of the borrowers and lenders. The capacity was increased from $2.1 billion to $2.3 billion.
  - Three commercial paper programs supported by credit facilities - $1.2 billion at Ameren Corp., $800 million at Ameren Missouri and $800 million at Ameren Illinois
  - Available liquidity as of December 31, 2019, was approximately $1.9 billion[1]
- **Commitment to maintaining strong credit ratings and credit metrics and a healthy capital structure while growing rate base**
- **Disciplined dividend policy**
  - Expect payout ratio to range from 55% to 70% of annual earnings

[1] Liquidity amount does not include additional $540 to $550 million available under the forward equity contract.

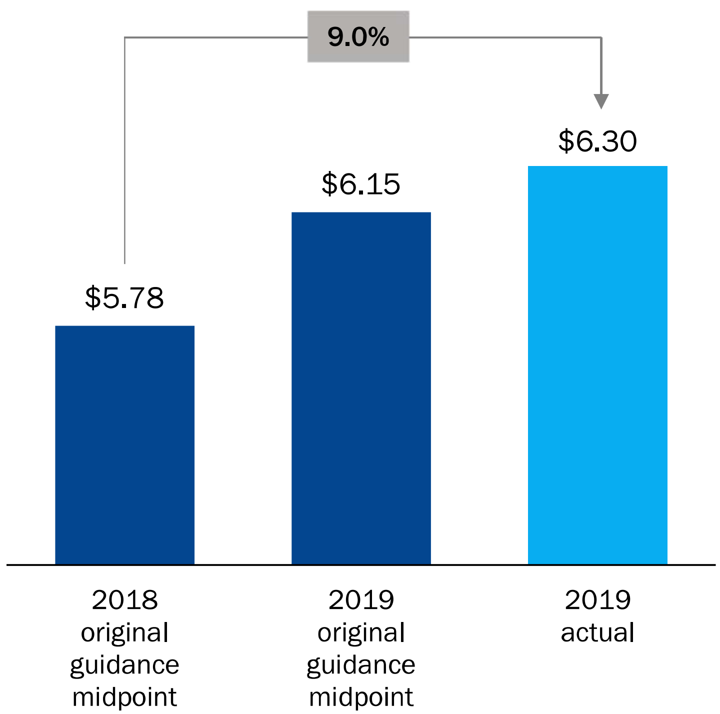
DTE YEAR END 2019 EARNINGS CONFERENCE CALL

FEBRUARY 5, 2020

DTE

Strong operational and financial performance in 2019

Operating EPS[1]



- Delivered strong financial results in 2019
  - Operating EPS growth rate of 9.0% from 2018 original guidance
  - Exceeded original guidance midpoint for 11th consecutive year
  - Increased dividend 7%; targeting 7% dividend growth through 2021[2]
- Achieved excellent results around key customer and employee initiatives

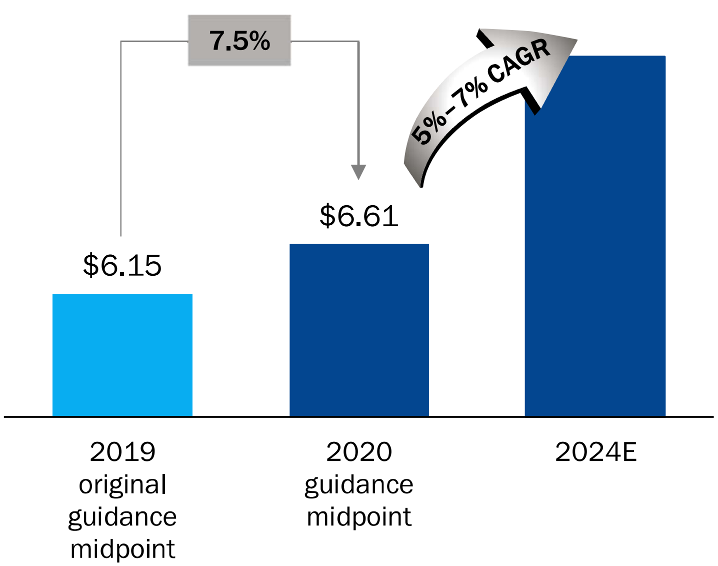
Solid results position DTE for future growth

DTE

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix
2. Subject to Board approval

Positioned for continued growth from strong 2020 guidance

Operating EPS[1]



Targeting 5% – 7% operating EPS growth through 2024 from 2020 base

- 2020 operating EPS guidance midpoint provides 7.5% growth from 2019 original guidance
- Well-positioned for 5% – 7% operating EPS growth through 2024
- Continued investment in utilities
  - Investing 80% of 5-year capital in utility infrastructure and cleaner energy
- Delivering non-utility operating earnings with increased certainty
  - Supported by deep development queue and high-quality contracted assets
- Commitment to positive culture provides a solid framework for success

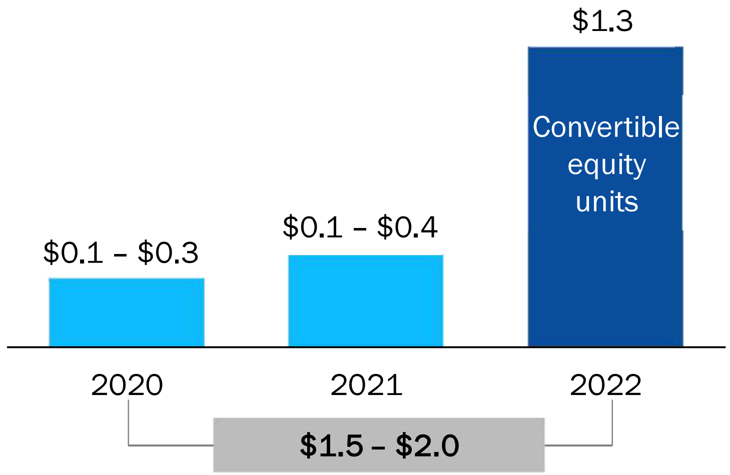
DTE

1. Reconciliation of operating earnings (non-GAAP) to reported earnings included in the appendix

Maintaining strong cash flow, balance sheet and credit profile

(billions)

Planned equity issuances 2020 – 2022



- $1.6 billion of available liquidity at year-end 2019
- Maintaining strong investment-grade credit rating and FFO[1]/Debt[2] target at 18%

Credit ratings

	S&P	Moody's	Fitch
DTE Energy (unsecured)	BBB	Baa2	BBB+
DTE Electric (secured)	A	Aa3	A+
DTE Gas (secured)	A	A1	A

DTE

1. Funds from Operations (FFO) is calculated using operating earnings
2. Debt excludes a portion of DTE Gas' short-term debt and considers 50% of the junior subordinated notes and 100% of the convertible equity units as equity

Investor Meetings
February 2020

WORLD CLASS PERFORMANCE
DELIVERING
HOMETOWN SERVICE

FOCUSED ON WORLD CLASS PERFORMANCE

CMS ENERGY

CMS LISTED NYSE

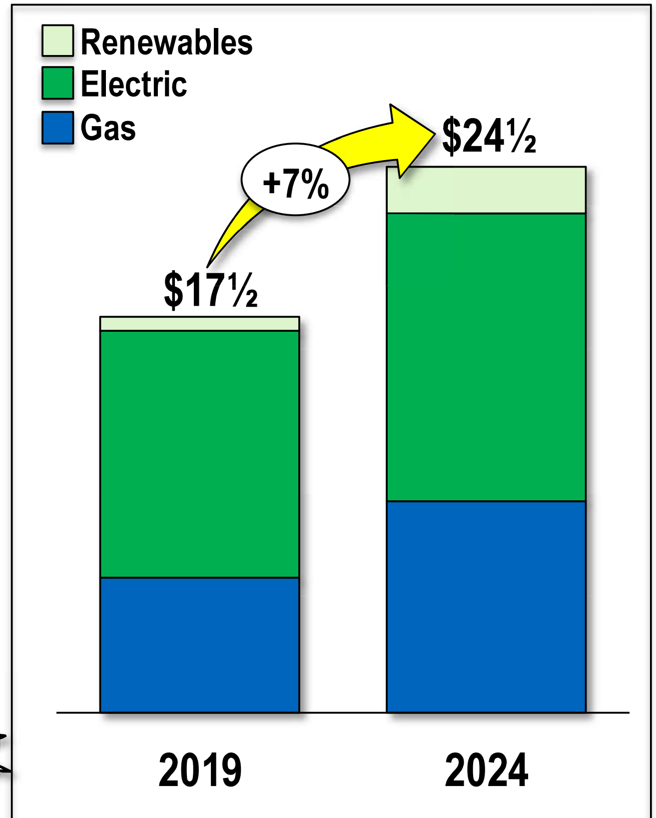
Utility Customer Investment Plan . . .

CMS ENERGY

Investment Plan

Capital Investment (Bn):	Prior '19-'23 Plan	New '20-'24 Plan
Renewables	$ 1¾	$ 1¾
Electric Utility	5	5½
Gas Utility	5	5
Total	$ 11¾	$12¼

Rate Base Growth

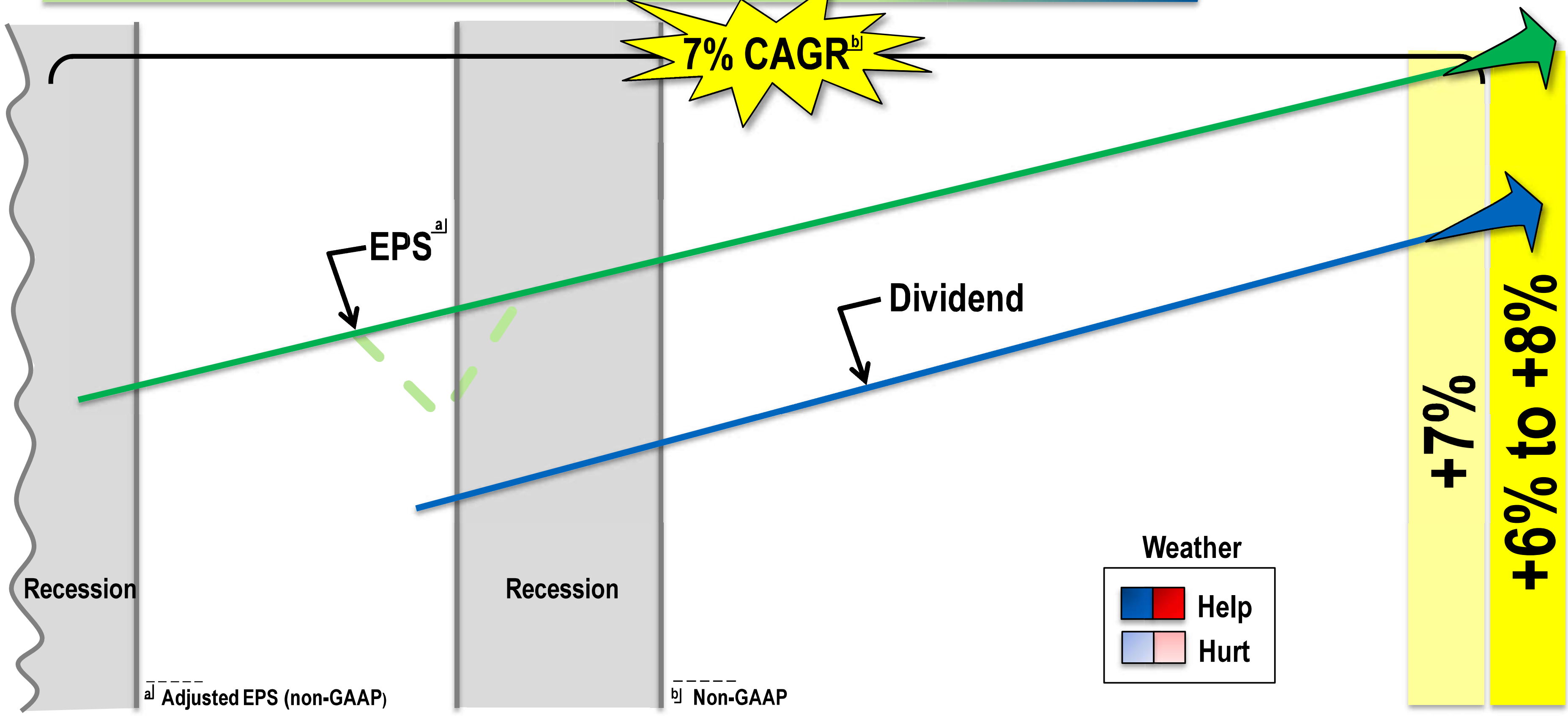


$25 Bn 10-Yr Plan[a] with $3 - $4 Bn of Opportunities

[a] 10-yr Plan includes years 2019 through 2028

. . . includes increased renewables and maintains focus on safety & reliability.

Consistent Growth Through . . .



[a] Adjusted EPS (non-GAAP)

[b] Non-GAAP

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Cold winter	Mild summer	Hot summer	Warm winter	Mild summer	Cold winter	Summer-"less"	Hot summer	Hot summer	Warm winter	Mild summer	Polar vortex	Cold Feb. Warm Dec	Warm winter	Warm winter	Hot summer	Storms	
Governor (D)								Governor (R)								(D)	
Commission (D)					Commission (D)				Commission (R)				Commission (I)			(D)	

. . . changing circumstances.

2020 Priorities . . .

CMS ENERGY

People	Planet	Profit
• Top decile safety performance – Implement gas safety management system (API 1173) – Eliminate 9,250 gas vintage services • Top quartile Customer Experience Index (CXi ≥ 72) • Maintain top quartile employee engagement	• Continue progress in reduction of CO_2 and methane emissions • Enhance, restore or protect 1,000 acres of land • Reduce water use by 200 million gallons	• Consistent industry-leading financial performance • Solid investment grade credit ratings • Meet customer affordability targets • Meet O&M cost performance targets

ENABLING THOSE CLOSEST TO THE WORK

Performance through CE WAY

Utilizing the 5 Basic Plays

Visual Management

Operating Reviews

Problem Solving

Standard Work

WASTE ELIMINATION

. . . will enable an 18th year of strong performance.

Consolidated Edison, Inc.

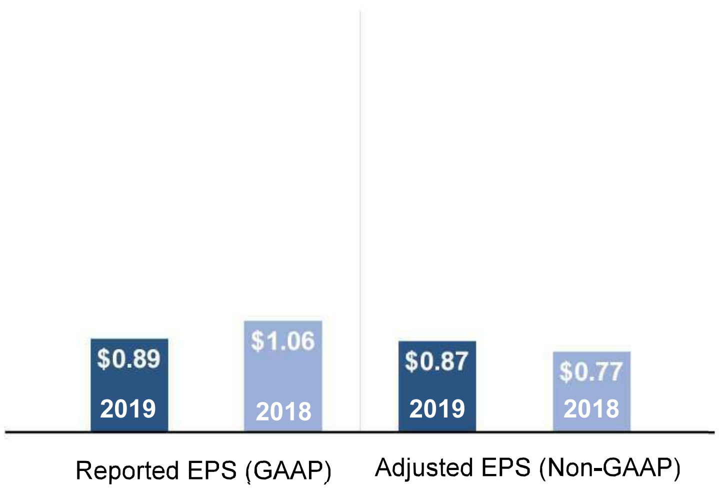
March 2020 Update &
2019 Earnings Release Presentation

conEdison

Dividend and Earnings Announcements

- On January 16, 2020, the company issued a press release reporting that the company had declared a quarterly dividend of 76.5 cents a share on its common stock -- an annualized increase of 10 cents over the previous annualized dividend of $2.96 a share and its 46th consecutive annual increase.
- On February 20, 2020, the company issued a press release forecasting its adjusted earnings per share for the year 2020 to be in the range of $4.30 to $4.50 a share[a]. The company is also forecasting a five-year compounded annual adjusted earnings per share (EPS) growth rate of 3% to 5% based off 2020 adjusted earnings per share guidance.

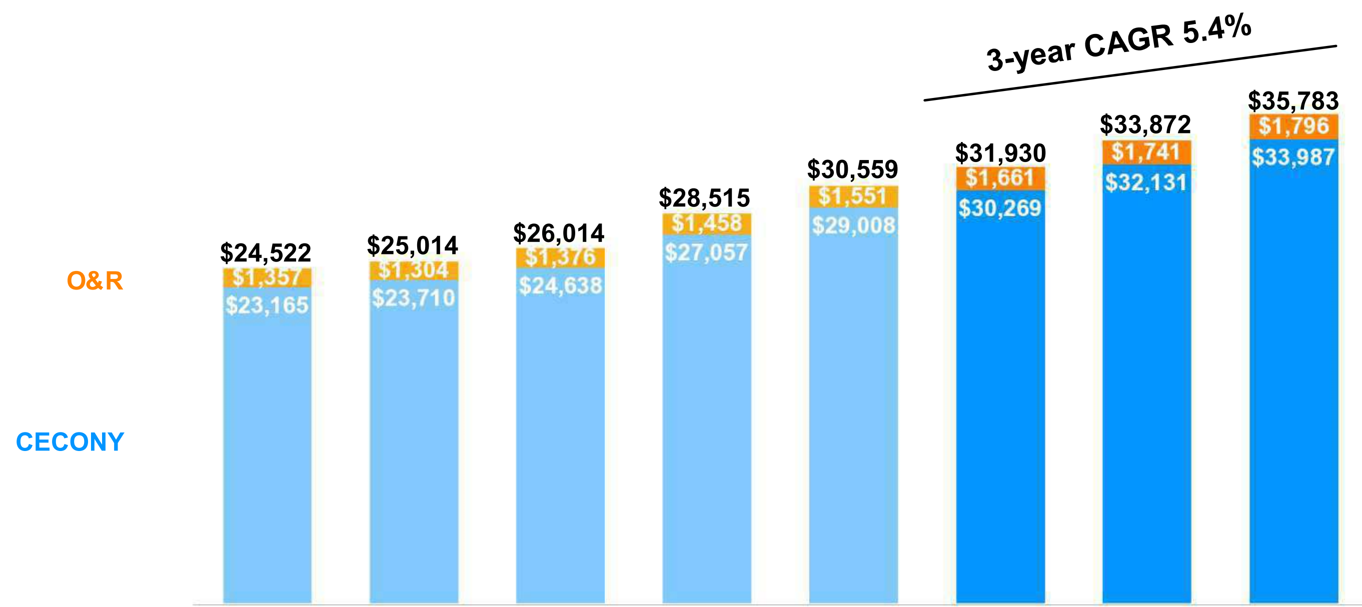
4Q 2019 vs. 4Q 2018



2019 vs. 2018

a. Adjusted earnings per share exclude the effects of hypothetical liquidation at book value (HLBV) accounting for tax equity investments in certain of the Clean Energy Businesses' renewable electric production projects (approximately $(0.19) a share). Adjusted earnings per share also exclude the Clean Energy Businesses' net mark-to-market effects, the amount of which will not be determinable until year end.

Average Rate Base Balances
($ in millions)



		Actual 2015	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Forecast 2020E(a)	Forecast 2021E(a)	Forecast 2022E(a)
CECONY	Electric	$ 17,599	$ 17,971	$ 18,513	$ 20,057	$ 21,149	$ 21,660	$ 22,783	$ 23,926
	Gas	4,023	4,267	4,723	5,581	6,408	7,171	7,911	8,622
	Steam	1,543	1,472	1,402	1,419	1,451	1,438	1,437	1,439
O&R	Electric	769	731	759	806	842	906	948	964
	Gas	386	362	392	426	455	476	498	524
RECO	Electric	202	211	225	226	254	279	295	308

a. Amounts reflect the CECONY electric and gas rate plan approved on January 16, 2020.


CenterPoint Energy
4TH QUARTER 2019
EARNINGS CALL
FEBRUARY 27, 2020

OUR INVESTOR VALUE PROPOSITION

CenterPoint Energy

Largely pure-play regulated gas LDC and T&D utility across 8 states

Regulatory Strategy

Pure-play regulated utility with diversified portfolio and favorable mechanisms providing timely recovery of capital

Predictable Earnings Growth

5 – 7% utility EPS(1)(2) growth supported by strong regulated investment and rate base growth

8-10%
Total Shareholder Return

5-7%
Utility EPS(1)(2) Growth

> 4%
Dividend Yield

~7.5%
Rate Base CAGR(3)

Low 70s
Targeted Payout Ratio

Capital investment

~$13B 5-year(2) capital investment plan to provide safe and reliable service to customers across high growth jurisdictions

Investment Grade Credit Quality

Continued commitment to solid investment grade credit quality and balance sheet strength

Supported by strong cash flow from Enable to fund regulated growth

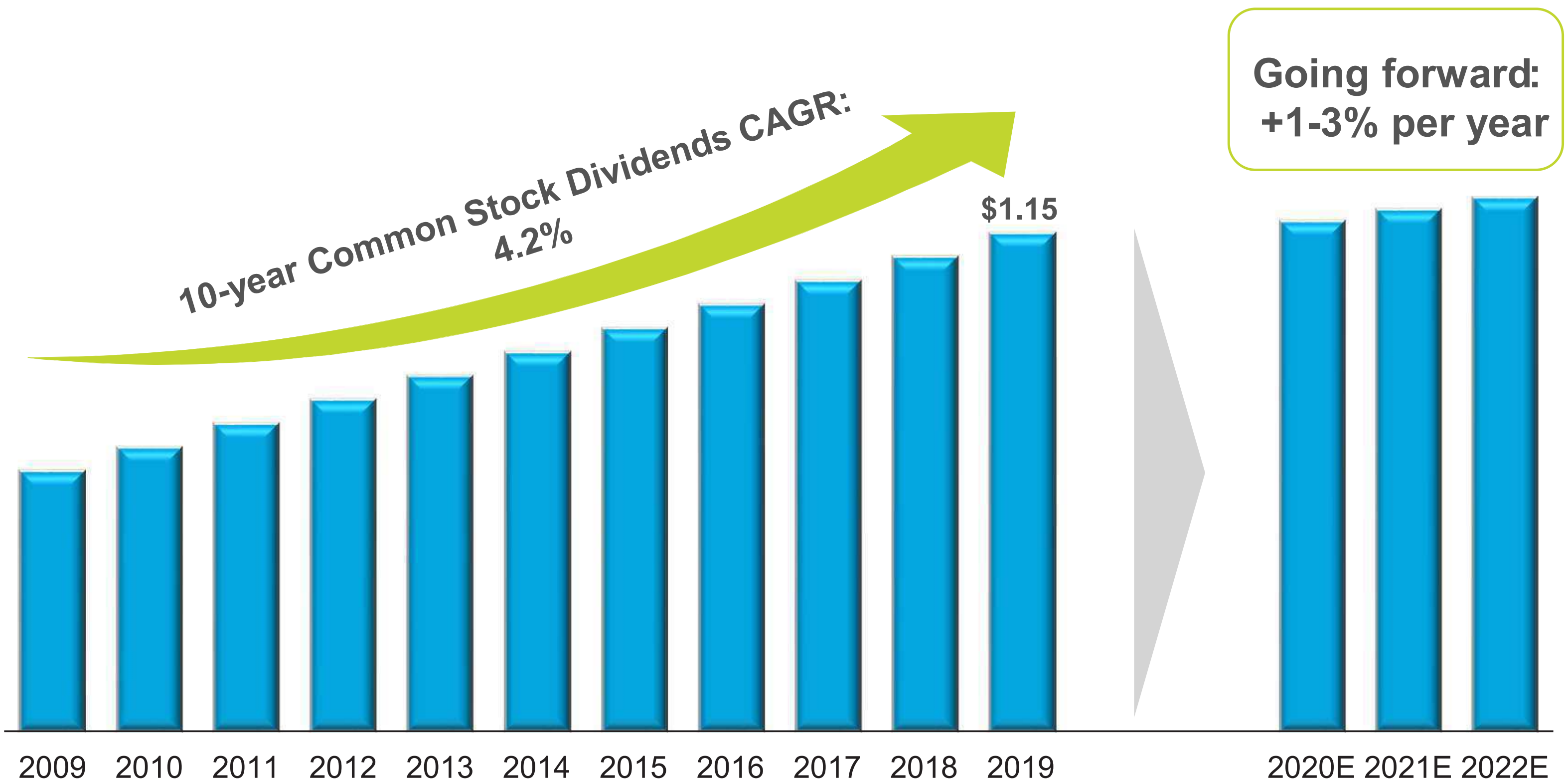
Note: Refer to slide 2 for information on forward-looking statements
(1) Utility earnings per share on a guidance basis
(2) Compound annual growth rate over the period 2020 through 2024
(3) Based off 2019E through 2024E Electric T&D, Electric Generation and Natural Gas Distribution rate base as calculated by the individual jurisdictions

ONGOING COMMITMENT TO THE COMMON STOCK DIVIDEND

CenterPoint Energy

Payout ratio over time:

2009A		2019A	2020E Post CIS/CES		Long-term target
72%	*10 years of DPS increases* →	*64%*	*83%*[(1)]	→	*Mid-70s*



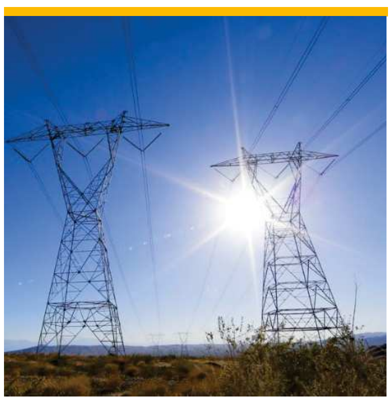
Common Stock Dividend per share

Note: Refer to slide 2 for information on forward-looking statements and slide 3 for information on non-GAAP measures

(1) Assumes the midpoint of 2020 utility guidance basis EPS range and Midstream Investments earnings range, which utilizes the Enable Midstream Partners' 2020 guidance range as provided on Enable's 4th quarter earnings call on February 19, 2020 and assumes an allocation of CenterPoint Energy corporate overhead based upon its relative earnings contributions

Fourth Quarter and Full-Year 2019 Financial Results

February 27, 2020

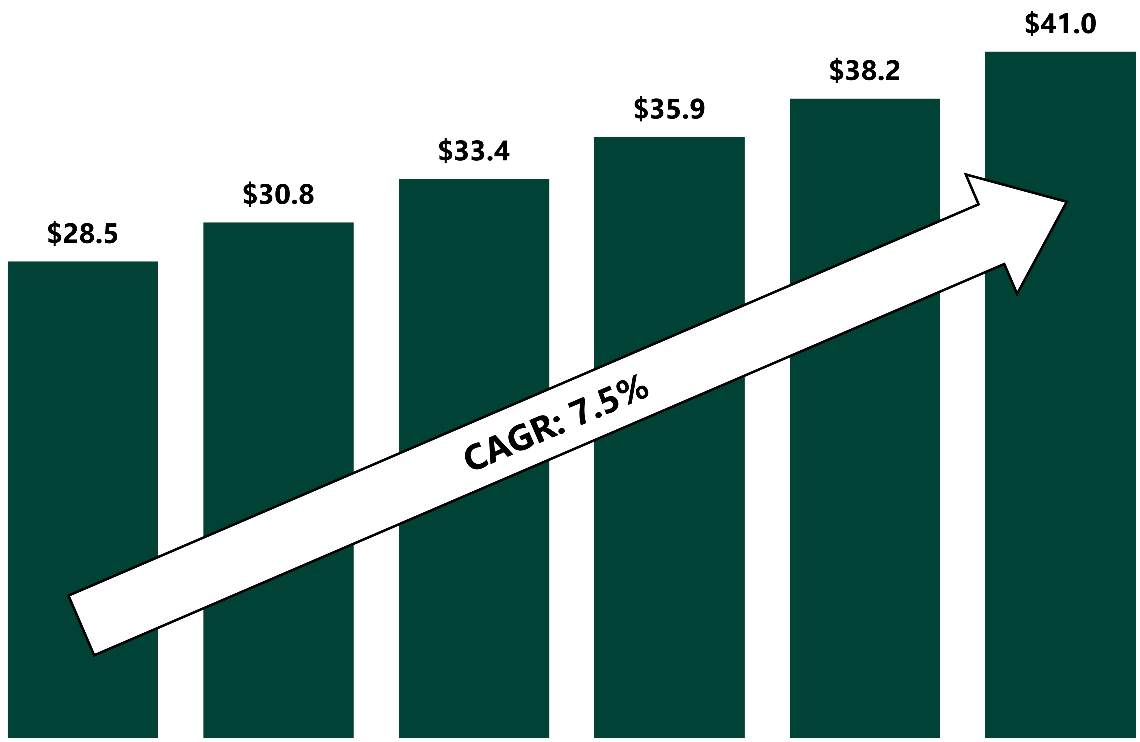



Energy for What's Ahead®

EDISON INTERNATIONAL®

SCE Rate Base Forecast

($ billions)



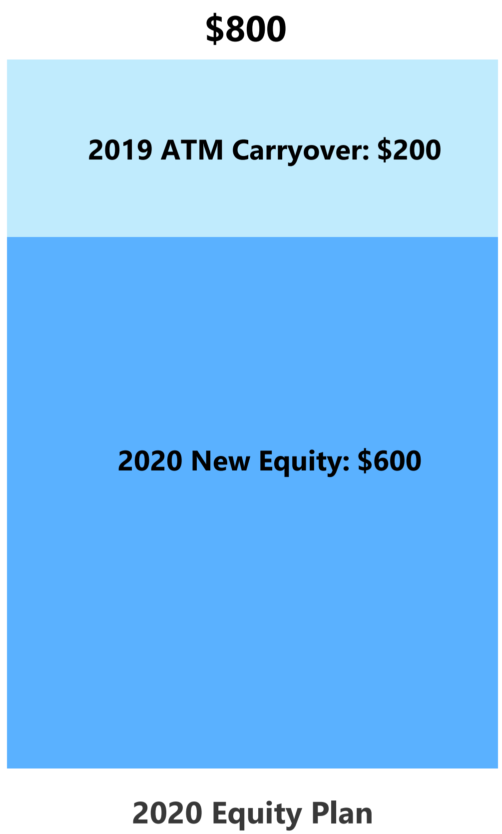
	2018	2019	2020	2021[1]	2022	2023	***Range Case CAGR***
Range Case [2]	$28.5	$30.8	$33.3	$35.1	$37.0	$39.2	***6.6%***

1. Morongo Transmission holds an option to invest up to $400 million in the West of Devers Transmission Project, or half of the estimated cost of the transmission facilities only, at the in-service date, estimated to be 2021. In the table above, the rate base has been reduced to reflect this option. Capital forecast includes 100% of the project spend
2. Rate base forecast range case reflects capital expenditure forecast range case

Note: Weighted-average year basis. FERC based on latest forecast and represents approximately 20% of total rate base throughout the forecast period. CPUC excludes the ~$1.6 billion of SCE's fire risk mitigation capital expenditures in accordance with Assembly Bill 1054. CPUC also excludes the "rate-base offset" adjustment related to the 2015 GRC write-off of the regulatory asset for 2012-2014 incremental tax repairs and rate base associated with projects or programs that have not yet been approved, except for GS&RP spend incurred before August 1, 2019.

EIX Financing Framework – 2020 and Beyond

($ millions)



Growth Financing Framework

- $800 million of 2020 equity issuance to complete 2019 financing plan and support SCE growth capital needs
- $400 million of HoldCo debt in 2020 to fund remaining EIX and SCE 2020 needs[1]
- Continuation of internal equity programs for 2020
- Targeting long-term FFO/debt ratio of 15-17%
  - Supports investment grade credit rating
  - Imputed 2017/2018 wildfire claims payments and memorandum account balances related to wildfire mitigation and wildfire insurance expenditures impact metrics in the near term
  - Potential credit ratings upgrade as rating agencies' view of wildfire risk and California outlook improves

A measured approach to support balance sheet and maintain investment grade credit rating

1. In addition to SCE's debt financing

DUKE ENERGY®

Earnings Review & Business Update

FOURTH QUARTER 2019

Lynn Good *Chairman / President and CEO*
Steve Young *Executive Vice President and CFO*

February 13, 2020

Delivering on commitments

DUKE ENERGY.

DELIVERING ON FINANCIAL RESULTS…

- ✓ 2019 EPS above guidance range midpoint
- ✓ Strong year-over-year results represent 7% growth
- ✓ Well positioned to continue to deliver 4-6% EPS growth

AND COMMITMENT TO THE DIVIDEND…

- ✓ 93rd consecutive year paying a dividend

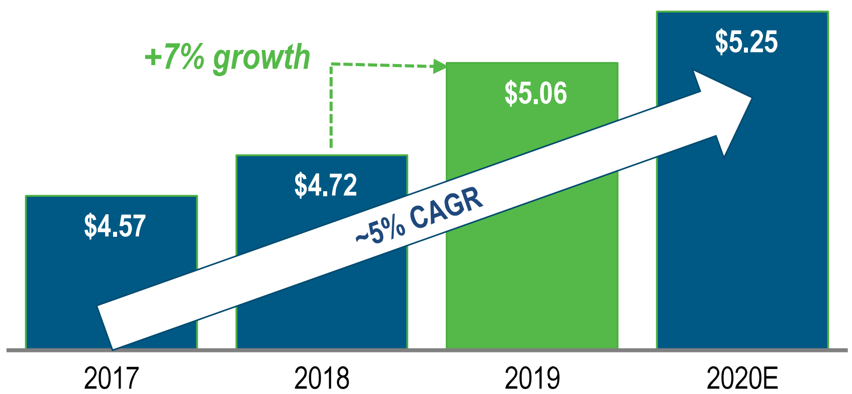
…WHILE MAINTAINING FOCUS ON THE CUSTOMER

- ✓ Delivered outstanding improvement in customer service, increasing reliability measures by 15% and customer satisfaction measures by 25%

$5.06 IN 2019

2019 REPORTED AND ADJUSTED EPS
IN TOP HALF OF GUIDANCE RANGE

ADJUSTED EPS GROWTH



$5.25 TARGET MIDPOINT FOR 2020

INTRODUCING 2020 ADJUSTED EPS
GUIDANCE RANGE OF $5.05-$5.45

4% – 6% GROWTH THROUGH 2024 OFF MIDPOINT OF ORIGINAL 2019 ADJUSTED EPS GUIDANCE RANGE ($5.00)

Focused on investor value creation

DUK LISTED NYSE

A STRONG LONG-TERM RETURN PROPOSITION

DUK LISTED NYSE

3.9%

DIVIDEND YIELD(1) WITH DIVIDEND **GROWTH COMMITMENT**(2)

~8-10%

ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**(3)

4-6%

HIGHLY ACHIEVABLE **EPS GROWTH THROUGH 2024**(4)

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) *As of Feb. 11, 2020*
(2) *Subject to approval by the Board of Directors.*
(3) *Total shareholder return proposition at a constant P/E ratio*
(4) *Based on adjusted EPS off the midpoint of the 2019 guidance range ($5.00)*

Business Update

October 30, 2019

Energy for What's Ahead®

EDISON INTERNATIONAL®

EIX Strategy Should Produce Long-Term Value

Sustained Earnings and Dividend Growth Led by SCE

SCE Rate Base Growth Drives Earnings

- 7-8% average annual rate base growth through 2023
- SCE earnings expected to track rate base growth over the long term

Constructive Regulatory Structure

- Decoupling of electricity sales
- Balancing accounts
- Forward-looking ratemaking

Sustainable Dividend Growth

- Target payout ratio of 45-55% of SCE earnings

Electric-Led Clean Energy Future

EIX Vision

- Lead transformation of the electric power industry
- Focus on clean energy, efficient electrification, grid of the future and customers' technology choice

Wires-Focused SCE Strategy

- Infrastructure replacement – safety and reliability
- Grid resiliency and safety
- Grid modernization – California's low-carbon goals
- Operational excellence

Edison Energy Strategy

- Services for large commercial and industrial customers

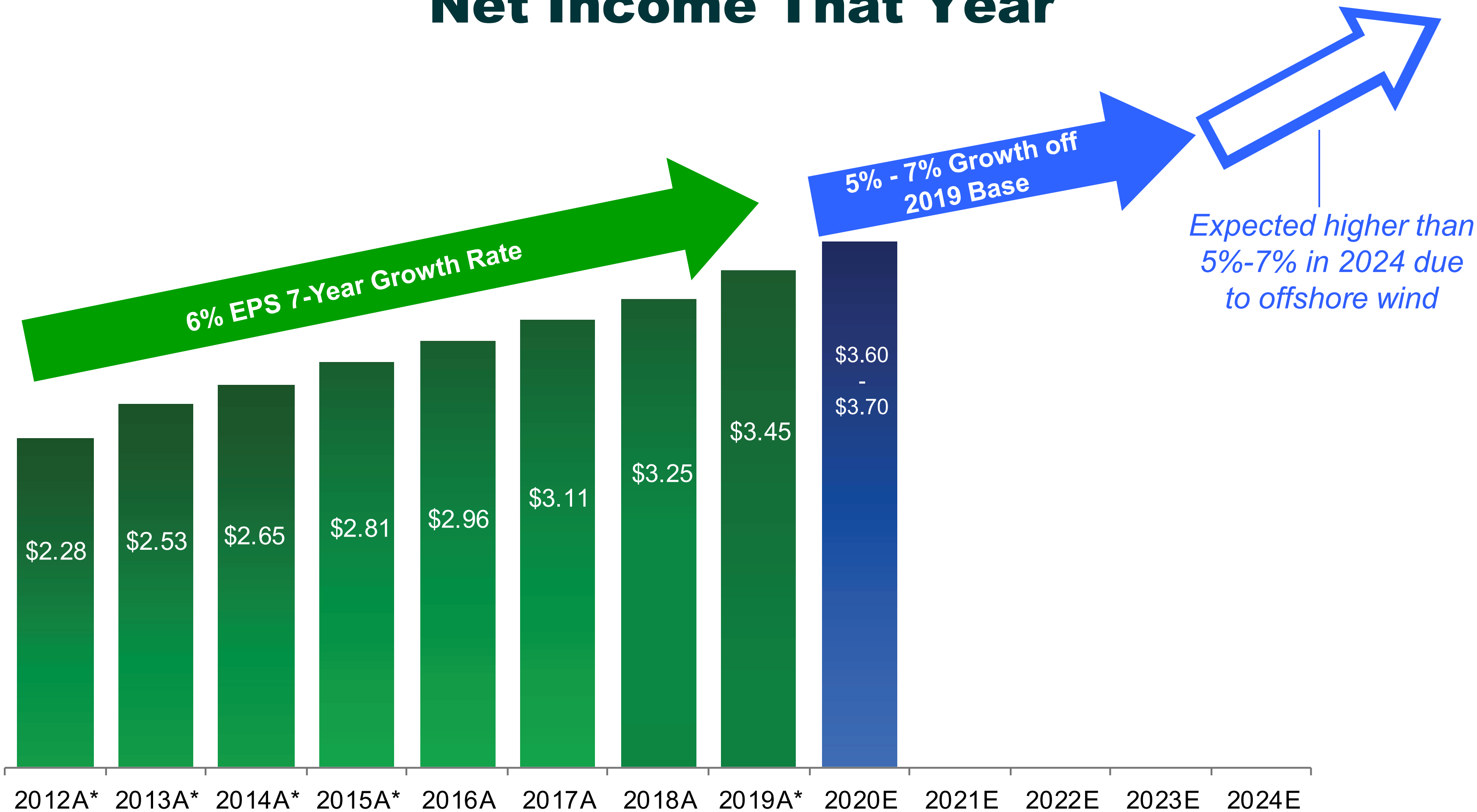
2019 Year-End Investor Call

February 20, 2020

EVERSOURCE ENERGY

EVERSOURCE ENERGY

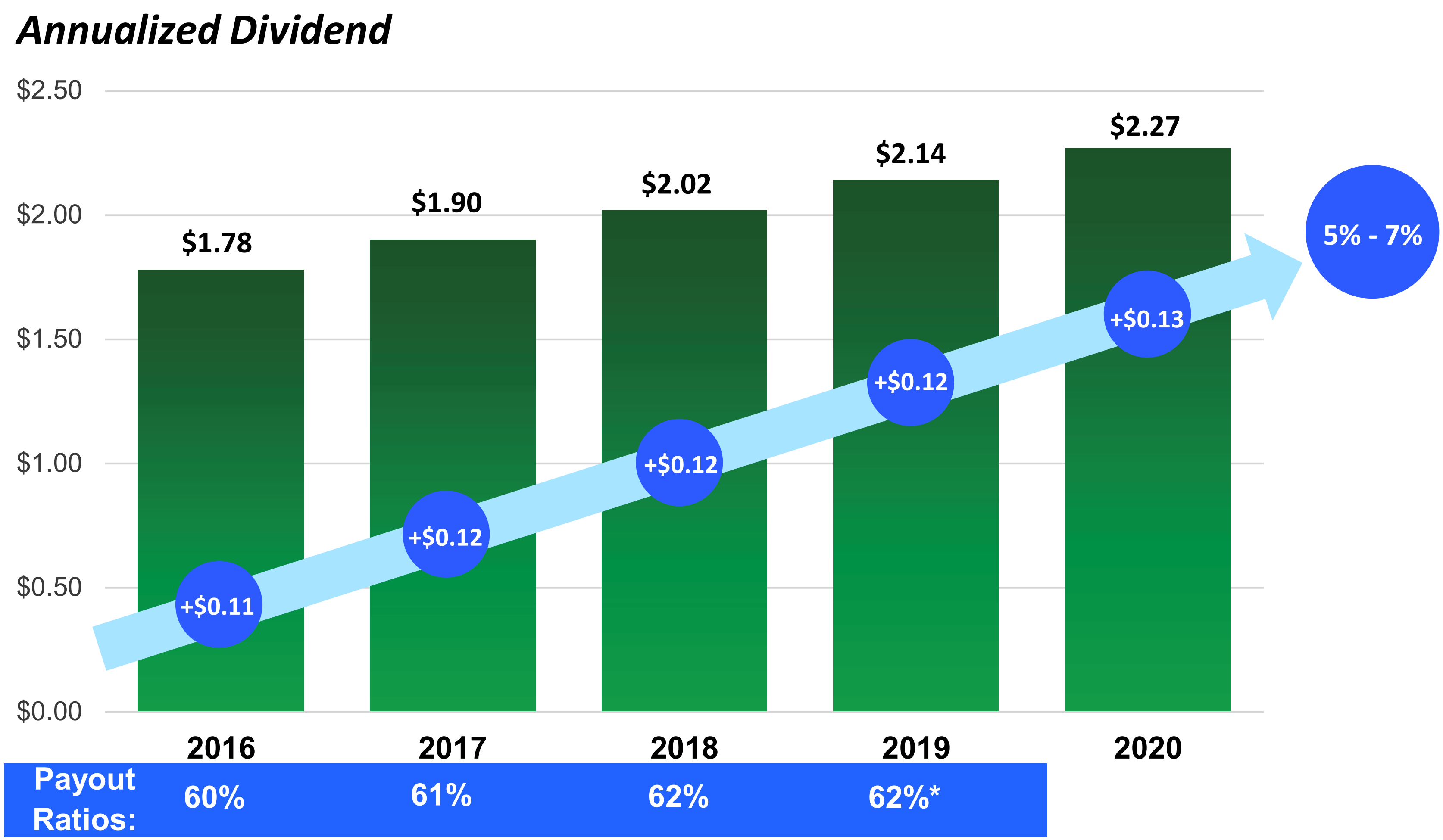
Earnings Growth Could Accelerate in 2024 Should Revolution Wind Provide Meaningful Net Income That Year



*Excludes merger and integration costs in 2012-2015 and NPT charge in 2019

EVERSOURCE ENERGY

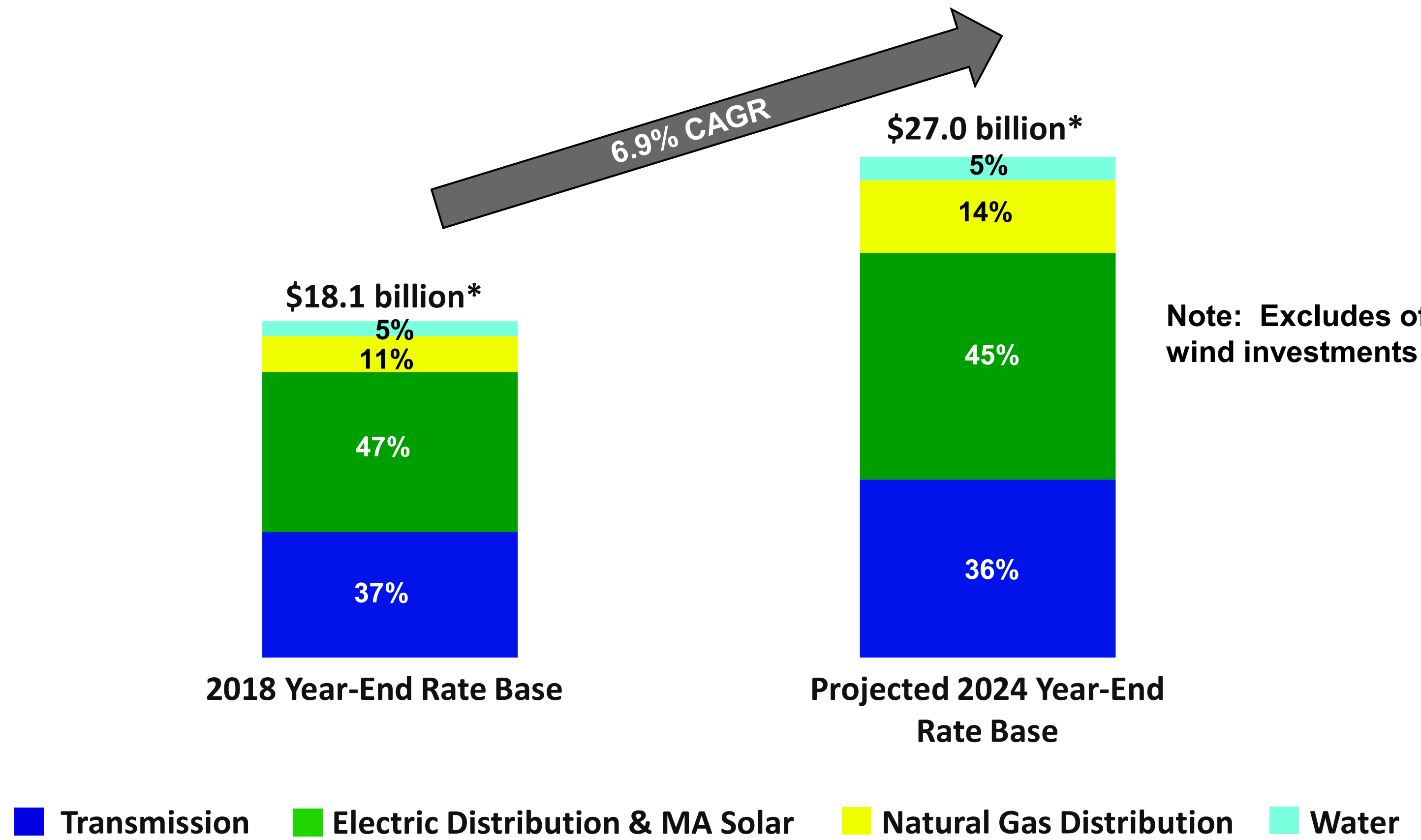
Dividend Growth Continues to Outperform Peers



*Excludes charges related to NPT in 2019

EVERSOURCE ENERGY

Rate Base by Core Business – Current and Future



Note: Excludes offshore wind investments

*Rate base estimates do not include CWIP, which totaled $1.72 billion as of 12/31/18

EVERSOURCE ENERGY

A Value Proposition That Delivers Results for Investors

Keys to Our Success:	*Results Delivered:*	
1. Exceed industry EPS and dividend growth	Seven-year average recurring EPS and dividend growth of 6.1% and 7.2%, respectively, through 2019. Growth driven by robust regulated Cap Ex program and effective cost control	✓
2. Control O&M spending	Seven-year average O&M reduction 2+%/yr. through 2019 (~ $220M)	✓
3. Maintain strong financial condition	Top tier credit rating	✓
4. Deliver top-tier service quality and reliability	Reliability metrics now top decile	✓
5. Manage a robust investment program focused on safety, reliability, customer service	Capital expenditures of $14.2 billion for 2020 -2024 for core businesses ensure a safe and reliable delivery system for our 4 million customers	✓
6. Pursue clean energy solutions for the region	Progress on solar, storage, EV infrastructure, energy efficiency, offshore wind initiatives	✓
7. Address environmental, social and governance strengths	Achieving top industry ratings from key sustainability raters	✓

4th quarter 2019 earnings teleconference

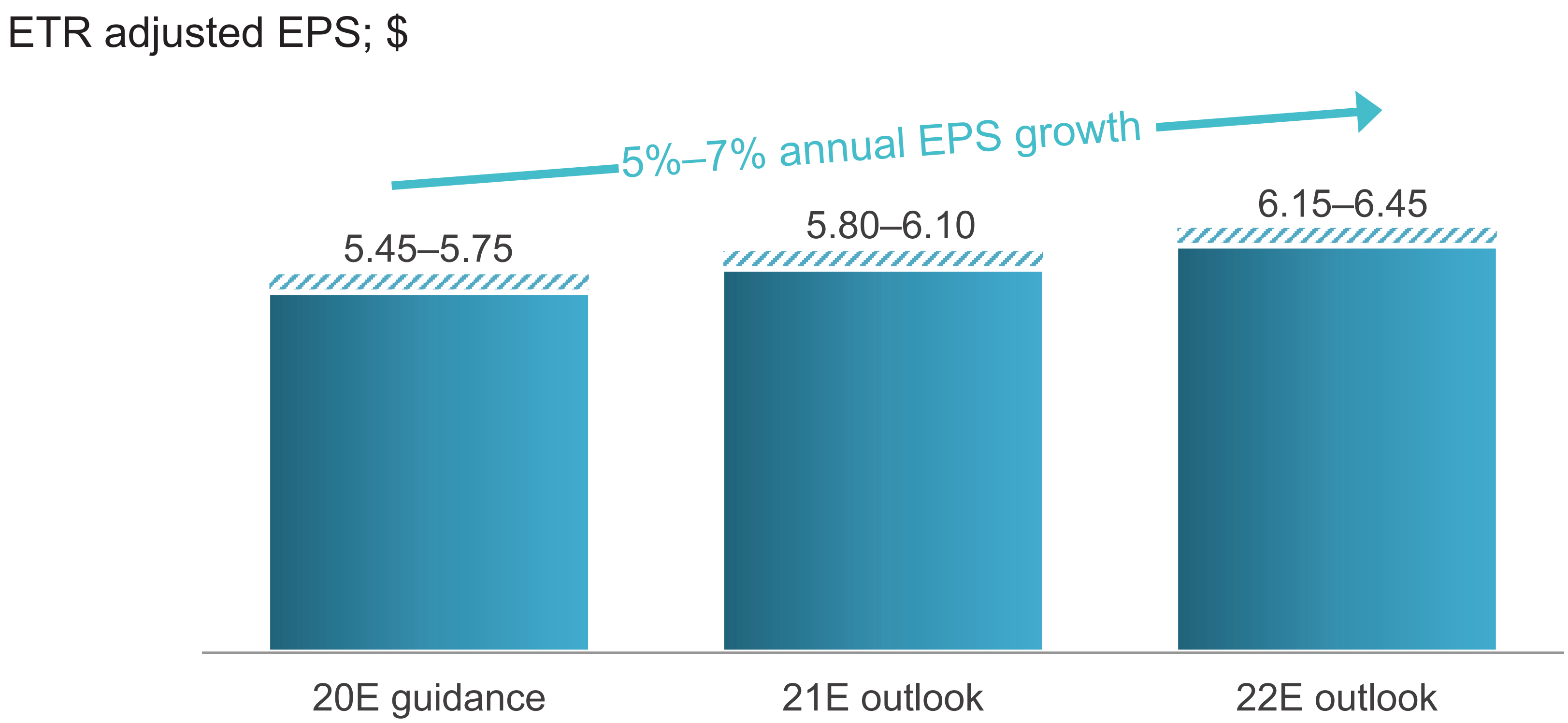
February 19, 2020

Entergy® | WE POWER LIFE℠

Creating sustainable value

ETR adjusted EPS guidance and financial outlook

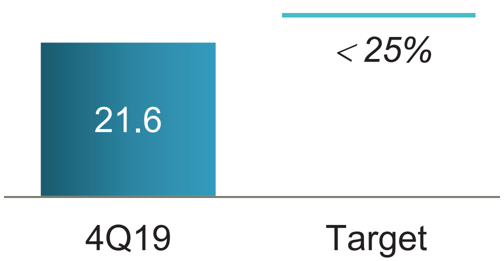
Expect to align dividend growth rate with EPS growth rate in 4Q21[1]



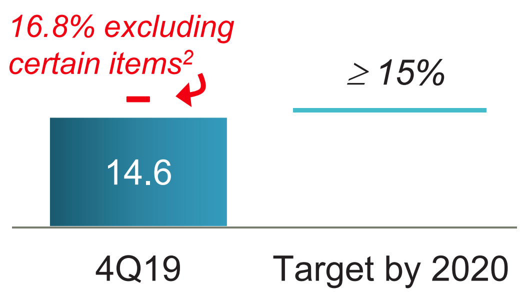
[1] Subject to Board of Directors decision in 4Q21

Credit and cash profile

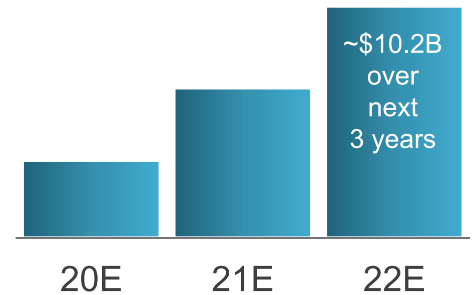
Parent debt to total debt[1]; %



FFO to debt[1]; %



Cumulative OCF; $B



Credit ratings[3] (outlook)

	E-AR	E-LA	E-MS	E-NO	E-TX	SERI	ETR
S&P	A (stable)	A (stable)	A (stable)	A (stable)	A (stable)	A (stable)	BBB+ (stable)
Moody's	A2 (stable)	A2 (stable)	A2 (stable)	Baa2 (stable)	Baa1 (positive)	Baa1 (stable)	Baa2 (stable)

1 LTM, excluding securitization debt; see appendix for Regulation G reconciliation
2 Excluding securitization debt, return of unprotected excess ADIT, and severance and retention payments associated with exit of EWC; see appendix for Regulation G reconciliation
3 Senior secured ratings for the OpCos and SERI; corporate credit rating for Entergy

Fourth Quarter 2019 Earnings Call

March 2, 2020

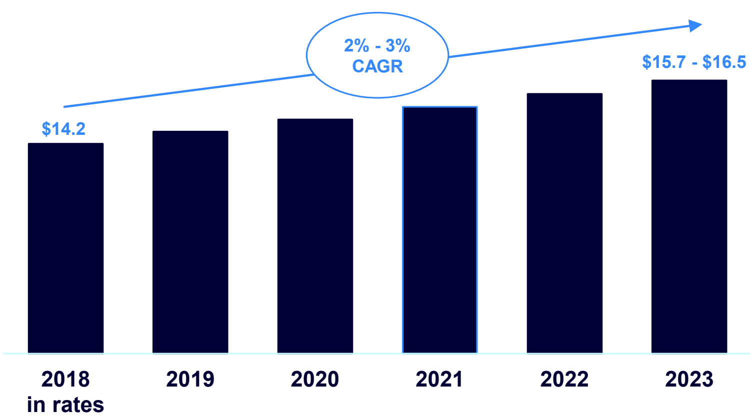
evergy

Enhanced Capital Plan Drives Higher Rate Base Growth

~$7.6B of Utility Investment 2020 through 2024

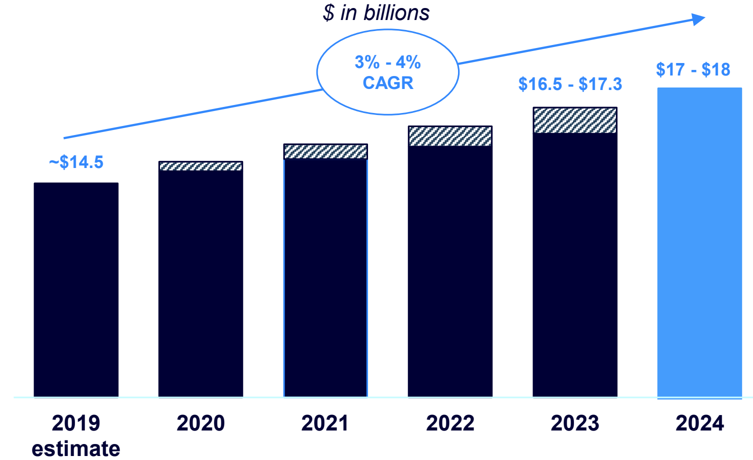
Targeted Rate Base Growth (prior plan)

$ in billions

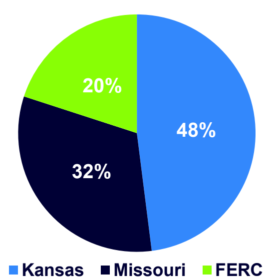


Targeted Rate Base Growth (current plan)

$ in billions



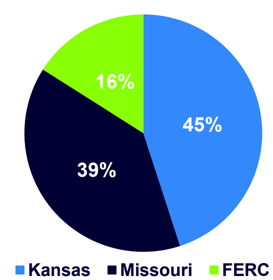
Projected 2019-2023 CapEx by Jurisdiction



~$1.5B

Current 5-yr CapEx plan (2020-2024) increases by $1.5B compared to prior 5-yr plan (2019-2023)

Projected 2020-2024 CapEx by Jurisdiction



NOTE*:*
1. Investment levels and growth rates to be further informed by Strategic Review & Operations Committee and updated accordingly.

evergy™

Public

Investor Update

November 2019

evergy™

Recent News

- On 3rd quarter earnings call affirmed 2019 adjusted EPS[1] guidance: $2.80 - $3.00
  - Long-term projected EPS CAGR of 5% to 7%[2]
- Merger savings on track for 2019 annual target of $110M; ahead YTD
- Continuing focus on optimizing capital allocation
  - Share repurchases remain on plan; ~73% complete
  - Reallocating $150M of CapEx through 2022 from KS to MO
  - Spending an incremental minimum of $150M in MO over same time period; with further opportunity under evaluation
- Announced plans to reduce carbon emissions 80% by 2050, from 2005 levels
- Financing activities
  - On September 5th issued $1.6B of holding company debt
    - $800M of 2.45% 5-yr Notes; $800M of 2.90% 10-yr Notes
    - Proceeds used to payoff $1B term loan and to continue share repurchase program
  - In early September, entered into a $500M ASR to be closed out by year-end

1. *Adjusted EPS is a non-GAAP financial measure. A reconciliation of 2019 adjusted EPS guidance (non-GAAP) to 2019 EPS guidance, the most comparable GAAP measure, is included in the appendix.*
2. *Based on mid-point of 2019 adjusted EPS guidance (non-GAAP) of $2.90 through 2023.*

Investment Outlook

- 2019 adjusted EPS guidance[1]: **$2.80 - $3.00**
- Targeting **EPS CAGR of 5% to 7% through 2023**, using base of 2019 adjusted EPS guidance mid-point of $2.90
  - Targeting middle to low end of 2021 range implied by previous 6% to 8% EPS CAGR 2016 through 2021[2]
- Plan to invest over **$6 billion in CapEx** from 2019 through 2023
- **Rate Base growth** of 2% to 3% through 2023
- Projected **dividend growth in line with EPS**, while targeting **payout ratio of 60% to 70%**

1. *A reconciliation of 2019 adjusted EPS guidance (non-GAAP) to projected earnings per share, the most comparable GAAP measure, is included in the appendix.*
2. *Previous 6% to 8% EPS CAGR was based on Westar Energy's 2016 actual EPS of $2.43*

Targeted Adjusted EPS Growth[1]

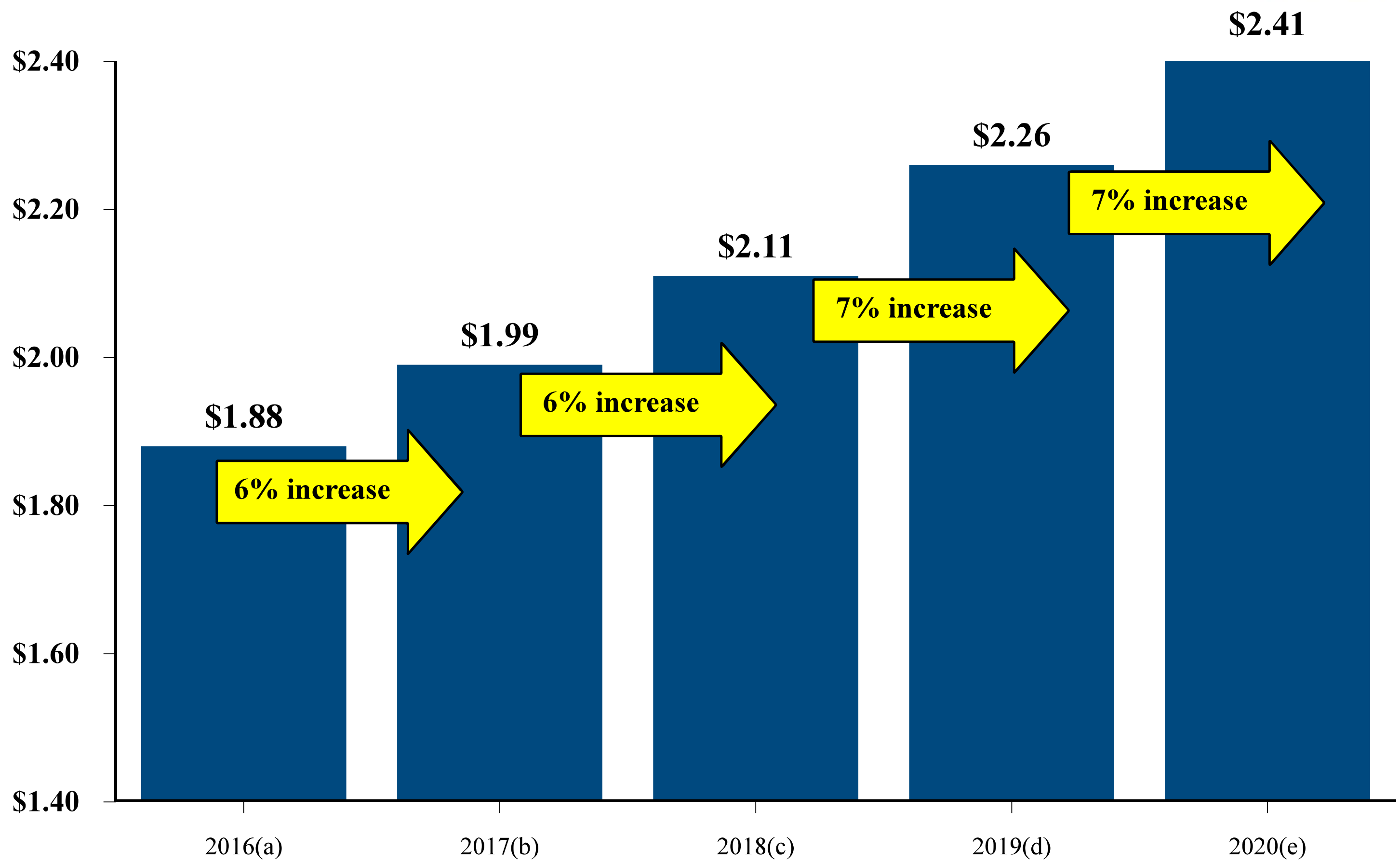
Alliant Energy Corporation
Supplemental Information
February 21, 2020 Earnings Call

Forward Looking Statements

The information regarding forecasted earnings per share, forecasted generation additions, forecasted effective income tax rates, financing plans, and regulatory plans contain forward-looking statements. Actual results could differ materially because the realization of those results is subject to many uncertainties, including: the state of the economy in the service territories of IPL and WPL; state and federal legislation and regulatory actions; weather; and other factors discussed in more detail in Alliant Energy Corporation's earnings release dated February 20, 2020 and in Alliant Energy's SEC filings. Alliant Energy cannot provide any assurance that the assumptions used in the forward-looking statements or otherwise are accurate or will prove to be correct. All forward-looking statements included in this presentation are based upon information presently available, and Alliant Energy assumes no obligation to update any forward-looking statements.

Consistent Earnings Growth

Non-GAAP Temperature Normalized EPS



(a) 2016 GAAP EPS from continuing operations was $1.65. Non-GAAP EPS adjustment was ($0.23) for a valuation charge related to the Franklin County wind farm.
(b) 2017 GAAP EPS from continuing operations was $1.99. Non-GAAP EPS adjustments were ($0.06) for temperature impacts, $0.08 related to Federal Tax Reform and ($0.02) for net write-down of regulatory assets due to IPL electric rate review settlement.
(c) 2018 GAAP EPS from continuing operations was $2.19. Non-GAAP EPS adjustments were $0.06 for net temperature impacts and $0.02 related to Federal Tax Reform.
(d) 2019 GAAP EPS from continuing operations was $2.33. Non-GAAP EPS adjustments were $0.05 for net temperature impacts and $0.02 for American Transmission Company (ATC) Holdings return on equity reserve adjustments.
(e) 2020 midpoint of EPS guidance range.

2019 Non-GAAP Temperature Normalized Earnings to Mid-point of 2020 Consolidated Earnings Guidance Walk

2019 GAAP EPS from continuing operations		$2.33
Net temperature impact on retail electric and gas sales	(0.05)	
ATC return on equity reserve adjustments	(0.02)	
2019 Non-GAAP temperature normalized EPS from continuing operations		2.26
Higher revenue requirements primarily due to increasing rate base	0.65	
Higher depreciation expense	(0.18)	
Lower AFUDC	(0.13)	
Equity dilution	(0.08)	
Higher interest expense	(0.03)	
Other	(0.08)	
2020 Forecasted EPS Midpoint		$2.41

Powering What's Next

Edison Electric Institute Finance Conference

November 10-12, 2019

Alliant Energy

Investment considerations

5-7%
EPS growth
through 2023[a]

~8-10%
Total Shareholder Return[b]

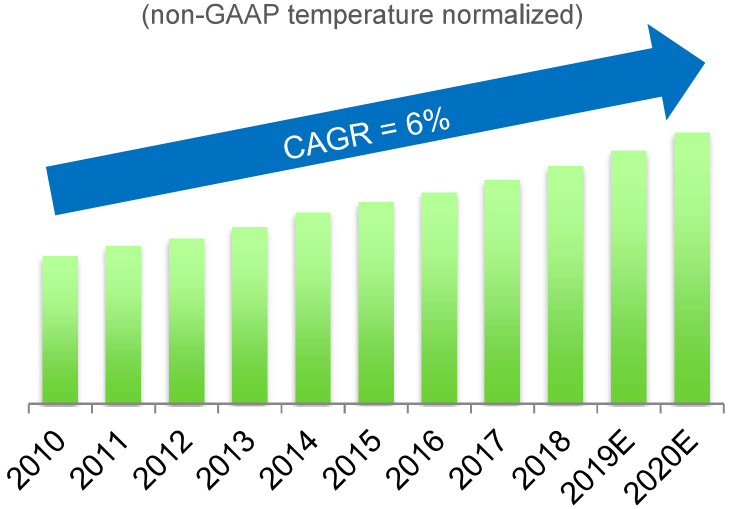
~3%
Dividend yield
with 5-7% CAGR[c]

Constructive regulatory environments, customer-focused investments, virtually all earnings from regulated operations, strong balance sheet and liquidity

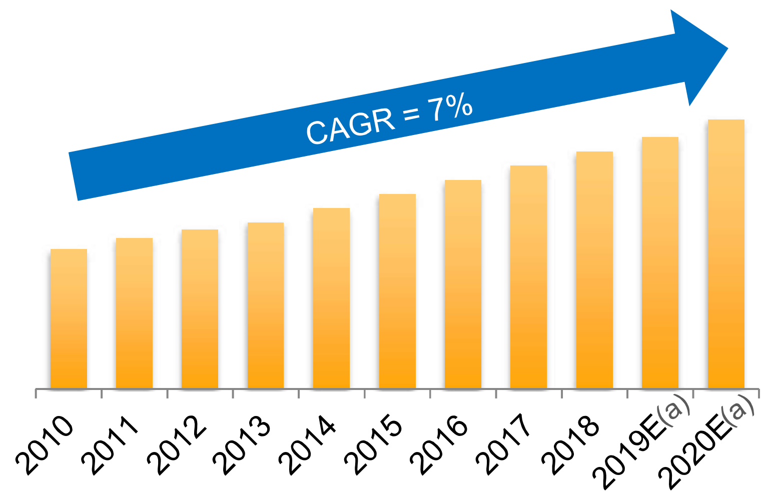
(a) Based on 2018 Non-GAAP temperature normalized EPS of $2.11
(b) Total shareholder return proposition at a constant P/E ratio
(c) Subject to approval by the Board of Directors

Consistent performance

Adjusted earnings per share from continuing operations
(non-GAAP temperature normalized)



Dividends per common share



(a) Annual common stock dividend target. Payment of the quarterly dividends is subject to the actual dividend declaration by the Board of Directors.

2020 First Quarter Earnings Webcast

April 23, 2020

NorthWestern Energy
Delivering a Bright Future

Significant Events

- **Net income for the first quarter of 2020 decreased $22.1 million, or 30%, as compared to the same period in 2019.**
  - Diluted earnings per share decreased $0.44, or 31%, as compared to the same period in 2019.
  - After adjusting for weather difference, Non-GAAP* adjusted earnings per share decreased $0.17, or 14%, as compared to the same period in 2019.
- The Board of Directors declared a quarterly dividend of $0.60 per share payable June 30th to shareholders of record as of June 15th, 2020.

- Due to the anticipated impacts from COVID-19 related disruption across our service territory and first quarter results below our expectations, we are lowering 2020 earnings per share guidance to $3.30 - $3.45 (from $3.45 - $3.60). Despite this short-term set-back, our long-term business prospects remain strong.
  - Issued term-loan and priced first mortgage bond to increase liquidity
  - 2020 and longer-term capital investment program remains unchanged
  - No change to our long-term targeted 6% to 9% total shareholder return

NorthWestern Energy
Delivering a Bright Future

** See slides 14 & 30 for additional information and Non-GAAP disclosures.*

IDACORP®

Earnings Conference Call

1st Quarter 2020

April 30, 2020

SUSTAINABLE GROWTH

2020 Earnings Per Share Guidance & Estimated Key Financial & Operating Metrics

(Millions Except for Per Share Amounts)

	2020 Estimates	
	Current(1)	Previous(2)
IDACORP Earnings Per Diluted Share Guidance	No Change	$ 4.45 – $ 4.65
Idaho Power Additional Amortization of Accumulated Deferred Investment Tax Credits	No Change	None
Idaho Power Operations & Maintenance Expense	No Change	$ 350 – $ 360
Idaho Power Capital Expenditures, Excluding Allowance for Funds Used During Construction	No Change	$ 300 – $ 310
Idaho Power Hydroelectric Generation (MWh)	6.0 – 8.0	6.5 – 8.5

(1) As of April 30, 2020.

(1) As of February 20, 2020, the date of filing IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2019.

Earnings Conference Call
Fourth Quarter 2019

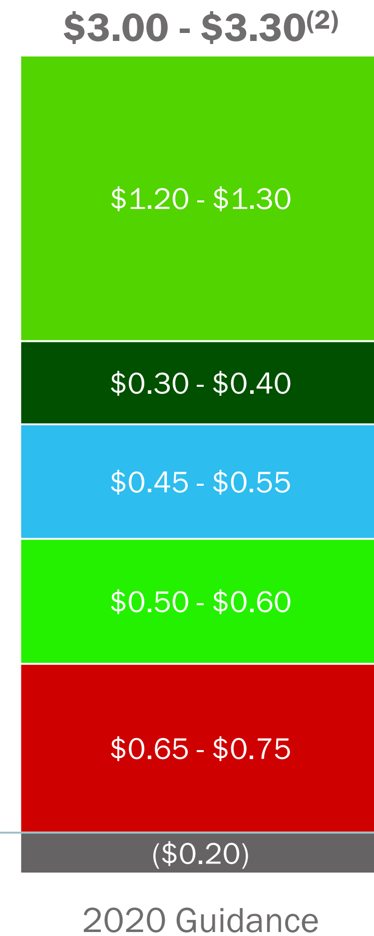
February 11, 2020

Exelon.

2020 Adjusted Operating Earnings* Guidance

Key Year-Over-Year Drivers

- **ExGen:** Lower realized energy prices and capacity revenues and absence of R&D tax benefit and NDT realized gains
- **BGE:** Higher depreciation, partially offset by higher distribution and transmission revenues
- **PECO:** Higher depreciation and interest, partially offset by higher transmission revenues
- **PHI:** Higher distribution and transmission revenues, partially offset by higher depreciation
- **ComEd:** Increased capital investments to improve reliability in distribution and transmission, offset by impact of treasuries



Expect Q1 2020 Adjusted Operating Earnings* of $0.85 - $0.95 per share

Note: Amounts may not sum due to rounding
(1) 2019 results based on 2019 average outstanding shares of 974M
(2) 2020E earnings guidance based on expected average outstanding shares of 978M

Exelon.

1Q 2020 Strategic & Financial **Highlights**

FirstEnergy

Charles E. Jones, President and CEO
Steven E. Strah, SVP and CFO

April 24, 2020

Financial Summary

5+ years of consistently meeting or exceeding the midpoint of the quarterly guidance we've provided

1Q 2020 Results

- Reported GAAP earnings of $0.14 per basic share
  - Includes the impact from the February 26th remeasurement of Pension/OPEB plans
- Reported Operating earnings of $0.66 per share; $0.01 above midpoint of 1Q guidance range
  - Results driven by higher transmission margin and lower expenses, which helped to offset the impact of mild weather on our distribution revenues

Guidance Updates

- Updating 2020 GAAP earnings forecast to $1,020M - $1,130M, or $1.88 - $2.08 per share
  - Includes the impact from the February 26th remeasurement of Pension/OPEB plans
- Affirming 2020 Operating (non-GAAP) earnings guidance of $2.40 - $2.60 per share(1)
- Affirming Operating (non-GAAP) EPS CAGR(2) projection of 6% - 8% from 2018 through 2021, and 5% - 7% extending through 2023
  - Includes up to $600M of equity annually in 2022 and 2023, to fund growth initiatives
- Introducing 2Q 2020 GAAP and Operating (non-GAAP) earnings guidance of $0.48 to $0.58 per share

(1) Refer to the Earnings Supplement to the Financial Community section for reconciliations between GAAP and Operating (non-GAAP) earnings
(2) Refer to slide 2 for information on Non-GAAP Financial Matters

FORTIS INC.

Investor Presentation
Q2 2020

FORTIS INC.

Long-Term Strategy

- ✓ The safety and health of our employees is the priority
- ✓ Focused on delivering reliable service to our customers

6%
Average Annual Dividend Growth Guidance through 2024

STRATEGY
Leverage the operating model, footprint of our businesses, operating expertise, reputation and financial strength to execute on growth opportunities

Focused on Growth

AREAS OF FOCUS:

Capital Investment Plan	Customer & Regulatory Relationships	Sustainability & Delivery of Cleaner Energy	System Resiliency, Innovation & Cybersecurity	Energy Infrastructure, LNG Expansion & Energy Storage	Investment Grade Credit Ratings

Hawaiian Electric Industries, Inc.

1st Quarter 2020 Financial Results & Outlook

May 5, 2020

HEI
Catalyst for a better Hawai'i

HEI 2020 guidance – see below

UTILITY EPS: $1.46 - $1.54

KEY ASSUMPTIONS:

- No change to decoupling or recovery mechanisms
- No material impact from PIM penalties and rewards
- O&M (excluding pension)[1] increase at or below inflation; identifying potential expense offsets for revenue increase in Hawaiian Electric rate case
- 2020 capex of ~$360 million[2]
  - *Potential for $30 million (less than 10%) reduction in 2020*
- Rate base growth: ~4% over 2019
- Equity capitalization at approved rate case levels
- *Assumes deferral of COVID-19 related costs currently estimated to be ~$22 million (primarily bad debt expense), is approved in 2020 for later recovery*

Utility net income range reaffirmed, although likely at the bottom half

BANK—
Revisions to pre provision elements

KEY ASSUMPTIONS:

- *Continued profitable operations with pre-tax, pre-provision income: $90 to $110 million*
  - Previous: $121 to $127 million embedded in guidance
- Low to mid- single digit earning asset growth
- *NIM: ~3.45% to 3.55%*
  - Previous: ~3.70% to 3.80% (1Q 3.72%)
- *Provision expense: no guidance at this time*
  - Previous: $17 million to $22 million (1Q $10.4 million)
- *ROA: no guidance at this time*
  - Previous: >1.10% (1Q 0.87%)

Bank provision and net income too early to determine at this time

Holding company range reaffirmed

Consolidated EPS not provided due to provision uncertainty at the bank

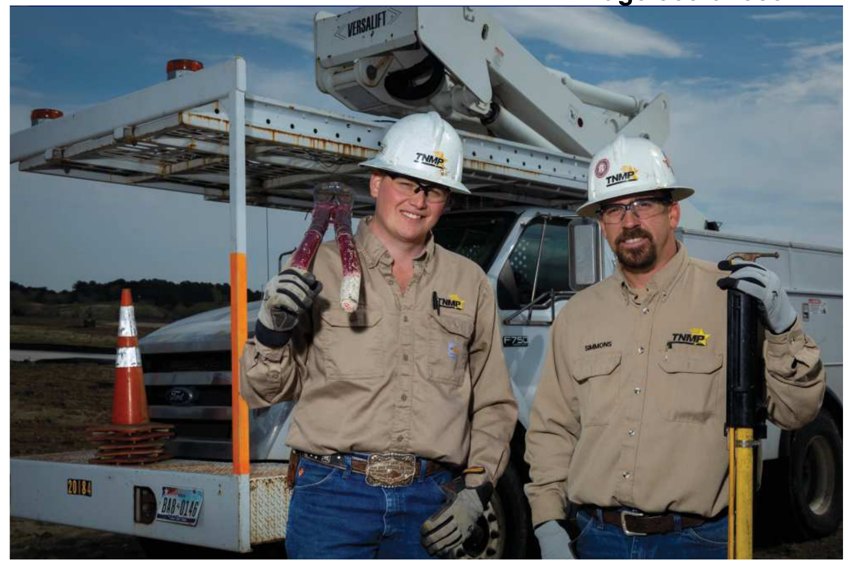
Note: Holding company and other net loss estimated at $0.27 - $0.29.
[1] Also excludes O&M expenses covered by surcharges or by third parties that are neutral to net income.
[2] 2019-20 capex averages ~$400 million given acceleration of certain 2020 projects into 2019.

OTTER TAIL CORPORATION

2020 First Quarter Earnings Conference Call

2020 EARNINGS GUIDANCE

Diluted Earnings Per Share	2019 EPS by Segment	2020 Guidance February 17, 2020		2020 Guidance May 5, 2020	
		Low	High	Low	High
Electric	$1.48	$1.67	$1.70	$1.65	$1.70
Manufacturing	$0.32	$0.31	$0.35	$0.14	$0.23
Plastics	$0.51	$0.43	$0.47	$0.43	$0.47
Corporate	($0.14)	($0.19)	($0.15)	($0.22)	($0.15)
Total	$2.17	$2.22	$2.37	$2.00	$2.25
Return on Equity	11.6%	11.0%	11.7%	9.9%	11.1%



COVID-19 Update and Q1 2020 Earnings Review

May 1, 2020

PNM Resources®

Ongoing Earnings Guidance Affirmed Based on COVID-19 Stage 1

2020 Earnings Guidance affirmed based on Stage 1 COVID-19 Considerations

$2.16 Consolidated EPS $2.26

	COVID-19 Load Impacts		Mitigating Impacts
March	$0.00	***Stage 1: Manage within Guidance***	Lower interest and financing costs, weather, managing O&M
April	($0.02)		
May	($0.02)		
June	($0.02)-($0.03)	*Stage 2: Guidance at Risk*	Phase-in cost contingency plans, regulatory filings, weather
July	($0.02)-($0.03)		
August	($0.02)	***Stage 3: Outside of Guidance***	Reassess guidance
September	($0.02)		
Q4	($0.02) / month		

PNM Resources

OG+E | Earnings Conference Call
First Quarter 2020 – May 7, 2020

2020 Outlook

- OG&E guidance is unchanged and is projected to be between approximately $346 million to $357 million of net income **or $1.72 to $1.78 per average diluted share** assuming normal weather.
- As a result of the revised guidance by Enable and the equity method investment impairment recorded by the Company, OGE Holdings projects earnings contributions to be between **($2.59) to ($2.55) per average diluted share**. Ongoing earnings are projected to be between **$0.36 and $0.40 per average diluted share.**

PINNACLE WEST
CAPITAL CORPORATION

POWERING GROWTH
DELIVERING VALUE

First Quarter 2020 Results
May 8, 2020

2020 EPS GUIDANCE

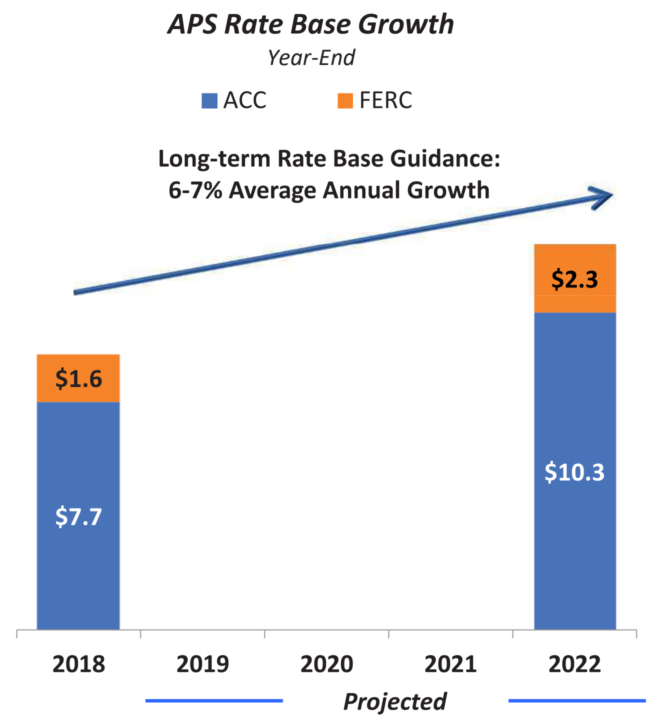
Key Factors & Assumptions as of May 8, 2020

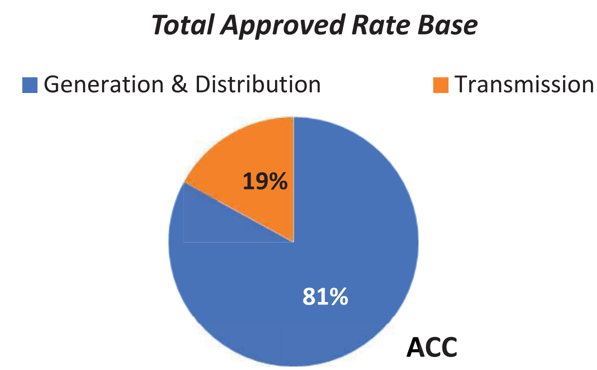
	2020
Adjusted gross margin[1,2] (operating revenues, net of fuel and purchased power expenses)	$2.48 – $2.54 billion
• Retail customer growth about 1.5-2.5%	
• Weather-normalized retail electricity sales volume about 1-2% higher compared to prior year (excludes potential data center load growth)	
• Assumes normal weather	
Adjusted operating and maintenance (O&M)[1,2]	$830 – $850 million
Other operating expenses (depreciation and amortization, deferrals, and taxes other than income taxes)	$830 – $850 million
Other income (pension and other post-retirement non-service credits, other income and other expense)	$70 – $80 million
Interest expense, net of allowance for borrowed and equity funds used during construction (Total AFUDC ~$35 million)	$235 – $245 million
Net income attributable to noncontrolling interests	$20 million
Effective tax rate	14%
Average diluted common shares outstanding	112.8 million
EPS Guidance[3]	$4.75 – $4.95

[1] Excludes O&M of $65 million, and offsetting revenues, associated with renewable energy and demand side management programs.
[2] The Covid-19 disconnect suspension and summer disconnection moratorium and revised policies are currently estimated to result in a decrease of approximately $20 million to $30 million of pre-tax income in 2020 depending on certain assumptions, including customer behavior.
[3] Guidance range assumes impacts from Covid-19 dissipate by the end of the second quarter and customer and sales growth resume once the economy normalizes.

RATE BASE

APS's revenues come from a regulated retail rate base and meaningful transmission business





	ACC	FERC
Rate Effective Date	8/19/2017	6/1/2019
Test Year Ended	12/31/2015[1, 2]	12/31/2018
Rate Base	$6.8B	$1.6B
Equity Layer	55.8%	54.6%
Allowed ROE	10.0%	10.75%

[1] Adjusted to include post test-year plant in service through 12/31/2016
[2] On 10/31/19 APS filed an ACC general rate case with a proposed $8.9B rate base for an adjusted test year ended 6/30/19.

Rate base $ in billions, rounded

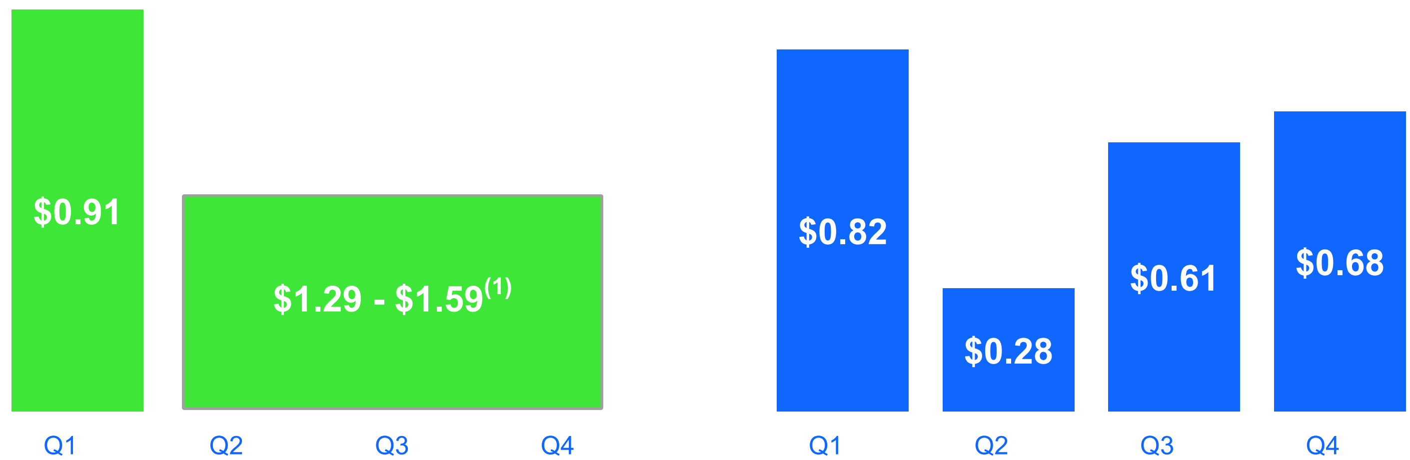
Exhibit 99.2

Portland General Electric

Earnings
Conference call
First quarter 2020

First quarter 2020 financial results

	Q1 2020	Q1 2019
Net income (in millions)	$81	$73
Diluted earnings per share (EPS)	$0.91	$0.82



2020 Diluted EPS:
$2.20 - $2.50

2019 Diluted EPS:
$2.39

(1) Estimates based on revised 2020 guidance range

PPL 1st Quarter Earnings Call

May 8, 2020

A century of people **powering life.**

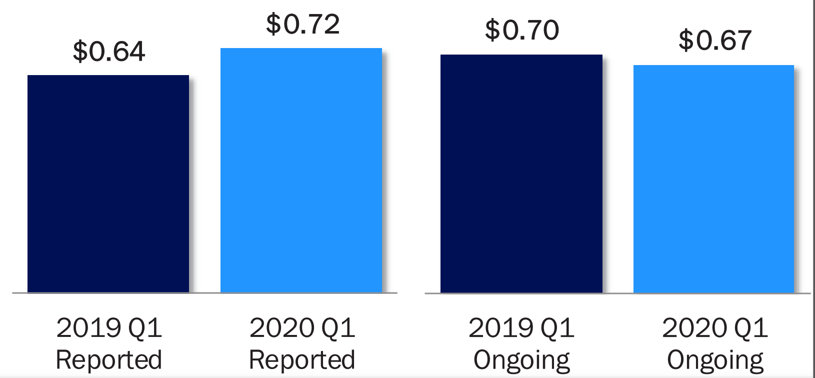
Q1 Executive Review

Q1 Highlights

- Delivered Q1 2020 ongoing earnings results of $0.67 per share vs. $0.70 per share in Q1 2019
  - Variance primarily driven by share dilution and mild Q1 2020 weather, partially offset by returns on capital investments
- No change to 2020 forecast of $2.40 to $2.60 per share
  - On-track through Q1; minimal impacts from COVID-19
  - Too early to clearly determine full scope and duration of potential implications
- Maintained 2021 forecast of $2.40 to $2.60 per share

Q1 Earnings Results

(Earnings Per Share)



Long-term Fundamental Value Intact

- Capital plans and rate base growth
  - ✓ 5-year forecasts remain on track
- Attractive dividend yield
  - ✓ Strong, predictable cash flow
- Solid financial profile
  - ✓ Stable, investment grade credit

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

Public Service Enterprise Group

PSEG Earnings Conference Call

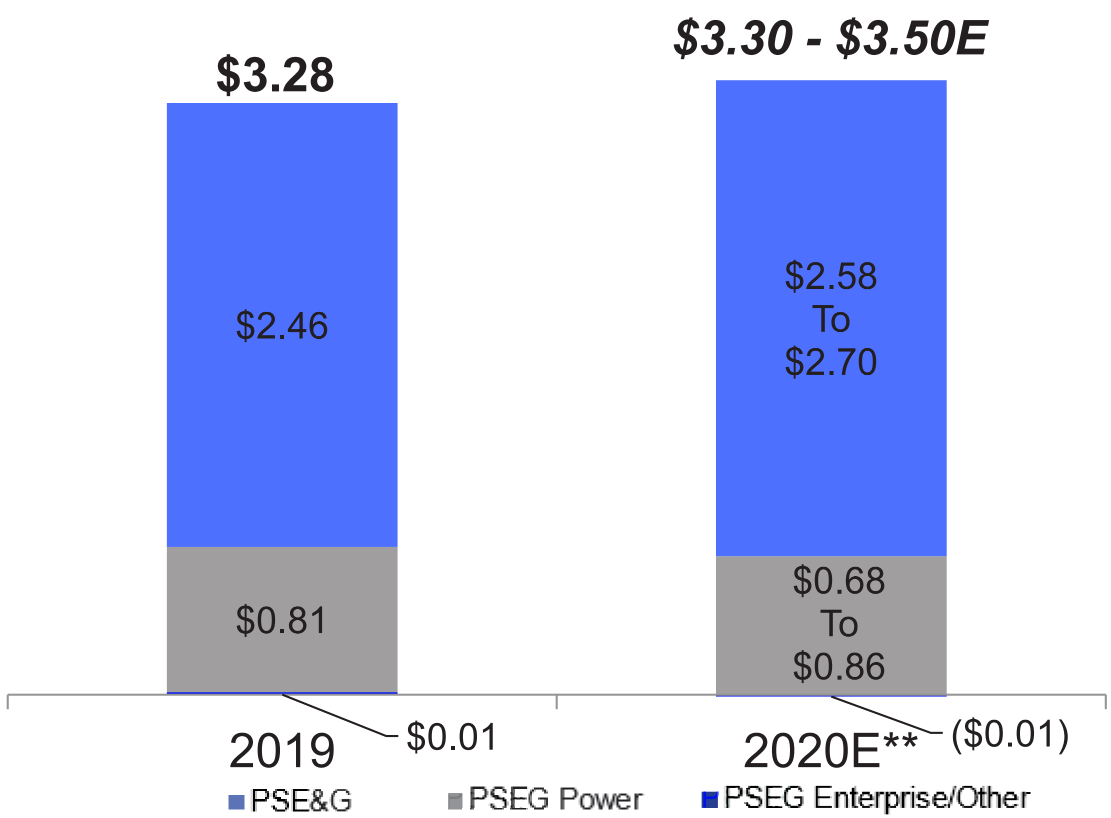
1st Quarter 2020

May 4, 2020

PSEG – Re-affirming 2020 Guidance

Drivers in 2020 include rate base growth, Q1 weather headwinds, potential margin impacts of COVID-19 on sales and load, and cost control

Non-GAAP Operating Earnings* Contribution by Subsidiary
2019 Actual and 2020E Guidance



*See Slides A and B for Items excluded from Net Income/(Loss) to reconcile to Operating Earnings (non-GAAP).
**Based on the mid-point of 2020 non-GAAP Operating Earnings guidance of $3.30 - $3.50 per share. E = Estimate.

Sempra Energy®

Sempra Energy

First Quarter 2020 Earnings Results

May 4, 2020

Executive Summary

Sempra Energy

Although these are challenging times, Sempra is committed to advancing its strategy to become North America's premier energy infrastructure company, while building resiliency into its business model + improving the competitive position of its portfolio

- Executing our disciplined strategy to become North America's premier energy infrastructure company
  - Nearing completion of capital rotation program, with Chile sale expected to close in May
  - Targeting a ~$7.5B 2020 capital program primarily related to our U.S. utility infrastructure(1)
  - Operating a more resilient business model to help deliver our financial commitments in various market conditions
  - Creating a high-growth platform with improved earnings power and visibility
- In combination, our strategy and disciplined execution is driving strong financial results
- Reporting Q1-2020 adjusted earnings per common share (EPS) of $3.08 compared to Q1-2019 adjusted EPS of $1.92(2)
- Reaffirming and guiding to the upper-end of our FY-2020 adjusted EPS guidance range of $6.70 – $7.50 and updating our FY-2020 GAAP EPS guidance range(2)
- Reaffirming our FY-2021 EPS guidance range of $7.50 – $8.10

1) Actual amounts expended will depend on a number of factors and may differ materially from the amounts reflected in our 2020 capital plan. The ~$7.5B represents our proportionate ownership share of the 2020 capital plan and includes ~$1.9B of capex that will be funded by unconsolidated entities, including our equity interests in Oncor, Sharyland and our unconsolidated JVs. Amount is before noncontrolling interests.
2) Represents a non-GAAP financial measure. GAAP EPS for Q1-2020 and Q1-2019 were $2.53 and $1.59, respectively. GAAP EPS Guidance Range for 2020 is $11.88 - $13.02 and includes the estimated gain on sale of the South American businesses and litigation costs related to Aliso Canyon and RBS Sempra Commodities LLP. See Appendix for information regarding non-GAAP financial measures.

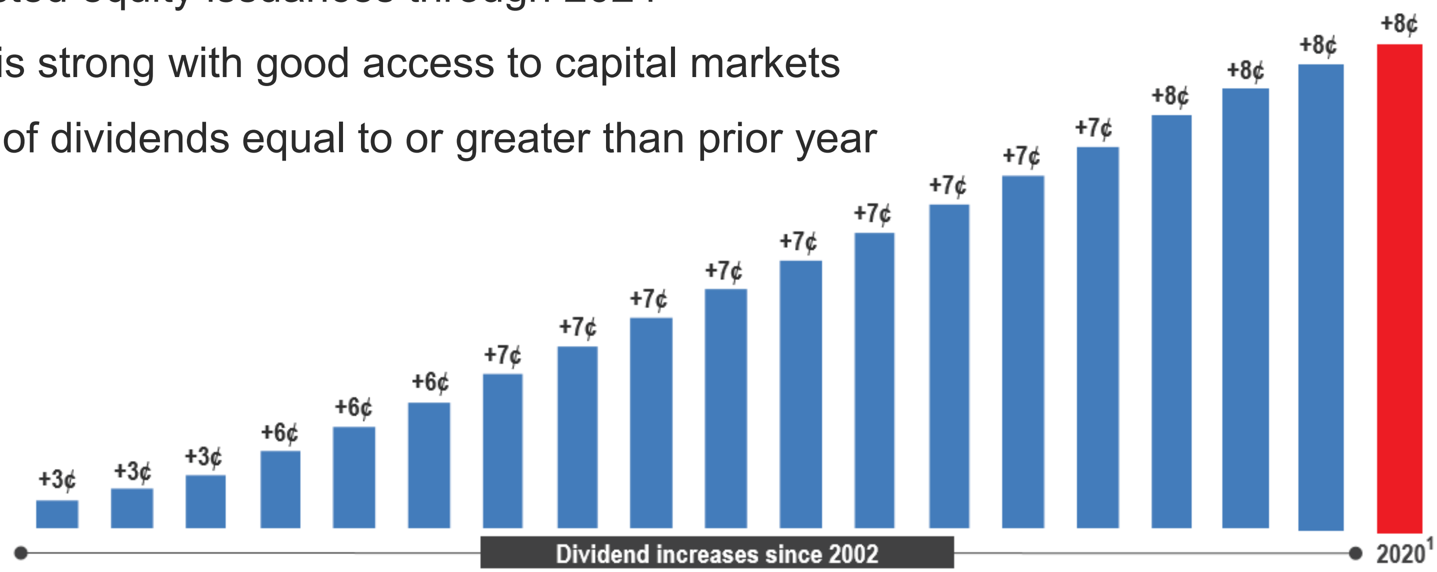
Southern Company

First Quarter 2020 Earnings Conference Call

April 30, 2020

COVID-19 Business Impacts

- We do not expect COVID-19 impacts to materially affect our long-term outlook:
  - Expected long-term EPS growth rate remains 4% to 6%
  - $40 billion, 5-year capital investment plan remains unchanged
  - No projected equity issuances through 2024
  - Liquidity is strong with good access to capital markets
  - 72 years of dividends equal to or greater than prior year



1. Future dividends are subject to approval of the Southern Company Board of Directors and depend on earnings, financial condition and other factors. Eight cent dividend increase approved by Southern Company Board of Directors on April 21, 2020.


Xcel Energy®
FIRST QUARTER 2020 EARNINGS REPORT PRESENTATION
MAY 7, 2020

2020 GAAP & Ongoing EPS Guidance: $2.73 – $2.83

Earnings Drivers	Key Assumptions (as compared to 2019 levels unless noted)
Regulatory proceedings	Constructive outcomes in all proceedings
Weather	Normal weather
W/A retail electric sales	Decline of approximately 4% (Base Case)
W/A retail natural gas sales	Decline of approximately 1% (Base Case)
Capital rider revenue (net of PTCs)	Increase of $45 million - $55 million
O&M expenses	Decline of approximately 4-5% (Base Case)
Depreciation expense	Increase of $160 million - $170 million
Property taxes	Increase of $35 million - $45 million
Interest exp. (net of AFUDC-debt)	Increase of $60 million - $70 million
AFUDC-equity	Increase of $25 million - $35 million
Effective tax rate (net of PTCs)	Approximately 0%

2020 EPS guidance of $2.73 to $2.83 assumes implementation of contingency plans to offset the negative impacts of COVID-19 under the base case scenario. Our contingency plans may not be able to offset the negative impacts under a severe scenario.

Ongoing earnings could differ from those prepared in accordance with GAAP due to unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing diluted EPS to corresponding GAAP diluted EPS.

Exhibit No. AMF-5

Federal Energy Regulatory Commission

Revenue Requirement Impact of RTO/ISO Membership - 100 bpt ROE Adder

Line	RTO/ISO	Company Name	Trans. Rate Base ($000s) (1)	Report Base ROE (2)	Equity Ratio (3)	100 Basis Point Adder (4)	Report ROE Plus Adder (5)	Tax Conversion Factor (6)	Revenue Impact ($000s) (7)
1	CAISO	Southern California Edison Co.	5,829,102	11.97%	55.54%	1.00%	12.97%	1.2658	40,981
2	CAISO	Pacific Gas and Electric Co.	7,646,547	12.00%	52.46%	1.00%	13.00%	1.2658	50,777
3	CAISO	San Diego Gas & Electric Co.	4,005,298	10.10%	55.83%	1.00%	11.10%	1.2658	28,306
4	CAISO	DATC Path 15 LLC	104,850	13.50%	55.17%	1.00%	14.50%	1.2658	732
5	CAISO	Trans Bay Cable LLC	522,202	13.50%	65.00%	1.00%	14.50%	1.2658	4,297
6		**Total CAISO**	**18,107,999**						**125,092**
7	MISO	Ameren Illinois	1,882,168	10.32%	52.87%	1.00%	11.32%	1.2658	12,596
8	MISO	Ameren Missouri	686,549	10.32%	53.00%	1.00%	11.32%	1.2658	4,606
9	MISO	Ameren Transmission of Illinois	1,325,931	10.32%	56.10%	1.00%	11.32%	1.2658	9,416
10	MISO	Indianapolis Power & Light Co.	210,949	10.32%	45.00%	1.00%	11.32%	1.2658	1,202
11	MISO	Minnesota Power Co.	692,704	10.32%	59.00%	1.00%	11.32%	1.2658	5,173
12	MISO	MidAmerican Energy Co.	1,207,813	10.32%	52.00%	1.00%	11.32%	1.2658	7,950
13	MISO	Duke Energy Indiana	939,991	10.32%	53.00%	1.00%	11.32%	1.2658	6,306
14	MISO	Entergy Arkansas Inc.	1,898,099	10.32%	47.89%	1.00%	11.32%	1.2658	11,506
15	MISO	Entergy Louisiana Inc.	2,895,429	10.32%	47.00%	1.00%	11.32%	1.2658	17,226
16	MISO	Entergy Mississippi Inc.	1,069,255	10.32%	49.38%	1.00%	11.32%	1.2658	6,684
17	MISO	Entergy New Orleans Inc.	105,164	10.32%	53.89%	1.00%	11.32%	1.2658	717
18	MISO	Entergy Texas Inc.	966,003	10.32%	52.15%	1.00%	11.32%	1.2658	6,377
19	MISO	ITC Midwest	2,716,629	10.32%	60.00%	1.00%	11.32%	1.2658	20,633
20	MISO	ITC Transmission	1,947,137	10.32%	60.00%	1.00%	11.32%	1.2658	14,788
21	MISO	Michigan Electric Transmission Co.	1,497,827	10.32%	60.00%	1.00%	11.32%	1.2658	11,376
22	MISO	Montana-Dakota Utilities	274,213	10.32%	50.00%	1.00%	11.32%	1.2658	1,736
23	MISO	(Northern) Indiana Public Service Co.	968,156	10.32%	55.00%	1.00%	11.32%	1.2658	6,740
24	MISO	Otter Tail Power Company	422,829	10.32%	55.00%	1.00%	11.32%	1.2658	2,944
25	MISO	Southern Indiana Gas & Electric Co.	309,265	10.32%	58.00%	1.00%	11.32%	1.2658	2,271
26	MISO	Northern States Power MN WI	2,891,643	10.32%	53.00%	1.00%	11.32%	1.2658	19,400
27	MISO	American Transmission Co.	3,899,703	10.32%	50.00%	1.00%	11.32%	1.2658	24,682
28	MISO	Cleco Power	342,480	10.32%	53.00%	1.00%	11.32%	1.2658	2,298
29		**Total MISO**	**29,149,937**						**196,625**
30	NEISO	Central Maine Power Co.	1,126,724	10.57%	59.13%	1.00%	11.57%	1.2658	8,433
31	NEISO	The United Illuminating Company	619,711	10.57%	56.63%	1.00%	11.57%	1.2658	4,442
32	NEISO	Emera Maine	226,099	10.57%	54.13%	1.00%	11.57%	1.2658	1,549
33	NEISO	Connecticut Light & Power Co.	2,777,860	10.57%	55.47%	1.00%	11.57%	1.2658	19,505
34	NEISO	NSTAR Electric Co.	1,384,529	10.57%	55.25%	1.00%	11.57%	1.2658	9,683
35	NEISO	Public Service Co. of New Hampshire	864,243	10.57%	61.80%	1.00%	11.57%	1.2658	6,761
36	NEISO	Western Massachusetts Electric Co.	736,171	10.57%	56.00%	1.00%	11.57%	1.2658	5,218
37	NEISO	New Hampshire Transmission LLC	46,067	10.57%	60.00%	1.00%	11.57%	1.2658	350
38	NEISO	Fitchburg Gas and Electric Co.	3,148	10.57%	48.10%	1.00%	11.57%	1.2658	19
39	NEISO	New England Power Co.	1,198,264	10.57%	63.46%	1.00%	11.57%	1.2658	9,626
40	NEISO	Vermont Transco LLC	895,913	10.57%	56.84%	1.00%	11.57%	1.2658	6,446
41		**Total NEISO**	**9,878,729**						**72,032**
42	NYISO	Niagara Mohawk Power Co.	2,039,412	9.80%	50.00%	1.00%	10.80%	1.2658	12,908
43	NYISO	New York Transco LLC	226,472	9.50%	52.96%	1.00%	10.50%	1.2658	1,518
44		**Total NYISO**	**2,265,884**						**14,426**
45	PJM	Appalachian Transmission Co.	29,318	9.85%	52.18%	1.00%	10.85%	1.2658	194
46	PJM	Indiana Michigan Transmission Co.	1,724,392	9.85%	54.20%	1.00%	10.85%	1.2658	11,831
47	PJM	Kentucky Transmission Co.	99,470	9.85%	54.30%	1.00%	10.85%	1.2658	684
48	PJM	Ohio Transmission Co.	2,416,084	9.85%	54.21%	1.00%	10.85%	1.2658	16,579
49	PJM	West Virginia Transmission Co.	857,200	9.85%	53.84%	1.00%	10.85%	1.2658	5,842
50	PJM	Appalachian Power Co.	2,101,335	9.85%	49.73%	1.00%	10.85%	1.2658	13,228
51	PJM	Indiana Michigan Power Co.	770,863	9.85%	45.11%	1.00%	10.85%	1.2658	4,402
52	PJM	Kentucky Power Co.	342,717	9.85%	45.66%	1.00%	10.85%	1.2658	1,981
53	PJM	Kingsport Power Co.	21,683	9.85%	47.72%	1.00%	10.85%	1.2658	131
54	PJM	Ohio Power Co.	1,355,197	9.85%	54.97%	1.00%	10.85%	1.2658	9,430
55	PJM	Wheeling Power Co.	79,048	9.85%	54.63%	1.00%	10.85%	1.2658	547
56	PJM	Virginia Electric and Power Co.	5,995,871	10.90%	52.10%	1.00%	11.90%	1.2658	39,542
57	PJM	Virginia Electric and Power Co.	5,995,871	10.90%	52.10%	1.00%	11.90%	1.2658	39,542
58	PJM	Duke Energy Kentucky	21,346	10.88%	52.00%	1.00%	11.88%	1.2658	141
59	PJM	Duke Energy Ohio	589,691	10.88%	56.00%	1.00%	11.88%	1.2658	4,180
60	PJM	Duquesne Light Company	586,143	10.90%	51.68%	1.00%	11.90%	1.2658	3,834
61	PJM	Duquesne Light Company	586,143	10.90%	51.68%	1.00%	11.90%	1.2658	3,834
62	PJM	Atlantic City Electric Co.	822,316	10.00%	50.00%	1.00%	11.00%	1.2658	5,205
63	PJM	Baltimore Gas & Electric Co.	1,175,192	10.00%	54.00%	1.00%	11.00%	1.2658	8,033
64	PJM	Commonwealth Edison Co.	3,737,904	11.00%	55.00%	1.00%	12.00%	1.2658	26,023
65	PJM	Delmarva Power & Light Co.	912,738	10.00%	50.12%	1.00%	11.00%	1.2658	5,791
66	PJM	PECO Energy	970,462	9.85%	53.61%	1.00%	10.85%	1.2658	6,586
67	PJM	Potomac Electric Power Co.	866,691	10.00%	50.00%	1.00%	11.00%	1.2658	5,485
68	PJM	American Transmission Systems Inc.	2,922,890	9.88%	60.00%	1.00%	10.88%	1.2658	22,199
69	PJM	Mid-Atlantic Interstate Transmission	1,020,420	9.80%	59.00%	1.00%	10.80%	1.2658	7,621
70	PJM	Trans-Allegheny Interstate (TrAILCo)	1,490,702	11.20%	60.00%	1.00%	12.20%	1.2658	11,322
71	PJM	PPL Electric Utilities	4,076,470	11.18%	54.50%	1.00%	12.18%	1.2658	28,122
72		**Total PJM**	**41,568,157**						**282,308**
73	SPP	Public Service Co. of Oklahoma	490,471	10.00%	49.00%	1.00%	11.00%	1.2658	3,042
74	SPP	Southwestern Electric Power Co.	1,053,463	10.00%	46.68%	1.00%	11.00%	1.2658	6,225
75	SPP	AEP Oklahoma Transmission	640,941	0.00%	50.69%	1.00%	1.00%	1.2658	4,113
76	SPP	AEP Southwestern Transmission	11	10.00%	48.95%	1.00%	11.00%	1.2658	0
77	SPP	Empire District Electric Co.	238,839	9.50%	49.15%	1.00%	10.50%	1.2658	1,486
78	SPP	Kansas City Power & Light Co.	190,629	10.60%	50.59%	1.00%	11.60%	1.2658	1,221
79	SPP	KCP&L Greater Missouri Operations	195,748	10.60%	50.59%	1.00%	11.60%	1.2658	1,254
80	SPP	Westar Energy Inc.	1,609,867	9.80%	51.19%	1.00%	10.80%	1.2658	10,432
81	SPP	ITC Great Plains	448,314	10.66%	60.00%	1.00%	11.66%	1.2658	3,405
82	SPP	Oklahoma Gas & Electric Co.	1,646,316	10.00%	53.47%	1.00%	11.00%	1.2658	11,143
83	SPP	Public Service Co. of Colorado	1,445,653	9.22%	56.28%	1.00%	10.22%	1.2658	10,299
84	SPP	Southwestern Public Service Co.	2,144,278	10.00%	54.47%	1.00%	11.00%	1.2658	14,785
85	SPP	Prairie Wind Transmission LLC	119,840	10.80%	45.66%	1.00%	11.80%	1.2658	693
86	SPP	Transource Missouri LLC	260,935	9.80%	55.00%	1.00%	10.80%	1.2658	1,817
87		**Total SPP**	**10,485,305**						**69,912**
88		**US Total**	**111,456,011**						**760,396**

Source:
Various S&P Global Market Intelligence RRA reports 2018-2020, provided as Exhibit No. AMF-4, pages 158-248.
Note:
NYISO utilities excluded if rates have not been unbundled.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy
Under Section 219 of the Federal Power Act

Docket No. RM20-10-000

Affidavit of Michael P. Gorman

SAINT LOUIS, MISSOURI ss:

BEFORE ME, the undersigned authority, personally appeared Michael P. Gorman, who after being by me first duly sworn, deposes and says that the facts stated herein are true based on personal knowledge.

I hereby affirm that the foregoing is true and correct to the best of my knowledge and belief. If called to testify in this matter, I would testify as set forth herein.

Further affiant says not.

Michael P. Gorman
Affiant

Subscribed and sworn to before me by Mr. Michael P. Gorman, who is known to me this 30th day of June, 2020.

Maria E. Decker
Notary Public

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2021
Commission # 13706793

My Commission Expires: May 5, 2021

ATTACHMENT B

Affidavit of Ali Al-Jabir
On behalf of American Manufacturers

Exhibit No. AMF-6

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act	Docket No. RM20-10-000

Affidavit of Ali Al-Jabir

On behalf of

American Manufacturers

July 1, 2020

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<u>Affidavit of Ali Al-Jabir</u>

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AFFIDAVIT
OF ALI AL-JABIR

July 1, 2020

SUMMARY

In this Affidavit, I address two main areas: a) that the FERC's existing transmission incentives policy has led to the construction of significant amounts of new transmission through the transmission expansion processes of FERC-jurisdictional regional transmission organizations ("RTOs") and through transmission construction pursuant to local utility planning processes; and b) expanded reliance on competitive bid processes for new transmission construction provides a superior means of incentivizing such construction relative to giving additional return on equity ("ROE") incentives to incumbent utilities as suggested in the Incentives NOPR.

My Affidavit contains the following findings and conclusions:

- There is insufficient evidence to conclude that additional administrative ROE incentives must be provided to incumbent utilities to induce new transmission investment in the areas identified in the Incentives NOPR.

- Significant amounts of new transmission investment have been added in the U.S. over the past several years under the current FERC policy framework. Such investment includes numerous projects designed to enhance system reliability, to integrate new generation into the grid and to support load growth. Moreover, existing RTO transmission expansion policies explicitly incorporate the need to accommodate factors such as integration of new generation technologies, vehicle electrification and load growth that the FERC relies upon to support the need to revamp its existing incentives policy. This evidence cast serious doubt on the need to grant additional ROE incentives to accomplish the FERC's stated policy goals that are driving the changes proposed in the Incentives NOPR.

- The evidence shows that FERC-jurisdictional ISOs and RTOs made over $75 billion in transmission investments over the period

2013-2017. Moreover, FERC-jurisdictional ISOs and RTOs approved approximately $40 billion in transmission investments over the period 2012-2017. This evidence underscores the fact that there are no obstacles to transmission investment under the current regulatory paradigm that merit an increase in administratively-induced ROE incentives of the kind proposed in the Incentives NOPR.

- ROE incentives come at a cost to ratepayers that is unnecessary if there are alternative means of incentivizing new transmission construction to meet the FERC's policy goals. An effective means of incentivizing new transmission investment while controlling the cost of transmission construction is to expand efforts to harness the forces of competition for new transmission projects.

- Competition, rather than administratively-induced ROE incentives to incumbent utilities, is the most efficient means of incenting transmission investment and delivering value to the grid and to consumers at the lowest reasonable cost.

- The experience to date has demonstrated that competitive bidding for new transmission construction has resulted in vigorous competition and has produced significant cost savings for customers relative to the initial RTO cost estimate for the construction of the projects. Moreover, competitive forces have incented bidders in these solicitations to offer innovative cost containment solutions such as caps on construction costs, caps on ROE and limitations on the equity component of the capital structure.

- The current limitations on the scope of competition for new transmission investment stem from a number of restrictions on the eligibility of transmission projects for competitive bidding under current FERC policies. The FERC should focus its transmission incentive policy initiative on opportunities to expand the scope of competition for new transmission investment in order to bring the discipline of competitive market forces to these projects and to provide a cost-effective and efficient means of incentivizing transmission construction in lieu of granting additional ROE incentives to the incumbent utilities.

Affidavit of Ali Al-Jabir

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Ali Al-Jabir. Atrium Plaza, Suite 412 C/D, 5151 Flynn Parkway, Corpus Christi, TX 78411.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and an Associate of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A During my twenty-three (23) years of employment by BAI, I have been engaged in assignments with respect to wholesale power market structure, market power, fuel costs, power procurement, cost allocation and rate design issues in the United States and portions of Canada. I hold a Master's Degree in Economics from the University of Texas at Austin. I have testified previously before state regulatory commissions and before the Federal Energy Regulatory Commission ("FERC") on various economic and regulatory matters. Appendix A to this Affidavit provides a more complete summary of my background and experience.

1. My firm has been retained by several groups comprising the American Manufacturers to review and to respond to the March 20, 2020 Notice of Proposed

Rulemaking regarding electric transmission incentives policy that the FERC issued in Docket No. RM20-10-000.[1]

2. Appendix A to this Affidavit was prepared under my direction and control. It is part of my Affidavit.

3. I conclude the following in this Affidavit:

- There is insufficient evidence to conclude that additional administrative ROE incentives must be provided to incumbent utilities to induce new transmission investment in the areas identified in the Incentives NOPR.

- Significant amounts of new transmission investment have been added in the U.S. over the past several years under the current FERC policy framework. Such investment includes numerous projects designed to enhance system reliability, to integrate new generation into the grid and to support load growth. Moreover, existing RTO transmission expansion policies explicitly incorporate the need to accommodate factors such as integration of new generation technologies, vehicle electrification and load growth that the FERC relies upon to support the need to revamp its existing incentives policy. This evidence cast serious doubt on the need to grant additional ROE incentives to accomplish the FERC's stated policy goals that are driving the changes proposed in the Incentives NOPR.

- The evidence shows that FERC-jurisdictional ISOs and RTOs made over $75 billion in transmission investments over the period 2013-2017. Moreover, FERC-jurisdictional ISOs and RTOs approved approximately $40 billion in transmission investments over the period 2012-2017. This evidence underscores the fact that there are no obstacles to transmission investment under the current regulatory paradigm that merit an increase in administratively-induced ROE incentives of the kind proposed in the Incentives NOPR.

- ROE incentives come at a cost to ratepayers that is unnecessary if there are alternative means of incentivizing new transmission construction to meet the FERC's policy goals. An effective means of incentivizing new transmission investment while controlling the cost of transmission

[1]Federal Energy Regulatory Commission, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket No. RM20-10-000, March 20, 2020 ("Incentives NOPR").

construction is to expand efforts to harness the forces of competition for new transmission projects.

- Competition, rather than administratively-induced ROE incentives to incumbent utilities, is the most efficient means of incenting transmission investment and delivering value to the grid and to consumers at the lowest reasonable cost.

- The experience to date has demonstrated that competitive bidding for new transmission construction has resulted in vigorous competition and has produced significant cost savings for customers relative to the initial RTO cost estimate for the construction of the projects. Moreover, competitive forces have incented bidders in these solicitations to offer innovative cost containment solutions such as caps on construction costs, caps on ROE and limitations on the equity component of the capital structure.

- The current limitations on the scope of competition for new transmission investment stem from a number of restrictions on the eligibility of transmission projects for competitive bidding under current FERC policies. The FERC should focus its transmission incentive policy initiative on opportunities to expand the scope of competition for new transmission investment in order to bring the discipline of competitive market forces to these projects and to provide a cost-effective and efficient means of incentivizing transmission construction in lieu of granting additional ROE incentives to the incumbent utilities.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the American Manufacturers, as identified in the Comments.

Q WHAT IS THE PURPOSE OF YOUR AFFIDAVIT?

A My Affidavit addresses two main areas: a) that the FERC's existing transmission incentives policy has led to the construction of significant amounts of new transmission through the transmission expansion processes of FERC-jurisdictional regional transmission organizations ("RTOs") and through transmission construction pursuant to local utility planning processes; and b) expanded reliance on competitive bid processes for new transmission construction provides a superior means of incentivizing such construction relative to giving additional return on equity ("ROE") incentives to incumbent utilities as suggested in the Incentives NOPR.

II. BACKGROUND

Discussion of the Policy Drivers for the ROE Incentives Proposal

4. In the Incentives NOPR, the FERC proposes several reforms to its transmission incentives policy. Such reforms include applying a net benefits test to establish eligibility for ROE incentives, an increase in the RTO incentive adder from 50 to 100 basis points, the introduction of new incentives for the deployment of new transmission technologies and a 250 basis points cap for all ROE incentives.

5. The Incentives NOPR acknowledges that transmission infrastructure development has generally remained robust. Moreover, the Incentives NOPR states that it is encouraged by the investment in transmission infrastructure to date.[2] Nevertheless, the Incentives NOPR perceives a need to change its incentives policy and to provide additional ROE incentives for the construction of new transmission projects. The Incentives NOPR asserts that changes to its incentives policy are needed to integrate existing and new technologies, such as renewables, natural gas, electric storage and distributed energy into the transmission grid. Moreover, the Incentives NOPR states that changes to the existing incentives policy are needed to ensure the

[2] Incentives NOPR at PP 26 and 31.

construction of new transmission that can adapt to changes in load patterns resulting from the electrification of industries such as transportation and agriculture. The Incentives NOPR also contends that policy changes are needed to better target incentives to transmission projects that demonstrate economic benefits.[3]

III. ANALYSIS

Transmission Investment Is Robust Under the Current Incentive Structure

6. The Incentives NOPR acknowledges that transmission development is robust under the existing incentive structure, but nevertheless argues that new and additional incentives are needed to ensure that sufficient new transmission investment is undertaken to facilitate the integration of new technologies into the grid and to support potential load growth. The evidence shows that significant amounts of new transmission investment has been added in the U.S. over the past several years under the current FERC policy framework. Such investment includes numerous projects designed to enhance system reliability, to integrate new generation into the grid and to support load growth. Moreover, existing RTO transmission expansion policies explicitly incorporate the need to accommodate factors such as integration of new generation technologies, vehicle electrification, and load growth, on which the Incentives NOPR relies to support the need to revamp the existing incentives policy. This evidence raises serious doubts with respect to the need to grant additional ROE incentives to accomplish the FERC's stated policy goals that are driving the incentive changes proposed in the Incentives NOPR.

[3] Incentives NOPR at 15 - 19.

7. Currently, FERC-jurisdictional RTOs engage in a regional transmission planning process at regular intervals to evaluate the need for new transmission projects. These projects are evaluated in response to multiple drivers such as the need to preserve system reliability, to reduce grid congestion, to interconnect new generation to the grid, to accommodate load growth and to replace aging infrastructure. These regional planning processes typically incorporate forecasts of generation additions and load growth that reflect a range of assumptions regarding future changes to the generation fleet in the region. The futures scenarios that are analyzed include scenarios that assume the aggressive expansion of renewable generation, distributed generation and vehicle electrification. The RTOs rely on these futures scenarios to model the benefits associated with the addition of new transmission facilities. Moreover, for projects that are driven by the need to provide congestion relief to accommodate more efficient economic generation dispatch, the current RTO transmission expansion planning processes evaluate the estimated benefits of new transmission projects relative to their costs to ensure that new economic transmission projects provide projected benefits in excess of their costs under a range of futures scenarios. Typically, the projected benefits of such projects must exceed their estimated costs by a ratio of 1.25 to 1.0 or greater.

8. A case in point is the Midcontinent Independent System Operator, Inc.'s ("MISO's") transmission expansion plan process. In evaluating the need for new transmission projects to accommodate future changes in the generation mix within its footprint, MISO currently relies on four futures scenarios. Only one of the four scenarios assumes limited change to the existing generation fleet. The remaining three

futures either assume continued integration of renewable resources based on historical trend rates or more accelerated deployment of renewables, demand-side resources, distributed generation and storage resources relative to historical trends. Proposed transmission projects are modeled against these four futures scenarios to ensure that the proposed project is robust enough to be viable and can provide net benefits to customers, with a benefit to cost ratio of 1.25 to 1.0 under a weighted average of the futures scenarios.[4] MISO also engages in a transmission congestion planning study process to evaluate congestion within its footprint that could be alleviated through new transmission construction. The potential benefits of proposed transmission projects are evaluated using production cost modeling scenarios with and without the addition of the proposed transmission project. Moreover, MISO's selection of futures scenarios and its modeling of potential transmission projects is evaluated through a stakeholder process that provides all interested parties an opportunity to vet MISO's modeling and analyses to ensure that candidate transmission projects are viable under a range of system contingencies and potential futures.

9. Relying on this transmission expansion plan process, $23 billion in transmission projects have been constructed in the MISO region since 2003. MISO's 2019 transmission expansion plan ("MTEP19") approved almost $4 billion in new transmission projects for a single transmission planning cycle.[5] These projects include substantial investments to integrate new generation and to preserve system reliability, consistent with the standards of the North American Electric Reliability Corporation

[4] MISO's 2019 Transmission Expansion Plan Report ("MTEP19 Report") at page 34.
[5] MTEP19 Report at page 3.

("NERC"). Past MISO transmission plans have included Market Efficiency Projects ("MEPs") that reduce market congestion and provide net economic benefits to MISO customers in excess of their costs. In addition, MISO approved the construction of 17 Multi-Value Projects in 2011 that were driven by a combination of benefits, including not only economic and reliability benefits but also public policy benefits in the form of the integration of new renewable generation into the transmission grid.[6] The MISO MTEP19 transmission expansion plan also includes large transmission investments by individual transmission owners that are developed through local utility planning processes as solutions to local transmission issues identified by the individual transmission owners outside of the regional MISO planning process. These "Other Projects," which constituted 72% or $2.8 billion of the overall MISO transmission investment for the MTEP19 planning cycle, are driven by needs including preserving system reliability, accommodating load growth and replacing or upgrading aging transmission infrastructure.[7] This substantial amount of regional and local transmission investment is occurring under existing RTO and local utility transmission ROE policies. While a range of reliability, economic efficiency and public policy factors influence the need for these investments, much of the investment is driven, at least in part, by the factors that are identified in and appear to be motivating the Incentives NOPR, such as the need to integrate new generation technologies, the provision of net economic benefits to customers and the need to integrate new generation technologies.

[6]Ibid. at page 3.
[7]Ibid at page 16.

10. It is important to note that the RTO transmission expansion plans are not merely advisory in nature. Rather, they create an obligation on the part of member transmission owners to work in good faith to construct and put into service the projects that are approved in these expansion plans. For example, the MISO Tariff makes it clear that the designated transmission owner (or a selected competitive third party developer) for a transmission project "has the responsibility and obligation to construct the facilities that it is designated to construct" pursuant to the terms of the Independent System Operator ("ISO") agreement between MISO and the individual transmission owners within the MISO footprint.[8] Thus, barring other impediments to project construction such as siting complications, the individual transmission owners are obligated to ensure timely construction of transmission projects that are approved under the expansion plan. All of this new transmission construction has been undertaken under the existing transmission incentive policies and is subject to the obligation of transmission owners to construct approved projects.

11. This volume of transmission expansion to accommodate various drivers including system reliability, load growth, congestion reduction, market efficiency and integration of new generation technologies is by no means limited to MISO. A recent report from the Brattle Group found that transmission owners in FERC-jurisdictional ISOs and RTOs made over $75 billion in transmission investments over the period 2013-2017. The $75 billion figure is based on all transmission investments reported by these utilities in their FERC Form 1 reports. Moreover, the Brattle Group calculated that FERC-jurisdictional ISOs and RTOs approved approximately

[8]MISO ISO Agreement, Appendix B, Planning Framework.

$40 billion in transmission investments over the period 2012-2017. For MISO, the ISO-approved investment amount reported by the Brattle Group is limited to projects that were approved in a MISO transmission expansion plan and that have been placed into service as reported in MISO's in-service project list. For PJM, the amount of RTO-approved investment excludes Supplemental and transmission owner initiated projects. For California, the ISO-approved investment amount only covers the three largest investor-owned utilities in the state.[9] All of this evidence underscores the fact that there are no obstacles to transmission investment under the current regulatory paradigm that merit an increase in administratively-induced ROE incentives of the kind proposed in the Incentives NOPR.

Competition Is Superior to Administrative Incentives for Transmission Investment

12. The Incentives NOPR is largely premised on the notion that it is necessary to provide additional ROE incentives to incumbent transmission utilities in order to ensure that sufficient transmission is constructed to meet the policy objectives of integrating new generation technologies and accommodating load growth. However, these ROE incentives come at a significant cost to ratepayers that is unnecessary if there are alternative means of incentivizing new transmission construction to meet the FERC's policy goals. An effective means of incentivizing new transmission investment, while controlling the cost of transmission construction, is to expand efforts to harness the forces of competition for new transmission projects.

[9] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission – Experience to Date and the Potential for Additional Customer Value*, April 2019, Tables 1 and 21 ("Brattle Report").

Competition, rather than administratively-induced incentives to incumbent utilities, is the most efficient means of incenting transmission investment and delivering value to the grid and to consumers at the lowest reasonable cost. Administratively-induced incentives of the kind proposed in the Incentives NOPR will unnecessarily inflate the cost of transmission investment to consumers and stifle competition by increasing the incentives that the incumbent utilities already have to favor self-build projects that expand their own rate base through new transmission projects.

13. The FERC's current policy toward competition for new transmission construction is set forth in Order No. 1000. In that order, the FERC removed federal rights of first refusal for transmission projects selected in an RTO's regional transmission plan for purposes of cost allocation.[10] Subject to certain limitations, this directive effectively means that RTOs are required to subject new transmission projects to a competitive bid process where such projects are selected through the regional planning process and the costs of the projects are regionally allocated outside the local transmission pricing zone where the transmission project is sited.

14. Competition for new transmission construction creates powerful incentives for transmission companies to propose innovative solutions to deploy new transmission technologies and to do so in a manner that minimizes the cost of new transmission projects to end-use customers. There are several independent transmission companies that are actively competing against incumbent utilities for new transmission projects where FERC policy permits competitive bidding for new transmission projects. Indeed, in the competitive RTO transmission solicitations that have occurred to date,

[10] Order No. 1000, 136 FERC ¶ 61,051 at P 7.

the evidence shows that independent transmission developers have been willing to offer ROE limitations and project cost caps that minimize the cost of new transmission construction relative to the RTO's project cost estimate. The experience to date has demonstrated that competitive bidding for new transmission constructed has resulted in vigorous competition that has produced significant cost savings for customers relative to the initial RTO cost estimate for the construction of the projects. Increased reliance on such competitive forces would allow the FERC to achieve the policy goals articulated in the Incentives NOPR in a least-cost manner, without adding new ROE incentives for incumbent utilities that come at a significant cost to customers.

15. Indeed, the Brattle Report surveyed 31 competitive transmission solicitations in FERC-jurisdictional ISOs and RTOs since 2013 and concluded that these competitive bid processes consistently resulted in significant savings relative to the RTO/ISO cost estimate for the project or relative to the cost of the proposals submitted by the incumbent utilities. For example, for the projects surveyed, estimated cost savings in these competitive solicitations were 15% in MISO, 50% in the Southwest Power Pool ("SPP"), 22% in the New York ISO ("NYISO"), and as high as 60% for the Artificial Island Project in the PJM Interconnection, LLC ("PJM").[11] The Brattle Report specifically reviewed two competitive solicitations for new transmission projects in MISO and found the solicitations resulted in healthy competition involving 11 or 12 bidders. Moreover, the bids included many innovative solutions to ensure cost savings for customers, including various forms of cost caps. Notably, **<u>the proposals included ROE caps and caps on the equity component of the capital</u>**

[11] Brattle Report at pp. 30-32.

structure, showing that bidders were willing and able to construct new transmission projects to meet the needs of the planning region without the need for the types of ROE incentives proposed in the Incentives NOPR.[12]

16. A specific example of the efficacy of relying on competition to incentivize efficient transmission investment while limiting costs to consumers can be found in the Duff-Coleman 345 kV MEP that was competitively bid in MISO. The winning bidder for that project agreed to several binding commitments that resulted in the construction of new transmission facilities to provide economic benefits to consumers while minimizing the associated capital and construction costs. For example, the winning bidder agreed to a total cap on rate base costs that was below MISO's original cost estimate for the project and also agreed to forego construction work in progress ("CWIP") for the project. **Of direct relevance to the Incentives NOPR, the winning bidder agreed to an ROE cap and a limitation on the equity percentage of its capital structure. Moreover, in stark contrast to the Incentives NOPR's approach of providing additional ROE incentives to incumbent utilities, the winning bidder agreed to a penalty structure that imposed reductions to its project-specific ROE if it failed to meet the project in-service date specified in its agreement with MISO.**[13] The efficacy of these contractual commitments is demonstrated by the fact that Republic Transmission completed the Duff-Coleman project in June 2020, more than six months ahead of the scheduled January 2021

[12]Ibid at page 35.

[13]Duff-Coleman EHV 345kV Competitive Transmission Projects, *Second Amended and Restated Developer Agreement By and Between Republic Transmission, LLC and Midcontinent Independent System Operator, Inc.*, Appendix A, Section A.3.

in-service date, resulting in the timely completion of a transmission project that provides more than $1 billion in estimated economic benefits to customers without the need for the additional ROE incentives proposed by the FERC.[14]

17. Based on the experience with competitive solicitations to date, the Brattle Report estimates that competition for new transmission construction could generate cost savings for customers in the range of $4.4 billion to $9 billion over a five-year period. The Brattle Report states that the high-end savings estimate of $9 billion could be realized if 33% of total transmission investment was developed competitively and generated average savings of 30%.[15] The Brattle Report further demonstrates that there is ample opportunity to expand the application of competitive forces to new transmission construction in order to incentivize the build-out of new transmission in a least-cost fashion for the benefit of end-use customers. Indeed, the Brattle Report found that, for the years 2013-2017, only 3% of the average total transmission investment in FERC-jurisdictional ISOs and RTOs was subject to competitive bid processes.[16]

18. The current limitations on the scope of competition for new transmission investment stem from a number of restrictions on the eligibility of transmission projects for competitive bidding under current FERC policies. One significant limitation relates to the fact that the FERC's competitive bidding requirement has generally excluded transmission projects that are locally planned by the incumbent

[14] MISO Press Release, *New Member Company Republic Transmission Energized Their First Line This Month*, June 11, 2020.
[15] Ibid at page 13.
[16] Ibid at page 19.

utilities outside of the full RTO regional planning process. In fact, the Brattle Report shows that, on average, 47% of the total transmission investment within the FERC-jurisdictional ISO and RTO regions over the past several years has occurred with limited review by the applicable RTO or ISO.[17] As noted earlier, the FERC's competition directive in Order No. 1000 specifically applies to transmission projects selected in an RTO's regional transmission plan for purposes of cost allocation. This generally leads to the exclusion of locally planned transmission projects from the competitive bidding requirement.

19. A related restriction on the application of competitive forces to new transmission construction is the exclusion of projects that are allocated exclusively to the local transmission zone where they are sited. In MISO, for example, this restriction has effectively excluded all Baseline Reliability Projects and all sub-345 kV economic projects (designated as "Other Projects") from competitive bid requirements.[18] In PJM, transmission projects that are constructed to meet local utility planning requirements and designated as "Supplemental Projects" are also exempt from the competitive bidding requirements of Order 1000. Other exclusions from competitive bidding in PJM include sub-200 kV projects and substation equipment. Order 1000 also generally excludes upgrades to existing facilities from the competitive bidding process. These restrictions on competitive bidding apply even when the evidence demonstrates that the benefits of these transmission projects extend outside

[17]Ibid at page 25.

[18]MISO has submitted a filing to the FERC to reduce the MEP voltage threshold from 345 kV to 230 kV in Docket Nos. ER20-1723-000 and ER20-1724-000, but MISO's proposal would continue to exempt sub-230 kV economic projects from competitive bidding.

of the local transmission zone where the projects are sited. For example, the restriction on competitive bidding for economic projects in MISO is based purely on a voltage level threshold and does not consider the actual distribution of economic and other benefits on a project-specific basis.

20. Moreover, the FERC has permitted ISO New England, Inc. ("ISO-NE"), PJM and SPP to exclude transmission projects from competitive bidding if it can be demonstrated that the projects must be placed into service within 36 months for reliability reasons. This exclusion is generally labeled the Immediate Need Reliability Exemption.

21. The aforementioned restrictions have led to excluding a large amount of transmission investment from competitive bidding requirements and has also created incentives to expand the amount of projects that are excluded from these requirements. A case in point is the fact that the introduction of competitive bidding under Order 1000 has led to exponential growth in transmission investment in MISO and PJM that is planned by local utilities and that remains outside the competitive bidding requirement. In PJM, the Independent Market Monitor ("IMM") recently reported that the average number of Supplemental Projects in each expected in-service year increased by **720%** from 20 projects for the period 1998-2007 to 164 projects for the years 2008-2020. The average cost of Supplemental Projects has exploded at an even higher rate of **2,106%** from the period 1998-2007 to the period 2008-2020.[19] As shown in the table below, a review of MISO's recent transmission expansion plan

[19] Monitoring Analytics, 2020 State of the Market Report for PJM: January through March, May 14, 2020, pages 614 and 616 ("IMM Report").

reports shows that the approved Other Projects that are exempt from competitive bidding have increased at a compound annual growth rate of almost 48% over the 2015-2019 time frame.

Approved MISO Other* Projects by Planning Year ($M) [1]

	2015 [2]	2016 [3]	2017 [4]	2018 [5]	2019 [6]	Compound Annual Growth Rate
MISO Other Projects	$1,381	$1,747	$1,393	$2,317	$2,881	
Cumulative	$1,381	$3,128	$4,521	$6,838	$9,719	47.75%
Cumulative Year Over Year Growth		127%	45%	51%	42%	

*MTEP19 describes "Other" projects as projects that "do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects"

1. Values do not take into account project withdrawals or cancellations from prior planning years (ie they represent gross approval estimates rather than net).
2. MTEP15 Executive Summary, Table 1.1-1, p. 3
3. MTEP16 Book 1 Transmission Studies, Table 2.1-1, p. 4
4. MTEP17 Book 1 Transmission Studies, Table 2.1-1, p. 6
5. MTEP18 Book 1 Transmission Studies, Table 2.1-1, p. 6
6. MTEP19 Executive Summary and Report, Table 1.3-4, p. 30

22. The foregoing discussion highlights the fact that there are numerous exclusions that are being used to restrict competitive bidding for a large portion of new transmission construction under current FERC policy. As demonstrated by the concrete experience of MISO with regard to competitive bidding for MEPs, the FERC can create powerful incentives for new transmission construction by expanding the application of competitive forces to projects that are currently subject to these exclusions. A policy approach that emphasizes the expansion of competitive opportunities would allow the FERC to attain its stated policy goals for transmission investment in a manner that encourages cost-effective and innovative solutions to transmission needs, without relying on additional, administratively determined ROE incentives to the incumbent utilities to achieve these goals.

23. The FERC should focus its transmission incentive policy initiative on opportunities to expand the scope of competition for new transmission investment in order to bring the discipline of competitive market forces to these projects. This would be a more cost-effective and efficient means of incentivizing transmission construction in lieu of granting additional ROE incentives to the incumbent utilities.

Q DOES THIS CONCLUDE YOUR AFFIDAVIT?

A Yes.

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Qualifications of Ali Al-Jabir

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Ali Al-Jabir. My business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and an Associate with the firm of Brubaker & Associates, Inc. ("BAI").

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A I am a graduate of the University of Texas at Austin ("UT-Austin"). I hold the degrees of Bachelor of Arts and Master of Arts in Economics, both from UT-Austin. I have also completed course work at Harvard University. I received my B.A. degree with highest honors, and I am a member of the Phi Beta Kappa Honor Society.

Q PLEASE STATE YOUR EXPERIENCE.

A I joined BAI in January 1997. My work consists of preparing economic studies and economic policy analysis related to investor-owned, cooperative, and municipal utilities. Prior to joining BAI, I was employed at the Public Utility Commission of Texas ("Texas Commission") since 1991, where I held various positions including Policy Advisor to the Chairman. As Policy Advisor, I advised the Chairman on policy decisions in numerous rate and rulemaking proceedings. In 1995, I advised the Texas

Legislature on the development of the statutory framework for wholesale competition in the Electric Reliability Council of Texas ("ERCOT"), and I was involved in subsequent rulemakings at the Texas Commission to implement wholesale open access transmission service in the region.

During my tenure at the Texas Commission and in my present capacity, I have reviewed and analyzed several electric utility base rate and fuel filings in Texas. I have also worked on utility rate, fuel, and merger proceedings and rulemakings in Virginia, Missouri, Colorado, Indiana, Alberta, Pennsylvania, North Carolina, South Carolina, Michigan and Nova Scotia. In addition to my work on such proceedings, I have drafted policy papers, comments and affidavits regarding electric industry restructuring, competitive policy and market design issues in Texas, Alabama, Louisiana, Georgia, and Delaware, as well as before the Federal Energy Regulatory Commission. I have been an invited speaker at several electric utility industry conferences, and I have presented seminars on utility regulation and industry restructuring.

BAI and its predecessor firms have been active in utility rate and economic consulting since 1937. The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some competitive retail power providers and utilities and, on occasion, state regulatory agencies. In addition, we have prepared depreciation and feasibility studies relating to utility service. We assist in the negotiation of contracts and the solicitation and procurement of competitive energy supplies for large energy users, provide economic policy analysis on industry restructuring issues, and present seminars on utility regulation. In general, we are engaged in regulatory consulting, economic analysis, energy procurement, and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas and Phoenix, Arizona.

Q HAVE YOU PREVIOUSLY FILED TESTIMONY IN CONTESTED UTILITY PROCEEDINGS?

A Yes, I have filed written testimony in the following dockets:

1. Texas Docket No. 10035 – Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors;

2. Texas Docket No. 10200 – Application of the Texas - New Mexico Power Company for Authority to Change Rates;

3. Texas Docket No. 10325 – Application of the Central Texas Electric Cooperative, Inc. for Authority to Change Rates;

4. Texas Docket No. 10600 – Application of the Brazos River Authority for Approval of Rates;

5. Texas Docket No. 10881 – Application of the New Era Electric Cooperative, Inc. for Authority to Change Rates;

6. Texas Docket No. 11244 – Petition of the Medina Electric Cooperative, Inc. to Reduce its Fixed Fuel Factor and the Application of the South Texas Electric Cooperative, Inc. for Authority to Refund an Over-Recovery of Fuel Cost Revenues and to Reduce its Fixed Fuel Factor;

7. Texas Docket No. 11271 – Application of Bowie-Cass Electric Cooperative, Inc. for Authority to Change Rates;

8. Texas Docket No. 11567 – Application of Kaufman County Electric Cooperative, Inc. for Authority to Change Rates;

9. Texas Docket No. 18607 – Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs;

10. Texas Docket No. 20290 – Application of Central Power & Light Company for Authority to Reconcile Fuel Costs;

11. Virginia Case No. PUE980814 – In the matter of considering an electricity retail access pilot program: American Electric Power – Virginia;

12. Texas Docket No. 21111 – Application of Entergy Gulf States Inc. for Authority to Reconcile Fuel Costs and to Recover a Surcharge for Under-Recovered Fuel Costs;

13. Virginia Case No. PUE990717 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Virginia Code Section 56-249.6;

14. Texas Docket No. 22344 – Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule § 25.344;

15. Texas Docket No. 22350 – Application of TXU Electric Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Phase III);

16. Texas Docket No. 22352 – Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

17. Texas Docket No. 22353 – Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

18. Texas Docket No. 22354 – Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

19. Texas Docket No. 22356 – Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344;

20. Texas Docket No. 22349 – Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

21. Virginia Case No. PUE000584 – Application of Virginia Electric and Power Company for Approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act;

22. Texas Docket No. 24468 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool;

23. Texas Docket No. 24469 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council;

24. Virginia Case No. PUE-2002-00377 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Section 56-249.6 of the Code of Virginia;

25. Texas Docket No. 27035 – Application of Central Power and Light Company for Authority to Reconcile Fuel Costs;

26. Texas Docket No. 28818 – Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas;

27. Virginia Case No. PUE-2000-00550 -- Appalachian Power Company d/b/a American Electric Power: Regional Transmission Entities;

28. Texas Docket No. 29408 – Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs;

29. Texas Docket No. 29801 – Application of Southwestern Public Service Company for: (1) Reconciliation of its Fuel Costs for 2002 and 2003; (2) A Finding of Special Circumstances; and (3) Related Relief;

30. Texas Docket No. 30143 -- Petition of El Paso Electric Company to Reconcile Fuel Costs;

31. Texas Docket No. 31540 – Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Substantive Rule 25.501;

32. Texas Docket No. 32795 – Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA Section 39.253(f);

33. Texas Docket No. 33309 – Application of AEP Texas Central Company for Authority to Change Rates;

34. Texas Docket No. 33310 – Application of AEP Texas North Company for Authority to Change Rates;

35. Michigan Case No. U-15245 – In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Rate Relief;

36. Texas Docket No. 34800 – Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs;

37. Texas Docket No. 35717 – Application of Oncor Electric Delivery Company LLC for Authority to Change Rates.

38. RIPUC Docket No. 4065 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11;

39. RIPUC Docket No. 4323 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-1-3-11;

40. Oregon Docket No. UE 283 -- In the Matter of Portland General Electric Company's Request for a General Rate Revision;

41. Washington Docket No. UE-141368 – In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes;

42. Federal Energy Regulatory Commission Docket No. EL15-82-000 -- Illinois Industrial Energy Consumers, Complainant, v. Midcontinent Independent System Operator, Inc., Respondent;

43. RIPUC Docket No. 4568 – In Re: Review of the Narragansett Electric Company d/b/a National Grid's Rate Design Pursuant to R.I. General Laws Section 39-26.6-24;

44. Washington Docket Nos. UE-170033 and UG-170034 – Washington Utilities and Transportation Commission, Complainant, v. Puget Sound Energy, Respondent;

45. RIPUC Docket No. 4770 – The Narragansett Electric Company d/b/a National Grid – Application for Approval of a Change in Electric and Gas Base Distribution Rates;

46. RIPUC Docket No. 4780 – The Narragansett Electric Company d/b/a National Grid – Proposed Power Sector Transformation Vision and Implementation Plan;

47. Federal Energy Regulatory Commission Docket Nos. ER19-1486-000 and ER19-58-000, Enhanced Price Formation In Reserve Markets of PJM Interconnection, L.L.C.;

48. Texas Docket No. 49494 – Application of AEP Texas Inc. for Authority to Change Rates; and

49. Washington Docket Nos. UE-190529 and UG-190530 – Washington Utilities and Transportation Commission, Complainant, v. Puget Sound Energy, Respondent.

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AFFIDAVIT OF ALI AL-JABIR

Glossary of Abbreviations and Acronyms

BAI	Brubaker & Associates, Inc.
CWIP	Construction Work In Progress
FERC	Federal Energy Regulatory Commission
IMM	Independent Market Monitor
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator, Inc.
MTEP19	MISO 2019 Transmission Expansion Plan
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
PJM	PJM Interconnection, L.L.C.
RTO	Regional Transmission Organization
SPP	Southwest Power Pool

Ali Al-Jabir

STATE OF TEXAS)
) **SS**
COUNTY OF NUECES)

Subscribed and sworn to before me this 26th day of June, 2020.

AMY MORIN
My Notary ID # 6349873
Expires August 29, 2023

NOTARY PUBLIC
STATE OF TEXAS

Notary Public

APPENDIX 1

List of Companies and Groups Comprising American Manufacturers

1. American Chemistry Council
2. American Forest & Paper Association
3. American Foundry Society
4. American Fuel & Petrochemical Manufacturers
5. American Iron and Steel Institute
6. Associated Industries of Arkansas
7. Association of Businesses Advocating Tariff Equity
8. California Large Energy Consumers Association
9. Cargill, Incorporated
10. Carolina Utility Customers Association
11. Chemistry Council of New Jersey
12. Coalition of MISO Transmission Customers
13. Domtar Corporation
14. Electricity Consumers Resource Council
15. Florida Industrial Power Users Group
16. Gerdau
17. Glass Packaging Institute
18. Illinois Industrial Energy Consumers
19. Industrial Energy Consumers of America
20. Industrial Energy Users-Ohio
21. Industrial Minerals Association – North America
22. Indiana Industrial Energy Consumers, Inc.
23. Iowa Business Energy Coalition
24. Iowa Industrial Energy Group, Inc.
25. Kentucky Industrial Utility Customers
26. Maine Industrial Energy Consumer Group
27. Messer LLC
28. Michigan Industrial Energy Association
29. Midwest Food Products Association
30. National Council of Textile Organizations
31. Ohio Energy Group
32. Ohio Manufacturers' Association Energy Group
33. Oklahoma Industrial Energy Consumers
34. Pennsylvania Energy Consumers Association
35. Portland Cement Association
36. West Virginia Energy Users Group
37. WestRock Company
38. Wisconsin Industrial Energy Group