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October 25, 2017

Antiquated Power Grids: What Can Age of Plant Tell Us About Future Rate Base Growth?

How might the age of a utility's transmission and distribution network affect its potential for investment in new transmission and distribution assets and thus its long term outlook for rate base growth? In this note we estimate the relative ages of the transmission and distribution networks of the U.S. regulated electric utilities and rank the utilities accordingly. Among the primarily regulated utilities whose aging electricity grids may lift long term rate base growth, the stocks of AEE, AVA, NWE and PNM may offer the most attractive opportunities, while AGR stands out among the hybrid electric utilities. We have also identified those utilities whose planned capital expenditures over 2017-2021 seems to fall well short of what could be required to replace aging plant, and where the potential may exist, therefore, to ramp up capex and rate base growth in the medium term. The utilities that appear most attractive on this basis are NWE, where planned T&D capex over 2017-2021 is equivalent to less than half of the estimated cost to replace pre-1988 T&D plant, and HE and OGE, where planned capex covers only three quarters of the estimated replacement cost of pre-1988 assets.

- We have used three approaches to estimate the relative age of transmission and distribution plant among the U.S. regulated electric utilities, and to rank the utilities accordingly:
  - The ratio of a utility's customers 30 years ago to its customers today, with a low ratio suggesting rapid growth in recent decades and thus a low average age of its electric grid (**Exhibit 5**);
  - The ratio of a utility's customers 50 years ago to its customers today, with a high ratio suggesting slow growth in recent decades and thus a high average age of its electric grid (**Exhibit 6**);
  - The ratio of the replacement cost of a utility's transmission and distribution plant in service to the book value of these assets (**Exhibits 7** and **8**). A utility whose additions of gross utility plant were concentrated in recent years should show little difference between the inflation adjusted and book value of its plant in service, while a utility whose additions of gross utility plant occurred in large part several decades ago should show a more substantial difference.
    - The higher the ratio of replacement cost to book value, the more likely that maintenance and replacement capex will materially exceed book depreciation, implying substantial positive net capex and thus the potential for more rapid rate base growth.
- Our analysis of the customer base of the various U.S. electric utilities points to Midwestern and Northeastern utilities such as ED, AGR, FE, CMS, DTE, PEG and AEE as having the oldest grids.
- The ratio of replacement cost of T&D plant in service to its book value suggests that AEE, AGR, AVA, DTE, GXP, NWE and PNM may have the oldest average age of T&D plant in service (see **Exhibit 10**).
- The need to replace aging T&D plant will contribute more to rate base growth at utilities whose T&D systems account for a large share of rate base (**Exhibit 9**). Taking this into account, AEE, AVA, NWE and PNM may offer the most attractive plays on the need to upgrade aging electricity grids.
- We have also identified those utilities whose planned capital expenditures over 2017-2021 seem to fall well short of what would be required to replace aging plant, and where the potential may exist, therefore, to ramp up capex and rate base growth in the medium term (see **Exhibit 11**). The utilities that we find

most attractive on this basis are NWE, where planned T&D capex over 2017-2021 is equivalent to less than half of the estimated replacement cost of pre-1988 T&D plant, and HE and OGE, where planned capex covers only three quarters of estimated replacement cost.

- Among the hybrid utilities, AGR, FE and PEG appear to have the oldest electric grids. AGR also ranks in the first quintile among electric utilities on the average age of its transmission and distribution plant in service, and thus may offer the most attractive play on the need to upgrade an aging grid.
- Among the utilities identified here as having the largest rate base growth opportunities from replacing aging plant, we note that AEE, AVA, DTE, GXP and PNM among regulated electric utilities, and AGR among the hybrid utilities, also screened as having strong long run rate base growth in our note from October 2, *"If This Is the Golden Age of Electric Utilities, What's Next? Or, How Fast Can Rate Base Grow in the Long Term and on What Will Utilities Spend?"* (see link below[1]).

Exhibit 1: Heat Map: Preferences Among Utilities, IPP and Clean Technology

Preferences Among Utilities, IPPs and Clean Technology			
Sector	Weighting	Favorites	Concerns
Regulated Electric Utilities	Overweight	AEP, PCG, XEL	ALE, SCG
Hybrid Electric Utilities	Neutral	NEE	D
IPPs	Underweight		
Renewables	Underweight		JASO, JKS
Yieldcos	Neutral	NEP	CAFD

Source: SSR analysis

Details

Is Distribution the Next Source of Rate Base Growth, and If So, Which Utilities Will Benefit Most?

Utility investment in distribution has materially lagged that in the transmission and generation segments since the turn of the century. Over the period 2000-2016, we calculate that the aggregate distribution plant rate base of U.S. investor owned utilities has expanded at 4.1% compound annual rate; by contrast, growth in generation plant rate base averaged 7.0% p.a. over this period, and growth in transmission plant rate base 8.5% p.a. Having grown as long and as rapidly as they have, transmission and generation rate base now comprise relatively high proportions of total electric plant rate base, while the share of distribution rate base is at its lowest level in 25 years (**Exhibit 2**). At 26%, the share of transmission plant to total electric plant rate base has never been higher over the last three decades; its average share of total rate for the period 1988-2016 is only 19%. Generation's share of aggregate electric rate base has been on an upswing for the last 15 years, and is now close to its 1988-2016 average of 34%. By contrast, the share of distribution in total electric rate base, at 41%, is at its lowest level since 1991 and well below its 1988-2016 average of 47%.

[1] http://www.ssrllc.com/publication/if-this-is-the-golden-age-of-electric-utilities-whats-next-or-how-fast-can-rate-base-grow-in-the-long-term-and-on-what-will-utilities-spend/

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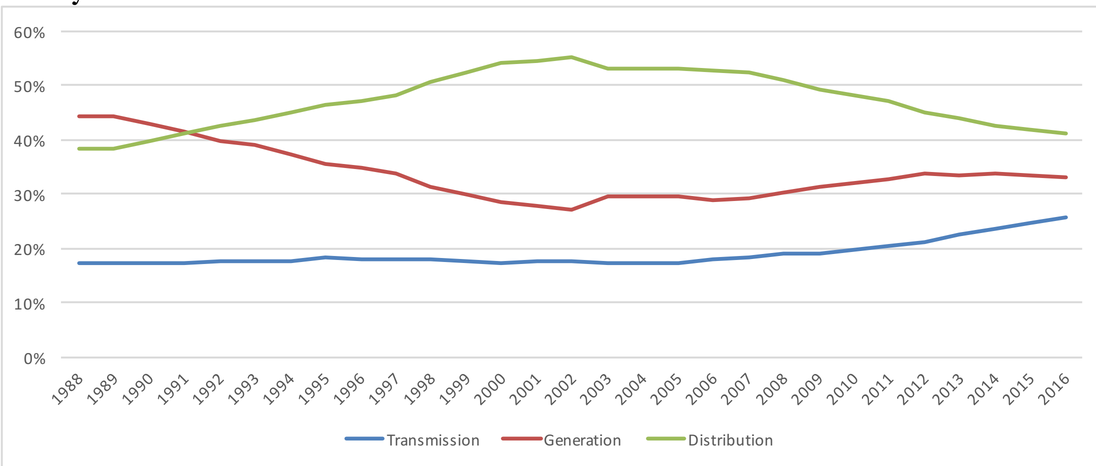
Exhibit 2: Share of Generation, Transmission and Generation Rate Base in Total Electric Utility Plant Rate Base Over 1988-2016



Source: Company FERC Form 1 filings, SNL, SSR analysis

As discussed in our note of October 2nd, *If This Is the Golden Age of Electric Utilities, What's Next? Or, How Fast Can Rate Base Grow in the Long Term and on What Will Utilities Spend?*[2], our analysis suggests that growth in distribution rate base is likely to accelerate in the years ahead, even as the growth of transmission and distribution rate base slows. Specifically, the disclosed capex plans of the publicly traded utilities for 2017-2021 point to a large increase in capital expenditures on distribution, modestly declining outlays on transmission, and a significant contraction in generation capex. As a share of total utility capex, we expect distribution capex to rise from 34% of the total over the last five years (2012-2016) to 46% of the total over the next five (2017-2021); the share of transmission capex is to remain relatively stable at 28%; and investment in generation to decline markedly, from 38% to 26% of the total (see **Exhibit 3**). We expect this shift to be reflected in an acceleration in the growth of distribution plant rate base, from 4.1% p.a. over 2012-2106 to 6.4% p.a. over 2016-2021, even as growth in generation and transmission rate base slows (**Exhibit 4**).

Could the relative age of utilities' distribution plant offer an insight into which utilities will benefit most benefit most in the long term from this expected recovery in distribution capex? We believe so, for three principal reasons.

First, maintenance capex has historically been the majority of distribution capex. For electric utilities, the capital expenditures that drive rate base growth are comprised of three components: i) maintenance and replacement of existing plant in service; ii) expansion of the system to meet customer and demand growth; and iii) upgrades to the system to improve reliability and operations with new technologies or upgraded components. Since 1988, we estimate that the maintenance and replacement of existing distribution plant has accounted for ~75% of total distribution capex.

[2] http://www.ssrllc.com/publication/if-this-is-the-golden-age-of-electric-utilities-whats-next-or-how-fast-can-rate-base-grow-in-the-long-term-and-on-what-will-utilities-spend/

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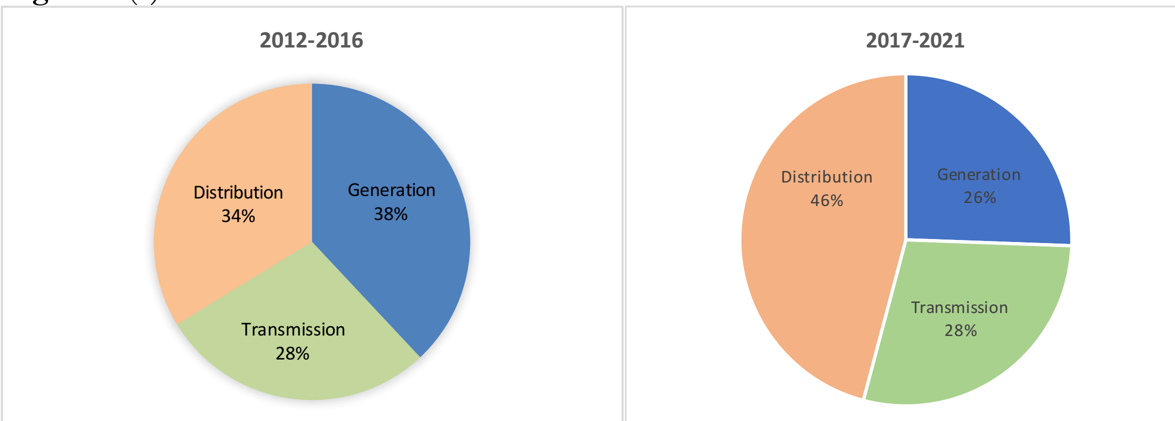
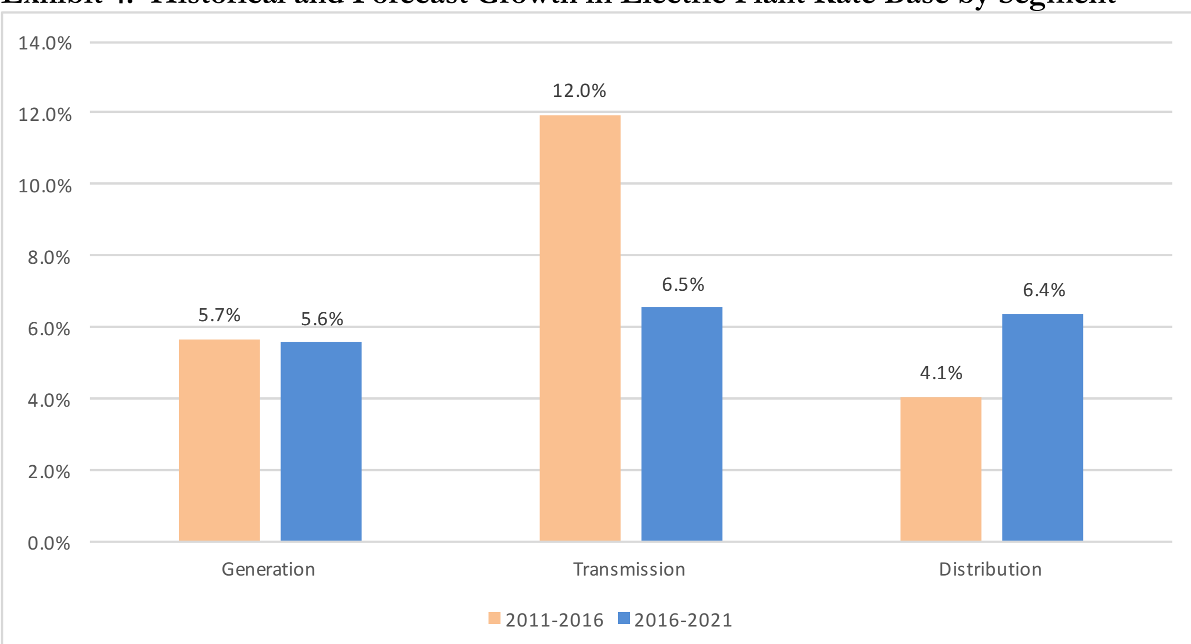
Exhibit 3: Estimated Composition of Aggregate Capital Expenditures on Electric Plant by Segment (1)



1. For 2012-2016, our estimates of capex by segment are based upon the annual additions of gross utility plant in the generation, transmission and distribution segments, aggregated across all U.S. investor owned, regulated utility operating companies. For 2017-2021, our capex estimates reflect the disclosed capital expenditure plans by segment of the publicly traded, U.S. investor-owned regulated utilities.
Source: SNL, FERC Form 1, SSR analysis and estimates

Exhibit 4: Historical and Forecast Growth in Electric Plant Rate Base by Segment



1. For 2012-2016, our estimates of capex by segment are based upon the annual additions of gross utility plant in the generation, transmission and distribution segments, aggregated across all U.S. investor owned, regulated utility operating companies. For 2017-2021, our capex estimates reflect the disclosed capital expenditure plans by segment of the publicly traded, U.S. investor-owned regulated utilities.
Source: SNL, FERC Form 1, SSR analysis and estimates

Second, utilities with the oldest distribution plant should face the most urgent need to replace aging equipment, potentially driving a more rapid pace of asset replacement than at utilities with more modern systems. The need could be particularly acute at utilities where key system components were built out over a relatively small number of years in response to rapid population growth, as occurred in California in the fifties and sixties, and now need to be replaced as they approach the end of their useful lives. (An example, drawn from another industry, would be the high volume gas transmission line serving San Francisco that exploded at San Bruno, California in 2010; installed in 1953, the pipe had been in service for almost 60 years).

Finally, unlike utilities in the United Kingdom or Australia, whose rate base is indexed to inflation, U.S. utilities calculate rate base using historical cost accounting; given the long useful life of utility assets, which can range from 25 to 40 years, depreciation expense calculated on the historical cost of these assets tends to lag behind the cost to maintain and replace them, which reflects the increase in the general price level during the intervening years. The older the average age of a utility's assets, and the greater the increase in the general price level since they were installed, the larger this gap will be. Older electric grids thus tend to have a higher maintenance capex to depreciation expense, contributing to more rapid growth in the book value of utility plant and thus in rate base.

Methodology

Given these links between the age of utilities' distribution systems and their potential to drive rate base growth, we have used a variety of approaches to estimate the relative age of distribution plant among the U.S. regulated electric utilities, and to rank the utilities accordingly.

The first of these is to rank the utilities by the proportion of their current customer base that was added in the last thirty years. The higher this proportion, the larger will be the share of distribution assets that will have been added in recent decades to serve this customer growth and, all else being equal, the lower will be the average age of system assets. Because electronic data on the number of customers per utility is available back to 1988, this analysis allows to identify those utilities least likely to have older distribution networks.

However, this approach does not identify those utilities with the oldest systems. To do so, it would be necessary to compare the number of a utility's customers, say, 50 years ago to those it has today; the utilities where this proportion is highest are likely to be those whose distribution assets are oldest. While we do not have access to electronic data on the number of customers per utility prior to 1988, we do have state-wide data on the total number of retail electricity consumers. To estimate the number of customers at each utility 50 years ago, therefore, we have assumed that each utility's customer growth over the years 1967-1988 matched the rate of growth in retail electricity consumers in the state as a whole. On this basis, we have been able to estimate each utility's customer base in 1967. The utilities with the oldest distribution systems, we assume, as those with the highest proportion of customers in 1967 relative to those today.

A third approach is to estimate the replacement cost of each utility's distribution plant in service and compare it to the book value of these assets. In this note, we use this method primarily to estimate the relative age of distribution networks across the universe of regulated utilities. In a later note, we intend to use it to estimate how the required level of maintenance capex will exceed depreciation expense at the various utilities, and thus contribute to long term rate base growth.

Our estimates of the replacement cost of each utility's distribution plant in service are based upon an analysis of its historical FERC Form 1 financial statements, which have been compiled electronically by SNL back to 1988. This analysis involved three steps. First, to estimate the replacement cost of gross utility plant placed in service since 1988, we multiplied at each utility (i) historical additions to gross utility plant in each year over the last three decades by (ii) the ratio of the 2017 price level, as measured by the producer price index, to that prevailing in the year of the plant addition.[3] Second, to estimate the replacement cost of gross utility plant in service in 1988, we assumed that these assets had been placed in service, on average, ten years earlier; to arrive at the replacement cost of these assets, therefore, we multiplied 1988 gross utility plant by the ratio of the 2017 price level to that prevailing in 1978. Third, having summed these estimates of gross utility plant in service, we then adjusted them down to take into account plant retirements since 1988. Similar to plant in service in 1988, we assumed the assets retired since 1988 were all in service in 1988 and had been place in service, on average, 10 years earlier. To account for retirements, we therefore multiplied (i) each utility's historical retirements of gross utility plant over the last three decades by (ii) the ratio of the 2017 price level, as measured by the producer price index, to that prevailing in 1978. Subtracting inflation adjusted retirements from inflation adjusted plant in service in 1988, and adding inflation adjusted additions of utility plant since 1988, we were able to estimate the inflation adjusted value of gross utility plant in service today.

We believe that the ratio of (i) inflation adjusted gross utility plant, as calculated above, to (ii) gross utility plant in service per a utility's financial statements as presented in its FERC Form 1, can be used as a comparative indicator of the relative age of utilities' transmission and distribution networks. A utility whose additions to gross utility plant were concentrated in recent years should show little difference between the inflation adjusted and book value of its plant in service. By contrast, a utility whose additions to gross utility plant occurred in large part several decades ago should show a more substantial difference between the inflation-adjusted value of these plant additions and their value on the utility's books.

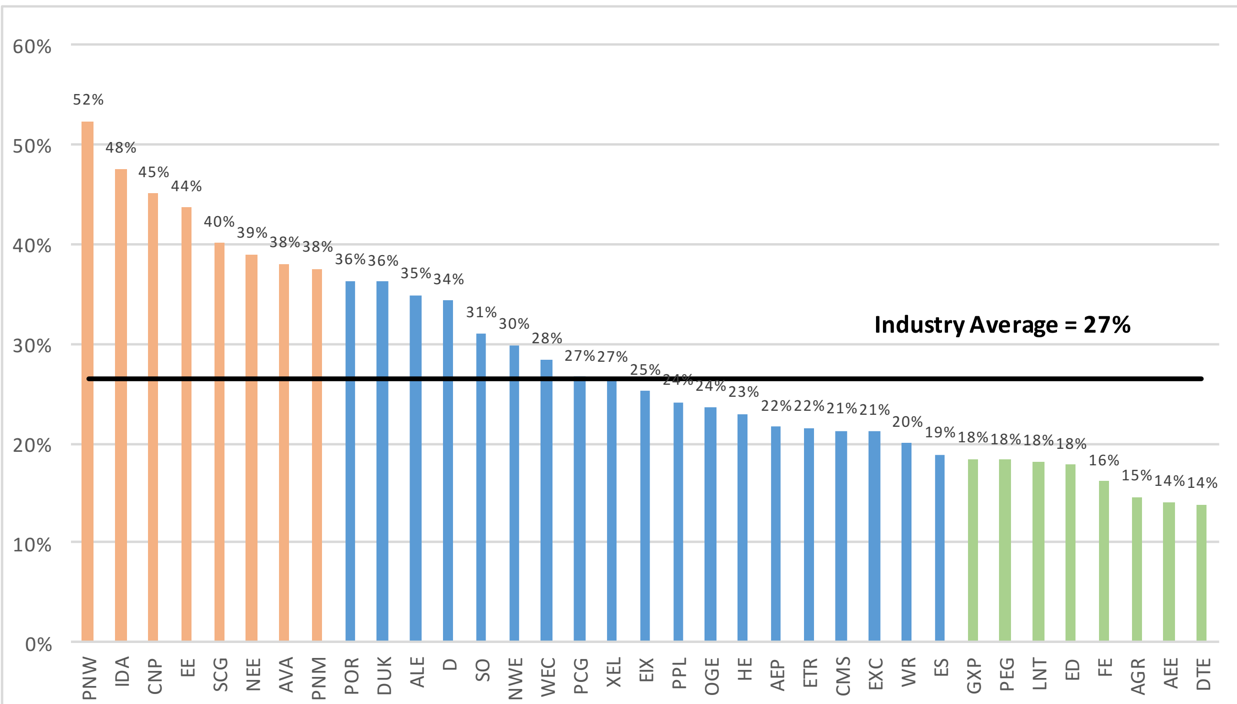
The ratio of the replacement cost to book value of gross utility plant in service may also be indicative of the extent to which the cost of maintaining and replacing utility plant is likely to exceed depreciation expense. For U.S. regulated electric utilities as a group, this ratio is ~1.45x, suggesting that for each dollar of depreciation expense, $1.45 of capital expenditure may be required to maintain existing utility plant in service. Because maintenance and replacement capex is likely to exceed depreciation expense for the foreseeable future, regulated utilities are positioned to achieve rate base growth even in the absence of growth capex.

As an example of the historical importance of maintenance and replacement capex as a driver of rate base growth, we estimate that, since 1988, the cost of maintaining and replacing existing plant has accounted for ~75% of total distribution capex. Since 1988, distribution capex has averaged 6.2% of gross plant in service. Over this period, depreciation of distribution assets has averaged 3.2% of gross plant in service. However, adjusting for inflation by multiplying the depreciation rate by the ratio of replacement value to book value of distribution assets (146%, on average across the industry; see **Exhibit 10**), the cost of maintaining and replacing existing plant would be about 4.7% of gross distribution plant in service, or about 75% of historical distribution capex.

3. To make this adjustment as accurate as possible we used the average of the transformer and power wire and cable sub-components of the producer price index.

Exhibit 5 presents a ranking of the U.S. publicly traded electric utilities by the number of utility customers added since 1988 as a percentage of the total number of utility customers in 2016. As can be seen there, on average across the industry, 27% of regulated utilities' current customer base has been added in the years since 1988. The utilities highlighted in orange on the far left of the chart, which are concentrated in the West, show much higher percentages: 52% at PNW, 48% at IDA, 45% at CNP and 44% at EE. A high proportion of post-1988 customer additions is also evident among some of the utilities in the Southeast, including SCG (40%) and NEE (39%). On the plausible assumption that a similar proportion of these utilities' distribution assets were added over the last 30 years, these companies are less likely to face a significant need to replace aging plant and thus to require high levels of replacement capex.

Exhibit 5: Number of Utility Customers Added Since 1988 as Percentage of Total Number of Utility Customers in 2016

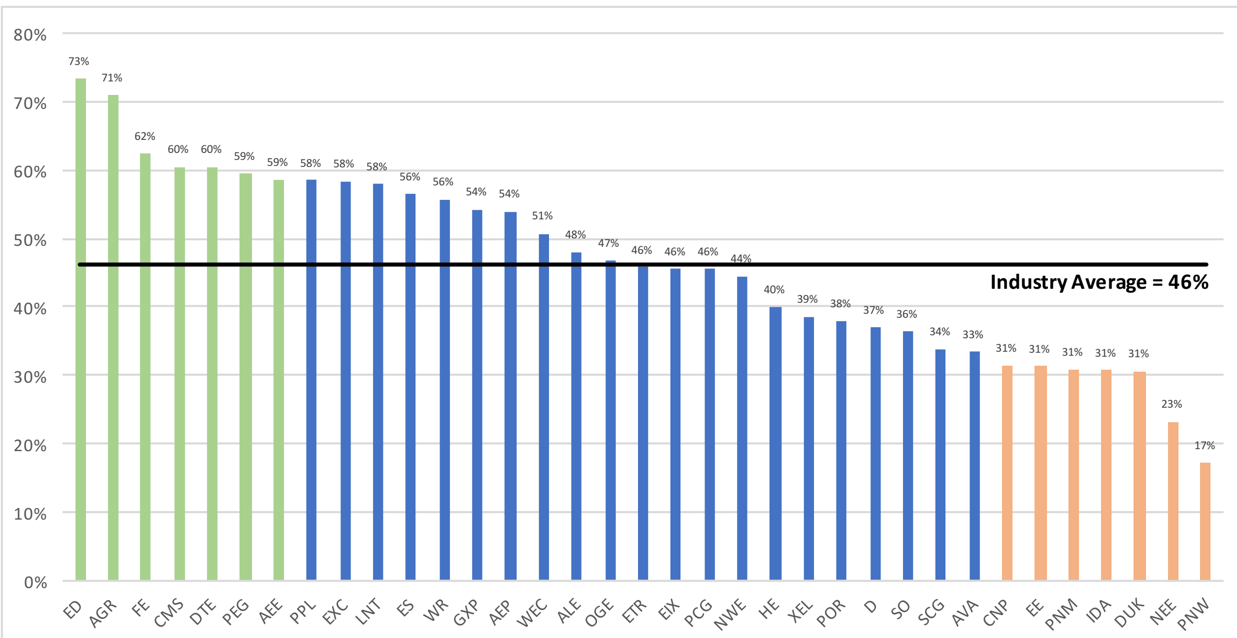


Source: Company FERC Form 1 filings, SNL, SSR analysis and estimates

At the right end of **Exhibit 5**, highlighted in green, are those utilities with the lowest proportion of customers added since 1988. These firms (DTE, AEE, AGR, FE, ED, LNT, PEG, GXP and ES) are concentrated in the Midwest, Mid-Atlantic and New England, where population growth has lagged the national average over the last 30 years. We believe therefore that these utilities' distribution assets are likely to be materially older than the industry average. We note, however, that this is not necessarily the case; the absence of customer growth over the last 30 years would not have precluded these companies from investing to upgrade their aging distribution systems over this period, reducing the average age of system assets.

For a second perspective on the relative age of utilities' distribution assets, we have estimated for each utility the ratio of its number of customers in 1967 to its number of customers today (see **Exhibit 6**). Because we do not have access to electronic data on the number of customers per utility prior to 1988, the estimates used in **Exhibit 6** were derived by assuming that each utility's customer growth over the years 1967-1988 matched the rate of growth in retail electricity consumers in the state as a whole. With the exception of CMS, the utilities identified on this basis as possibly having the oldest distribution networks (ED, AGR, FE, CMS, DTE, PEG and AEE) are also those so identified in **Exhibit 5**. Similarly, among those utilities identified in **Exhibit 6** as having the lowest ratios of customers in 1967 to customers today, PNW, NEE, IDA, EE and CNP overlap with those identified as likely having the newest distribution systems in **Exhibit 5.**

Exhibit 6: Ratio of Number of Utility Customers in 1967 to Number of Utility Customers in 2017



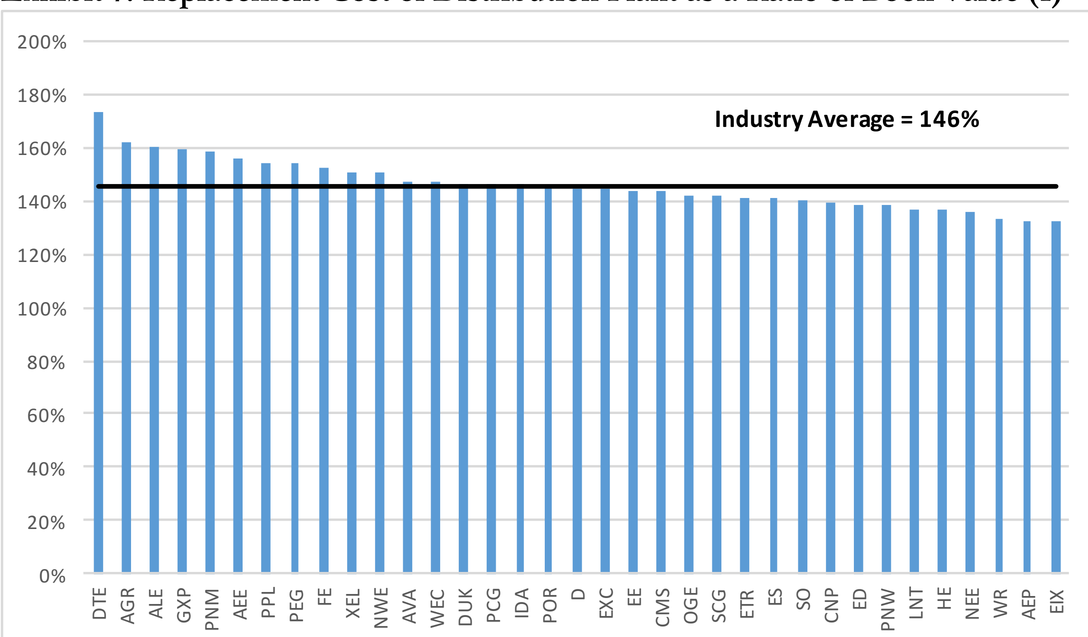
1. Calculated as the ratio of (i) cumulative additions of gross utility plant, net of retirements, each adjusted for inflation and expressed in 2017 dollars, to (ii) gross utility plant in service per FERC Form 1 financial statements.
Source: Company FERC Form 1 filings, SNL, SSR analysis and estimates

Exhibit 7 presents what we believe to be the most reliable of our three estimates, the ratio of replacement cost to book value of gross distribution plant at each of the publicly traded electric utilities.[4] The utilities with the highest ratios of replacement cost to book value, and therefore likely to have the oldest distribution assets, are DTE, AGR, ALE, GXP, PNM and AEE. Of these, all except ALE and PNM are identified in **Exhibits 5** and **6** as possibly having among the oldest distribution networks.

[4] As can be seen there, this ratio is remarkably constant across the industry; the industry average ratio is 146%, the standard deviation across the utilities is 9%, and the ratio of the standard deviation to the average is only 6%.

By contrast, there is more limited overlap between the utilities with the lowest ratios of replacement cost to book value of gross distribution plant (EIX, AEP, WR, NEE, HE and LNT) and those identified in **Exhibits 5** and **6** as possibly having the newest distribution systems; only NEE appears on the other two lists. We believe this illustrates the potential for utilities with older distribution systems to upgrade their networks through infrastructure replacement and upgrade programs, thus reducing the average age of utility plant in service. A low ratio of replacement cost to book value does not preclude periods of accelerated capex to replace aging plant, particularly at utilities with multiple subsidiaries, such as SO and AEP, some of which could have replacement cost to book value ratios that are materially higher than the company average, and thus require more rapid replacement of aging plant than the company's average ratio might imply. System upgrades, such as the rollout of smart meters or the storm hardening of distribution systems, could similarly reduce the average age of distribution plant.

Exhibit 7: Replacement Cost of Distribution Plant as a Ratio of Book Value (1)



1. Calculated as the ratio of (i) cumulative additions of gross utility plant, net of retirements, each adjusted for inflation and expressed in 2017 dollars, to (ii) gross utility plant in service per FERC Form 1 financial statements.
Source: Company FERC Form 1 filings, SNL, SSR analysis and estimates

Results of Our Analysis: Which Utilities Have the Oldest Transmission Networks?

We expect growth in transmission capex to slow materially in the years ahead, from 12.0% p.a. over 2011-2016 to 6.5% p.a. over 2016-2021. It is nonetheless instructive to ask which regulated utilities could capitalize on the age of their high voltage transmission networks to add to maintenance and replacement capex, and thus rate base growth, in the years ahead.

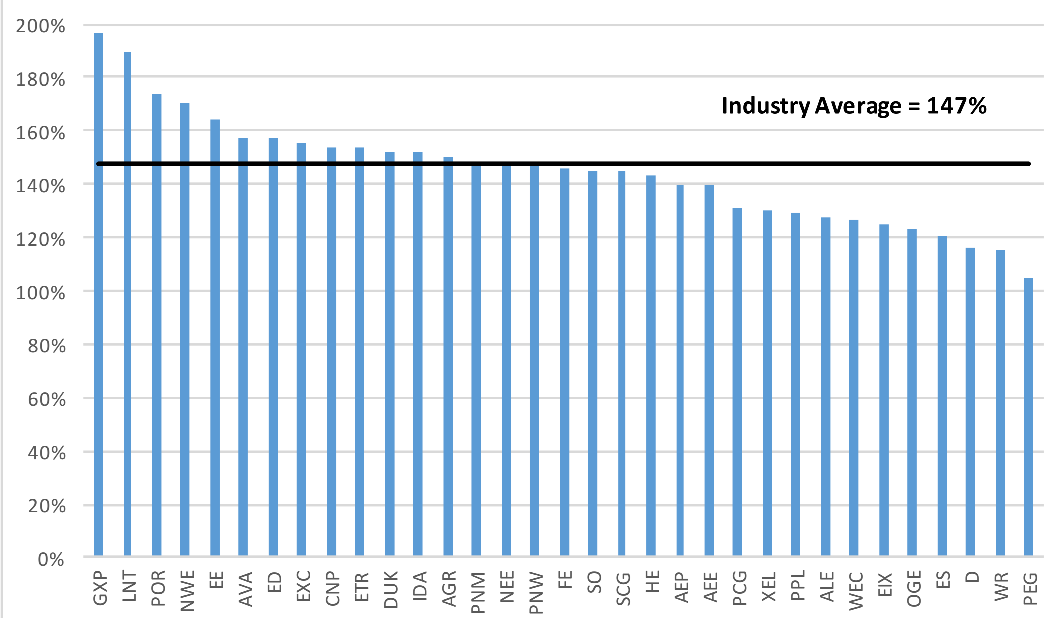
Exhibit 8 presents the ratio of replacement cost to book value of gross transmission plant at each of the publicly traded electric utilities.[5] The utilities with the highest ratios of replacement cost to

[5] The variation in this ratio across the industry is significantly wider for transmission assets than it is for distribution (compare **Exhibits 7** and **8**). In the transmission sector, the industry average ratio is 145%, the standard deviation

book value, and therefore likely to have the oldest transmission assets, are GXP, LNT, POR, NWE and EE. Of these, only GXP and LNT are also identified in **Exhibit 5** as possibly having among the oldest electricity grids. None are so identified in **Exhibit 6**. The utilities in **Exhibit 8** with the lowest ratios of replacement cost to book value of transmission assets, and thus likely to have the newest transmission assets, are PEG, WR, D, ES, OGE and EIX. None of these utilities are identified in **Exhibits 5** and **6** as having particularly new electricity grids; indeed, PEG is identified as likely to have one of the oldest systems in the country in both of these charts.

We believe the discrepancy between the analysis presented in **Exhibit 8** of the relative age of utilities' transmission plant, and the estimates of the relative age of utilities' electricity grids in **Exhibits 5** and **6**, reflects the fact that primary drivers of transmission capex in recent years have affected utilities in less uniform ways than have the drivers of distribution capex. As discussed in our note of October 2nd, *If This Is the Golden Age of Electric Utilities, What's Next? Or, How Fast Can Rate Base Grow in the Long Term and on What Will Utilities Spend?* (see link below[6]), the rate of capital expenditures on distribution plant has been remarkably constant over the last three decades, while the rate of transmission capex has varied markedly over the years in response to changes in federal and state energy policies. As we explain below, these new policies and associated incentives have caused transmission rate base to grow at an 8.5% compound annual rate over the sixteen years from 2000 through 2016. Among the utilities best positioned to capitalize on these policies and incentives going forward, we believe, are those grouped on the left side of **Exhibit 8**.

Exhibit 8: Replacement Cost of Transmission Plant as a Ratio of Book Value (1)



1. Calculated as the ratio of (i) cumulative additions of gross utility plant, net of retirements, each adjusted for inflation and expressed in 2017 dollars, to (ii) gross utility plant in service per FERC Form 1 financial statements.
Source: Company FERC Form 1 filings, SNL, SSR analysis and estimates

across the utilities is 20%, and the ratio of the standard deviation to the average is 14%. By contrast, for distribution assets, the ratio of standard deviation to mean is only 6%.

[6] http://www.ssrllc.com/publication/if-this-is-the-golden-age-of-electric-utilities-whats-next-or-how-fast-can-rate-base-grow-in-the-long-term-and-on-what-will-utilities-spend/

A critical element of the transmission policy framework that began to be put in place around the turn of the century was FERC Order No. 2000. Issued in December, 1999, Order 2000 encouraged the formation of independent system operators to manage regional transmission systems on an open-access basis, including regional transmission planning for reliability and reduced congestion. The Northeast power blackout of August 2003, which was triggered by transmission rather than generation failures, created a further impetus for transmission upgrades to enhance system reliability. Finally, in response to these developments, the Energy Policy Act of 2005 sought to accelerate investment in the bulk power grid by granting FERC the authority to grant incentive ROEs on new transmission projects. Utilities belonging to RTOs, and particularly those whose service territories are home to important regional transmission bottlenecks, accelerated their investment in transmission projects to capitalize on these incentives; four of the utilities on the right hand side of **Exhibit 8**, PEG, D, ES and EIX are good examples of this.

A second important trend in energy policy that offered a material stimulus to transmission investment was the adoption by 29 states, accounting for 65% of U.S. electricity consumption, of renewable portfolio standards requiring utilities to procure a stipulated percentage of their retail electricity sales from renewable resources. In the years since the turn of the century, the lowest cost renewable resource in the United States has been wind; as the nation's wind resources were developed to comply with these state renewable portfolio standards, wind power rose from 0.1% of total U.S. generation in 2000 to 5.6% by 2016, a compound annual rate of growth 13.5%. Because the best wind resources in the country are located in the Great Plains states, and not in the states with the highest renewable portfolio standards, companies such as WR and OGE benefited significantly. Transmission lines linking remote wind, solar and hydroelectric resources to load centers also benefited ES and EIX.

Given what we believe to be the much greater importance of federal and state energy policy in driving investment in transmission assets, we are less confident that measures of the relative age of existing transmission assets can be used to identify leaders and laggards in transmission capex going forward.

Conclusion

In assessing the results of our analysis of the relative ages of utilities' transmission and distribution plant it is critical to bear in mind the very different relative importance of transmission and distribution rate base across America's regulated electric utilities. Across the industry as a whole, distribution rate base comprises 41% of aggregate rate base and transmission rate base 23%. Only among a small of utilities, however, does the share of transmission and distribution rate base reflect these industry averages; the composition of rate base at most regulated utilities diverges markedly from the industry mean (see **Exhibit 9**). For example, among nine of the 35 publicly traded electric utilities, transmission and distribution rate base accounts for an average of 92% of total electric plant rate base. At the other extreme are nine vertically integrated utilities where transmission and distribution rate base comprises, on average, only 40% of the total. As **Exhibit 9** illustrates, our analysis of the growth potential implicit in an older electricity grid will be most relevant to the transmission and distribution utilities, and least relevant to those with highest share of generation assets in total rate base.

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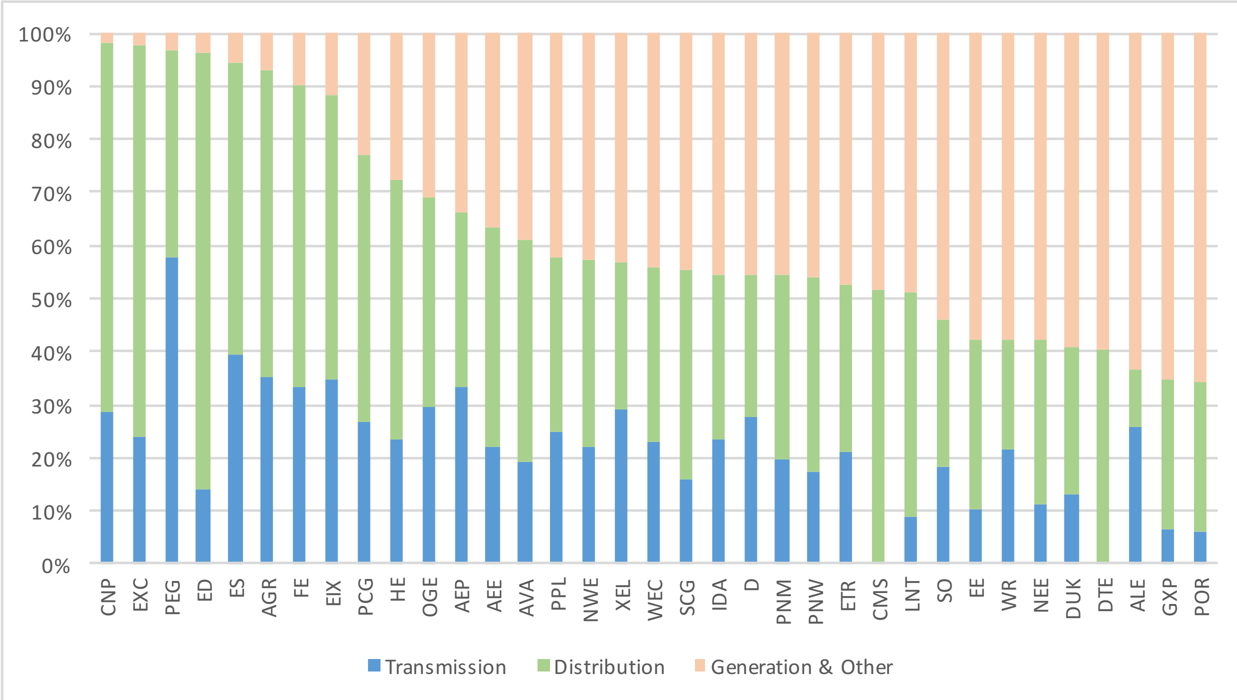
Exhibit 9: Transmission and Distribution Rate as a Percentage of Total Rate Base



Source: Company FERC Form 1 filings, SNL, SSR analysis and estimates

Our analysis of the relative age of utilities' electricity grids is summarized in **Exhibit 10**. On the left, the exhibit presents the ratio of the replacement cost of transmission and distribution plant to the book value of these assets, both separately and on a combined basis, for each of the regulated electric utilities. On the right, the exhibit ranks the utilities into quintiles on the basis of these ratios, assigning a first quintile ranking to utilities with the highest ratio of replacement cost to book value. Among these utilities, it is probable that maintenance and replacement capex will materially exceed book depreciation, tending to drive more rapid rate base growth.

The utilities we believe to be most attractively positioned for growth are those that (i) rank in the first quintile in the two right hand columns of **Exhibit 10**, indicating that their distribution plant in service, and combined transmission and distribution plant in service, is among the oldest in the industry, and (ii) appear on the left side of **Exhibit 9**, indicating that their transmission and distribution rate base contributes a high proportion of total rate base. Falling in the first basket -- utilities with the oldest distribution grids and combined transmission and distribution networks -- are AEE, AGR, AVA, DTE, GXP, NWE and PNM. Of these, AGR has the highest proportion of transmission and distribution assets in total rate base; however, AGR is a hybrid utility, with a substantial fleet of competitive generation assets, so that regulated utility operations account for only 54% of consolidated EBITDA. AEE, AVA, NWE and PNM, by contrast, are primarily regulated utilities and have relatively high ratios of transmission and distribution rate base to total rate base, ranging from 63% to 54% of the total. DTE and GXP are also primarily regulated utilities, but have much greater investment in generation rate base. At GXP, transmission and distribution rate base accounts for only 35% of total electric plant rate base. At DTE, transmission and distribution rate base account for 40% of total electric plant rate base (see **Exhibit 9**), which in turn contributes only two thirds of consolidated EBITDA due to the scale of DTE's gas distribution business. In conclusion, among the utilities whose aging electricity grids may accelerate future rate base growth, the stocks of AEE, AVA, NWE and PNM may offer the most attractive pure play opportunities.

Exhibit 10: Replacement Cost of Transmission and Distribution Plant as a Ratio of Book Value (1)

	Ratio of Replacement Cost to Book Value			Quintile Ranking		
Tickers	Transmission	Distribution	T&D	Transmission	Distribution	T&D
AEE	139%	156%	152%	4	1	1
AEP	140%	132%	136%	4	5	5
AGR	150%	162%	158%	2	1	1
ALE	127%	160%	139%	4	1	4
AVA	157%	147%	151%	1	2	1
CMS		144%	144%		3	3
CNP	154%	139%	143%	2	4	3
D	116%	145%	132%	5	3	5
DTE		174%	174%		1	1
DUK	152%	146%	148%	2	2	2
ED	157%	139%	142%	1	4	4
EE	165%	144%	150%	1	3	2
EIX	125%	132%	129%	5	5	5
ES	121%	141%	133%	5	4	5
ETR	153%	141%	146%	2	4	2
EXC	155%	144%	147%	2	3	2
FE	146%	152%	150%	3	2	2
GXP	196%	160%	167%	1	1	1
HE	143%	136%	138%	3	5	4
IDA	152%	146%	149%	2	3	2
LNT	190%	137%	144%	1	5	3
NEE	147%	135%	139%	3	5	4
NWE	170%	151%	158%	1	2	1
OGE	124%	141%	134%	5	4	5
PCG	131%	146%	142%	4	3	3
PEG	105%	154%	128%	5	2	5
PNM	147%	159%	155%	3	1	1
PNW	147%	138%	141%	3	5	4
POR	174%	146%	149%	1	3	2
PPL	130%	154%	145%	4	1	3
SCG	145%	141%	143%	3	4	3
SO	145%	140%	142%	3	4	3
WEC	127%	147%	141%	5	2	4
WR	115%	133%	125%	5	5	5
XEL	130%	151%	141%	4	2	4
Industry	***147%***	***146%***	***145%***			

1. Calculated as the ratio of (i) cumulative additions of gross utility plant, net of retirements, each adjusted for inflation and expressed in 2017 dollars, to (ii) gross utility plant in service per FERC Form 1 financial statements.
Source: Company reports per FERC Form 1, SNL, SSR analysis and estimates

Another way to capitalize on the opportunities offered by aging electricity grids is to identify those utilities whose planned capital expenditures over 2017-2021 seems to fall well short of would could be required to replace aging plant, and where the potential may exist, therefore, to ramp up capex and rate base growth. In **Exhibit 11**, we present for each of the publicly traded electric utilities the ratio of (i) planned transmission and distribution capex over 20172-2021 to (ii) our estimate of the replacement cost of the utility's transmission and distribution plant in service that was installed in 1988 or earlier and which may therefore need to be replaced over a similar time frame. On the right side of **Exhibit 11**, we have ranked the utilities into quintiles on the basis of this ratio, assigning to the first quintile those utilities whose ratios of planned capex to replacement cost of aging plant is among the lowest in the industry.

Assessed across their transmission and distribution segments, the utilities that would seem to offer the most opportunity for capex increases are NWE, where planned T&D capex over 2017-2021 is equivalent to only 47% of the estimated replacement cost of pre-1988 T&D plant, GXP (48%), POR (57%), DTE (66%), HE (76%), OGE (77%) and EE (80%) (see **Exhibit 11**). Of these utilities, however, POR, GXP, DTE and EE have well below average ratios of transmission and distribution rate to total rate base (see **Exhibit 9**), limiting the impact on these stocks of any increase in T&D capex. By contrast, HE, OGE and, to a lesser extent, NWE have above average ratios of T&D to total rate base.

SSR

Exhibit 11: Capital Expenditures Planned Over 2017-2021 as a Ratio of Replacement Cost of Pre-1988 Gross Plant in Service (1)

	Planned Capex to Pre-1988 Plant in Service			Quintile Ranking		
Ticker	Transmission	Distribution	T&D	Transmission	Distribution	T&D
AEE	137%	76%	95%	3	2	2
AEP	188%	590%	238%	4	5	5
AGR	217%	63%	121%	4	1	3
ALE	238%	31%	129%	5	1	3
AVA	70%	149%	115%	2	3	2
CMS		216%	216%		4	4
CNP	138%	244%	181%	3	4	4
D	268%	163%	202%	5	3	4
DTE		66%	66%		1	1
DUK	78%	292%	178%	2	5	4
ED	100%	128%	118%	3	3	2
EE	41%	111%	80%	1	2	1
EIX	153%	452%	317%	3	5	5
ES	217%	234%	226%	5	4	4
ETR	96%	274%	150%	3	5	3
EXC	61%	171%	121%	1	4	3
FE	84%	80%	81%	2	2	2
GXP	25%	63%	48%	1	1	1
HE	86%	72%	76%	2	1	1
IDA	61%	122%	85%	1	3	2
LNT	180%	402%	340%	4	5	5
NEE	176%	971%	440%	4	5	5
NWE	31%	70%	47%	1	1	1
OGE	62%	90%	77%	1	2	1
PCG	234%	165%	182%	5	4	4
PEG	738%	111%	235%	5	2	5
PNM	88%	84%	85%	3	2	2
PNW	76%	1173%	238%	2	5	5
POR	23%	82%	58%	1	2	1
PPL	243%	69%	118%	5	1	2
SCG	75%	158%	120%	2	3	3
SO	110%	259%	162%	3	4	4
WEC	305%	201%	230%	5	4	5
WR	177%	141%	159%	4	3	3
XEL	165%	146%	154%	4	3	3

1. Calculated as the ratio of (i) planned capital expenditures over 2017-2021, as disclosed in SEC filings and investor presentations, to (ii) 1988 gross utility plant, adjusted for inflation and expressed in 2017 dollars, net of plant retirements over 1988-2016, also adjusted for inflation and expressed in 2017 dollars.

Source: Company reports per FERC Form 1, SNL, SSR analysis and estimates

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