2018 PJM Transmission Investment Analysis

Transmission Spending in PJM

Are You Obtaining Your Share of Transmission Investment?

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In PJM, total transmission investment by investor-owned utilities ("IOUs") and transmission companies ("Transcos") continues at high levels and is driving earnings. The factors encouraging investment show little sign of abating, ultimately leading to higher transmission rates. Many generation and transmission cooperatives ("G&Ts") and public power entities are facing higher transmission rates from this substantial investment. Obtaining their own fair share of transmission investment can provide a means to mitigate the impacts of transmission rate increases and provide value to their members.

EEI forecasts annual transmission investment will double from $12 billion per year in 2011 to about $24 billion per year by the end of 2018—an increase of 10.3% annually.

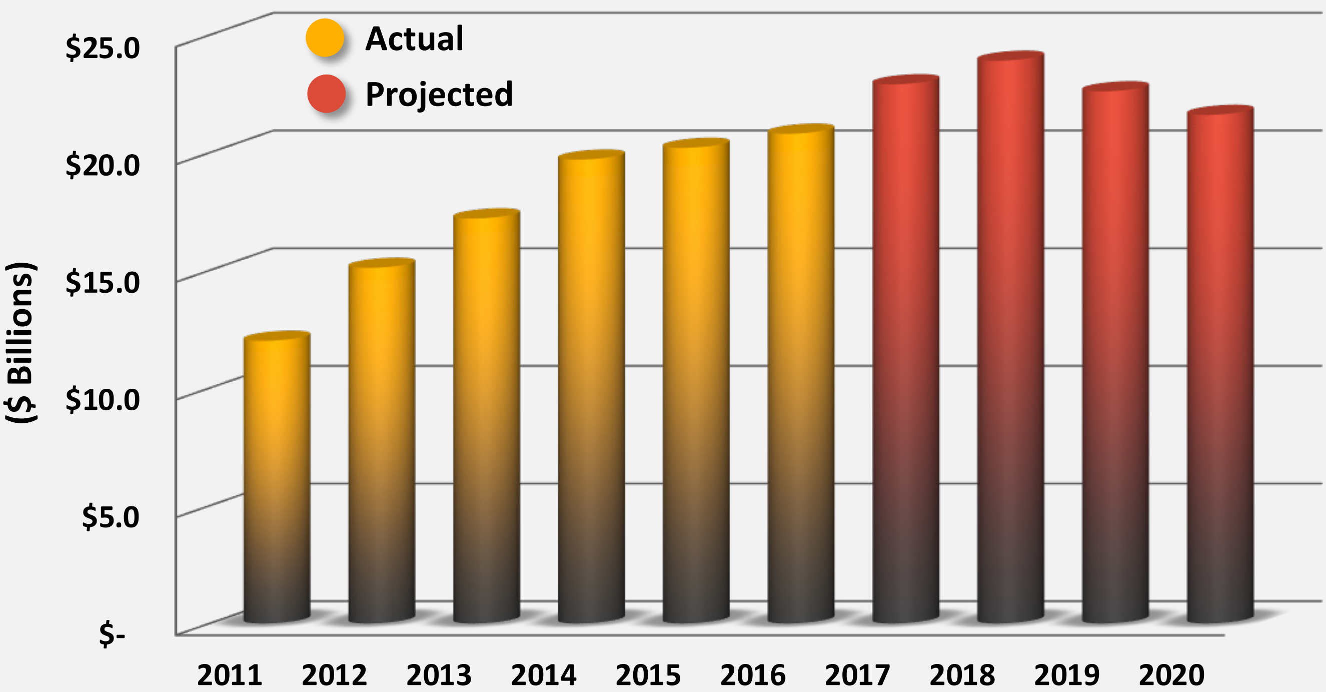
Tailwinds for Continued Nationwide Transmission Investment

Edison Electric Institute ("EEI") forecasts IOUs and Transcos across the country (excluding public and cooperative power) will double their rate of annual transmission investment from about $12 billion per year in 2011 to about $24 billion per year by the end of 2018, an average increase of 10.3% per year[1] (see Figure 1 on the next page). This massive increase in annual transmission investment is driven by a range of factors, including reliability standards and the growth of renewables, most notably wind power (see Figure 2 on page 3). In addition, the focus on cyber and physical security, the more recent "Puerto Rico Effect" of avoiding extended outages, and the head-nodding buzzwords of "grid resilience" and "improved infrastructure" are providing regulatory cover and tailwinds for continued investment in transmission.

In fact, Federal Energy Regulatory Commission ("FERC") staff's October 2017 transmission metric report showed that there are many high-priced energy pockets in various RTOs, thus indicating that there are still

[1] *Source: Edison Electric Institute Economics, Statistics and Industry Research Group. Updated September 2017.*

Figure 1
Nationwide IOU Transmission Investment ($ Billions)[2]



The FERC Staff transmission metric report showed there are still many high-priced energy pockets in various RTOs, thus indicating there are opportunities for additional transmission investment.

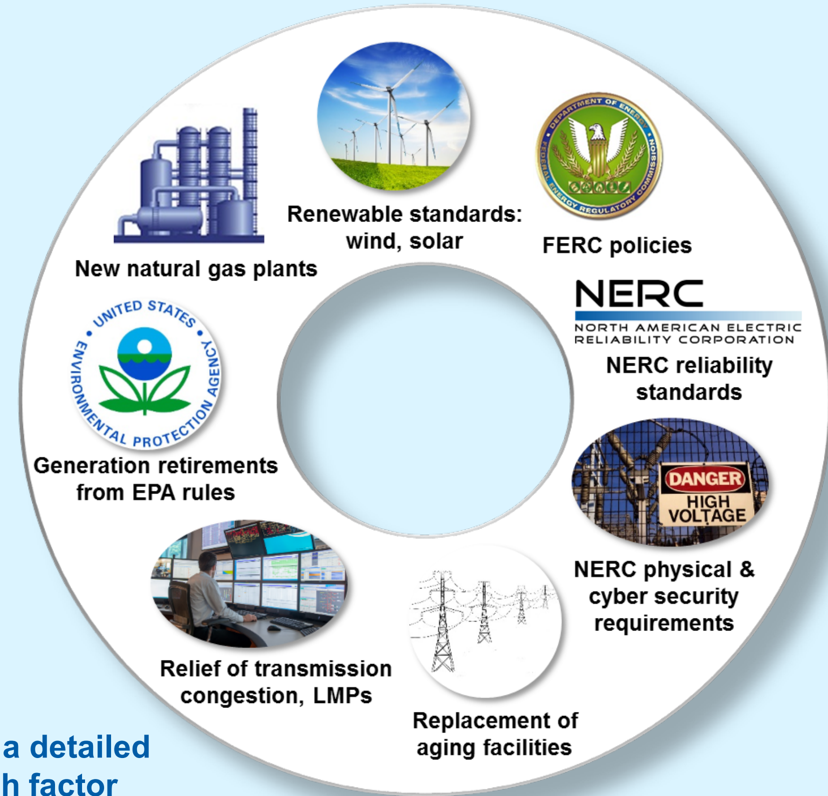
opportunities for significant additional transmission investment to ease congestion. Moreover, FERC is concerned that in some RTOs there have been few projects competitively bid under FERC Order 1000, implying that increased competition would spur more project proposals and even more transmission investment. For example, Commissioner Cheryl Lafleur recently said: *"It has been nearly seven years since the Commission issued its landmark Order No. 1000 rule to foster greater regional and interregional transmission planning. Much progress has been made in implementing regional planning and cost allocation, but challenges remain with respect to implementing competitive processes."* [2]

As compared to other RTOs, such as MISO and SPP, PJM has been relatively successful in promoting a large number of competitive projects.[3] By contrast, in 2016, FERC ordered MISO to come up with a better approach to address the dearth of competitive projects and to address the lack of seams projects between PJM and MISO. MISO made a filing in October 2017 to address interregional projects, generally adopting the PJM project evaluation criteria,

[2] *Source:* Written Testimony of Cheryl A. LaFleur Before the Committee on Energy and Commerce Subcommittee on Energy United States House of Representatives, Hearing on Oversight of the Federal Energy Regulatory Commission. April 17, 2018.

[3] Beginning in August, 2016, PJM revised the criteria tariff rules governing its competitive proposal window process to exclude reliability violations on transmission facilities operating below 200 kV within a zone. Thus, one might expect the number of competitive projects in PJM will decrease.

Figure 2
Policy and Operational Drivers of Transmission Investment



See Appendix for a detailed discussion of each factor

which should promote more seams projects that will be competitively bid. In order to address the lack of competitive projects and its related cost sharing issues, MISO formed a diverse stakeholder group to provide recommendations. A fall 2018 FERC filing will be addressing such controversial issues as:

- What voltages and dollar thresholds should be used as criteria for market efficiency projects ("MEPs")? Should the voltage level threshold be lowered to 200 kV from the current 345 kV?
- Which benefits should be included (e.g. reduced congestion and capacity prices, improved reliability or avoided costs of other projects) and should the number of years to calculate the benefit be increased?
- Is postage stamp cost sharing still a reasonable methodology to ensure project costs are paid by those benefiting from the project?

Returns for transmission are attractive given today's low cost of capital and returns are usually higher than an IOU's state jurisdictions for generation and distribution assets.

Lowering the voltage level and loosening the cost-benefit calculations for MISO MEPs could spur more competitive investment if it coincides with a planning process whereby more projects are proposed. This MISO example of encouraging more competitive investment is pertinent to other RTOs/ISOs such as SPP, thus potentially resulting in more investment nationwide.

The Financial Attractiveness of Transmission Investment

In addition to the drivers of investment shown in Figure 2, the large increase in nationwide transmission investment over the last seven years is also part of a "back to basics" infrastructure strategy whereby IOUs invest in the regulated "wires" side of their business in an effort to drive earnings growth with lower risk than generation investments. Investing in transmission is quite attractive from a regulatory standpoint. Transmission is FERC-regulated rather than state-regulated, typically using formula rates that automatically update each year without a full, time consuming, rate case. Although stakeholders can question or challenge costs in the annual update, the chances of significant costs being excluded is less likely than in a full rate case. Moreover, returns for transmission are attractive given today's relatively low cost of capital and are usually higher than an IOU's state jurisdiction returns for generation and distribution assets. Once approved by FERC, an established ROE cannot be challenged without a formal Section 206 complaint. In addition, most IOUs and Transcos have a forward-looking (projected) test year, so there is limited or no regulatory lag.

There was a net $5.8 billion increase in approved system enhancements in PJM in 2017 over 2016.

Most IOUs and Transcos in PJM see transmission investment as a major driver of earnings growth with attractive returns. For example, AEP's CFO, Brian Tierney has highlighted its transmission investment in its earnings calls with investment analysts:

> *"Transmission is still a preferred place for us to put capital."* [4]

Exelon's CFO Jonathan Thayer stressed its large investment in the wires business:

> *"We plan to invest $21 billion into our utilities over the next 4 years to ensure reliable, more resilient and more efficient transmission and distribution of electricity and gas that improves the customer experience."* [5]

PSE&G's Chairman and CEO Ralph Izzo relies on transmission investment to continue to increase earnings and is "doubling down" on transmission:

> *"There's still the #1 investment area that we will be focused on, which is transmission."* [6]

See Table 1 on the next page for additional quotes from utility executives emphasizing the importance of transmission to their businesses.

High Levels of Transmission Investment in PJM

The 2018 PJM Regional Transmission Expansion Plan ("RTEP"), states that between 1999 and 2017, the PJM Board has approved transmission system enhancements totaling $35.1 billion. This figure, through the end of 2017 reflects a net $5.8 billion increase over the cumulative December 31, 2016

[4] *Source: AEP 4Q 2017 earnings call.*

[5] *Source: Exelon Earnings Calls February 7, 2018.*

[6] *Source: PSEG Earnings Call April 30, 2018.*

Table 1
Quarterly Earnings Statements by Utility Executives

DOMINION ENERGY	
Thomas F. Farrell Chairman, President & CEO of Dominion Energy Midstream GP LLC	"The upgrade of our electric transmission network continues. In 2017, we invested $806 million and placed $519 million of assets into service. We plan to invest $800 million on electric transmission business this year and every year for at least the next decade." January 29, 2018
DUKE	
Lynn J. Good Chairman, CEO, President	"We have allocated nearly 60% of our $30 billion plan to transmission and distribution, which includes $10 billion for modernizing our grid infrastructure to make the systems smarter and more reliable." February 16, 2018
EXELON	
Christopher M. Crane CEO, President, Director	"We have completed 9 transmission and distribution rate cases, providing revenue increases of $397 million." February 8, 2018
FIRSTENERGY	
Charles E. Jones President, CEO, Director	"In our transmission business, we continue to implement our Energizing the Future investment program. More than 600 projects either underway or in the pipeline for 2018 were on track to invest $1.1 billion in our transmission system this year, consistent with the capital plans we announced in February." April 23, 2018
PPL	
Vincent Sorgi Senior Vice President, CFO	"Our Pennsylvania Regulated segment earned $0.21 per share in the first quarter of 2018, a $0.09 increase compared to the same period a year ago. This result was driven primarily by higher transmission margins from additional capital investment and higher peak transmission system demand in 2018." May 3, 2018
PSEG	
Daniel J. Cregg CFO	"PSE&G's investment of $3.1 billion in its transmission and distribution infrastructure in 2017 provided for approximately 13% growth in rate base to $17 billion. Of this amount, PSE&G's investment in transmission has grown to represent 46% or $7.8 billion of the company's consolidated rate base at the end of 2017. Supported by the ongoing transmission and distribution investment program, we are forecasting continued growth in PSE&G's net income to a range of $1 billion to $1,030,000,000 in 2018." February 23, 2018

figure of $29.3 billion. This compares with only a net increase of $1.0 billion and $2.6 billion for the previous two years.[7] Fifty-eight percent of the $5.8 billion increase (or $3.4 billion), came from baseline projects and 42% ($2.4 billion) from network projects, including generation interconnections.

PJM cited aging infrastructure as increasingly driving the need for baseline projects. PJM has witnessed a shift away from the higher voltage regional backbone projects to the lower voltage levels due to flatter load growth and generation shifts. Given the previously mentioned drivers of investment, the financial attractiveness of transmission investment and the regulatory momentum, it is not surprising that transmission investment in PJM is expected to continue at high levels.

Given the drivers of investment, the financial attractiveness of transmission investment and the regulatory momentum, transmission investment in PJM is expected to continue at high levels.

In addition to the baseline and network projects, the RTEP includes supplemental project spending which in 2017 alone totaled about $2.6 billion. These projects (known at one time as transmission owner initiated projects) are also a major source of a PJM transmission owner's ("TO") annual transmission revenue requirement ("ATRR"). These projects are not required for compliance with PJM system reliability, operational performance or market efficiency criteria. PJM reviews these projects to ensure they do not introduce other reliability criteria violations. While not subject to PJM Board approval, they are included in PJM's RTEP. Supplemental projects are local to a zone and address aging infrastructure and system reinforcement needs. In 2017, there were about $2.6 billion of these supplemental projects.

Looking at the change in gross transmission plant, including changes in construction work in progress ("CWIP"), over the past three years provides a good proxy for the levels of transmission capital investment for individual PJM transmission owners. For the purpose of the analysis, the 11 AEP operating companies and Transcos in PJM[8] were combined into one entity as some of the operating companies have related transmission companies (e.g., Indiana-Michigan Power and Indiana-Michigan Power Transmission Company; Ohio

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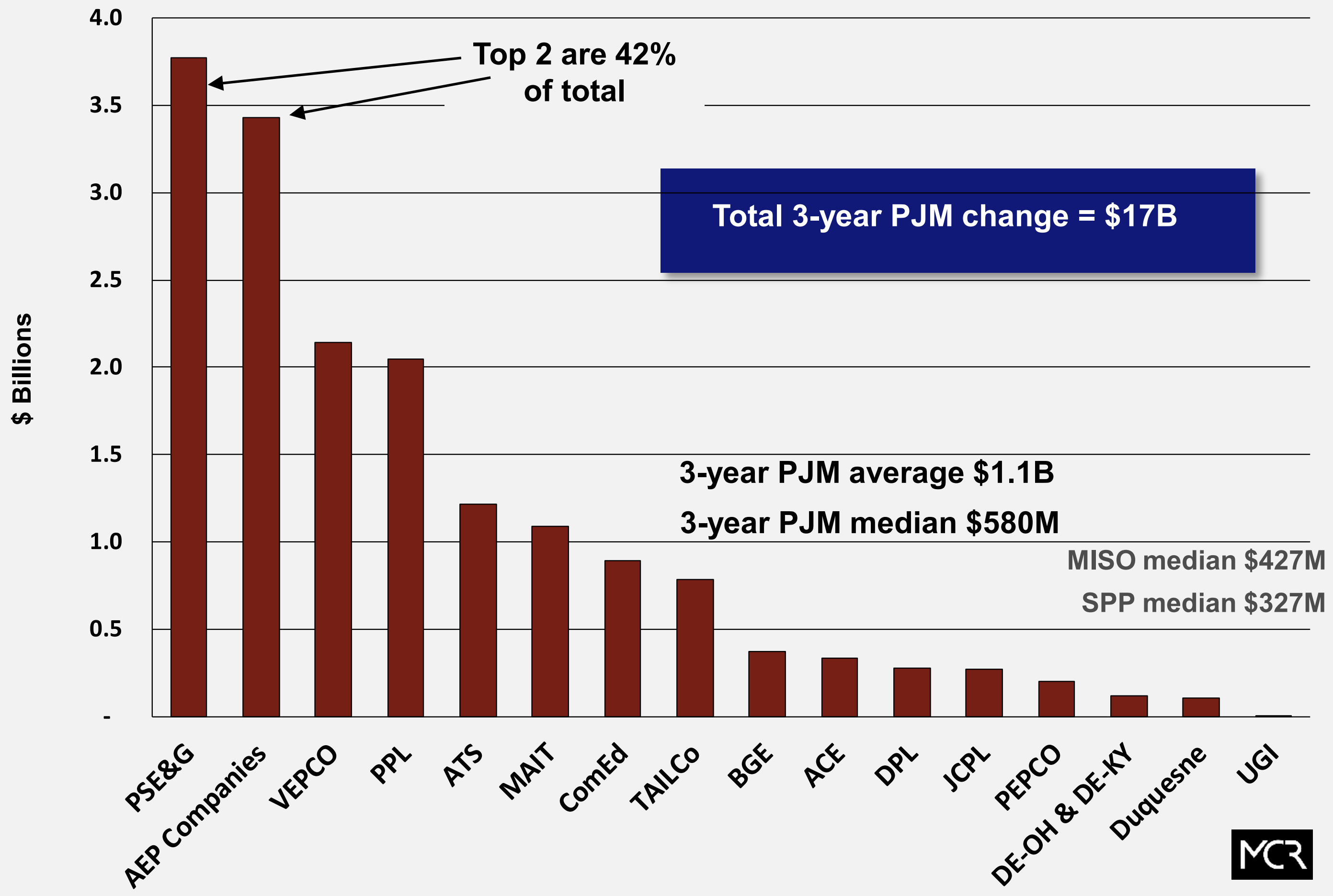
[7] Source: PJM 2017 RTEP issued February 28, 2018, PJM 2016 RTEP issued February 28, 2017 and PJM 2015 RTEP issued February 28, 2016. RTEP baseline projects ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. The projects are assigned to the incumbent TO and are not eligible for proposal window solution solicitation. Network projects are new or upgraded facilities required primarily to eliminate reliability criteria violations caused by proposed generation, merchant transmission or long term firm transmission service requests, but can also include certain direct connection facilities required to interconnect proposed generation projects.

[8] Appalachian Power Co, Indiana Michigan Power, Kentucky Power Co,. Kingsport Power Co., Ohio Power, Wheeling Power Co., Appalachian Transmission Co., Indiana Michigan Transmission Co., Kentucky Transmission Co.., Ohio Transmission Co., West Virginia Transmission Co.

Figure 3
Change in Gross Transmission Plant Balance for PJM IOUs and Transcos (2014-2017)



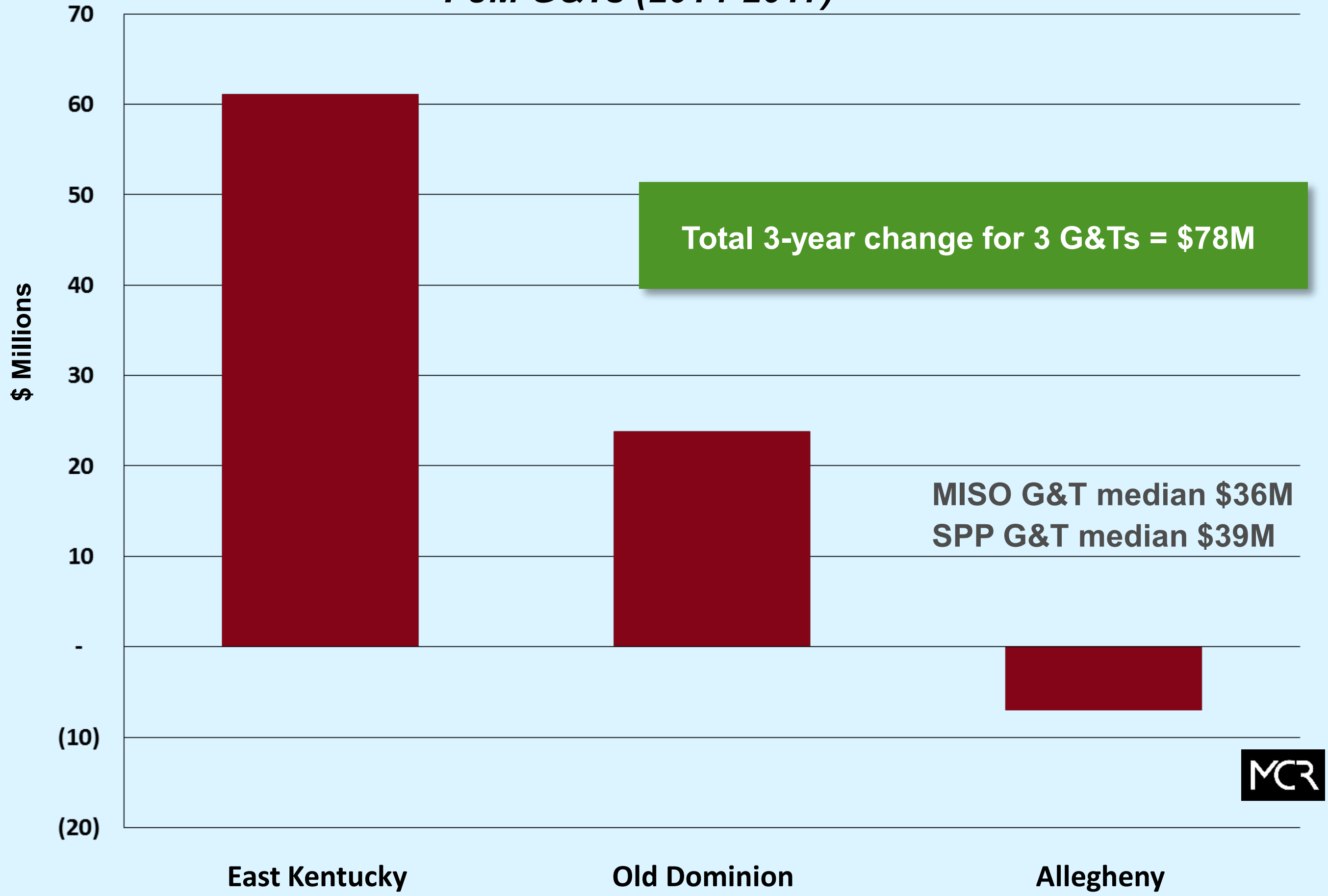
Power and Ohio Transmission Company). In contrast, FirstEnergy and Exelon subsidiaries[9] have fewer subsidiaries and are broken out in order to show more detail as to the geographic source of the investment.

The analysis in Figure 3 shows that over the three year period (2014 – 2017) gross transmission plant for PJM IOUs and Transcos increased by $17 billion.[10] PSE&G and the AEP operating companies had the largest change in gross transmission investment at $3.8 billion and $3.4 billion, respectively, or about

[9] *First Energy Corp. and Exelon Corporation entities are reported separately. First Energy entities include ATSI, Jersey Central Power & Light ("JCPL"), Mid-Atlantic Interstate Transmission ("MAIT"), and Trans-Allegheny Interstate Line Co. ("TAILCo"). Exelon entities include Commonwealth Edison (ComEd), Atlantic City Electric ("ACE"), Baltimore Gas & Electric ("BGE"), Delmarva Power & Light, and Potomac Electric Power Company (PEPCO).*

[10] *Sources: PJM Formula Rates website for each PJM transmission owner filing a transmission formula rate. Shows the change in the gross transmission plant and CWIP from 2014 to 2017 (three-year change) as a proxy for transmission investment for the time period. Transmission gross plant compared is rate year 2014 vs. rate year 2017 (i.e., the changes from 2014 to 2015, 2015 to 2016, and 2016 to 2017). http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx*

Figure 4
Change in Gross Transmission Plant Balance for PJM G&Ts (2014-2017)



The median three-year change in transmission investment for IOU/Transcos is lower at $580 million reflecting the dominance of PSE&G and AEP.

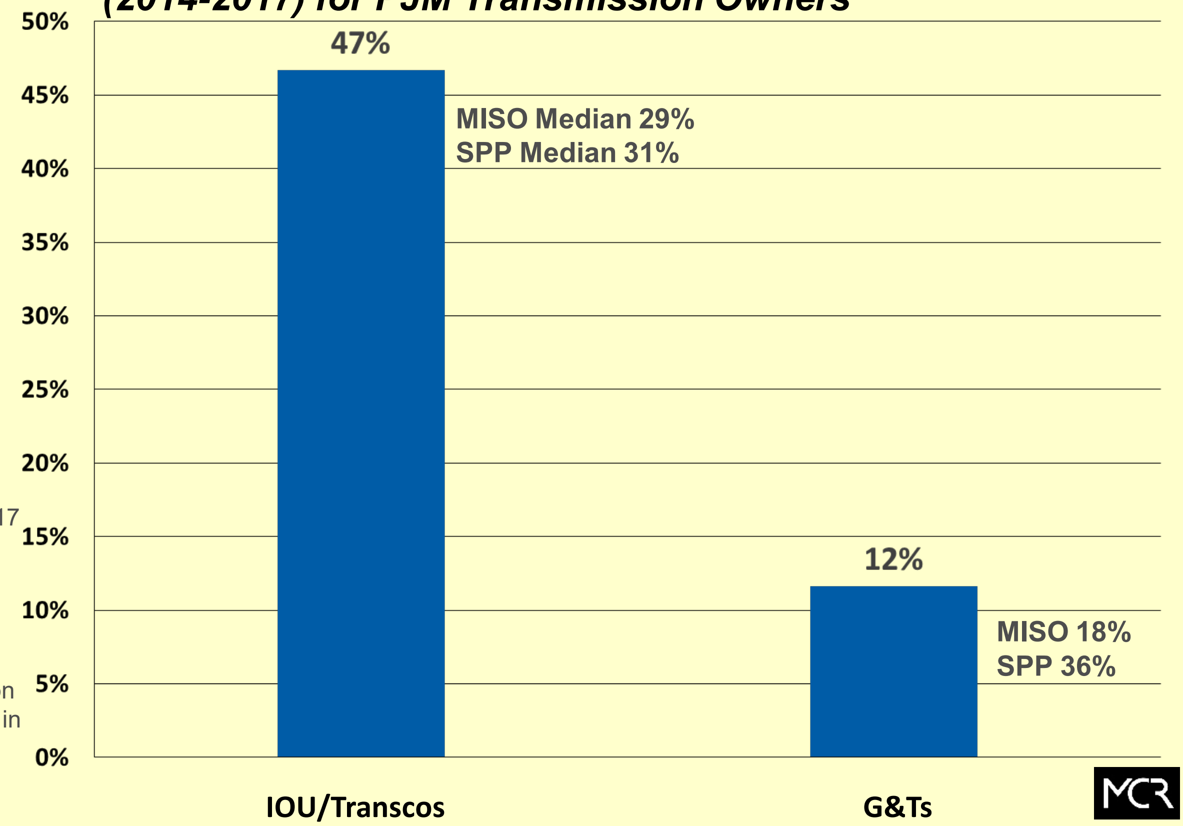
42% of the change in total investment for all IOU/Transcos in PJM. AEP's subsidiaries with the largest increases over the three years were the Ohio Transmission Company ($889 million), the Indiana-Michigan Transmission Company ($881 million), Appalachian Power ($655 million) and the West Virginia Transmission Company ($514 million). If one were to combine the four FirstEnergy subsidiaries, the total three-year change for FirstEnergy was equivalent to AEP at $3.4 billion. Additionally, the total three-year change for all five of the Exelon subsidiaries was $2.1 billion.

The average change in gross transmission plant for all 16 IOU/Transcos in PJM over this time period was $1.1 billion, or about $367 million per year. The median three-year change in transmission investment is lower at $580 million, reflecting the dominance of PSE&G and the AEP companies. As way of comparison, the $580 million median is $153 million higher than the median for MISO's IOUs and Transcos, and $253 million more than the median for SPPs IOUs and Transcos.

Figure 4 shows that the three G&Ts in PJM had a three-year dollar change in

Figure 5

Cumulative 3-Year Percentage Change in Gross Transmission Plant (2014-2017) for PJM Transmission Owners[11]



Note: Figures are weighted averages of each group.

[11] Source: 2014-2017 PJM Formula Rate Templates, G&T company data supplemented by annual reports, as necessary. Based on percentage change in gross transmission plant and CWIP in rate base.

gross transmission plant of $78 million.[12] Most of the increase ($61 million or 78%) came from East Kentucky Power Cooperative ("East Kentucky"). Old Dominion Electric Cooperative ("Old Dominion") had a three-year increase in gross transmission plant of $24 million while Allegheny Electric Cooperative ("Allegheny") had a decline in gross transmission plant of about $7 million. These numbers compare to the MISO median increase for G&Ts of $36 million and SPP's median increase of $39 million.

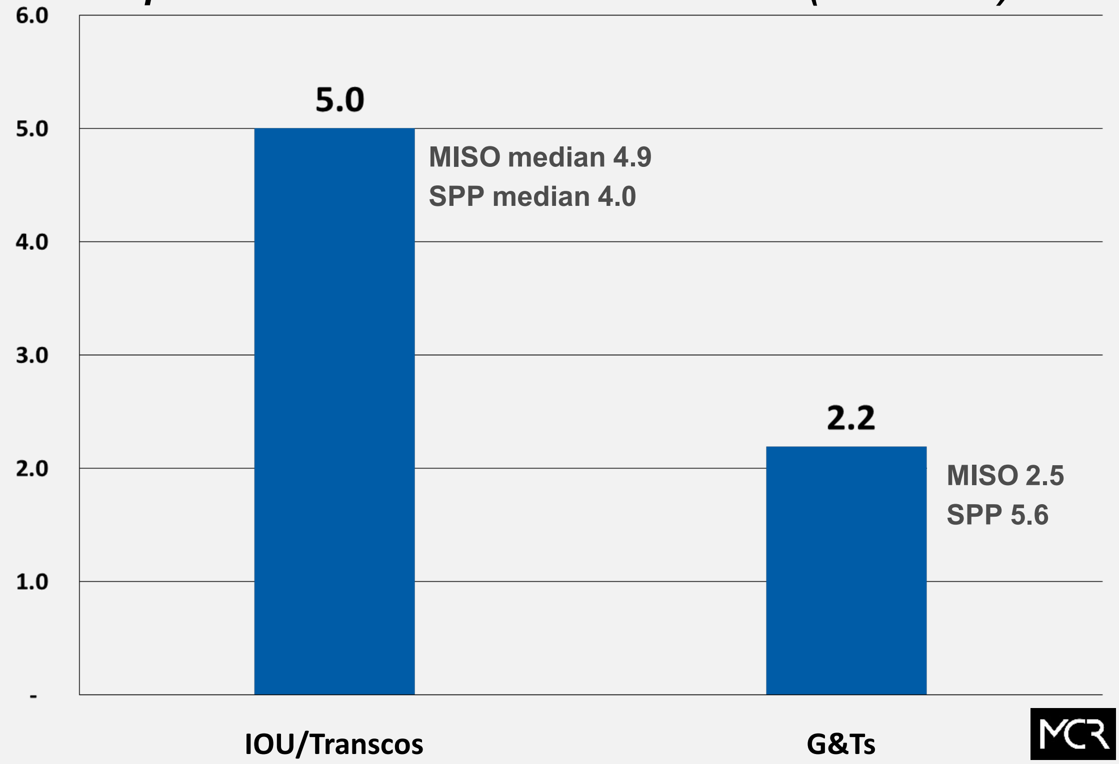
Thus, the three year median investment for IOUs/Transcos in PJM of $580 million is about 10 times the three-year investment of EKPC and 24 times the Old Dominion investment level. This compares to median ratios of IOU/Transco to G&T investment of 10 times for MISO and eight times for SPP.

Figure 5 highlights the percentage change of gross transmission plant for PJM

[12] *Sources: Transmission investment data was provided by each of the three G&Ts. The change in gross transmission plant from 2014 to 2017 (three-year change) is used as a proxy for transmission capital investment for the time period. Transmission gross plant compared is rate year 2014 vs. rate year 2017 (i.e., the changes from 2014 to 2015, 2015 to 2016, and 2016 to 2017). The reported gross transmission plant is before any exclusions. That is, it may include plant classified by the utility as transmission but it may not be necessarily included in the revenue requirement. For example, transmission facilities under 69 kV may be included in the gross transmission plant used in the analysis but could be ineligible for revenue recovery. Old Dominion has about $47 million of ineligible gross plant out of its total reported $88 million. East Kentucky has $16 million of ineligible plant out of its $624 million total.*

Figure 6

Investment Intensity—Change in Gross Transmission Plant Balance Compared to Depreciation Expense for PJM Transmission Owners (2014-2017)[13]



Note: Figures are weighted averages of each group.

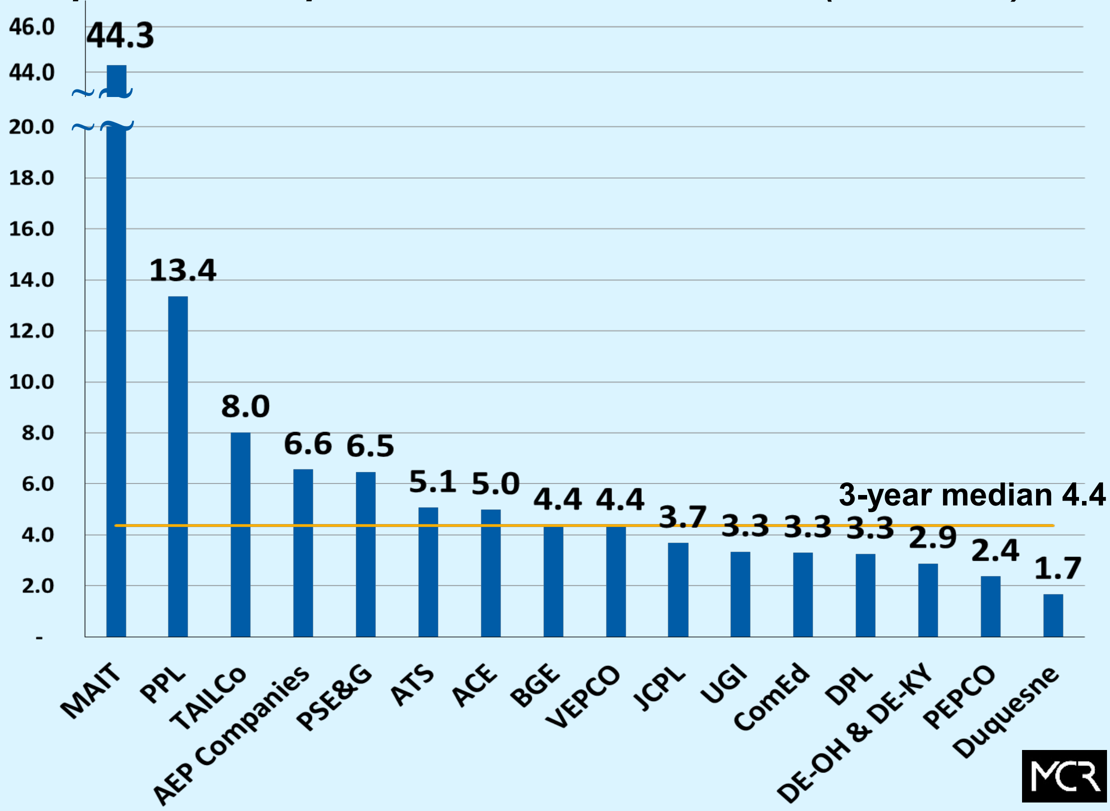
[13] Source: PJM Formula Rate templates, G&T company data and annual reports. Shows total three-year change in transmission gross plant and CWIP in rate base divided by sum of three years of depreciation expense.

IOU/Transcos in PJM had an substantial 47% increase in gross transmission plant since 2014 compared to the three G&Ts, which had a combined 12% increase.

IOU/Transcos vs. G&Ts over the three-year period. As a group, IOU/Transcos in PJM had a substantial 47% increase in gross transmission plant since 2014 compared to the three G&Ts, which had a combined 12% increase. The strong median increase of 37% by PJM IOU/Transcos demonstrates IOU's belief that transmission investment continues to be an important driver of earnings growth. PPL led the way with an impressive three-year investment increase of 99% followed by FirstEnergy's Trans-Allegheny (TAILCo) at 62% and PSE&G at 61%. As way of comparison, the median three-year percentage increase in MISO and SPP for IOU/Transcos was 29% and 31%, respectively. For 2017, there was a 13% overall change in the total transmission gross plant balance for PJM IOU/Transcos with a median increase of 7%. This compares to the 2017 median increases for MISO and SPP IOU/Transcos of 11% and 9%.

The 12% increase by PJM G&Ts compares to a median 18% increase in MISO G&Ts and a 36% increase from SPP G&Ts over the same three years. Old Dominion had a sizable three-year percentage increase in gross transmission plant of 37% followed by East Kentucky's 11% increase and Allegheny's decline of 16%. Looking at 2017 only, the total gross transmission plant for the three G&Ts in PJM as a whole was only 3% higher than 2016, dampened by a $7 million decline in Allegheny. This compares to a median 2017 increase for MISO G&Ts of 7% and a median 6% increase for SPP G&Ts.

Figure 7
Investment Intensity—Change in Gross Transmission Plant Balance Compared to Depreciation Expense for PJM IOU/Transcos (2014-2017)[14]



[14] Source: 2014-2017 PJM Formula Rate Templates and annual reports. Shows total three-year change in transmission gross plant and CWIP in rate base divided by sum of three years of depreciation expense.

Varying Levels of Investment Intensity

Looking at these growth rate differences from a different angle, Figures 6, 7 and 8 show the ratio of transmission investment to depreciation expense, or "investment intensity." A high investment intensity ratio indicates that a transmission owner was building significant new facilities relative to existing net plant, or was replacing fully depreciated facilities.

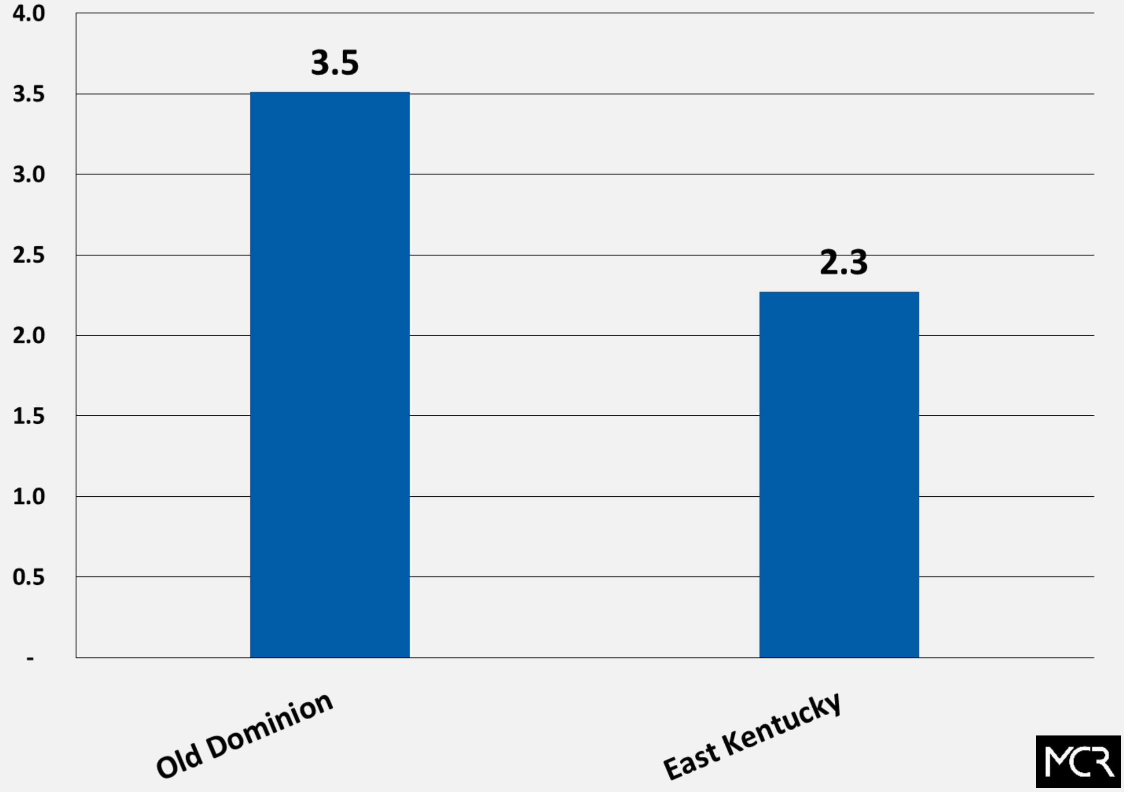
IOU/Transcos in PJM are investing at five times their depreciation, indicating that current levels of investment are very strong.

Figure 6 on the prior page shows that IOU/Transcos in PJM as a group are making investments at five times their transmission depreciation expense, indicating that current levels of investment are very strong by historical standards. G&Ts are much lower with a ratio of 2.2. By comparison, MISO IOU/Transcos have a similar ratio of 4.9, whereas G&Ts in MISO are at 2.5. In SPP, the ratio for IOU/Transcos is 4.0 whereas G&Ts are much higher at 5.6

Figures 7 above and Figure 8 (on the next page) show the ratios for each PJM IOU/Transco and G&T, respectively. The companies with the greatest investment intensity are MAIT, PPL, TAILCo, AEP and PSE&G. Old Dominion had a ratio of 3.5 and East Kentucky's ratio was 2.3, both under the IOU/Transco median of 4.4.

Figure 8

Investment Intensity—Change in Gross Transmission Plant Balance Compared to Depreciation Expense for PJM G&Ts (2014-2017)[15]



[15] Source: 2014-2017 G&T data supplied by each G&T, supplemented by annual reports as necessary. Shows total three-year change in transmission gross plant divided by sum of three years of depreciation expense. Allegheny not shown due to negative ratio.

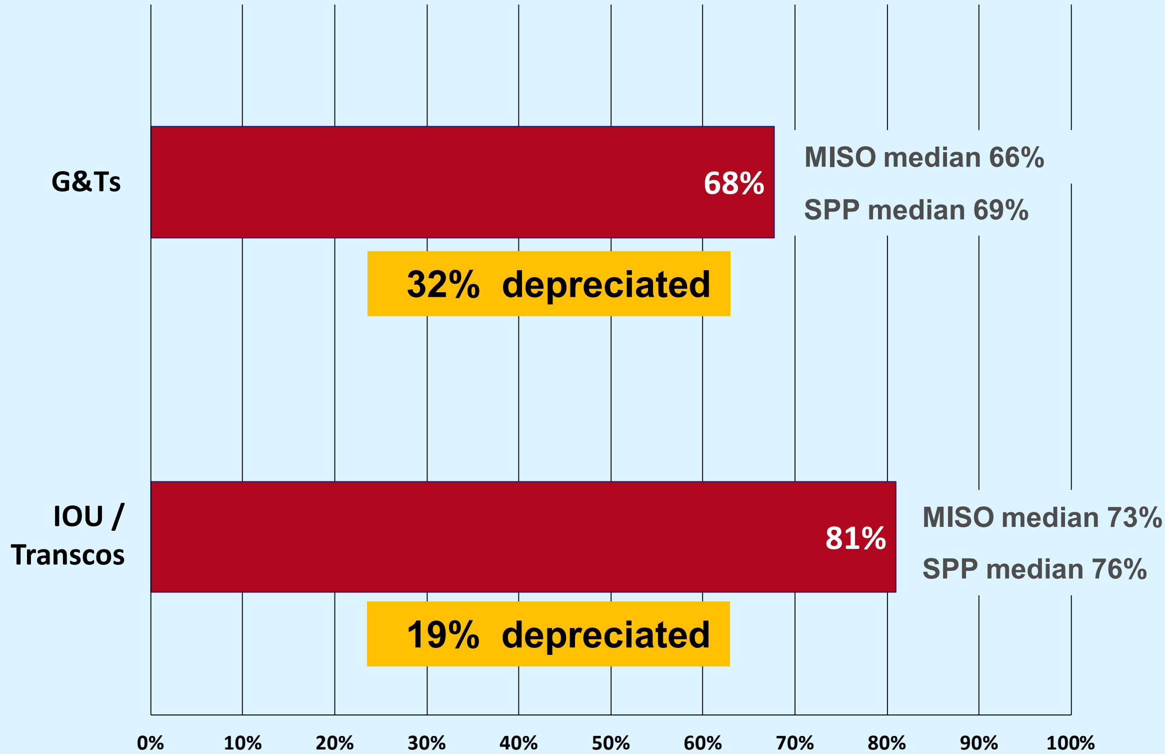
Significant Age Differences in Transmission Facilities

The age difference in PJM IOU/Transcos transmission plant is apparent when looking at individual companies.

Figure 9 on the next page shows the ratio of net transmission plant to gross transmission plant and provides an indication of the average age of a utility's transmission facilities. Figure 9 indicates that G&T transmission plant in PJM is more depreciated or "older" than PJM IOU/Transcos. G&Ts are 32% depreciated and IOU/Transcos are only 19% depreciated. The actual difference in the age of the G&T facilities could be less as G&Ts tend to follow more aggressive depreciation rules based on RUS accounting.

By comparison, the IOU/Transcos in MISO and SPP are older than IOU/Transcos in PJM at 27% and 24% depreciated, respectively. G&Ts in MISO and SPP are similar to the PJM G&T group at 34% and 31% depreciated, respectively. The age difference in the transmission plant of PJM IOU/Transcos is apparent when looking at individual companies. For example, Figure 10 (on the next page) shows UGI has the oldest transmission plant (36% depreciated) whereas TAILCo has the newest transmission plant at only 8% depreciated, reflecting its Transco status and relatively recent investment.

Figure 9
2017 Net Transmission Plant as a Percent of Gross Transmission Plant for PJM Owners of Transmission[16]



[16] Source: 2017 PJM Formula Rate Templates, G&T company data supplemented by annual reports. Represents weighted averages for each group, e.g., total IOU and Transco transmission net plant divided by total IOU and Transco transmission gross plant and CWIP in rate base.

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Figure 10
2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO IOUs and Transcos

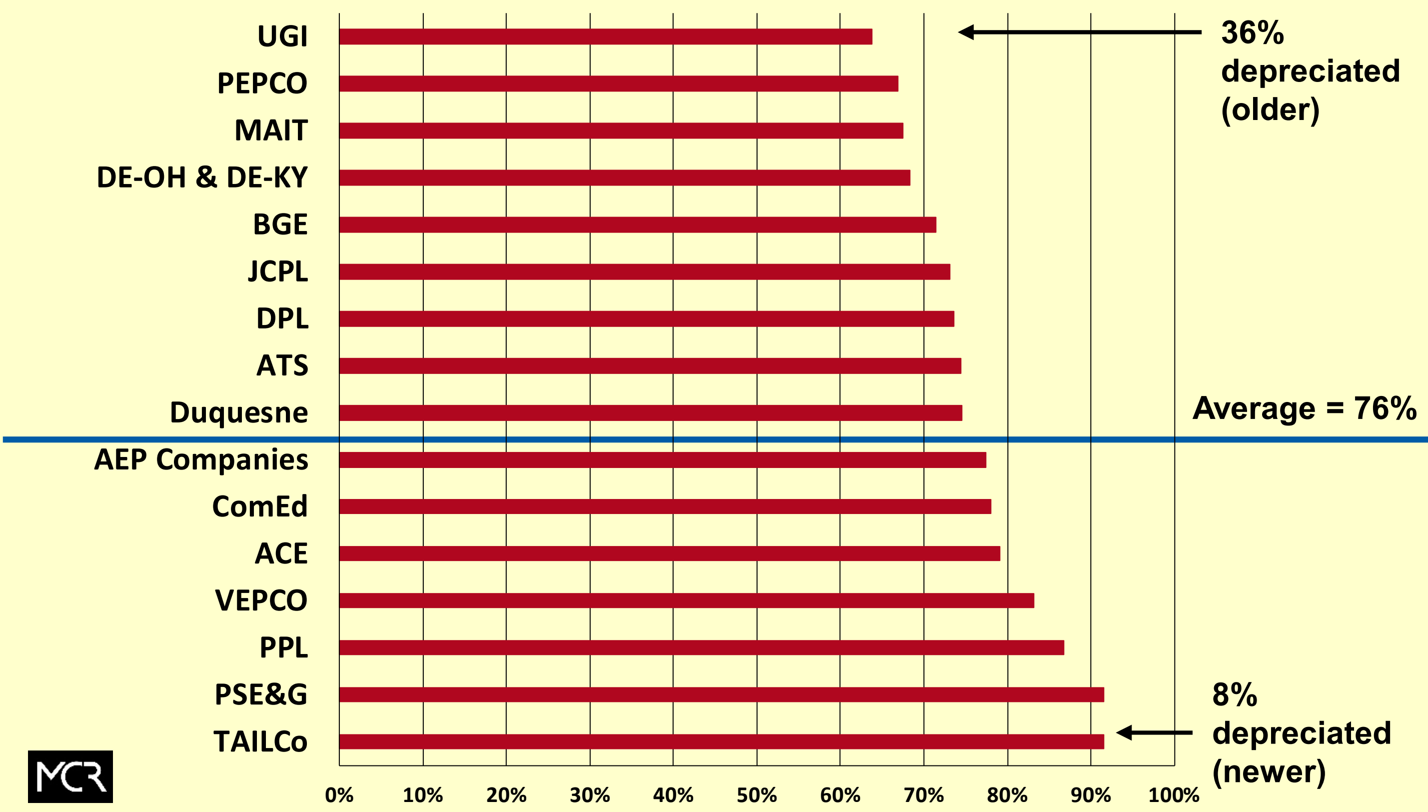

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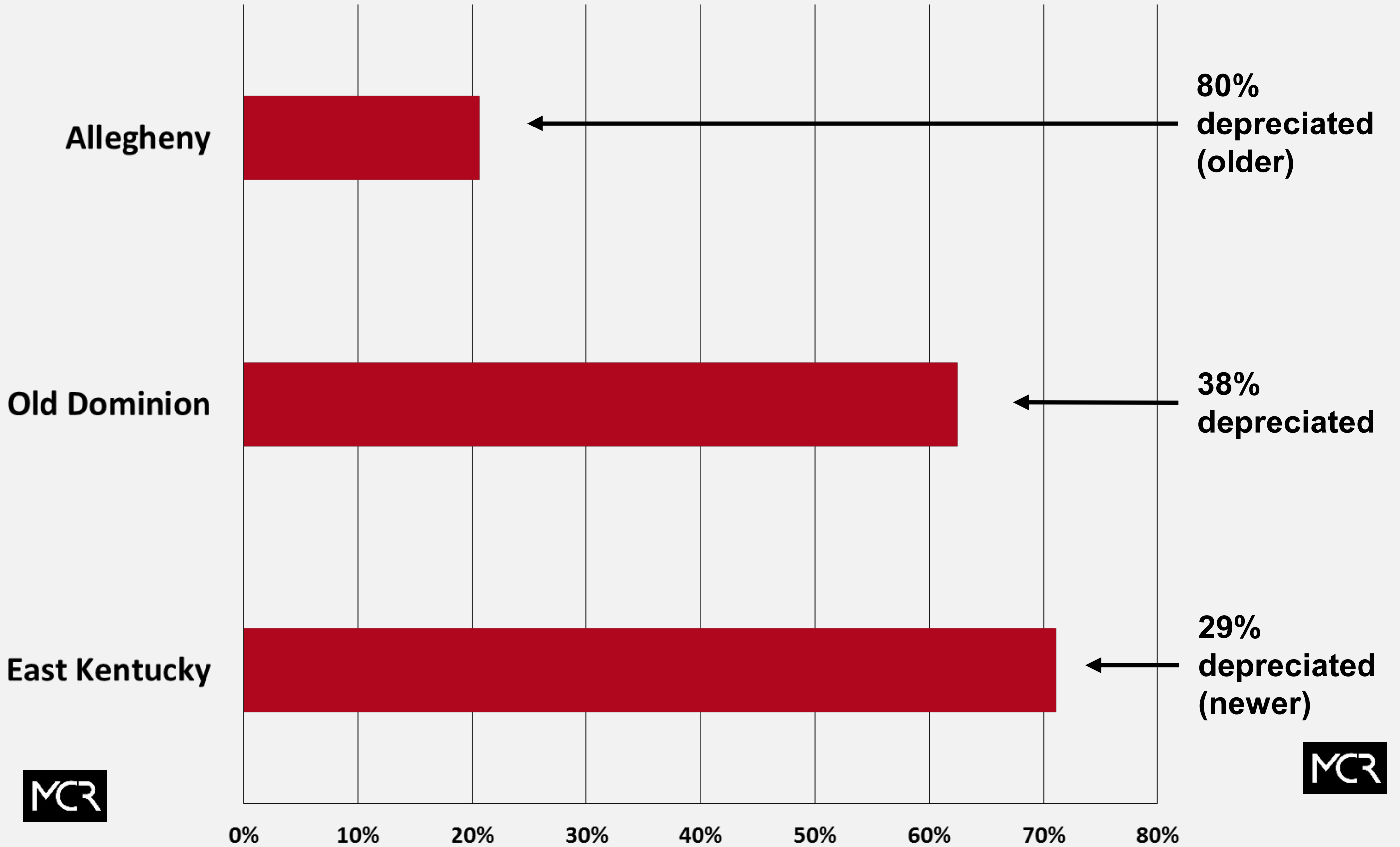
Figure 11

2017 Net Transmission Plant as a Percent of Gross Transmission Plant for PJM G&Ts



There is considerable room for many IOUs and G&Ts in PJM to make additional investment, in the form of upgrades and/or replacement.

Figure 11 shows that the differing average ages of transmission for the three PJM G&Ts is even more pronounced. Allegheny's transmission plant is the oldest (80% depreciated) whereas East Kentucky transmission plant is much newer, only 29% depreciated. Old Dominion is 38% depreciated, older than the MISO and SPP G&T averages. Allegheny has a stated/fixed transmission rate (rather than a formula rate that automatically updates each year) which may be a factor in why they have not invested at the same rate as other G&Ts. Figures 10 and 11 indicate that transmission investment levels are not "saturated" and there is considerable room for many IOUs and G&Ts in PJM to make additional investment, in the form of upgrades and/or replacement of aging facilities.

Investment Commensurate with Load Ratio Share

The three PJM G&Ts represent about 5% of the 2017 PJM load for IOU/Transcos and G&Ts but only represent about 0.5% of the change in transmission investment (see Table 2 on page 16). That is, over the last three years, the three G&Ts as a group have not been investing at a rate consistent with their load ratio share. For example, Old Dominion is about 2.2% of the total load of IOU/Transcos and G&Ts in PJM but has less than 0.2% of the transmission investment over the last three years. East Kentucky is 2.4% of the total load but only had 0.4% of the transmission investment over the last three years. A similar picture emerges if one looks at current total gross transmission investment as a percent of the total.

Old Dominion has less than 0.2% and East Kentucky has 1.2% of the total current gross transmission plant—both well under their load ratio shares. Similarly, Allegheny has 0.5% of the total load and only 0.1% of the total current gross transmission plant.

As a result, those entities in a joint pricing zone, such as Old Dominion (in the Dominion Energy zone) and Allegheny (in the PPL zone), may not be producing a sufficient level of transmission revenue to offset their transmission tariff costs. Old Dominion receives transmission revenue credits from Dominion Energy for its eligible transmission facilities in the Dominion Energy zone. Depending on the specific joint pricing arrangements with Dominion Energy and the relative investment and load ratios in the zone, Old Dominion may be disproportionately paying for a significant amount of transmission investment made by others.[17] This is the case for many G&Ts, particularly in MISO. As a group, G&Ts in MISO are about 11.5% of the load but only had 6.7% of the transmission investment since 2013. In contrast, SPP G&Ts as a group have recently stepped up their level of investment and have achieved, their load ratio share of the total investment over the last years. While this is true in aggregate, there are still many G&Ts in SPP that are falling short in terms of investment relative to load share.

Obtaining a load ratio share of transmission in a pricing zone does not necessarily provide sufficient transmission revenue to offset the substantial transmission zonal rate increases.

Note, however, that obtaining a load ratio share of transmission in a pricing zone does not necessarily provide sufficient transmission revenue to offset the substantial transmission zonal rate increases if the G&T or public power entity resides in a joint pricing zone with an IOU or Transco. That is, IOUs and Transcos have significantly higher revenue requirements than G&Ts, joint action agencies ("JAAs") and many municipals for the same level of transmission investment.

The revenue requirement will be higher for an IOU or Transco as compared to a G&T because:

- IOUs and Transcos pay state or federal income taxes; and those costs are included in the IOU or Transcos's cost of service; whereas G&Ts do not pay income taxes.

[17] Some G&Ts have grandfathered agreements that protect themselves from various transmission charges by an incumbent or the RTO. Also, gross transmission plant is only one element of a transmission owner's revenue requirement so it does not show the entire ATRR picture.

Table 2
Comparison of Change in Gross Transmission Plant Balance to Current Load Ratio Share for PJM IOU/Transcos and G&Ts (2014-2017)[18]

	3-Year Change in Trans. Gross Plant Balance (Proxy for Cap Expenditures) ($ Millions)	% of Total Gross Plant Change	Estimated 12 CP Load (MWs)	Estimated % of Total Load
IOU, Transcos	$17,079	99.5%	93,321	95%
G&Ts	$78	0.5%	5,011	5%
Total	$17,157	100.0%	98,332	100%

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- The typical equity ratio for an IOU or Transco is much higher than for a G&T, so the IOU or Transco's weighted average cost of capital, which is also referred to as the overall rate of return, is higher.
- The cost of incremental long-term debt can be higher for an IOU or Transco, particularly if the G&T finances through the Rural Utilities Service ("RUS").

The typical IOU/Transco's revenue requirement is about 35% to 40% higher than the typical G&T.

Thus, for the same investment, and assuming the same ROE, the typical IOU/Transco's revenue requirement is about 35% to 40% higher than the typical G&T, even with the recent reduction in the corporate tax rate.[19] This means that even if the G&T has invested at its load ratio share, it still is faced with the higher revenue requirement from the IOU/Transco costs in the pricing zone. That is, the zonal tariff paid by the G&T will exceed the zonal tariff revenue received by the G&T. In order to be in a "neutral investment position," a G&T residing in a joint pricing zone with an IOU or Transco must therefore invest at a rate higher than its load ratio share.

How Cooperatives and Public Power Can Create Value from Transmission Investment

As discussed previously, IOUs can create value for their shareholders through transmission investments that increase rate base, and in turn, create

[18] *Sources: PJM formula rate templates and G&T company-supplied data and annual reports, including 12 CP load supplemented as necessary from other sources.*

[19] *See for example, MCR Point of View entitled: The New Tax Law: Will a Lower Tax Rate for IOUs Impact the Advantage Public Power and Cooperatives Have in Transmission Investing?*

incremental earnings. The business model of G&Ts, JAAs and municipals, of course, is much different than IOUs in that G&Ts and JAAs are owned by their members. For example, generating higher earnings for a G&T does not necessarily create value for a member cooperative if the increased earnings are fully paid by its members/customers—this is simply moving money from the "left pocket to the right pocket." Ultimately, what matters is whether the cooperative or public power entity is creating real value for its members/customers from the investment.

Cooperatives and public power can create value from transmission by pursuing the approach(es) that best fit(s) their unique situations.

If your utility is still examining whether it makes sense to move forward with transmission projects, it is useful to think about how value can be created for your members. While there is no "one size fits all" answer for all cooperative and public power utilities to create value from transmission investment, there are six common approaches that should be explored to determine the best fit given the utility's unique situation. These are:

1. Optimize and gain revenue from any existing transmission assets
2. Participate in new projects where other customers (beyond the investing utility's customers) also pay a portion of the transmission costs
3. Achieve higher returns from transmission investment vs. current cost of capital, so the difference can be used to help offset transmission rate increases
4. Enhance reliability at the local load level, not just at the regional backbone level
5. Improve access to wholesale markets to reduce power costs and/or to lower congestion costs
6. Capitalize on public power and cooperatives having a lower revenue requirement than IOUs and Transcos by being a sole or major investor in all projects affecting their load

Let's take a more detailed look at each of these approaches.

1. Optimize revenue from existing transmission assets—Each G&T or public power entity, regardless if they are currently a transmission owner or contemplating it, should analyze its current distribution and sub-transmission assets to determine if there are investments that can be made to make existing assets eligible for transmission revenue recovery. These projects could include, for example, looping an existing radial line or upgrading a combination T&D substation.

2. Participate in projects where other customers pay a portion of costs—Cost-shared projects (e.g., many PJM baseline transmission reliability and market efficiency upgrade projects) have been particularly attractive investments, because a large portion of the total costs are paid by other customers. However, these types of regional, higher-voltage projects are typically competitively bid. Despite this, lower voltage, local baseline reliability projects in a joint pricing zone can still be financially attractive, because the costs are paid by all customers in the pricing zone.[20] The lower the percentage of load a company has of the entire load in the joint pricing zone, the more attractive their investment is, because other customers will pay a portion of the costs. This tends to be a key factor for cooperatives and public power to create value for their members/customers. Nevertheless, even if a utility has a relatively high percentage of the load in their pricing zone, it can still create value by some other ways discussed below.

The lower the percentage of load a company has of the entire load in the joint pricing zone, the more attractive their investment is, because other customers will pay a portion of the costs.

3. Achieve returns higher than the cost of capital—Because cooperatives and public power currently have a very low incremental cost of capital (e.g., RUS long-term debt can be in the 3% range and public power "A" rated tax-exempt debt is about 3.50%), these utilities can produce substantial margin from a transmission investment. The larger the investment, the larger the dollar margin. The overall return is based on a weighted average of debt and equity. The percentage equity on the balance sheet is combined with the ROE and the percentage long-term debt is combined with the average, historical cost of debt. For example, a public power entity with a 50% equity ratio, a 10% ROE and a historical average cost of debt of 4.5%, produces an overall municipal rate of return of about 7.3% vs. an incremental market cost of debt of only about 3.50%, resulting in a margin of 3.8%, which is very high in today's low interest rate environment. The margin from transmission investments can be used to help partially offset the rising transmission rates faced by all public power entities. The same opportunity applies to cooperatives.

4. Enhance reliability at the local level—Cooperatives and public power can focus their investment to improve reliability for its members/customers. Although these utilities are paying for large, regional backbone cost-shared projects, these project benefits do not necessarily extend down to the local level to enhance reliability at the lower voltages (e.g., 69 kV, 115 kV or 138 kV). Examples of the types of reliability projects (e.g., PJM Supplemental Projects) that can be undertaken to improve local reliability include:

[20] *This may not be the case if the participants in the zone have contractual true-up features with payments that equalize transmission investment based on load ratio share or a grandfathered agreement that exempts certain customers from charges.*

- Looping a radial line and connecting to the PJM network
- Adding a substation and lines to create redundancy and mitigate a catastrophic scenario
- Re-conductoring an existing line and/or upgrading its voltage level
- Updating and/or expanding an existing substation
- Replacing poles/structures
- Investing in a new or spare transformer
- Deploying fiber optics for transmission purposes

The margin from transmission investments can be used to help partially offset rising transmission rates.

5. Improve wholesale access and/or lower congestion costs—Cooperatives and public power and can participate in projects in their zone to better interconnect to the PJM network in order to provide a more liquid market that can lower overall power supply costs in the RTO. Providing multiple feeds improves reliability and can reduce congestion on a nearby line or potential overloading of a substation.

6. Lower revenue requirements for the same transmission—As discussed previously, most cooperatives and public power have a significant revenue requirement advantage over IOUs and Transcos when contemplating the same investment. Thus, it nearly always makes sense for the cooperative or public power entity to make the investment serving its load, because it results in lower rates to all customers in the zone—it makes sense to own transmission rather than "rent."

Moving Forward with Transmission Investment

The level of investment in PJM is at a high level driven largely by IOUs and their Transco subsidiaries seeking enhanced reliability and earnings growth with reasonable risk. The factors driving transmission investment are not abating and are thus continuing to open up new opportunities for additional investment. Each cooperative or public power entity should determine its "rightful share" of transmission investment and understand the opportunities to create value for its members/customers. Upgrading an aging transmission system and obtaining an appropriate share of new transmission has become imperative as industry factors continue to drive increases in transmission rates and transmission costs become a more significant portion of the customer's total power bill.

Given the potential for many G&Ts and public power entities to have highly depreciated existing transmission investments and lower cost investment opportunities, there exist many reasons for cooperatives and public power entities to continue to expand their transmission investments, particularly for those transmission owners that have lagged behind in investment and are in a joint pricing zone. IOUs and Transcos are continuing to invest at high levels and will therefore persist in creating a need for cooperatives and public power to identify ways to mitigate rate increases and create value for their members and customers through increased transmission investment.

APPENDIX

Drivers of Transmission Investment

The need for additional transmission investment across the US is being driven by many policy and operational factors, including those listed below.

Renewables Standards: Wind and Solar—The US and individual states have promoted the development of renewable energy, especially wind and solar, through tax credits and renewable energy standards. Wind generation and central solar farms are generally located a considerable distance from population centers where the energy is needed, thus requiring significant transmission capacity.

FERC Policies—The Federal Energy Regulatory Commission ("FERC" or "Commission") has promoted investment through the development of Regional Transmission Organizations ("RTO") with coordinated transmission planning, formula rates, postage stamp pricing[A1] joint pricing zones and the granting of relatively high returns on equity ("ROEs") in a low interest rate environment. It has been FERC's general policy to set transmission returns at levels at least as high, if not higher than state levels. In addition, the Commission has granted various rate incentives to encourage new projects and the formation of dedicated Transcos. These incentives have included granting a hypothetical capital structure to increase the level of equity, incentive ROE adders, allowing construction work in progress ("CWIP") in rate base, recovery of abandoned plant costs, and establishing regulatory assets for new entrants.

NERC Reliability Standards—Utilities must adhere to North American Electric Reliability Corporation ("NERC") transmission planning reliability standards, which have been reinforced over the last 10 years, thus requiring a continual focus on reliability and ability to manage contingent events. Changes in compliance requirements, revisions to the definition of Bulk Electric System ("BES") and required upgrades in transmission planning modeling and hardware have increased investment requirements. Significant reinforcement of substation or transmission lines may be required to correct "N-1" contingent conditions (i.e., a sequence of events consisting of the initial loss of a single transmission component, followed by corrective system adjustments).

NERC Physical and Cyber Security Requirements—NERC has become much more stringent in critical infrastructure protection standards. This change has required additional physical investment in substation security and cyber

[A1] Postage stamp pricing allocates the project costs across all entities; it thus encourages individual utilities to invest, because customers other than their own will pay a portion of the costs.

security. The interdependency of the internet and the constant threat of cyber-attacks have vastly raised the bar for utility's and RTO's computer systems to withstand cyber threats. NERC's Critical Infrastructure Protection Reliability Standards (Version 5) specify, for example: 1) the need to protect certain transmission stations, substations, and their associated primary control centers; 2) consistent and sustainable security management controls to protect BES cyber systems against compromise that could lead to instability in the BES; and 3) special protection systems that support the reliable operation of the BES, such as protective relays and circuit breakers.

Replacement of Aging Facilities—Although load growth has been flat or modest recently, there was a pent-up demand to enhance reliability resulting from an environment of rate freezes and minimal transmission investment in the 1990s. Moreover, there was no regulatory framework for reliable cost recovery until the early 2000s when RTOs began emerging, which led to additional transmission investment through a structured approach to cost recovery. More recently, the emphasis on infrastructure and "upgrading the grid" gives added impetus and political cover to replace or significantly upgrade aging transmission assets.

Relief of Transmission Congestion, LMPs—The onset of RTOs and locational marginal pricing ("LMP") that charge for transmission congestion provide an economic advantage to expand transmission in order to lower delivered power prices.

EPA Rules on Generation Retirements—Due to more stringent environmental rules from the Environmental Protection Agency ("EPA"), retirements of older coal units have created an additional demand for changes in transmission to help maintain voltage levels and grid stability.

New Natural Gas Plants—Inexpensive natural gas prices combined with the impact environmental rules had on coal plants have contributed to the rise of new natural gas plants as a major power supply source. These new plants may be sited in locations without adequate transmission, thus prompting new transmission investment.

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ABOUT THE MCR TRANSMISSION STRATEGY PRACTICE

MCR provides strategy support to G&T and T&D cooperatives, joint action agencies and municipals in various RTOs/ISOs with a focus on finding value for our clients. Our services:

Formula Rate and Cost Analysis

- **Development of Annual Transmission Revenue Requirements (ATRR) for New Transmission Owners (TOs).** MCR develops cost data to support full RTO revenue recovery, which involves, for example, developing MISO's Attachment O, and Attachment H in PJM and PJM.
- **Formula Rate Review for Existing TOs.** MCR reviews costs for formula rate filings to optimize revenue, properly record costs and withstand stakeholder scrutiny.
- **Challenge to Incumbent/IOU Formula Rate Costs.** MCR reviews neighboring utility transmission costs to ensure adherence to protocols and formula rates.
- **Staff Education Workshops.** MCR conducts workshops to educate client staff on the development and optimization of transmission formula rates.

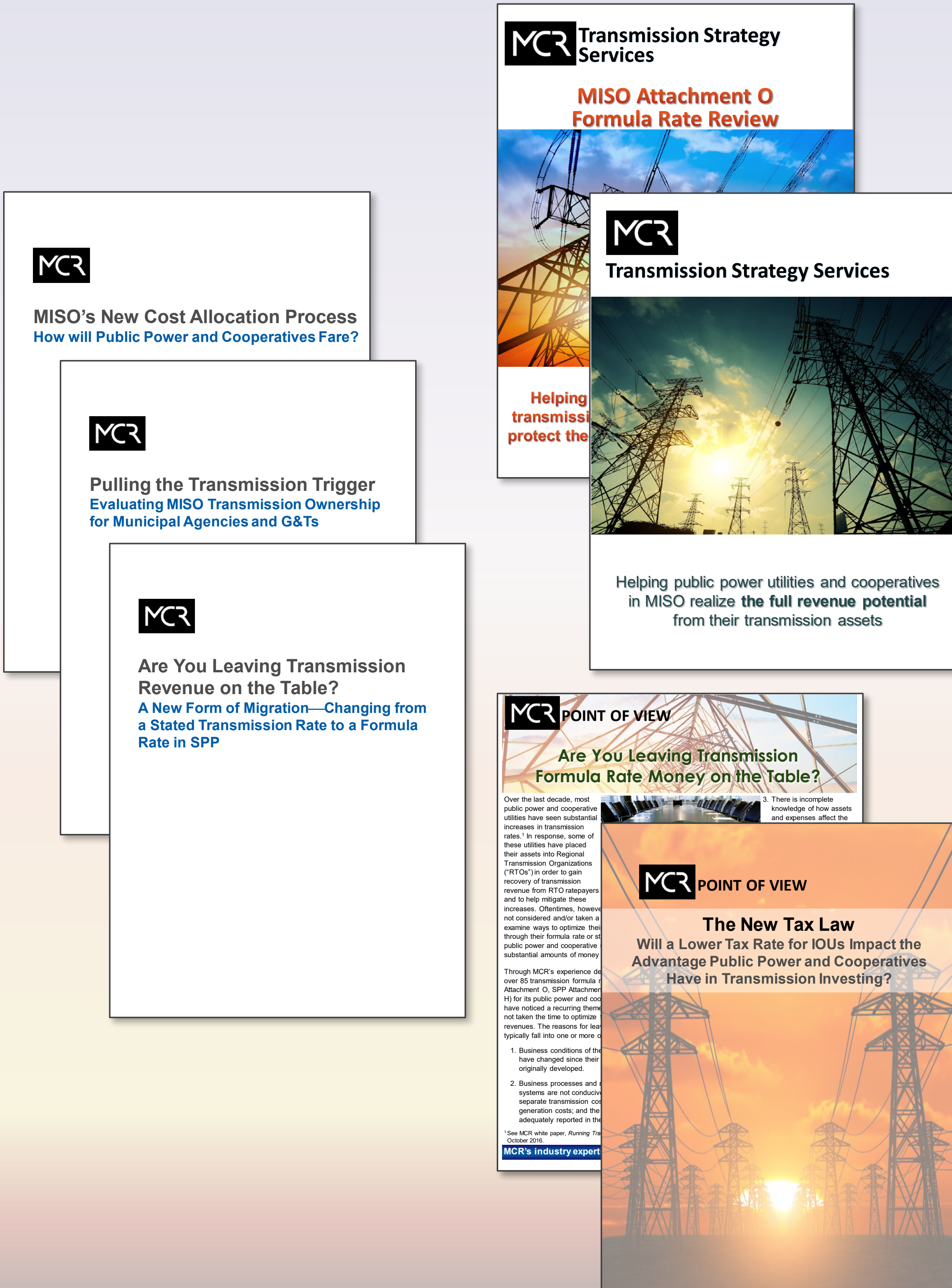
FERC Filings

- **Section 205 Rate Filing Support.** MCR provides expert testimony for ATRR filings, including new transmission formula rates or changes to an existing formula rate.
- **Cost of Capital Expert Testimony.** MCR provides expert testimony and analytics to support proposed cost of capital requests of public power and cooperatives.
- **Transmission Incentive Rate Filings.** MCR provides expert testimony and supporting analytics for incentive rate applications, including CWIP, hypothetical capital structure, abandoned plant and regulatory asset.
- **Intervention and Mediation Support.** MCR provides analytical and intervention support during intervention, settlement, mediation and hearing.
- **Reactive Power Revenue Filings.** MCR provides testimony and analysis to support recovery of reactive power costs.

Strategic Analysis

- **Development of Transmission Business Plan.** MCR works with clients to define issues, goals, strategies and project opportunities, providing analytic support.
- **Economic Evaluation of Transmission Investment.** MCR determines economics, risks of new investment, or sale/purchase of existing assets.
- **Evaluation of RTO Membership.** MCR conducts economic and risk analysis to determine the cost-benefit of becoming a TO.
- **Analysis and Development of Negotiating Strategies.** MCR provides analytical support to clients in negotiations with IOUs.

SAMPLING OF MCR TRANSMISSION KNOWLEDGE PIECES



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