*2017 MISO Transmission Investment Analysis*

# The Transmission Arms Race Continues

## Are You Obtaining Your Share of Transmission Investment?

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Jim Pardikes
Ron Kennedy
Chris Nagle

This paper is an updated and expanded version of MCR's Transmission White Paper released in the fall of 2016.

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**The "arms race" for transmission investments continues. In addition to investor-owned utilities ("IOUs") and transmission companies ("Transcos"), generation and transmission cooperatives ("G&Ts") and public power in MISO are increasing their levels of investment. But in many cases, G&Ts and public power make transmission investments at a disproportionally lower percentage than their load ratio share. This mismatch results in substantial exposure to transmission rate increases for their members and customers. In order to mitigate the impacts of these transmission rate increases, public power and cooperatives need to focus on how transmission investing can create value for their members.**

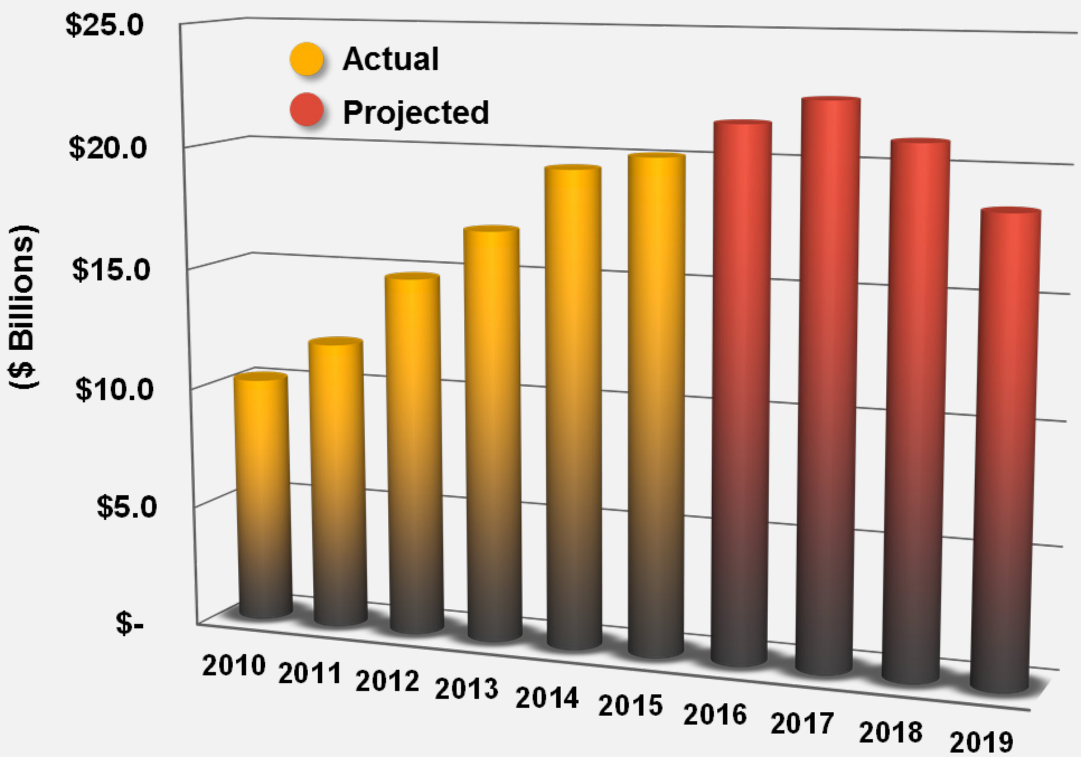
**By the end of 2017, EEI forecasts transmission investment will increase from $10 billion per year to over $22 billion per year—an increase of over 12.3% annually.**

### Escalating Nationwide Transmission Investment

By the end of 2017, Edison Electric Institute ("EEI") forecasts that IOUs and transmission companies (excluding public and cooperative power) across the country will more than double their rate of transmission investment from about $10 billion to about $22.5 billion per year—an average increase of 12.3% 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 the need for reliability and the growth of renewables, most notably wind power (see Figure 2 on page 3). This increase is also part of a "back to basics" infrastructure strategy whereby IOUs invest in the "wires" side of their business in an effort to drive earnings growth with lower risk than many other generation investments.

[1] Source: "Transmission Projects: At A Glance, Investment of investor-owned electric utilities and stand-alone transmission companies. *(2010-2019)*," EEI, December 2016.

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




## The Financial Attractiveness of Transmission Investment

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

Transmission is FERC-regulated rather than state-regulated and is thus often subject to formula rates that automatically update each year without a full rate case. Although stakeholders can question or challenge costs through protocols in the annual formula rate update, the likelihood of significant costs being excluded is typically less likely than in a full rate case filing. Moreover, returns for transmission are attractive given today's low cost of capital[3] and are usually higher than an IOU's state jurisdictions 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 no regulatory lag.

Most IOUs and Transcos in MISO see transmission investment as a major driver of earnings growth with attractive returns. For example, Ameren's CEO, Warner

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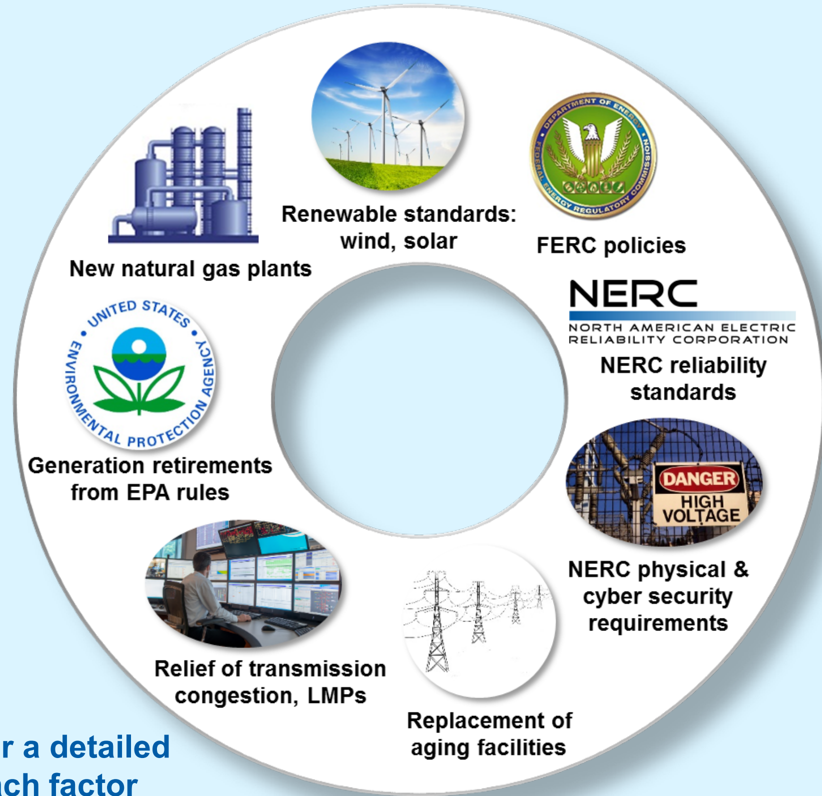
[2] Source: Transmission Projects: At A Glance, Edison Electric Institute, December 2016

[3] The MISO ROE of 12.38% in place until 2013 has been reduced to a base ROE of 10.32%; the recommendation from the administrative law judge ("ALJ") for the second (most recent) complaint against MISO transmission owners provides for a 9.70% base ROE. This recommendation is awaiting FERC review and approval. The ROE adder of 50 basis points for RTO membership is in addition to the base ROE.

*Figure 2*
***Policy and Operational Drivers of Transmission Investment***




**See Appendix for a detailed discussion of each factor**

Baxter has highlighted its transmission investment in its earnings calls with investment analysts:

> *"This 41% earnings per share growth [in the transmission business unit] was driven by increased infrastructure investments at both ATXI and Ameren Illinois…." [4]*

> *"Our transmission projects are projected to increase FERC-regulated rate base by 13% compounded annually over the 2016 through 2021 period." [5]*

**Since 2003, MISO transmission owners have constructed about $15 billion in transmission projects.**

## The Transmission Arms Race in MISO

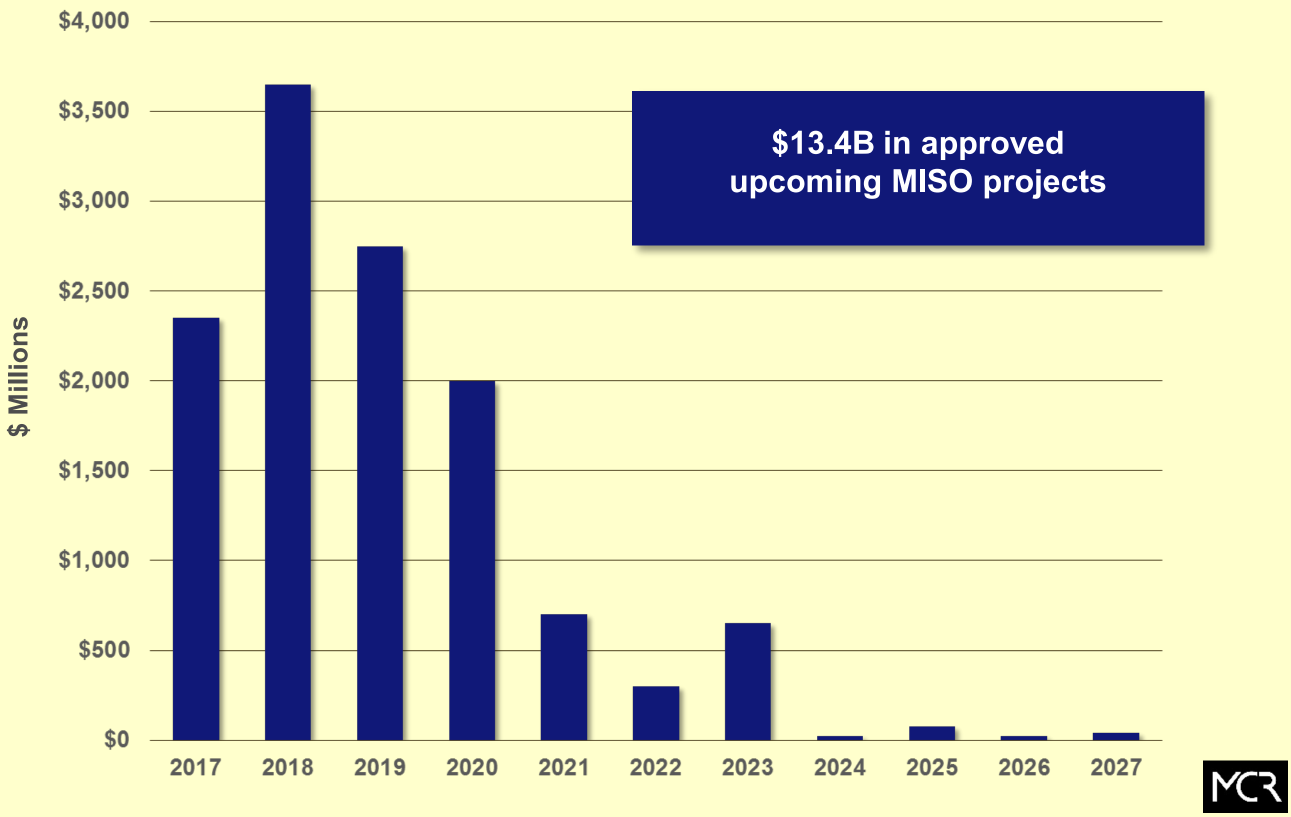
Given the previously mentioned drivers of investment and the financial attractiveness of transmission investment, it is not surprising that transmission investment in MISO has continued at high levels. Since 2003, utilities in the MISO region have constructed about $15 billion in transmission projects.[6] In

[4] Source: Warner Baxter, Chairman, President and CEO, Ameren 4Q 2016 Earnings Call Transcript

[5] Source: Warner Baxter, Chairman, President and CEO, Ameren 4Q 2016 Earnings Call Transcript.

[6] Source: 2017 MISO Transmission Expansion Plan, MTEP17 Report Book 1 // First Draft August 10, 2017, page 27.

**Figure 3**
**MISO Approved MTEP Projects by Projected in-Service Dates**




2003, there were 19 utilities filing an Attachment O in MISO for revenue recovery; now there are 85 utilities.

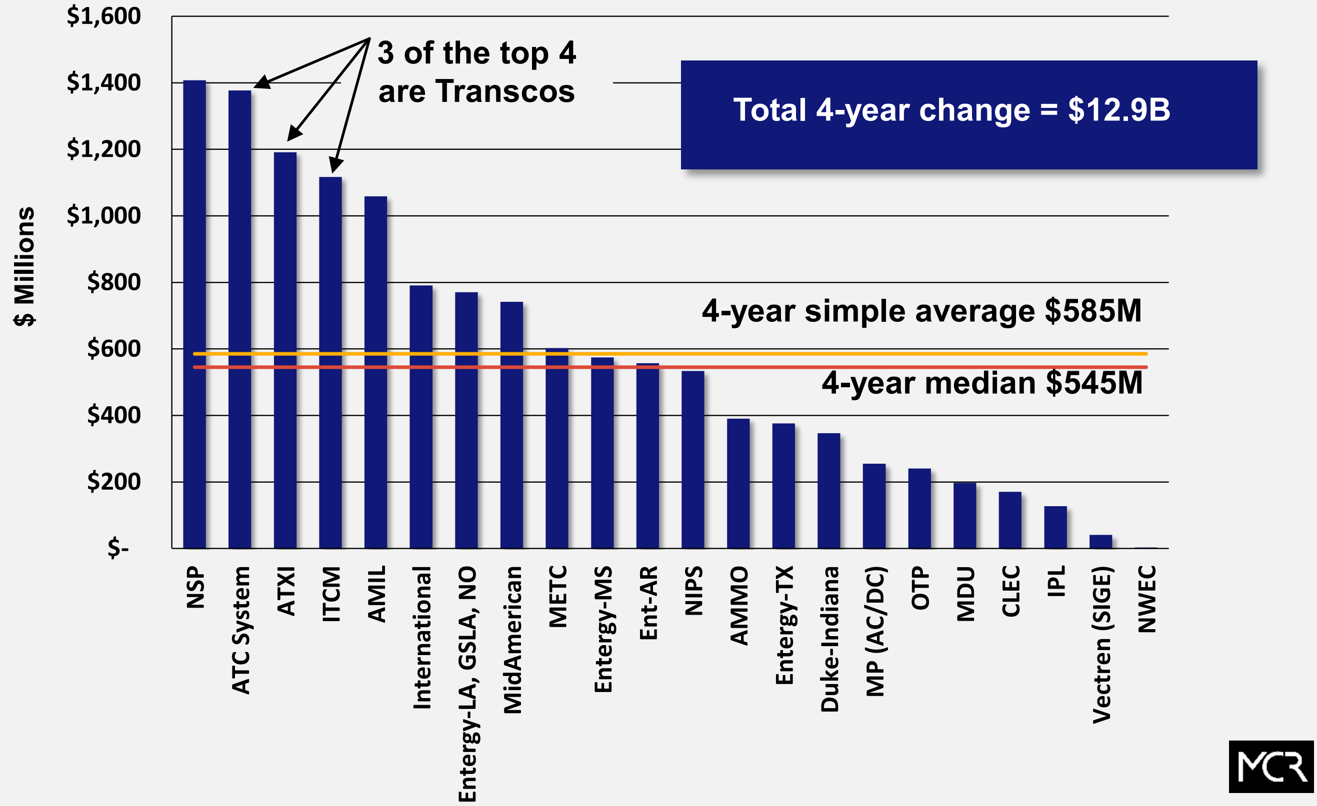
This high level of transmission investment in MISO will continue for the foreseeable future. There are 1,062 total MISO Appendix A (i.e., approved) projects in the 2017 Preliminary MISO Transmission Expansion Plan ("MTEP17") in various stages of planning or construction, amounting to $13.4 billion (see Figure 3). This includes MISO's recommendation for at least $2.5 billion in new projects for MTEP17.[7] In addition, there are another $4 billion in Appendix B projects awaiting further review, evaluation and approval.

Analyzing MISO transmission investment over the last four years, it is evident that G&Ts, joint action agencies ("JAAs") and municipals have made lower absolute dollar investments than IOUs/Transcos (as expected given the size differences). Looking at the change in gross transmission plant over the past four years provides a good proxy for the absolute levels of transmission capital investment.[8]

[7] Source: 2017 MISO Transmission Expansion Plan, MTEP17 Report Book 1 // First Draft August 10, 2017, page 6.

[8] Source: June 2013-2017 MISO Attachment O Net Plant Tab which shows gross transmission plant  Covers Schedule 9, 26 and 26-A investments. For those companies using a projected test year, captures the change in projected data for each year. For those companies using an historical test year, captures the change in previous end-of-year data for each year.

***Figure 4***
***Change in Gross Transmission Plant Balance for MISO IOUs and Transcos (2014-2017)***[9]



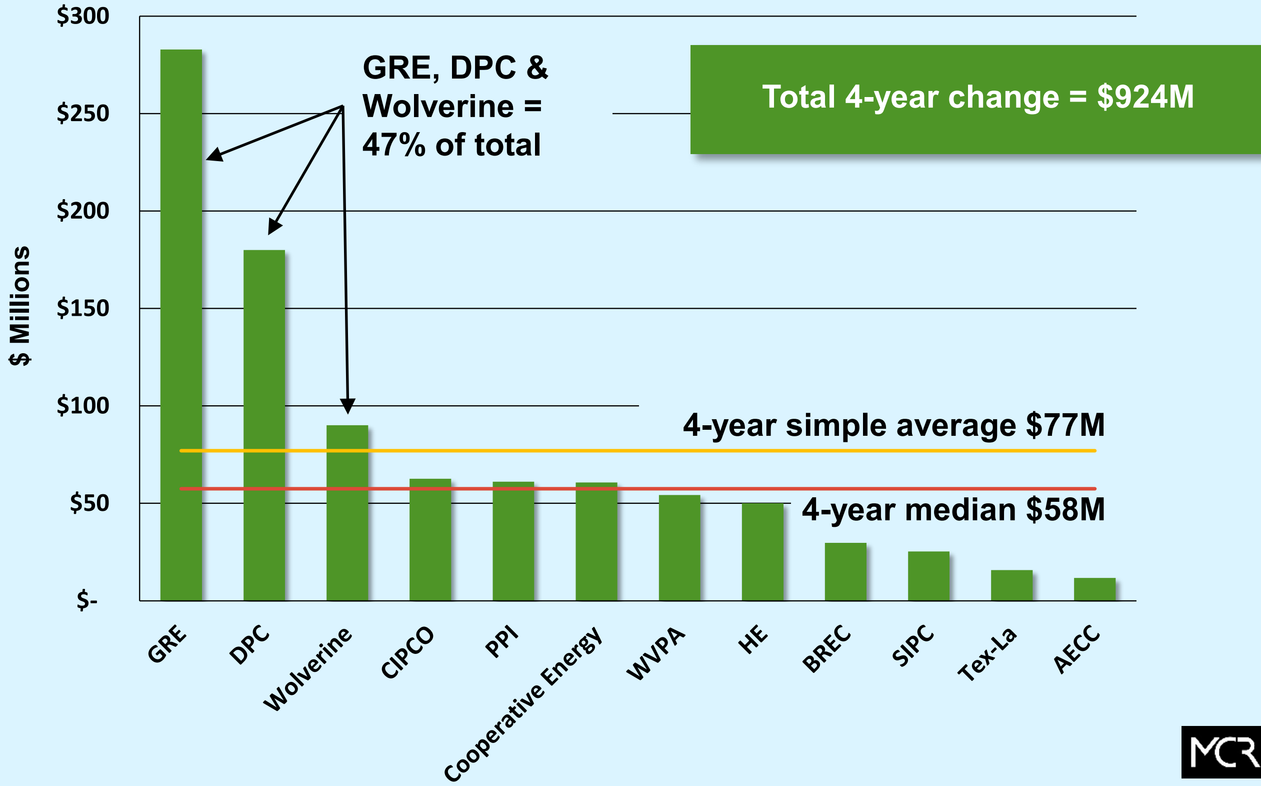

The analysis in Figure 4 shows that the change in gross transmission plant for MISO IOUs and Transcos was $12.9 billion over the last four years.[10] In this timeframe, three of the top four companies were Transcos. This dominance by Transcos reflects their business model, which is based solely on transmission and largely on increasing their asset base to produce earnings growth.

The average change in gross transmission plant over the last four years for IOUs/Transcos was about $585 million, or about $146 million per year. The median of $545 million indicates that transmission investing for IOUs/Transcos has become widespread rather than concentrated in a few companies. In 2017, there was approximately a 12% weighted average increase in gross transmission plant for IOUs/Transcos over 2016 levels. Note that each year represents the Attachment O rate year (e.g., TOs with projected test years are effective January 1, 2017 and those with a historical test year are effective June 2017).

[9] IOUs and Transcos are categorized together because the MISO Transcos are mostly owned by IOUs and/or are profit-making entities. Transmission gross plant compared is rate year 2013 vs. rate year 2017, i.e., the changes from 2013 to 2014, 2014 to 2015, 2015 to 2016 and 2016 to 2017.

[10] Source: June 2013-2017 MISO Attachment O Net Plant Tabs. Formula = change in gross plant + change in CWIP in rate base. Does not match annual capital expenditures, because it includes transfers and retirements. Transfers could for example, include a reclassification of distribution plant as transmission. Does not include any change in CWIP that is not in rate base. Study does not include group of three T&D cooperatives in MISO due to insufficient sample size.

*Figure 5*
*Change in Gross Transmission Plant Balance for MISO G&Ts (2014-2017)*[11]



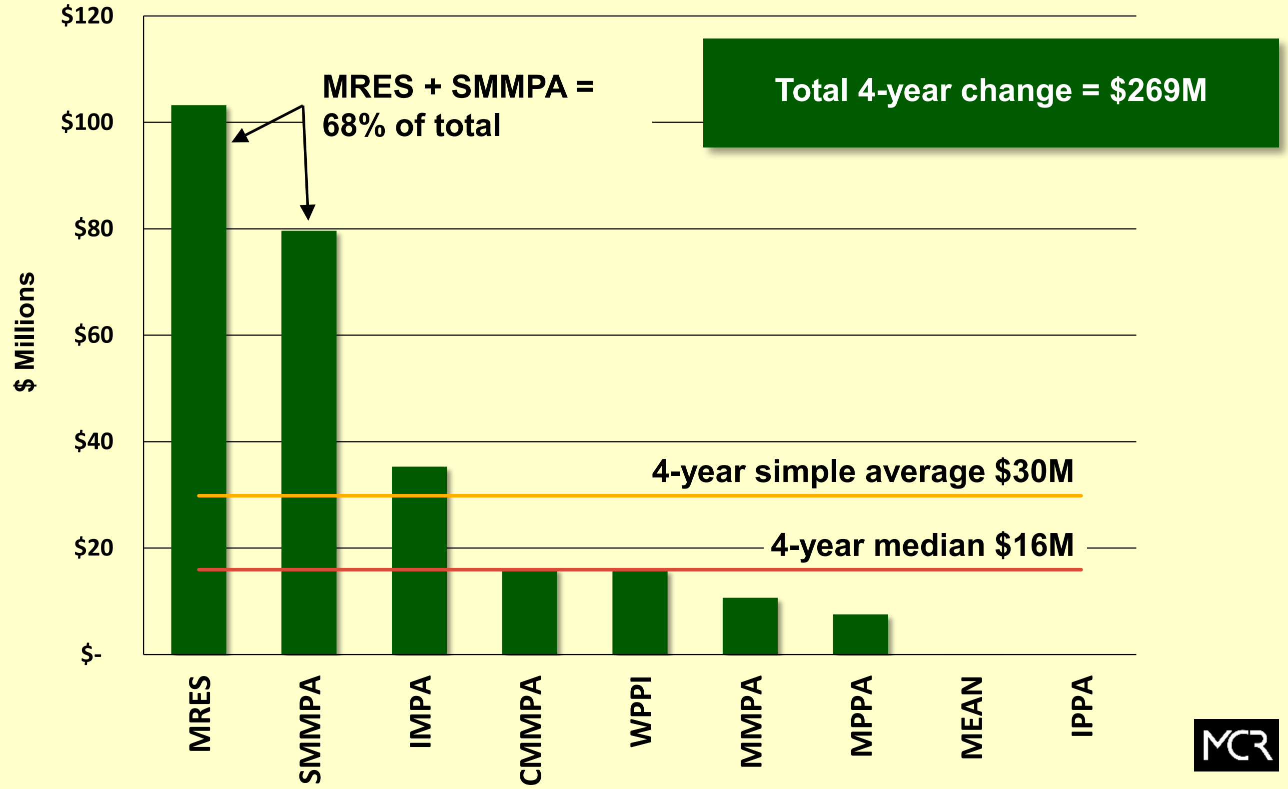

Figures 5, 6, 7 and 8 on this page and the following pages show the change in gross transmission plant over the last four years for MISO G&T, JAA, and municipal transmission owners ("TO"), respectively. Figure 5 shows that G&Ts had a four-year change of about $924 million. Great River Energy ("GRE"), Dairyland Power Cooperative ("DPC")[12] and Wolverine Power Cooperative comprised nearly half of the total G&T change in gross transmission plant over the last four years. The four-year average for the G&T group was $77 million ($19 million per year) and the median of $58 million ($15 million per year). A significant portion of GRE and DPC's investments included their participation in CapX2020 projects.[13] In 2017, Prairie Power and Tex-La Electric Cooperative ("Tex-La") had the highest percentage

[11] Reflects the 11 MISO G&T transmission owners and CIPCO (which files an Attachment O, but is not a MISO TO). Does not include Minnkota Power Cooperative (which is not a MISO TO and does not file an Attachment O). Does not include Central Power, East River and Upper Missouri due to insufficient years of data. Existing transmission assets for newly added utilities to the sample are not counted as new investment.

[12] Dairyland switched from an historical test year used for their June 2013 Attachment O (based on end of year 2012 data) to a projected test year beginning January 1, 2014, which is based on the projected monthly average of gross plant for 2014. Therefore, their gross plant balance effectively reflects an additional half year of investment for the 2014 figures compared to the prior year.

[13] The CapX2020 Initiative is a regional planning initiative by 11 utilities in the region known as the Transmission Capacity Expansion Initiative by the Year 2020 ("CapX2020 Initiative"). The utilities involved include Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy Services, Inc. For a detailed report of the CapX2020 initiative, see https://www.hhh.umn.edu/sites/hhh.umn.edu/files/capx2020_final_report.pdf

***Figure 6***
***Change in Gross Transmission Plant Balance for MISO JAAs (2014-2017)***



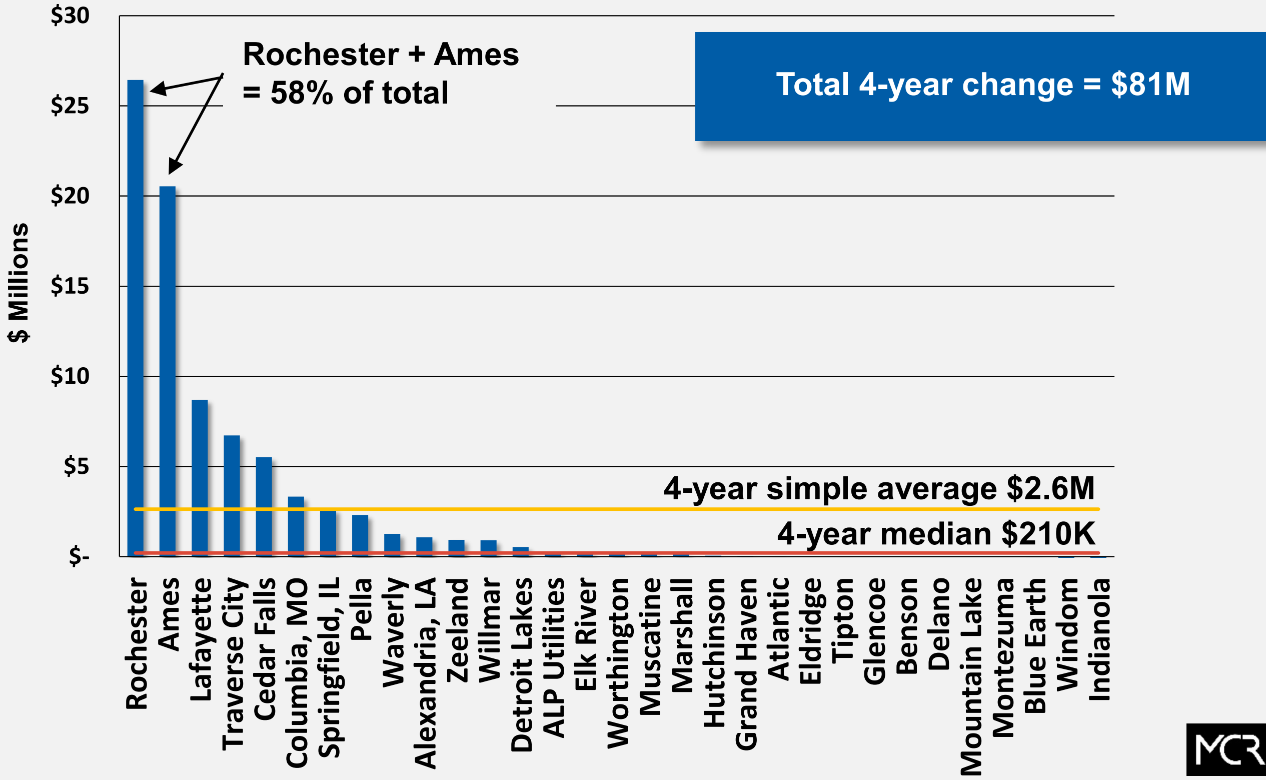

changes from the prior year, each increasing their gross transmission plant by 14%. G&Ts as whole increased their gross transmission plant by 6% in 2017 over 2016. This year, Central Iowa Power Cooperative ("CIPCO") and Tex-La were added to the G&T sample.

Figure 6 shows the four-year change in gross transmission plant for joint action agency transmission owners in MISO. The total increase for MISO JAAs was $269 million. Missouri River Energy Services ("MRES") and Southern Minnesota Municipal Power Agency ("SMMPA") comprised about two-thirds of this investment increase, much due to the CapX2020 projects. When looking at only the last year, SMMPA had a substantial 26% increase in gross transmission plant compared to the prior year with the JAA group up by 8%.

Figure 7 on the next page shows the total four-year change in gross transmission plant of $81 million for municipal owners of transmission in MISO.[14] Rochester Public Utilities ("RPU") and the City of Ames Iowa led the group of 31 MISO municipals comprising 58% of the total change in gross transmission plant during the four-year period. Two-thirds of the municipals

[14] Note that certain municipals or G&Ts entered MISO after the study period began. Once the base year is set, the increase in investment per the Attachment Os was included. In some cases, for those years without an Attachment O, MCR estimated the gross transmission plant from annual financial reports or filings, where possible. The source of load data (12 CP) for most municipals is the Attachment O. In some cases, where a municipal's load is not reported in its Attachment O, the municipals' loads were estimated based on publicly available sources such as the EIA Form 861 peak demand data adjusted with a 75% factor to obtain 12 month coincident peak load.

***Figure 7***
***Change in Gross Transmission Plant Balance for MISO Municipals (2014-2017)***



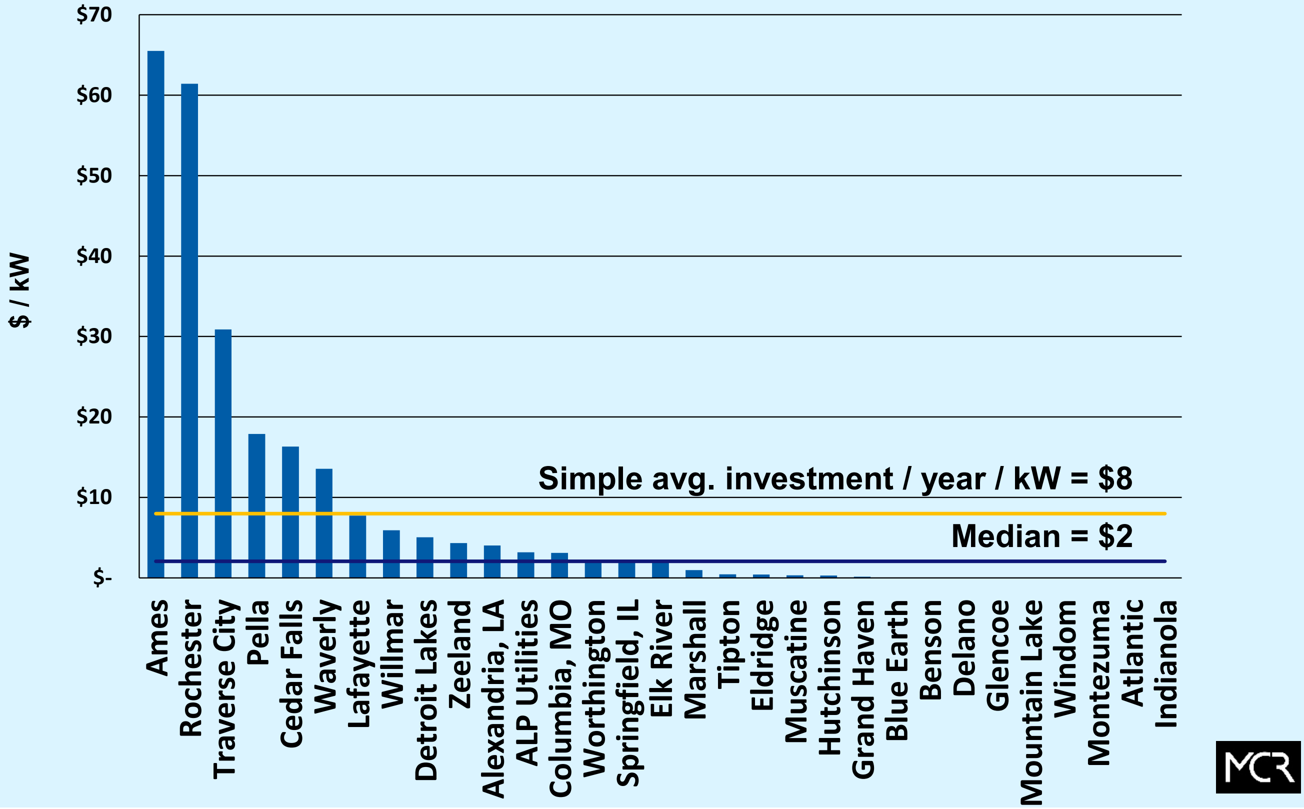

had a four-year change of less than $1 million, indicating that total municipal transmission investment has been concentrated in relatively few municipal utilities. The largest percentage increases over the prior year's gross transmission plant were for Cedar Falls Utilities (27%), RPU (17%) and Wilmar Municipal Utilities (13%). As a whole, municipals were up by 5% over 2016.

**After adjusting for load size, IOUs and Transcos invest in transmission at a rate of nearly five times the municipal group.**

This disparity in investment levels among municipals is also highlighted with the fact that the average four-year change for each municipal was $2.6 million with a median of only $210,000. Even after adjusting for size differences, on a kW basis per year (see Figure 8 on the next page), about half of municipals are showing little or no transmission investment. The average municipal transmission investment per year per kW (12 CP) is estimated at only about $8 with a median of $2, which is much less than the IOU/Transco average of $37. In other words, even after adjusting for load size, IOUs/Transcos invested in transmission at nearly 5 times the municipal group over the four-year period.

It is important to note, however, that many municipals that are members of a JAA have financially benefited from investments made by their respective joint action agencies at the regional level. For example, Central Minnesota Municipal Power Agency, a project-based agency, invested in the regional CapX2020

*Figure 8*
*Change in Gross Transmission Plant Balance Per Year Per kW for Municipals (2014-2017)*



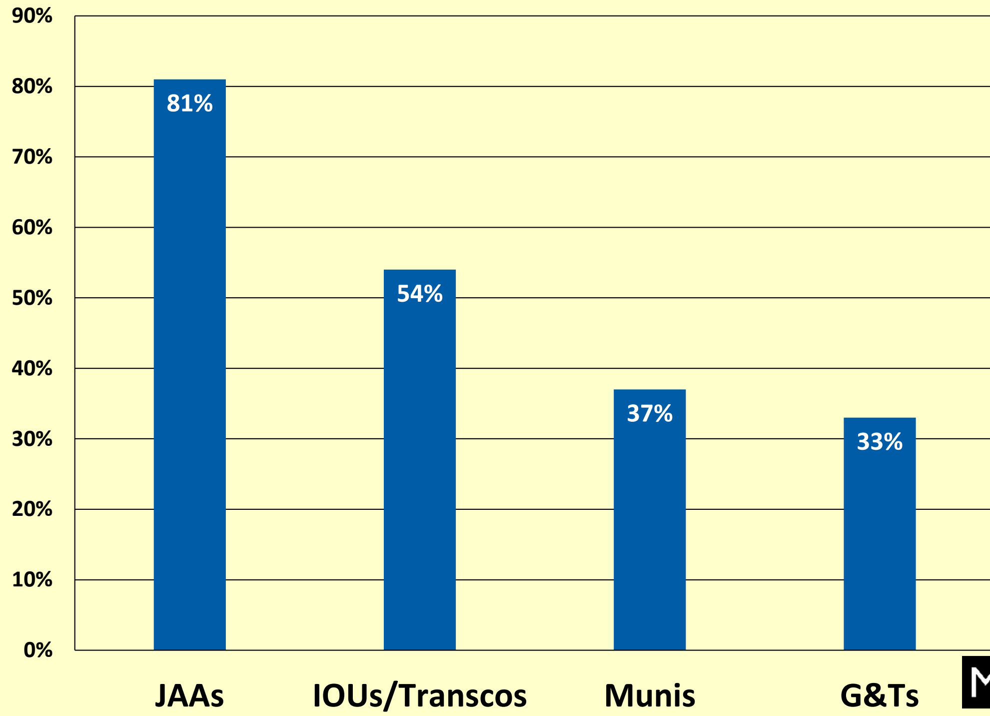

Brookings project on behalf of their agency members and members of Midwest Municipal Transmission Group ("MMTG") who chose to participate in the project.

Other municipals who are members (owners) of full requirements JAAs have also benefited through lower rates from their agency and/or a healthier balance sheet of their agency. Nevertheless, the data shows that at the local level, municipal transmission investment has been concentrated in a few utilities, raising the question of whether there are looming reliability issues for many municipals leading to opportunities for increased investment.

**Most G&Ts and municipals in MISO have increased their gross transmission plant at a lower growth rate than IOUs/Transcos.**

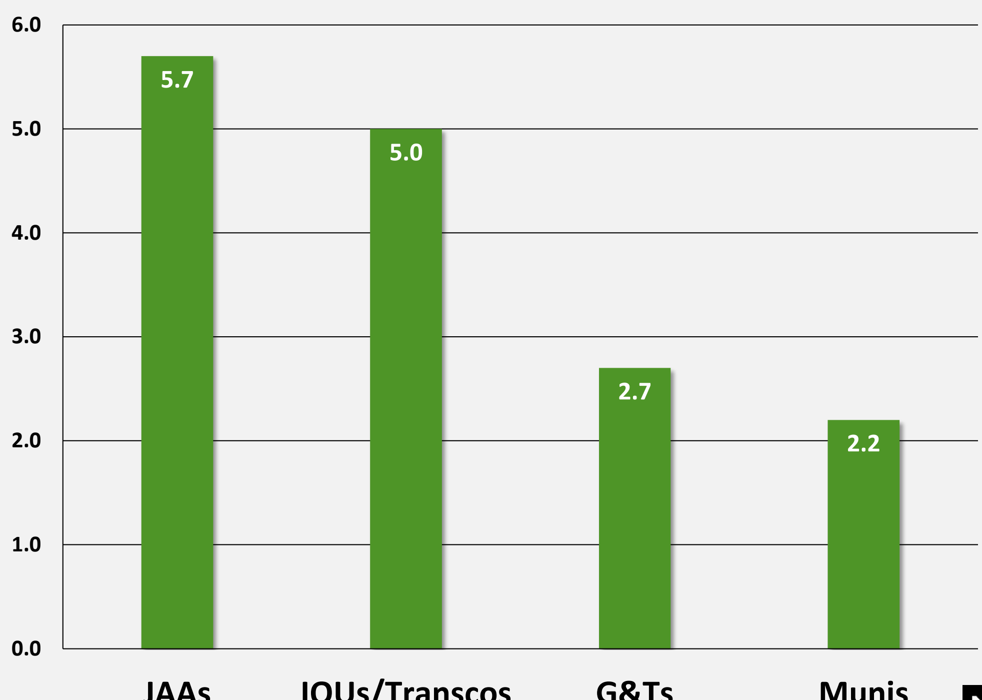
Figure 9 (on the next page) shows the percentage change in gross transmission plant over the four-year period. As a group, JAAs have been gaining ground on IOUs/Transcos, with an increase in gross transmission plant of 81% since 2013. Most G&Ts and municipals in MISO, however, have increased their gross transmission plant at a lower growth rate. Compared to their 2013 gross transmission plant balance, IOUs/Transcos have increased their gross transmission plant balance by 54% compared to 33% for G&Ts and 37% for municipals. Looking at these growth rate differences from a different angle, Figure 10 (on the next page) shows that MISO IOUs/Transcos are making investments at a rate of 5 times their transmission depreciation expense.

## *Figure 9*
## *Cumulative 4-Year Percentage Change Compared to 2013 Ending Balance for MISO Transmission Owners*[15]



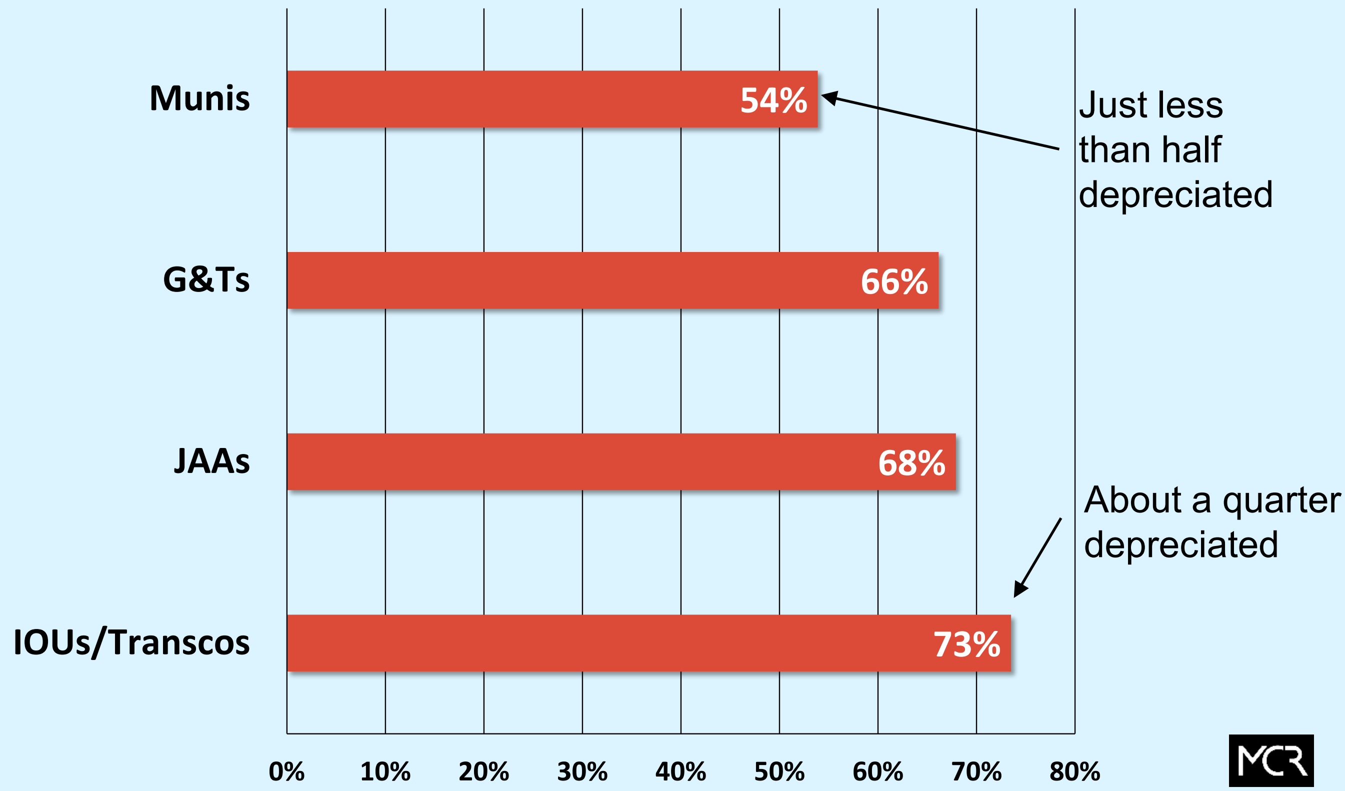

[15] Source: June 2013-2017 MISO Attachment O Net Plant Tab which shows gross plant. Represents weighted averages for each group.

## *Figure 10*
## *Change in Gross Transmission Plant Balance Compared to Depreciation Expense for MISO Transmission Owners (2014-2017)*[16]




[16] Sources: June 2013-2017 MISO Attachment O Net Plant Tabs and 2014-2017 Individual Attachment Os for depreciation expense. Represents weighted averages for each group. Shows total change in transmission gross plant divided by sum of four years of depreciation expense.

***Figure 11***
***2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO Owners of Transmission[17]***




JAAs are slightly higher at 5.7 times annual depreciation. In contrast, G&Ts are investing at about 2.7 times their depreciation expense and municipals, as a group, at only 2.2 times. Again, however, a few utilities are bringing up the municipal average. In fact, only 11 of the 31 MISO municipals are investing at a level sufficient to replace their annual depreciation (i.e., a ratio of at least 1.0).

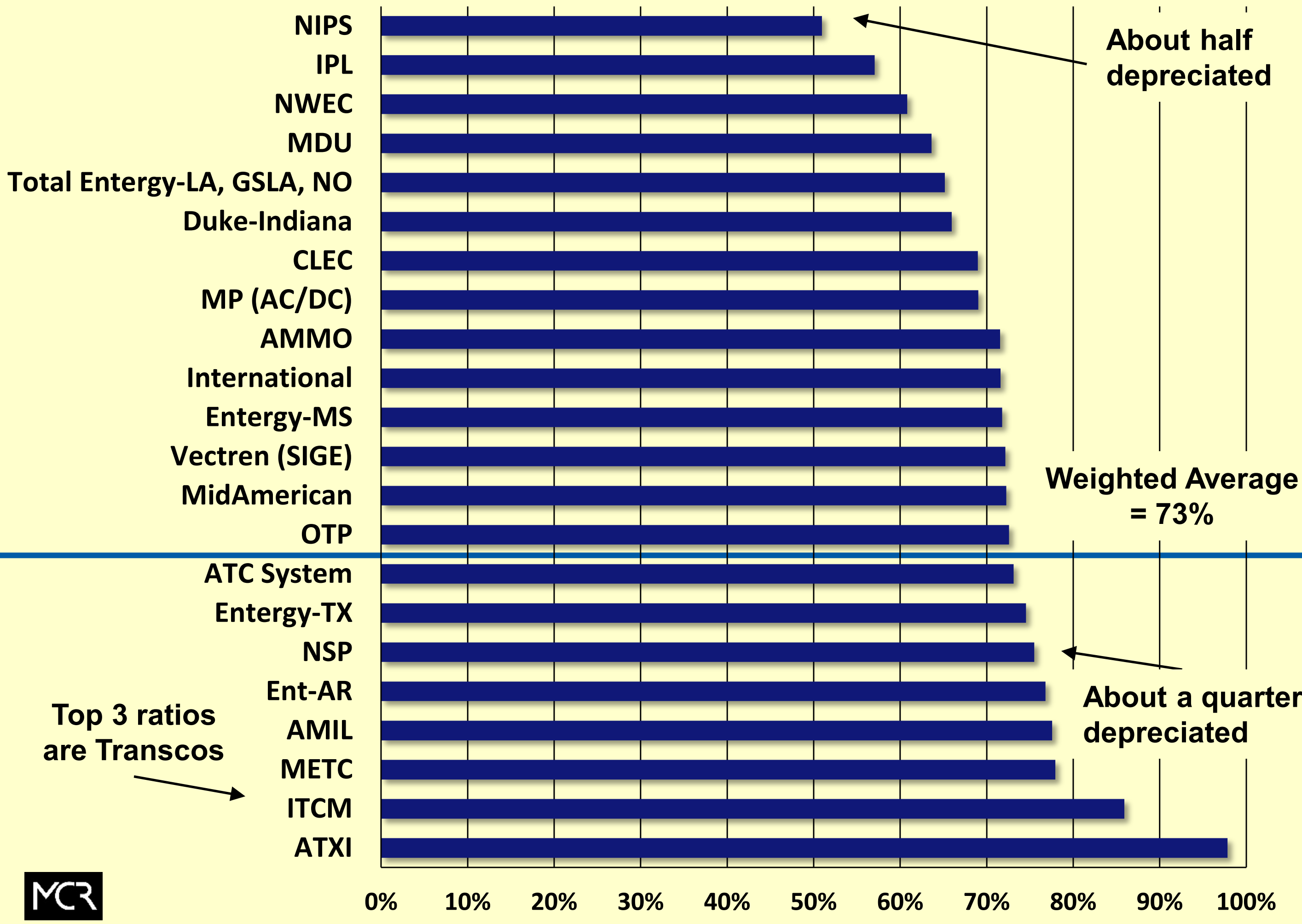
**Only 11 of 31 MISO municipals are investing at a level sufficient to replace their annual depreciation.**

In contrast, all IOUs/Transcos had ratios above 1.0 and 23 of 25 IOUs/Transcos had ratios above 2.5. Excluding Ameren Transmission Company of Illinois "ATXI", which is an outlier because it is a new company, the IOUs/Transco group ratio comes down to an average of 4.6 from 5.0.

Figure 11 provides another sign that IOUs/Transcos, G&Ts, JAAs and municipals have been investing over the years at much differing rates. It shows the ratio of net transmission plant to gross transmission plant and provides an indication of the age of each type of utility's transmission facilities. IOUs/Transcos, as a group, have the newest transmission assets with their combined net transmission plant equaling 73% of their gross transmission plant.

[17] Source: March 2017 MISO Attachment O Net Plant Tab, Above percentages are weighted averages of utilities in each group, e.g., total IOU and Transco transmission net plant divided by total IOU and Transco transmission gross plant.

*Figure 12*
*2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO IOUs and Transcos*




**Municipals have the oldest transmission plant with a net plant to gross plant ratio of 54%.**

Municipals have the oldest transmission plant with a net plant to gross plant ratio of 54%. Figure 12 shows the detail for each IOU/Transco. The three utilities with the highest ratio are all Transcos. Breaking out IOUs and Transcos into separate groups shows the IOUs have a weighted average ratio of 71% and Transcos 78%.

JAAs and G&Ts on average, are somewhat lower than the IOUs and Transcos at 68% and 66% respectively (see Figures 13 and 14). The G&Ts with the lowest ratio (an indicator of older plant) tend to be those where the G&T has their own pricing zone and where their load is a significant portion of the total in the pricing zone (e.g., Big Rivers Electric, Southern Illinois Electric Cooperative and Hoosier Energy)—see Figure 15. That is, a contributing reason to their relatively low level of investment may include receiving little or no "payments from others" for transmission investment as compared to a G&T that is part of a

*Figure 13*
*2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO JAAs*

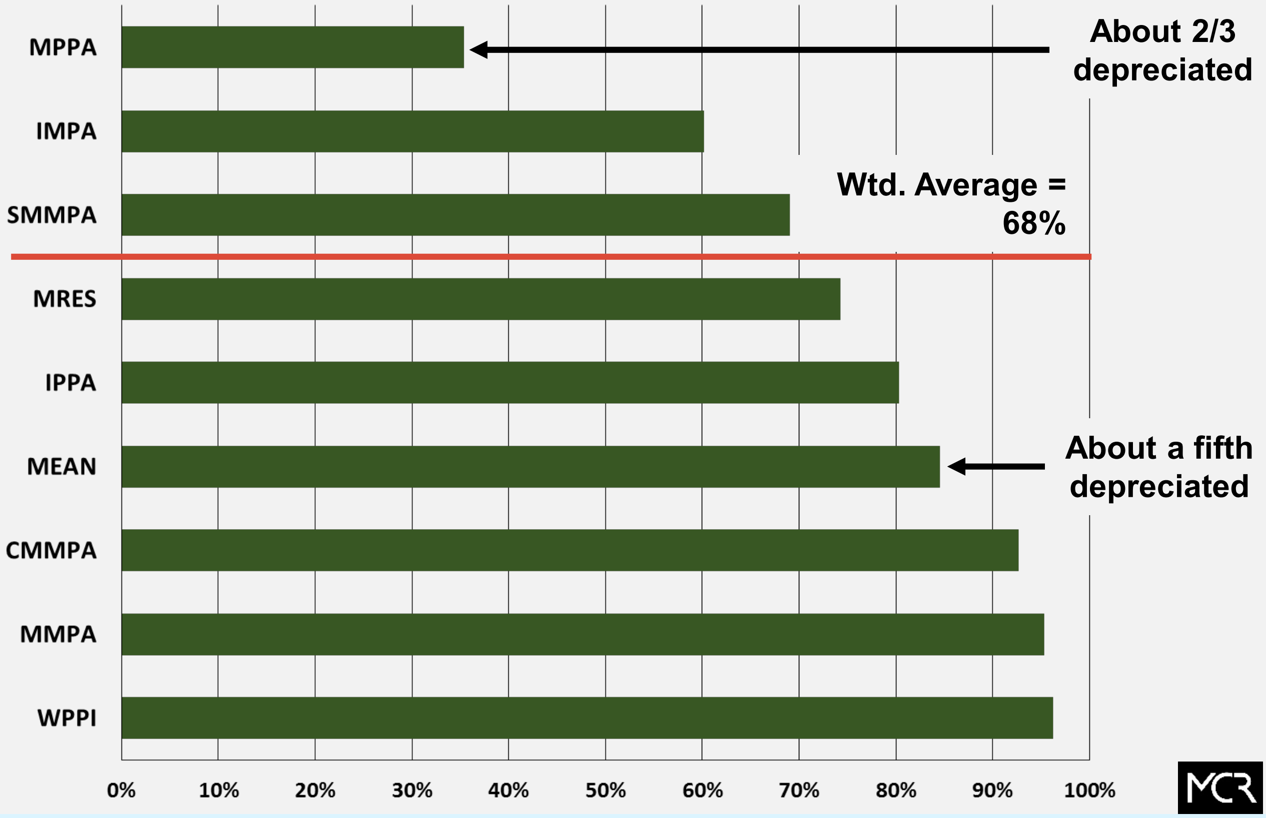



*Figure 14*
*2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO Municipals*

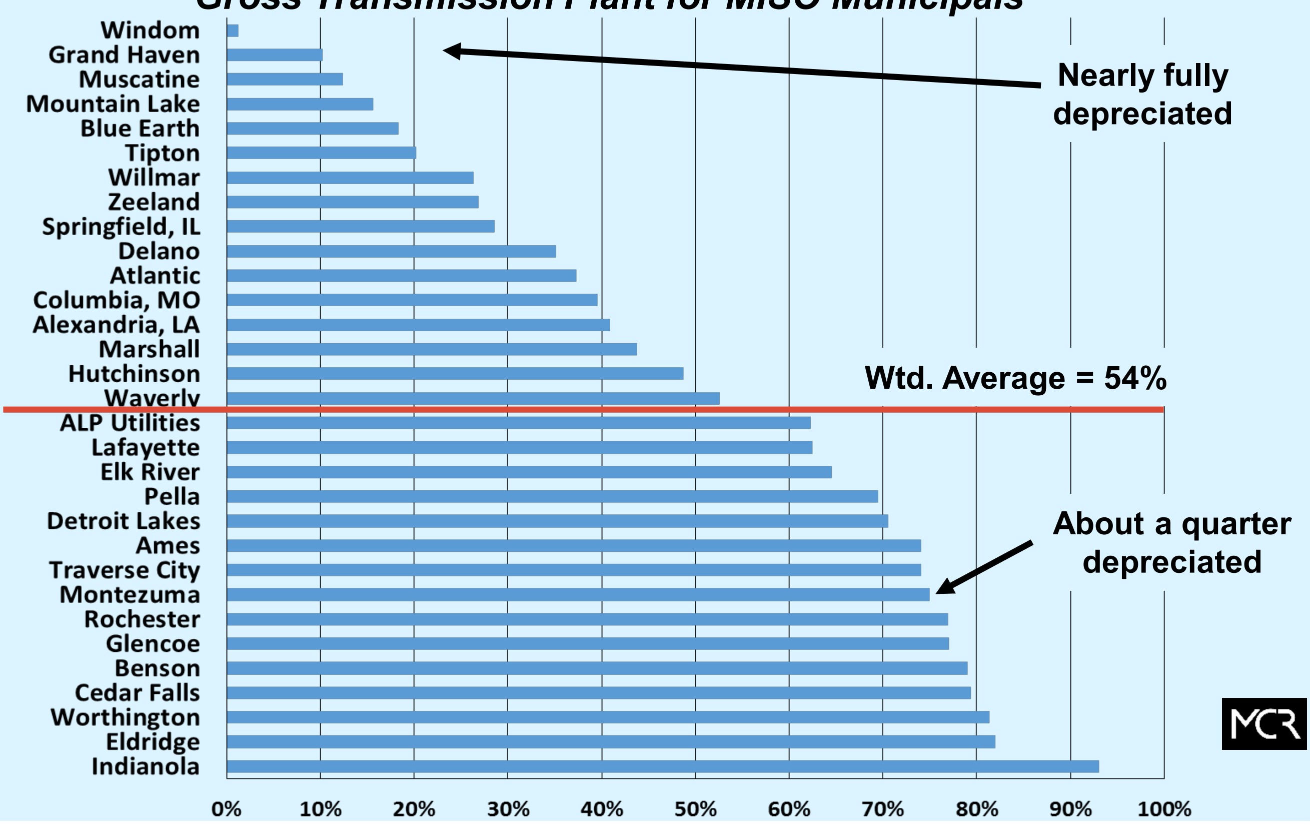
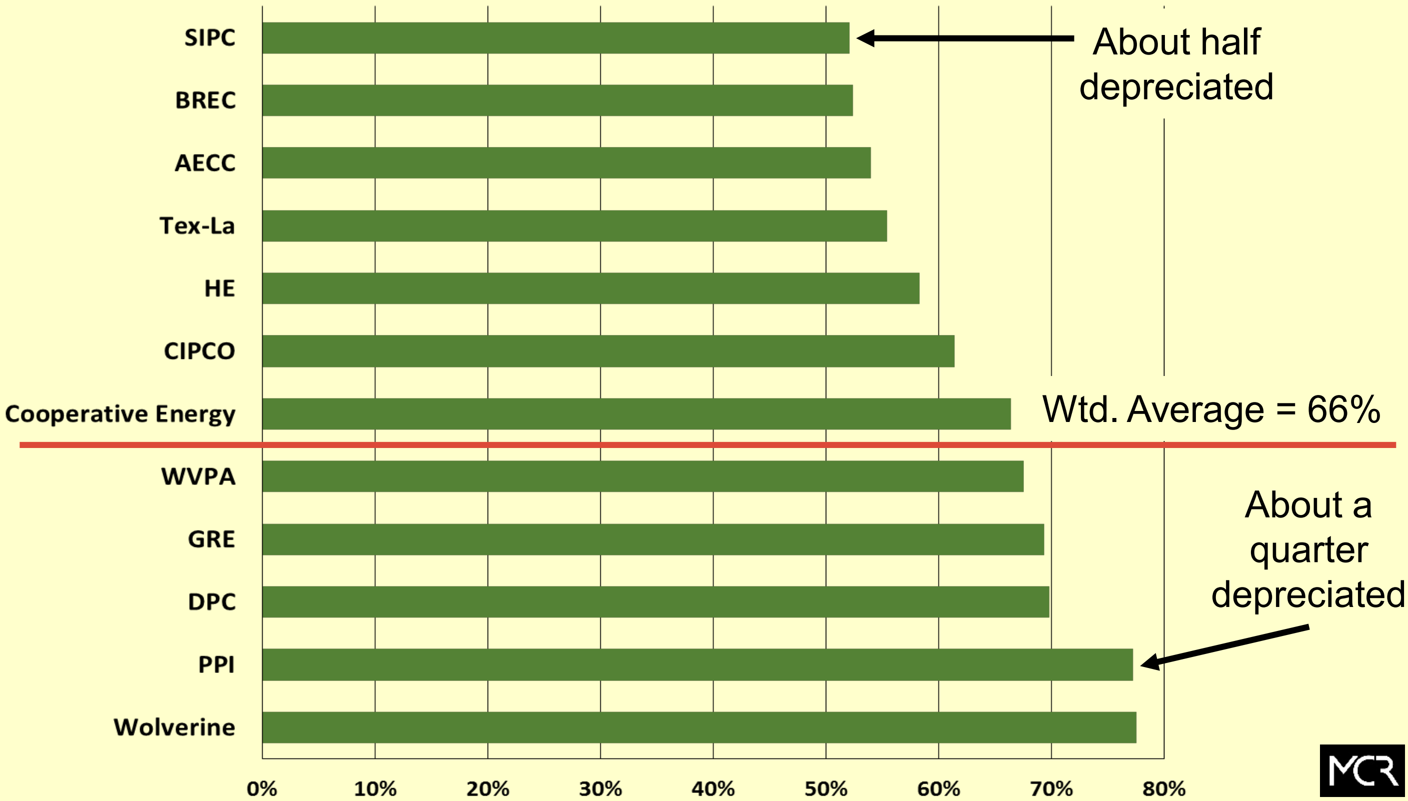


***Figure 15***
***2017 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO G&Ts***




**G&T and municipal groups in MISO have not been investing at a rate consistent with their load ratio share and likely have not been producing a sufficient level of transmission revenue to offset their transmission tariff costs.**

joint pricing zone and has a smaller portion of the total load in the zone. Wolverine and Prairie Power, both high investors, fall into this latter category. Other G&Ts with high levels of investment include GRE and Dairyland, who have had opportunities to invest in some cost-shared projects spread across pricing zones.

The bottom line is that overall, G&Ts and municipals in MISO are investing at a lower rate than IOUs/Transcos. Focusing on investment over the last four years, G&Ts represent about 11.5% of the 2017 MISO load for IOUs/Transcos, G&Ts and municipals, but only represent about 6.7% of the new transmission investment (see Table 1 on next page). Similarly, municipals represent about 2.2% of the total IOU/Transco, G&T and municipal load in MISO, but only represent .06% (just over one half of one percent) of the new transmission investment. That is, over the last four years, G&T and municipal groups in MISO have not been investing at a rate consistent with their load ratio share and likely have not been producing a sufficient level of transmission revenue to offset their transmission tariff costs. As a result, G&Ts and municipals may be disproportionately paying for a significant amount of transmission investment made by others.

**_Table 1_**
**_Comparison of Change in Gross Transmission Plant Balance to Current Load Ratio Share for MISO IOUs/Transcos, G&Ts and Municipals (2014-2017)_** [18]

| | 4-Year Change in Trans. Gross Plant Balance (Proxy for Cap Expenditures) ($ Millions) | % of Total Gross Plant Change | Estimated 12 CP Load[20] (MWs) | Estimated % of Total Load |
|---|---|---|---|---|
| IOU, Transcos | $12,870 | 92.7% | 86,238 | 86.3% |
| G&Ts | $924 | 6.7% | 11,480 | 11.5% |
| Municipals | $82 | 0.6% | 2,202 | 2.2% |
| Total | $13,876 | 100% | 99,920 | 100.0% |

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### The Impact of Transmission Investment on Rates

In order to understand how transmission projects increase rates, it is important to understand how costs are shared in transmission projects. That is, we need to look at whose customers pay for what portion of costs when a transmission project is built and put into service. Recently and over the next several years, a significant portion of the increase in transmission costs (and therefore the impact on transmission rates) will be due to 17 multi-value projects ("MVPs").

In 2012, the MISO Board approved a portfolio of MVPs (currently totaling about $6.5 billion) that are allocated based on MWh across all MISO North pricing zones. Per the MISO MVP Dashboard, as of the second quarter in 2017, four of the 17 projects are completed, eight underway and five are "pending."

Many of these projects are large (most are 345 kV), regional backbone projects and do not necessarily directly support local reliability needs at the sub-transmission level. The ability to invest in these types of large, cost-shared

[18] Sources: June 2013-2017 MISO Attachment O Net Plant Tabs and Report Tab from June 2017 for Load. Report Tab for load may be adjusted upward where the G&T's load is in multiple pricing zones, but the reported 12 month coincident peak load only reflects the G&T's load in their own pricing zone. Sources also include MCR estimates based on FERC Form 1, page 400, column e, "firm service for self" and RUS Form 12. Does not include T&D cooperatives and joint action agencies (some JAAs do not have load themselves or their member's load is addressed in the municipal group). Additional sources for municipal investment and load include audited financial statements and EIA form 861 Operational Data. Excludes Minnesota Power DC load.

projects significantly changed, however, with the introduction of FERC Order 1000 in 2012/2013, which requires that any newly proposed project that has a cost-sharing mechanism across pricing zones must be competitively bid rather than built by the local or nearby incumbents. As a result of FERC 1000, there is now a built-in incentive for a utility interested in investing in transmission to define a project as a “baseline reliability project” within its own zone as opposed to a “cost-shared project” in order to avoid the FERC Order 1000 competitive bid requirement. In fact, since FERC Order 1000 was approved, MISO has defined only two projects as cost-shared, thus requiring a competitive bid.[19]

Currently, there is a MISO cost allocation working group examining the question of whether the minimum voltage level for cost-shared projects should be reduced in order to make more projects eligible for competitive bidding. Barring rights of first refusal (which exist in Minnesota, South Dakota and North Dakota), lowering the eligible voltage level for cost-shared projects could reduce a local utility’s ability to invest in transmission projects. Regardless, it is still possible for public power entities and cooperatives that reside in a joint pricing zone with multiple TOs to benefit from cost sharing within its own zone by focusing on reliability projects within its own zone.

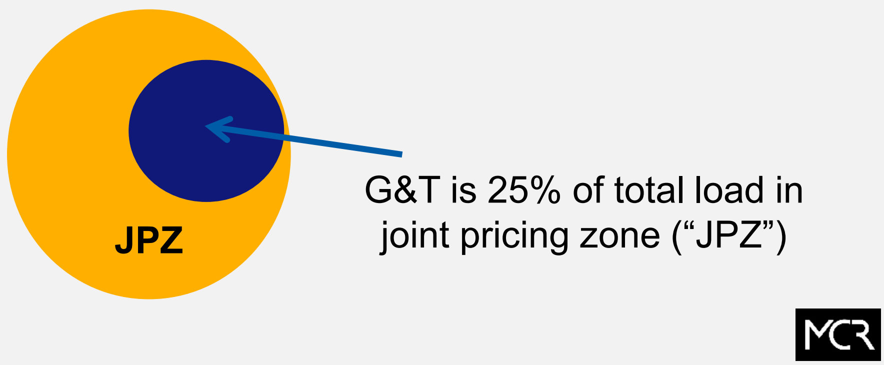
**Being a “small fish in a big pond” pays off.**

Consider the example of a G&T that has no counteracting grandfathered agreements and has the ability to invest in a necessary lower voltage transmission reliability project. This project is located in a pricing zone where the G&T has only 25% of the total load and the remaining load is split among an IOU (60%) and municipals (15%). In this case, being a “small fish in a big pond” pays off. The MISO tariff calls for the G&T’s project costs to be shared by all load in the joint pricing zone; thus, the revenue it obtains from the project will be paid 25% by its own cooperative members and 75% by the customers of the IOU and municipals (see Figure 16 on the next page). This creates an incentive for the G&T to invest in its own transmission projects rather than rely on the incumbent IOU to address the G&T’s transmission reliability issues in the zone. Even if the project was completed jointly with the IOU, the IOU in this example still has an incentive to invest, because their customers only pay 60% of the costs and the project increases the IOU’s rate base and earnings.

Although rates are determined by the total cost of service (including return, depreciation, transmission O&M and allocated A&G, property taxes and income taxes), the considerable transmission investment in MISO has correspondingly led to a significant rise in transmission rates for many pricing zones within

[19] The pending Huntley–Wilmarth 345 kV ($108M) project and the $50M Duff-Coleman project awarded in early 2017.

***Figure 16***
***Favorable Impacts of Load in a Joint Pricing Zone***




MISO.[20] Thus, transmission rates have become a significant and increasing portion of the total power bill. As investment increases, depreciation and the dollar return on rate base increase along with allocators.[21]

**There is an extremely wide range in the 2017 absolute transmission network rates ($1.49–$10.15) and the percentage rate increase since 2005 (-6% to 376%).**

Table 2 (on the next page) shows the average system-wide MISO network (Schedule 9) transmission rate has increased from $1.51 per kW/month in June 2005 to $3.26 per kw/month in June 2017, an increase of 116% or 6.6% compound annual growth. This compares with an average Consumer Price Index in the same period of only 2.2% per year. Compared to 2016, the system average rate for 2017 fell by a modest five cents per kW/month largely due to the reduction in the MISO-wide standard ROE.

Across the sampled pricing zones,[22] there is an extremely wide range in both the 2017 absolute transmission network rates ($1.49–$10.15) and the related percentage rate increase since 2005 (-6% to 376%). The top three percentage rate increases in the sample were for pricing zones that included Transcos (ITC-Midwest, Michigan Electric Transmission Company ("METC") and Ameren-IL, which includes ATXI). Note that these figures are only for Schedule 9 zonal projects, such as local reliability projects, and do not include cost-shared projects. Compared to last year, the Indianapolis Power & Light ("IP&L") zone showed a large percentage increase of 38% from $1.08/kW/month to $1.49 (still

[20] Pricing zones often consist of multiple participants. For example, the Duke Energy-Indiana ("DEI") pricing zone consists of assets from DEI, Indiana Municipal Power Agency and Wabash Valley Power Association.

[21] For example, the gross plant allocator used to allocate property taxes (or payment in lieu of taxes) to transmission will rise as transmission gross plant increases (all other gross plant being equal). Also, the wage and salary allocator based on transmission wages as a percentage of total functional wages will likely increase as gross transmission plant increases.

[22] Sampled pricing zones include those zones in existence from 2005. Also includes the MidAmerican ("MEC") and Dairyland Power pricing zones, which began in 2010. Due to an insufficient number of years of data, does not include the MISO South zones, which were established in 2014.

***Table 2***
***Transmission Schedule 9 Network Rate Increases[23]***
***MISO Average and Select Pricing Zones***
***2005-2017***

| Index/Pricing Zone | $/kW/Month | | | Cumulative % Change | Compound Annual % Increase |
|---|---|---|---|---|---|
| | **2005** | ***2010*** | **2017** | | |
| **Consumer Price Index** | | | | | **2.2%** |
| **MISO System Average** | 1.51 | | 3.26 | 116% | **6.6%** |
| **Otter Tail** | 3.39 | | 3.17 | -6% | **-0.6%** |
| **MDU** | 3.05 | | 3.14 | 3% | **-0.2%** |
| **S. IL Power Coop** | 2.20 | | 2.50 | 14% | **1.1%** |
| **NIPSCO** | 2.20 | | 3.81 | 73% | **4.7%** |
| **ITC** | 1.61 | | 2.90 | 80% | **5.0%** |
| **Hoosier** | 3.27 | | 6.06 | 85% | **5.3%** |
| **Duke-Indiana** | 1.25 | | 2.33 | 86% | **5.3%** |
| **IP&L** | 0.79 | | 1.49 | 88% | **5.4%** |
| **Ameren-MO** | 0.83 | | 1.61 | 93% | **5.7%** |
| **ATC** | 2.27 | | 4.79 | 111% | **6.4%** |
| **NSP (Xcel)** | 1.87 | | 4.15 | 122% | **6.9%** |
| **MN Power (Allete)** | 1.61 | | 3.69 | 129% | **7.2%** |
| **GRE** | 2.15 | | 5.12 | 139% | **7.5%** |
| **SIGECO (Vectren)** | 0.90 | | 2.58 | 188% | **9.2%** |
| **Ameren-IL** | 0.88 | | 2.73 | 211% | **9.9%** |
| **METC** | 0.98 | | 3.47 | 254% | **11.1%** |
| **ITC-Midwest** | 2.13 | | 10.15 | 376% | **13.9%** |
| | | | | | |
| **MidAmerican Energy** | | 1.82 | 2.53 | 39% | ***4.8%*** |
| **Dairyland Power Coop.** | | 3.55 | 6.37 | 79% | ***8.7%*** |

[23] Source: MCR Analysis based on June 2005 and 2017 Attachment O Files. MEC and DPC began as TOs in 2010. Excludes Entergy, CLECO, Cooperative Energy and Lafayette zones due to insufficient number of years of data but MISO system average rate does include these MISO South zones. 2017 rates do not include potential second MISO ROE rate refund.

a very low rate) and the Minnesota Power zone showed a 33% increase from $2.77/kW/month to $3.69. The ATC, Duke-Indiana, Otter Tail, Vectren and Xcel/NSP zones all showed decreases in their network rates, primarily due to the reduction of MISO-wide ROE from 12.38% to 10.82%, which includes the 50 basis point ROE adder for RTO membership.

With the impacts of cost-shared regional projects (Schedule 26 and Schedule 26-A[24]) layered on top of the Schedule 9 costs, the rate increases over the 12 year period become even more substantial. For example, when adding in the rate impact of cost-shared projects, MCR estimates the MISO system average rate increase jumps from 6.6% annually to 9.2% annually, with an even more stunning range of cumulative percentage increases of 16% to 440% across the sampled pricing zones (see Table 3 on the next page).[25] These cost-shared projects include the previously discussed 17 large MVPs[26] that are allocated based on MWh across all MISO zones using Schedule 26-A.[27] The estimated total cost of these MVP projects have increased about 23% from an initial estimate of $5.2 billion in the 2011 MTEP to the latest estimate of $6.5 billion in the 2017 preliminary MTEP. Cost-shared projects also include other Schedule 26 projects[28] that are cost-allocated 20% across MISO and 80% to local or adjacent zones based on load flow.[29]

**When adding in the rate impact of cost-shared projects, the annual average MISO system rate increase jumps from 6.6% to 9.2%, with an even more stunning range of cumulative percent increases of 16% to 440% across the sampled pricing zones.**

For the combined estimated total transmission rate per kW month for schedules 9, 26 and 26-A, the ITC-Midwest pricing zone has the highest rate at $11.51; IP&L zone has the lowest rate at $2.33; and the overall MISO system average is $4.35. The Otter Tail, Ameren-MO, Vectren, IP&L, Minnesota Power and METC pricing zones attribute large portions of their total transmission rate to Schedule 26 and 26-A charges. For example, these cost-shared charges comprise about 43% of the total Schedule 9, Schedule 26 and Schedule 26-A rates for the Otter Tail pricing zone and 39% for the Ameren-MO pricing zone.

[24] Schedule 26 (recovered through Attachment GG) began in 2007 and Schedule 26-A (recovered through Attachment MM) began in 2012.

[25] MISO publishes indicative charges for both Schedule 26 and 26-A. Schedule 26 is in $/kW/month whereas Schedule 26-A is in $/MWh. Note that MCR converted the MVP (Schedule 26-A) charges to a kW/month basis by taking the total zonal Schedule 26-A charges divided by the zonal 12CP kW/12 to place Schedule 26 and 26-A on an equal basis of $/kW/month.

[26] See 2017 MTEP MISO MVP Dashboard.

[27] The MWh for calculating the rate per MWh has included exports and wheel-throughs, excluding those that sink in PJM. On July 13, 2016, however, FERC ruled that MVP costs should also be applied to MWh that sink in PJM.

[28] These Schedule 26 projects were mainly Regional Expansion Criteria and Benefits (“RECB”) projects, but also included generator interconnection projects and market efficiency projects. Post FERC Order 1000, Schedule 26 has fewer projects and only includes generator interconnection and market efficiency projects. MISO has convened a stakeholder working group to review cost allocation and eligibility criteria for these types of projects.

[29] The local portion of the allocation (80% of total) is now allocated based on MISO Resource Zones.

***Table 3***
***Total Estimated Transmission Rate Increases[30]***
***MISO Average and Select Pricing Zones (Schedules 9, 26 and 26-A)***
***2005-2017***

| Index/Pricing Zone | $/kW/Month | | | Cumulative % Change | Compound Annual % Increase |
|---|---|---|---|---|---|
| | 2005 | *2010* | 2017 | | |
| **Consumer Price Index** | | | | | **2.2%** |
| **MISO System Avg** | 1.51 | | 4.35 | 188% | **9.2%** |
| **S. IL Power Coop** | 2.20 | | 2.54 | 16% | **1.2%** |
| **MDU** | 3.05 | | 4.19 | 37% | **2.7%** |
| **Otter Tail** | 3.39 | | 5.57 | 64% | **4.2%** |
| **Hoosier Energy** | 3.27 | | 6.39 | 95% | **5.7%** |
| **NIPSCO[31]** | 2.20 | | 4.81 | 119% | **6.7%** |
| **ITC** | 1.61 | | 3.88 | 141% | **7.6%** |
| **Duke-Indiana[32]** | 1.25 | | 3.20 | 156% | **8.6%** |
| **ATC** | 2.27 | | 6.36 | 180% | **9.0%** |
| **IP&L** | 0.79 | | 2.33 | 195% | **9.4%** |
| **NSP (Xcel)** | 1.87 | | 5.79 | 210% | **9.9%** |
| **GRE** | 2.15 | | 6.76 | 215% | **10.0%** |
| **Ameren-MO[33]** | 0.83 | | 2.63 | 216% | **10.1%** |
| **MN Power (Allete)** | 1.61 | | 5.62 | 249% | **11.0%** |
| **Ameren-IL[34]** | 0.88 | | 3.66 | 318% | **12.7%** |
| **SIGECO (Vectren)** | 0.90 | | 4.06 | 353% | **13.4%** |
| **METC** | 0.98 | | 5.26 | 437% | **15.0%** |
| **ITC-Midwest** | 2.13 | | 11.51 | 440% | **15.1%** |
| | | | | | |
| **MidAmerican Energy** | | 1.82 | 3.25 | 78% | **8.6%** |
| **Dairyland Power Coop.** | | 3.55 | 6.65 | 87% | **9.4%** |

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[30] 2017 rates based on latest available MISO Attachment O of June, 2017 and indicative MISO Schedule 26 and 26-A rates. MISO Schedule 26-A indicative rate is based on $ per MWh. MCR converts this to $ per Kw/Mo. Note that 2017 rates do not include the potential second MISO ROE refund still awaiting FERC review.

[31] GridAmerica-Northern Indiana Public Service in 2005/2006 and NIPSCO thereafter.

[32] For 2005, calculated based on Duke-Cinergy. Includes IMPA and WVPA.

[33] GridAmerica-Ameren (included AmerenUE and AmerenCIPS) in 2005/2006 and Ameren-MO thereafter.

[34] For 2005, calculated as the weighted average of the CILCO and Illinois Power pricing zones. In 2007, includes CIPS.

Interestingly, member load of select G&Ts with grandfathered agreements (e.g., Hoosier Energy, Dairyland, Southern Illinois Power Cooperative and Big Rivers Electric) has been exempted from Schedule 26 and 26-A charges in their pricing zones as FERC ruled that transmission expansion and transmission upgrades were not substantially different than the types of bundled services traditionally offered by these companies to their full requirements members.[35]

MVPs have been particularly attractive investments, because the entity(s) making the investment receive(s) a healthy return on these investments, but pay(s) only their load ratio share of the entire MISO load.[36] Where else could someone make 10.82% return on their equity[37] and typically have 90% or greater of their project revenue paid for by customers other than their own?

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

## How Public Power and Cooperatives Can Create Value from Transmission Investment

As discussed previously, IOUs can create value for shareholders through transmission investments by increasing rate base, thus a major contributor to incremental earnings growth. The business model of G&Ts, joint action agencies and municipals, of course, is much different than IOUs in that G&Ts and JAAs are owned by their member-customers. Similarly, municipals are owned by their customers. For example, generating higher earnings for a JAA does not necessarily create value for a member if the increased earnings are fully paid by the member owners—this is simply moving money from the "left pocket to the right pocket." Ultimately, what matters is whether the public power entity or cooperative is creating real value for its members/customers.

While there is no "one size fits all" answer for all public power and cooperative utilities to create value from transmission, 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 customers other than a utility's own 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

[35] 138 FERC ¶ 61,142, February 28, 2012 P. 41.

[36] MVPs are allocated based on MWh. MISO South companies are exempt from most cost-shared projects in MISO North for a transition period likely ending after MTEP18.

[37] The MISO standard ROE is likely being reduced pending Commission approval of the second ALJ decision. The ALJ for the second MISO ROE complaint recommended a 9.7% base ROE, excluding the RTO membership adder of 50 basis points, which is in place for most TOs.

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 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.

**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.**

**1. Revenue from any existing transmission assets**—Each G&T or public power entity, regardless if they are currently a TO or contemplating becoming a new TO 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. Other customers pay a portion of costs**—As mentioned previously, MISO cost-shared projects (e.g., MVPs) have been particularly attractive investments, because a large portion of the total costs are paid by other customers. However, these types of regional projects have begun to be competitively bid. Despite this, lower voltage, local reliability projects in a joint pricing zone can still be financially attractive, because the costs are paid by all customers in the pricing zone.[38] 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 public power and cooperatives 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.

**3. Substantial returns, higher than the cost of capital**—Because public power and cooperatives currently have a very low incremental cost of capital (e.g., Rural Utilities Service ("RUS") long-term debt can be less than 2% and public power tax-exempt debt is about 3.25%), these utilities can produce substantial margin from a transmission investment. The larger the investment, the larger the dollar margin. The overall return in MISO is based on a weighted average of debt and equity. The percentage equity on the balance sheet is combined with the MISO ROE and the percentage long-term debt is combined with the average, historical cost of debt. For example, the average municipal in

[38] This may not be the case if the participants in the zone have contractual true-up features with payments that equalize investment based on load ratio share.

MISO has an equity ratio of about 80%. This produces an overall municipal rate of return of about 8.85%[39] vs. an incremental market cost of debt of only about 3.25%, resulting in a margin of about 5.6%, which is very high in today's low interest rate environment. This margin can be used to help partially offset the rising transmission rates faced by all municipals.

FERC has consistently encouraged public and cooperative power investment in various landmark orders, such as FERC Orders 2000, 890, 1000 and 679.[40] Indeed, under Order 679, G&Ts and JAAs have applied at FERC for rate incentives, such as a hypothetical capital structure, for certain types of projects. For example, WPPI Energy was granted a hypothetical capital structure of 45% equity for its portion of the Hampton-Rochester-La Crosse investment and 50% equity for its investment in the Badger-Coulee project. This raised its overall return and margin on these investments, because the ROE for the project costs is calculated on a higher amount of equity than WPPI's actual equity ratio at the time of about 32%. FERC requires, however, that each incentive request under Order 679 be analytically substantiated based on, for example, the company's unique financial characteristics and credit rating impacts on the utility plus the risks of the project. Given the high returns available to public power and cooperatives, it makes sense to own transmission rather than "rent."

**Because public power and G&Ts currently have a very low incremental cost of capital, these utilities can produce substantial margin from a transmission investment.**

**4. Enhanced reliability at the local level**—Public power and cooperatives can focus their investment to improve reliability of its member/customers. Although these utilities are paying for large, regional backbone projects, such as the MISO MVPs, these projects do not necessarily penetrate 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 that can be undertaken to improve local reliability include:

- Looping a radial line and connecting to the MISO 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

[39] Assumes 10.2% total ROE reflecting the second ALJ recommendation of 9.7% ROE plus 50 basis point adder for RTO membership, 80% equity, 3.5% average historical cost of debt.

[40] For example, Order 679 states, in part: "We agree with comments that public power participation can play an important role in the expansion of the transmission system….the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities … for a particular joint project."

- Investing in a new or spare transformer
- Deploying fiber optics for transmission purposes

**5. Improved wholesale access and/or lower congestion costs**—Public power and cooperatives can participate in projects to better interconnect to the MISO 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.

**G&Ts, joint action agencies and many municipals have significantly lower revenue requirements than IOUs and Transcos for the same level of transmission investment.**

**6. Lower revenue requirements for the same transmission investment**—G&Ts, joint action agencies and many municipals have significantly lower revenue requirements than IOUs and Transcos for the same level of transmission investment. For example, assuming that a G&T's or JAA's incremental operation and maintenance expense to service a new transmission investment is comparable to an incumbent, their revenue requirement will be considerably lower than the IOU's. The revenue requirement will be lower because:

- Cooperatives and public power do not pay state or federal income taxes; whereas IOUs do pay income taxes and those costs are included in the IOU's cost of service.
- The typical equity ratio for G&Ts and joint action agencies is lower than IOUs and Transcos (median of 28% and 25% for G&Ts and JAAs vs. 53% for IOUs/Transcos), so the G&T's and JAA's weighted average cost of capital, which is also referred to as the overall rate of return, is lower.
- The cost of incremental long-term debt is typically lower for the JAA than an IOU, because it is tax-exempt and can be lower for a G&T or T&D cooperative if it finances through the RUS.

For the same investment, and assuming a 10.2% ROE, the typical IOU/Transco's revenue requirement is about 40% higher than the typical G&T and JAA.[41]

This means for example, that if the IOU's incremental revenue requirement for a

[41] Source: MCR analysis and MISO August, 2017 Attachment O file. Assumes median equity ratio for MISO G&T and JAAs of 26.8% with median historical cost of debt of 4.8%. Equity ratio for IOU/Transco assumes a median of 52.7% with a 4.6% median historical cost of debt. Assumes same incremental O&M and other taxes estimated at 3.25% of gross transmission plant for incremental investment. Assumes combined IOU/Transco federal/state income tax rate of 39%. Assumes 10.2% ROE (9.7% plus 50 basis point RTO adder). Under certain circumstances, G&Ts and joint action agencies can apply to FERC for a higher equity ratio in order to increase their return on a particular project investment, which would lower but not eliminate the difference in revenue requirement. For example, with a 45% hypothetical equity ratio for a G&T and a 10.2% total ROE, the ATRR difference is about 30%.

particular transmission investment is $1.4 million, the corresponding G&T or JAA's revenue requirement is $1 million for the same investment. The difference in revenue requirements between IOUs/Transcos and municipals is not as stark but still significant. A lower revenue requirement translates into a lower rate for members and customers. Therefore, it makes sense to be a sole or major investor in all projects affecting load.

## Moving Forward with a Business Plan

Actively participating in today's transmission investments requires public power and cooperatives to initiate a mindset change that begins with a vision, ambition and plan for the transmission business. This mindset reflects being an owner rather than renter and "going on offense" with regard to transmission. The transmission business plan is the starting point and it covers the unique ways each public power or cooperative utility will create value for its members and customers. This requires wringing out existing transmission assets for every inch of value and proactively identifying opportunities for new transmission investment. Upgrading an aging transmission system and obtaining a "rightful share" of new transmission has become an imperative as industry factors continue to drive rapid increases in transmission rates and become a significant portion of the customer's total power bill.

# APPENDIX

## The Need for Additional Transmission Investment

The need for additional transmission investment across the US is being driven by many policy and operational factors

**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] 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).

[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.

**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 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 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 provides an economic advantage to expand transmission in order to lower delivered power prices.

**Generation Retirements from EPA Rules**—Retirements of older coal units due to more stringent environmental rules from the Environmental Protection Agency ("EPA") 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.

# ABOUT THE AUTHORS

**Jim Pardikes** is a Vice President at MCR and leads the Transmission Strategy Practice. He has over 30 years of experience consulting to the utility industry, including public power, G&Ts and IOUs. His expertise includes electric transmission cost recovery, public power cost of capital and capital project economic evaluation. Jim has extensive experience in providing expert transmission testimony for public power utilities and G&Ts, facilitating client working teams and presenting to executive management and Boards of Directors. Jim has written extensively on transmission-related topics, such as factors in RTO membership, the value of transmission investments and making the case for transmission incentives. Jim can be reached at jpardikes@mcr-group.com.

**Ron Kennedy** is a Director with MCR. He has 15 years of experience in consulting to the utility industry, including G&Ts, public power and IOUs. His expertise includes development and review of formula rate transmission cost data, RTO protocol compliance, FERC filings for Section 205 rate changes and transmission rate incentives, economic evaluation of RTO membership, and financial and risk evaluation of major transmission projects. Ron is experienced in presenting to executive teams and Boards of Directors. Ron can be reached at rkennedy@mcr-group.com.

**Chris Nagle** is a Consultant with MCR. He has over a decade of experience in transmission proceedings, rates and regulatory affairs. His expertise includes rate development, cost recovery and cost allocation. He has testified as an expert witness before public service commissions. Prior to joining MCR, Chris held numerous positions in rates and cost allocation at a major electric utility. Chris can be reached at cnagle@mcr-group.com.

# 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 SPP and PJM.
- Formula Rate Diagnostic for Existing TOs. MCR reviews costs for formula rate filings to optimize revenue, properly record costs and ensure documentation withstands 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 changes to the formula rate and FERC filings for projected test years and regulatory asset recovery.
- 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.

**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.

**MCR PERFORMANCE SOLUTIONS**
www.mcr-group.com
Tel: 847.562.0066
Fax: 847.562.0077

155 N. Pfingsten Rd., Suite 155
Deerfield, IL 60015