2021 MISO Transmission Investment and Rate Analysis

MISO Transmission Rates in Joint Zones

Will the Transmission Rate Express Train Continue?

November 2021

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MCR's Sixth Annual Transmission Investment and Rate Analysis for MISO Transmission Owners

Also Includes MCR's Five-Year Rate Projections by Joint Pricing Zone

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1. Executive Summary

MISO transmission rates have been rapidly escalating only to slow in recent years as transmission investment growth has moderated, the number of new transmission owners slowed, and the impacts of the corporate tax cut have played out. In 2021, however, MISO average transmission zonal rates increased by a stunning 17.7%, largely due to a 7.2% increase in transmission investment, a 4.1% decrease in load and the ending of deferred tax refunds. Looking to the next five years, MCR forecasts that zonal rates in joint pricing zones will increase by an average of 6.5% per year, well above the projected five-year inflation rate of 3.17%. We forecast that nine of the 20 joint pricing zones in MISO will see average annual rate increases over the next five years of at least 7%. These forecasted rate increases result from an expanding rationale for transmission investment as "resiliency" combines with social, political and regulatory changes; increasing capital, O&M and A&G costs due to rising inflation; and a continued hunger for earnings growth by IOUs and Transcos. The only way public power and cooperatives can protect their members and customers from the MISO "express train" of rising transmission rates is to develop a business plan to ramp up recoverable transmission investment that increases reliability, ensure no revenue is being left on the table by optimizing the transmission formula rate, and provide other transmission investing benefits to members and customers that make the impact of rising transmission rates more palatable.

2. Escalating MISO Zonal Transmission Rates

A few years ago, one MCR public power client compared the escalating MISO transmission rates to an out-of-control express train. MCR's annual tracking of zonal rates in MISO shows this rate history and how this train has slowed in the last couple of years only to accelerate again over the last year. It is also interesting to see the transmission zonal rate history viewed through five-year slices and their associated compound annual growth rates ("CAGR"). The systemwide CAGR for MISO Schedule 9 zonal rates from 2005-2021 was 6.4%, increasing from $1.51 to $4.07 per kW month (see Figure 1 below). The period from 2005 to 2010 experienced the highest CAGR of 8.0%; some zones were much higher than this average and other zones were lower.

This tremendous growth in average MISO zonal rates since 2005 coincides with the unleashing of transmission investment facilitated by more certain cost recovery in formula rates under the MISO tariff and the addition of new transmission owners ("TOs") in MISO.[1] Along with new transmission owners joining existing pricing zones, MISO added seven new pricing zones during this period of rapid expansion.[2] MISO zonal rates continued to increase at a CAGR of 4.6% during the 2010 to 2015 window, much higher than the

[1] As discussed later in this paper, the zonal rate will rise if the effective "rate" (ATTR/load) of new TOs is higher than the existing zonal rate.

[2] MISO added the Ameren Missouri ("AMMO"), METC subzone, NIPSCO, SMMPA, MEC, MPW and DPC pricing zones during this period.

Figure 1
Average MISO Systemwide Zonal Rate Increase by Time Period

Time Period	Average MISO Zonal Rate Percentage Increase	Consumer Price Index Average Increase
2005-2021	6.4%	2.4%
2005-2010	8.0%	2.4%
2010-2015	4.6%	1.7%
2015-2020	3.3%	1.8%
2021	17.7%	6.2%

Figure 2
Zonal Rate Comparison
Single Member Zone vs. Joint Pricing Zone

Time Period	Average Rate for Zones with Single TO Member ($/kW)	Average Rate for Joint Pricing Zones ($/kW)
2005	$1.84	$1.83
2010	$2.16	$2.77
2020	$3.09	$3.58
2021	$3.55	$4.16

average inflation rate of 1.7% during that timeframe. The increase in zonal rates tapered a bit in the 2015 to 2020 window to a CAGR of 3.3% reflecting the impact of the corporate tax rate cut and reductions in the standard MISO return on equity ("ROE") percentages, but still higher than the average inflation rate of 1.8%. The MISO rate express train slowed a bit as these factors dampened the growth of the Annual Transmission Revenue Requirements ("ATRR"), particularly for investor-owned utilities ("IOUs") and Transco transmission owners. In 2021, however, zonal rates dramatically increased by 17.7% primarily due to increases in transmission investment, a decrease in load and the end of deferred tax refunds (see Section 8 of this white paper).

In 2021, zonal rates dramatically increased by 17.7%.

Comparing the rate history of joint pricing zones ("JPZs") versus pricing zones with a single transmission owner in MISO reveals the results of the different investment dynamics between these two types of pricing zones. In a JPZ, a TO's transmission investments and costs are shared with all the load, including the loads of the other TOs in the zone, so long as those transmission facilities are integrated with the transmission network. This zonal cost sharing incentivizes transmission investment, because other utility customers pay a portion of the TO's costs. By contrast, in a single member pricing zone, any new transmission investments and costs are borne entirely by that TO's own load, thus making the economics of transmission investment much less attractive.

In 2005, the average zonal rate in a MISO pricing zone with a single TO member was $1.84 per KW month. The average zonal rate for a joint pricing zone in MISO was nearly identical at $1.83 per KW month (see Figure 2 above). These rates began to diverge during the period of 2005 to 2010. For a single TO zone, the average zonal rate increased to $2.16 per KW month or about a 17% increase, whereas the average zonal rate in a joint pricing zone increased to $2.77 per KW month, a staggering 52% increase. In other words, the average MISO transmission ratepayer was paying 28% more for transmission service by being in a JPZ in 2010. By 2020, this divide tempered a bit. The average zonal rate for a single TO pricing zone was $3.09 per KW month compared to an average of $3.58 per KW month for a JPZ in MISO or a 16% difference.

This difference between the two types of zones from 2010-2020 primarily narrowed because of two reasons: 1) there has been more recent investment in a few of the single TO pricing zones driven by facility replacements of highly depreciated assets with higher cost replacements and upgrades (e.g., Muscatine Power and Water in Iowa) and 2) many of the joint pricing zones in MISO are dominated by IOUs and Transcos, whose dominant zonal ATRRs have been reduced by the corporate tax cut and ROE reductions (e.g., METC, Ameren-IL, ITC-Midwest). By contrast, many of the single zones are municipals (e.g., City Water, Light & Power in Springfield, IL) or generation and transmission cooperatives (e.g., Southern IL Power Cooperative); thus, they saw no rate benefit from the reduction in the corporate tax rate and the ensuing flow-through of refunds for accumulated deferred income taxes. The deferred tax refund benefit for most IOUs and Transcos in JPZs, however, has now run its course. As we saw in 2021, and going forward, the change in rates will largely be driven by changes in investment levels and expenses. In fact, in 2021, the gap in average zonal rates widened again. The average zonal rate for a single member pricing zone was $3.55 per KW month whereas for a JPZ, the average zonal rate was $4.16 per KW month or a 17% gap in average rates.

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This history not only illustrates the difference in how rates have trended in single member pricing zones versus joint pricing zones but provides insight into what can be expected in the near future. The divergence in zonal rates between single member zones and joint zones largely reflects the different economic incentives for transmission investment for the TOs in these zones. This look back on zonal rates provides an indication that future investment growth may be slanted toward JPZs and informs expectations about MISO zonal rates in the future.

3. The Cost Factors Driving the Rise in Zonal Rates

What is driving the increases in rates? The increase in zonal rates in MISO over the years is primarily the result of the relentless growth in transmission investment by TOs and the overall growth in the number of TOs now recovering costs in MISO rates without a proportionate increase in load. As shown consistently in past MCR white papers[3] and again in this whitepaper,

[3] See for example, “The Eight Drivers of Increased Tension between IOU/Transco Incumbents and Other TOs in a Joint Pricing Zone—Pushing Back Against the Incumbent IOU/Transco in a MISO JPZ,” November 2020; “The Seven Potential Threats to the Transmission Business—Is Transmission in MISO Still a Solid Business?,” October 2019; and “No End in Sight—Can Transmission Investment in MISO Continue at this Pace?,” December 2018.

Figure 3
Average Annual Percentage Expense Increase by MISO Segment 2016–2021

	G&T	JAA	IOU/Transco	Municipal
O&M	7.3%	8.1%	1.7%	2.5%
A&G	13.7%	6.9%	0.8%	2.0%
Other Taxes	11.1%	19.8%	8.8%	2.1%
Income Taxes	------	------	(5.7%)	------

the drumbeat of transmission investment goes on. This is especially true for IOUs and Transcos, which see transmission investment as a prime driver of earnings. However, the dollar return on rate base from the expanding MISO transmission plant is not the only cost recovered in transmission rates and therefore not the only factor contributing to the upward climb in zonal rates.

IOUs and many Transcos realize economies of scale from operating and maintaining larger transmission systems and more urban systems.

In addition to the investment analysis shown in Section 10, MCR analyzed the change in the different cost components of a sample of TOs' Attachment Os in MISO from 2016 through 2021 to understand how these components were impacting the ATRR of the different segments of MISO TOs (see Figure 3 above). Interestingly, generation and transmission cooperatives ("G&Ts") and joint action agencies ("JAAs") are the two transmission owner segments that realized the largest increases in annual expenses over the last five years. The O&M 5-year CAGR was 7.3% for G&Ts and 8.1% for the JAAs. By comparison, the IOU and Transco segment realized an O&M 5-year CAGR of only 1.7%. IOUs and many Transcos realize economies of scale from operating and maintaining larger transmission systems and serving more urban systems, as they can leverage certain existing fixed O&M costs, such as supervision and management, and control centers across a larger set of assets and load. Additionally, IOUs and especially Transcos have newer facilities that require less O&M, as demonstrated by a comparison of the ratio of net transmission plant to gross transmission plant (see Figure 30 of Section 10 for segment comparisons).

G&Ts and JAAs

In addition to their high O&M growth rates, G&Ts and JAAs also led the way in the growth of Administrative and General Expense ("A&G") and Taxes Other Than Income Taxes ("TOTIT") expense. G&Ts and JAAs realized high 5-year CAGRs from 2016 through 2021 of 13.7% and 6.9%, respectively, in A&G recovered in their ATRRs. Similarly, the G&Ts and JAAs realized 5-year CAGRs of 11.12% and 19.77%, respectively, in the TOTIT expenses recovered in their ATRRs. These expenses are generally incurred on a companywide basis and utilize the Attachment O formula rate to allocate the amount of costs to the ATRR. As a TO's assets and wages are increasingly weighted toward transmission, more of these TOTIT and A&G expenses are allocated to the ATRR. As G&Ts and JAAs divest more of their asset-intensive generation and replace them with purchased power agreements while at the same time continuing to invest in new transmission assets, their Attachment O allocators become more heavily weighted to transmission and thus pull more of these A&G, TOTIT and other common costs into the ATRR. Over the last five years, the G&T average Wages & Salary Allocator ("WSA") has increased from 24.3% to 28.6% and the average Gross Plant Allocator ("GPA") has increased from 19.3% to 24.2%.

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Examples in the 2016-2021 time period include:

- Prairie Power's WSA grew from 17.7% to 29.0%
- Wabash Valley Power's WSA went from 14.9% to 35.6%
- Prairie Power's GPA doubled from 7.4% to 14.8%
- Wabash Valley Power's GPA went from 14.2% to 25.3%

The JAAs have realized an increase in their average WSA of 11.4% in 2016 to 14.8% in 2021 whereas their average GPA actually decreased from 20.6% in 2016 to 15.9% in 2021.[4]

IOUs and Transcos

In stark contrast, the IOUs and Transcos have seen only modest growth with an A&G 5-year CAGR of only 0.8%. This is largely from IOUs having less movement in their allocators and often spreading their corporate A&G costs out among multiple operating companies. Moreover, Transcos recover 100% of their A&G because they usually only have transmission assets; therefore, once a Transco establishes its staffing, its A&G expense is relatively stable because their allocators are 100% (or near 100%). Despite the modest CAGR for IOUs and Transcos, A&G expense is still a large cost; and a small percentage increase to A&G still adds to the rise in MISO zonal rates. Regarding TOTIT, IOUs and Transcos had an 8.8% CAGR, largely mirroring the increase in property taxes as transmission investment increases.

The income tax expense for IOUs and Transcos reflect the decrease in the corporate income tax rate from 35% to 21%, effective in 2018. Over the last five years, this TO segment realized a 5-year CAGR decrease of 5.7% in income tax expense, which has been a bright spot for transmission ratepayers in MISO. Accompanying this decline in income tax expense has

[4] JAAs have a small sample size. The average was lower primarily due to Missouri River Energy Service putting a large hydroelectric generating plant into service.

been the required refund of accrued excess balances of Accumulated Deferred Income Taxes ("ADIT") included in the IOU and Transco ATRRs, again as result of the corporate income tax reduction. However, these ADIT refunds have largely run their course and the segment's ADIT balances have begun building again. IOUs and Transcos have seen a CAGR increase of 9.0% in their ADIT balances over the last three years reflecting the end of accumulated ADIT refunds associated with the tax rate decrease and the continued investment in transmission by these TOs.

Municipals

The municipal TO segment has seen more modest growth in O&M, A&G and TOTIT expenses over the last five years of about 2% to 2.5%. As shown in the transmission investment data in Section 10, Figures 27 and 28, the municipal TO segment has not been aggressive in their transmission investment. Despite this, there have been some notable trends for municipals. The municipal segment's average equity ratio has improved due to a strong economy and more municipal utilities with higher equity ratios joining MISO. Higher equity percentages reflect the conservative nature of how municipal utilities use debt. From 2005 to 2016, the average municipal TO equity percentage increased from 63% to 79%. In the last five years, the average increased to 83% indicating that this growth in equity for the TO segment is waning and the driver of increases in the dollar return on rate base will mostly be increases in transmission investment going forward. Secondly, as municipal TOs have become more familiar with the Attachment O formula rate, some of these TOs have optimized their ATRRs by recording costs and operations more accurately. This optimization practice, however, has not been uniform across the entire municipal segment and so it is not readily apparent in substantial increases in WSAs and GPAs. This is evidence that for many municipal TOs, there is substantially more work to be done in optimizing their ATRRs.

For many municipal TOs, there is substantially more work to be done in optimizing their ATRRs.

4. Industry Issues Increasing Future Rates

In addition to recent drivers of investment such as the increase in renewables and aging facilities, there are six industry issues (see Figure 4 on the next page) that will likely help fuel the increase in transmission rates in MISO over the next five years. We discuss these issues below.

a) Resiliency. Extreme weather events and the potential for sinister threats to the grid have triggered utilities to make their networks more resilient. Resiliency is a vague term but has become the trendy way to support more transmission investment and can provide a "cover" for increased transmission rates.

b) Social, political and regulatory trends. As many states and utilities

Figure 4
Industry Issues Increasing Future Rates

- Resiliency
- Social, political & regulatory trends
- Escalating inflation
- FERC NOPR RM20-10
- Cyber security costs
- LRTP cost allocation

move aggressively to reduce carbon emissions and add renewable energy sources, they may be required to add substantial new transmission to transfer energy from these new resources to the loads that will consume it. The recently passed federal Infrastructure Investment and Jobs Act provides some tailwinds for transmission investment. The law addresses long-running uncertainty over FERC's electric transmission siting authority, clarifying that the agency can override state-level permit denials under certain conditions for projects sited in national interest electric transmission corridors. The law also allows the Department of Energy ("DOE") to act as an "anchor tenant" for new transmission projects before transferring its share of the power lines to private entities. DOE is specifically authorized to procure up to 50% of a new project's transmission capacity; and the department could also issue loans for new projects of up to $2.5 billion. The law also provides $3 billion in matching grants for Smart Grid projects.

Moreover, through its Advanced Notice of Proposed Rulemaking (ANOPR RM21-17), "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," FERC is actively seeking new ways to promote more expansive and coordinated inter-RTO projects and address the perceived lack of forward-looking planning for renewables growth. This ANOPR, which had a FERC Technical Conference on November 15, includes revisiting cost allocation methods for transmission investment and how to accommodate the deluge of generator interconnection projects associated with renewables.[5] The general tension between the participants emerged around a more top-down, standardized modeling and planning approach for the nation versus allowing flexibility

[5] See FERC Notice of Technical Conference, September 16, 2021.

for the different geographical regions. The parties also generally divided into two camps around the idea of building speculative transmission projects, i.e., the "Field of Dreams" approach of building transmission without requiring interconnection agreements. The Commission set a deadline on November 30 for written comments to respond to the discussion at the technical conference.

In parallel, FERC also convened on November 10 a new federal-state task force on the electric transmission build-out, including members of The National Association of Regulatory Utility Commissioners ("NARUC"). FERC hopes the group will produce specific proposals that can be incorporated into a final RM21-17 rule expected by the end of 2022 but early indications are that there are a myriad of views as to whether the states should become more involved in transmission planning or continue with the same model of the states mainly being involved up front in the policy-making and resource planning. Lastly, congressional proposals are contemplating tax credits for taxable entities and direct cash payments to public power and cooperatives to encourage certain high voltage transmission investments.[6]

Higher commodity costs for steel, aluminum, and cooper coupled with rising labor costs from increasingly scarce skilled labor will put pressure on TO costs and will begin to be included in TO ATRRs.

c) Escalating inflation. As the long-expected increase in inflation is arriving, it brings with it increased labor and material costs to operate and maintain transmission facilities and to build new facilities. Steel prices, for example as tracked through the U.S. Producer Price Index have increased about 120% in the 12 months ending August 2021 and recently continued their increase through October by another 20%.[7] S&P Capital IQ reports the NYMEX US Hot Rolled Coil Index, an industry benchmark used to measure the value of steel contracts, hit $1,959 per ton on Sept. 22, 2021, a 226.5% increase from the prior year price of $600.[8] Higher commodity costs for steel, aluminum, and cooper coupled with rising labor costs, from increasingly scarce skilled labor will put pressure on TO's costs and will begin to be included in TO ATRRs. The question is whether the TO's existing contracts and established capital forecasts will soften any additional ATRR increases due to inflation.

The Consumer Price Index and core inflation have recently risen at a 6.2% and 4.4% annual pace, respectively,[9] which is roughly two to three times the Federal Reserve target of 2.0%. *"[Federal Reserve] Chairman Jerome Powell*

6 See "House Democrats seek to boost US tax credits for clean energy, climate programs," S&P Capital IQ, September 13, 2021. Projects discussed include new stand-alone energy storage and needed new electric transmission lines.

7 U.S. Producer Price Index for Iron and Steel Mills was 156.30 in August 2020 and 342.60 in August 2021; October 2021 = 375.3. . Source: www.ycharts.com (accessed November 10, 2021).

8 "US steel goes green on record prices but risks deflating buoyant market," S&P Capital IQ, September 30, 2021.

9 "Inflation jumped 6.2% in October, biggest monthly rise in 30 years," CBS MoneyWatch, November 10, 2021.

recently conceded inflation would stay higher for longer than he had expected and Atlanta Federal Reserve President Raphael Bostic said central bank officials should stop calling inflation transitory."[10] Recognizing this inflation, Fed Officials on November 3 laid out a plan to slow their $120 billion in monthly Treasury bond and mortgage-backed security purchases by $15 billion a month starting in November.[11] The market currently expects a 3.17% Consumer Price Index ("CPI") inflation rate over the next five years.[12]

A prominent factor on the "transmission wheel" is the investment required to address cyber security.

d) FERC NOPR RM20-10. In March 2019, FERC issued a Notice of Proposed Rulemaking, "Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act," suggesting a change in the way FERC grants incentive rates for transmission projects. This new proposed method grants incentives to transmission projects that meet certain economic and reliability metrics. The new method will likely grant ROE rate incentives to many more projects, thereby increasing the return on rate base for transmission facilities included in transmission rates. These incentives may also prompt an increase in the sheer number of transmission projects.

e) Cyber security costs. As shown in Figure 5 on the next page, MCR has traced many factors that have driven (or at least been used to justify) transmission investment over the recent past. This wheel of investment drivers rotates, allowing new drivers to come to prominence; also, over the last few years, this wheel has expanded to add new drivers to it. As the wheel spins and grows, zonal transmission rates increase through new transmission investment that result from the various transmission drivers. A prominent factor on the "transmission wheel" right now is the investment required to address cyber security. In fact, FERC is considering incentives to encourage additional investment in cyber security to achieve security levels beyond the mandatory Critical Infrastructure Protection ("CIP") Reliability Standards (NOPR RM21-3). The industry is split on whether to proceed: IOUs and Transcos generally support the NOPR, whereas transmission-dependent utilities[13] generally see the NOPR leading to an unnecessary increase in costs.

f) LRTP cost allocation. MISO is considering modifying the Multi-Value Project ("MVP") tariff to include projects identified from the Long-Range Transmission Plan ("LRTP"). These projects are intended to address

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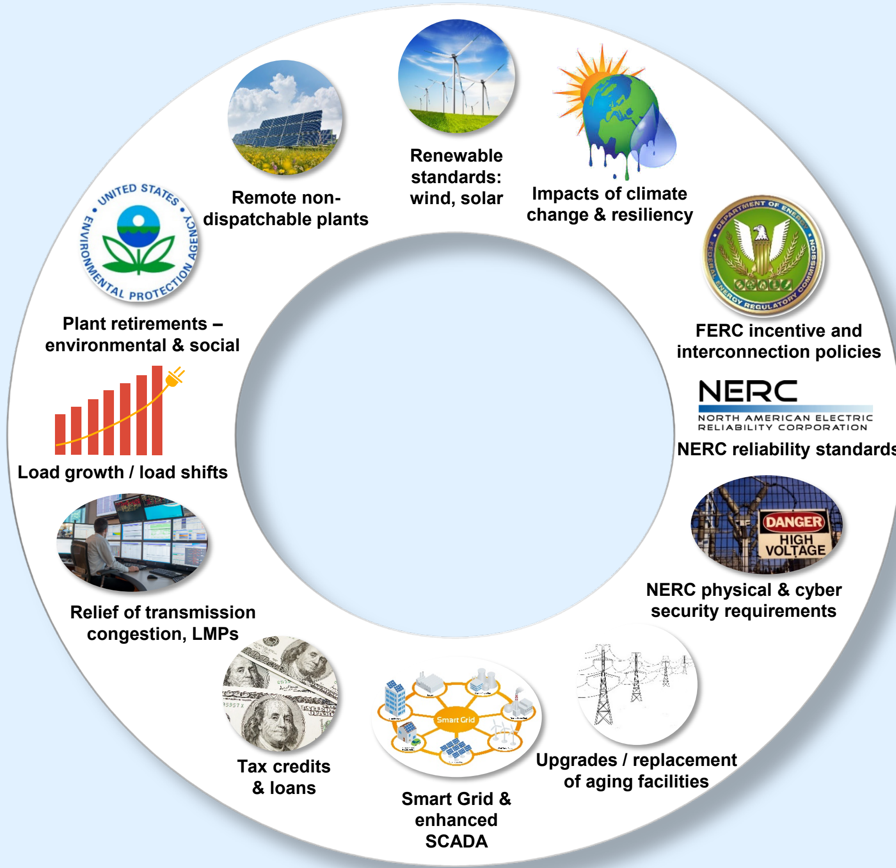
[10] "Inflation rises at 5.4% yearly pace in September, CPI shows, and stays at 30-year high." *MarketWatch*, October 13, 2021.

[11] "Fed Takes First Step Toward End of Pandemic Measures," *New York Times*, November 3, 2021.

[12] Five-year breakeven inflation rate, FRED Economic Data, November 15, 2021. Treasury See also "Traders' Five-Year Inflation Expectations Top 3%," Bloomberg, October 22, 2021. The 3.0% percent expected inflation rate recently rose to 3.17% as core inflation has reached 4.4%, as announced November 10, 2021.

[13] Utilities that own little/no transmission themselves and use IOU/Transco transmission.

Figure 5
Factors Driving Transmission Investment



reliability needs and respond to the resource changes that will occur in MISO from efforts to add more renewable energy to the grid. Including these projects as MVPs will add upward pressure on rates throughout the MISO footprint. This effort may eventually work in tandem with direction coming from the ANOPR RM21-17 described above but MISO is driving to get its filing done rather than waiting on direction from the ANOPR. The ANOPR could, however force MISO to revisit cost allocation issues in the near future. Nevertheless, the rate impact from these projects will be limited over the next five years given the typical long lead time of these types of projects.

A couple of other factors looming on the horizon are worth noting, but will likely have minimal, if any, impact on rates in the next five years. The first is a long-term, regional transmission planning initiative coordinated with MISO, called CapX2050. Following the success of CapX2020 in the upper Midwest, a new study called the CapX2050 Transmission Vision Report was conducted to learn how Minnesota's transmission system would need to evolve as reliable, dispatchable coal-fired power plants are closed and utilities replace them with intermittent, weather-dependent resources like wind and solar. The study by Grid North Partners (formerly known as

CapX2020) did not provide details on costs; regardless, any projects coming out of the Grid North Partners in the near future will have to go through the MISO Transmission Expansion Plan ("MTEP") process. These projects are not likely to significantly affect MISO transmission rates in the next five years, given the typical lead time of seven to ten years for a major transmission project. These projects could overlap with the LRTP effort described above.

Another potential long-term issue is the funding mechanism for generator interconnection projects. Under the rules of the MISO tariff Attachment X, TOs can elect to either self-fund network upgrades necessary as a result of Generator Interconnection ("GI") projects or have the generator customer pay for them. Either way, the capital costs and any return on this rate base is collected directly from the generator customer through a Facilities Service Agreement or from a contribution in aid of construction and not from zonal ratepayers. Thus, there is no impact to zonal rates. This existing funding methodology has come under scrutiny from renewable advocates saying that it is unfair to make the "last, incremental network user" pay for system upgrades that benefit all users. The ANOPR RM21-17 mentioned earlier could change the current cost allocation scheme for MISO. It remains to be seen how soon these policy and tariff changes for GI projects could be implemented. There is some momentum to make changes to the GI project cost funding whereby more backbone investment is made by TOs, resulting in fewer piecemeal network upgrades funded directly by the GI customers. If these changes to a broader backbone system can be implemented, this factor could become a new source for upward pressure on transmission rates but is unlikely to affect the next five years given the long lead time of large backbone projects.

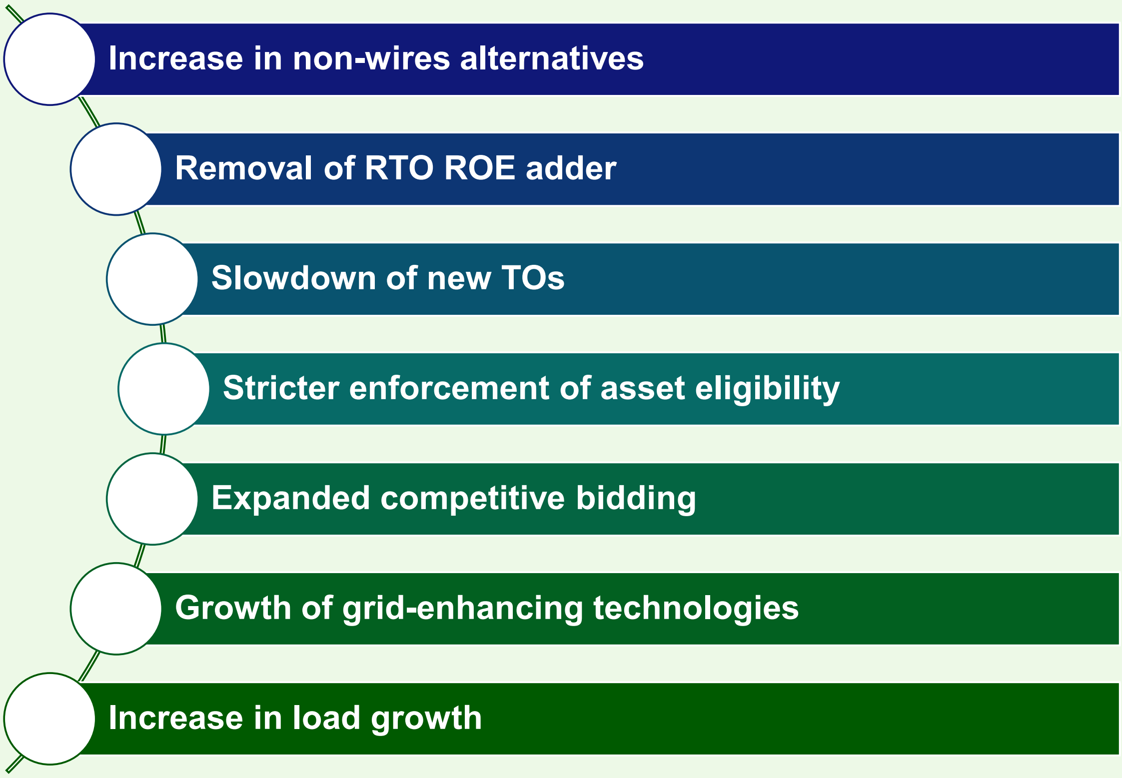
There are other considerations in MISO over the next five years that could mitigate some rate pressure and prevent the MISO transmission rate express train from returning to historic speeds.

5. Potential Mitigating Factors to Zonal Rate Increases

Despite these reasons that will put upward pressure on rates, there are other considerations in MISO over the next five years that could mitigate some rate pressure and prevent the MISO transmission rate express train from returning to historic speeds. These factors are related to FERC regulatory policies, load forecasts, and RTO-specific rules as well as technology advancements (see Figure 6 on the next page).

The first item is the potential **increase in non-wires alternatives** ("NWA"). The momentum for increased transmission investment could be moderated somewhat should state commissions (or FERC) intensify their efforts to entertain NWAs instead of transmission investment. NWAs currently are being considered in many company resource plans but are not often heavily scrutinized by outside stakeholders. Examples of NWAs include battery storage, distributed energy resources, energy efficiency and demand response. Deployed battery storage is still in its infancy in MISO, but there

Figure 6
Potential Mitigating Factors to Zonal Rate Increases



is substantial storage paired with renewables in the queue. It remains to be seen whether the dual power flows associated with storage will result in substantial new transmission facilities or whether storage closer to load (or even behind the meter) will lessen the need for new transmission.

The second factor that could mitigate some transmission rate increases is the potential **removal of the RTO ROE membership adder**. FERC is proposing that the 50-basis point ROE adder for voluntarily joining an RTO be removed after three years of RTO membership. This proposal has been met with stiff resistance from RTOs, IOUs and Transcos, so it is unclear whether this will be implemented. Recently in a case involving Dayton Power & Light, FERC declined its request for an RTO ROE adder, concluding that the state of Ohio mandated RTO membership, thus it was not voluntary.

Thirdly, the **slowdown of new transmission owners joining MISO** can naturally slow escalating transmission rates. In 2005, there were 25 transmission owners included in MISO transmission rates. In 2021, the number of utilities submitting an Attachment O is 92. As new TOs joined existing pricing zones, many TOs folded in a higher cost per kW than the existing zonal rate. As the number of new TOs submitting an Attachment O has slowed, the impact on rates from utilities new to MISO decreases.

Fourth, MISO appears to be implementing **stricter enforcement of**

BPM-028 which governs asset eligibility. BPM-028 is the business practice manual MISO follows to determine whether transmission facilities are qualified for cost recovery under the MISO tariff. BPM-028 applies the FERC seven-factor test to determine network facilities and defines exceptions for radial lines. MISO appears to be more strictly interpreting BPM-028, thus excluding proposed facilities that may have been included under a looser application of the tariff.

The fifth factor that could slow transmission rate increases is **expanded competitive bidding**. FERC Order 1000 requires that cost-shared projects be awarded through a competitive bidding process but the existence of Right of First Refusals ("ROFRs") in Minnesota, the Dakotas and Iowa has all but choked off these types of projects in MISO. If transmission developers are successful in proposing more projects in or across non-ROFR states that are awarded through competitive bidding and inter-RTO projects significantly expand, the competitive bidding process will likely result in lower cost solutions than if the transmission projects were built by incumbents. At face value, this competition should result in a lower cost per project; but more projects could emerge, thus largely offsetting any downward zonal impact.

FERC is entertaining grid-enhancing technologies because of their ability to increase capacity at a relatively low cost; but these projects may require incentives.

The sixth factor that could slow rate increases is **significant growth in grid-enhancing technologies**. The industry is testing technology advancements such as no-contact sensors and software systems that enable operators to implement dynamic line ratings that can boost transfer capacity of existing power lines by up to 40% with relatively low transmission investment compared to traditional upgrades and expansions. FERC is entertaining grid-enhancing technologies because of their ability to increase capacity at a relatively low cost; but these projects may require incentives, such as shared savings, in order for them to quickly take off. However, it is unlikely these technologies will have a meaningful impact over the next five years as existing traditional projects in the pipeline have momentum and the incentives for shifting to grid-enhancing technologies may be insufficient.

The last potential factor that would slow transmission rates is **an increase in load growth** due to higher rates of electrification. For example, MTPEP21's Future 2 Scenario lays out an average energy growth rate of 1.1% compared to the base case energy growth of 0.5% in Future 1.

6. Projected Rates by MISO Joint Pricing Zone

Figure 7 on pages 16 and 17 shows the MCR five-year (2022 to 2026) zonal rate forecasts for the 20 joint pricing zones in MISO. There is a wide range of expected zonal increases for these zones, but the consistent theme is the MISO rate express train will continue to chug along. We forecast zonal rates in joint pricing zones will increase by an average of about 6.5% per year, over double the projected five-year inflation rate. We project that nine of the

20 joint pricing zones in MISO will see average annual rate increases of at least 7% percent. These increases are for Schedule 9 only, so they exclude Attachment GG and MM projects. We utilized various publicly available sources for our rate forecasts including: MTEP Appendix A of approved projects; earnings call presentations and transcripts; 2022 projected Attachment Os; state-required capital plans; stakeholder presentations related to the formula rate; historical growth rates of expenses and capital from MCR's database; expected inflation; and the estimate of load growth from MISO. Using these sources as inputs, MCR applied its own modeling analysis[14] to determine the forecast 5-year annual growth of the zonal rate for 2022 to 2026 for each joint pricing zone.

MCR forecasts zonal rates in joint pricing zones will increase by an average of about 6.5% per year, over double the projected five-year inflation rate.

For example, MCR forecasts very high growth rates of 18.6% and 18.0% per year for Ameren Illinois and Ameren Missouri zonal rates reflecting the aggressive grid modernization capital spending plans reported in the Q2 2021 Ameren earnings call. In the Ameren IL pricing zone, GridLiance, Hoosier Energy and Prairie Power also contribute ATRR and their transmission investments will also increase the zonal rate. However, these three TO' ATRRs are only 7% of the total zonal ATRR. In the Ameren MO pricing zone, Wabash Valley Power Alliance contributes 5% of the total zonal ATRR and will add slightly to the zonal rate increases as it invests in the pricing zone. The MDU zonal level of investment is expected to pick up considerably; we forecast an average annual growth rate in rates of 9.8% per year through 2026. This growth rate could be higher if MDU's substantial investment level through 2024 continues into 2025 and 2026. The METC zone's historical high level of transmission investment is projected to continue resulting in a five-year CAGR of 7.8%. Conversely, the Minnesota Power and Otter Tail zonal rate forecasts of only 2.5% and 1.5% per year, respectively, reflects relatively low capital expenditure forecasts. Entergy-Arkansas' relatively low projected transmission rate growth reflects that their planned investments over the forecast period are much smaller than other Entergy operating companies in Mississippi, Texas, and Louisiana.

Given the large recent cost increases in steel, aluminum and copper, and a tight labor market, there is a real possibility that the inflation rate pertinent to transmission could be higher. To understand the impacts of using an inflation rate higher than our assumed 3.0%, we also calculated the NSP rate forecast at inflation rates of 6% per year and 9% per year. At 6% average inflation, the base case 6.5% CAGR and $6.10 per kW rate in 2026 rises to a CAGR of 6.9% with a 2026 rate of $6.20. At 9%, the CAGR increases to 7.2% and 2026 rate of $6.30 per kW.

[14] The MCR analysis keeps rate of return constant (i.e., constant equity ratio, cost of debt and capital structure) unless the TO specifically indicates otherwise. Assumes MISO's 0.4% load growth across all zones. Source: July 9, 2021 MISO forecast of Schedule 26 Indicative Annual Charges.

Figure 7

Forecast Zonal Schedule 9 Rates by Joint Pricing Zone 2022-2026

Joint Pricing Zone	Current 2021 Zonal Rate	Projected 2026 Zonal Rate	Compound Annual Growth Rate 2022-2026 (base = 2021)	Comments
Ameren IL	$4.16	$9.78	18.6%	• In its 2Q 2021 earnings call, Ameren reports an aggressive transmission capital investment forecast for Illinois. • Other TOs impacting this rate are Prairie Power, Hoosier Energy and GridLiance Heartland.
Ameren MO	$1.90	$4.35	18.0%	• Ameren-MO is also reporting a very aggressive capital investment forecast for transmission to modernize the grid in its filing with the MO PSC.
MDU	$3.06	$4.90	9.8%	• MDU has about $27M of new transmission projects planned through 2024. If MDU continues to fill the investment pipeline after 2024, this forecast would be higher.
Great River Energy	$5.81	$8.67	8.4%	• Other TOs impacting this rate include Wilmar Municipal Utilities, SMMPA and Elk River Municipal Utilities.
METC	$4.59	$6.67	7.8%	• METC investment is driven by reliability and rebuild projects, mostly at the 138 kV level.
ITC	$3.13	$4.53	7.7%	• ITC investment is driven by reliability projects, mostly at the 120 kV level. • Only two projects are listed outside the local zone (Attachment GG projects).
Duke Indiana	$3.29	$4.73	7.5%	• The DEI pricing zone has a Joint Transmission Agreement that determines the investment levels for most TOs in the zone.
Entergy-TX	$4.33	$6.07	7.0%	• There is very little investment in this zone from the non-Entergy TOs. • Entergy has an aggressive transmission capital plan across most of its operating companies, including Entergy-TX.
NSP	$4.45	$6.10	6.5%	• Xcel has an aggressive capital plan across its utilities, including NSP.

Figure 7 (continued)

Joint Pricing Zone	Current 2021 Zonal Rate	Projected 2026 Zonal Rate	Compound Annual Growth Rate 2022-2026 (base = 2021)	Comments
ITC-Midwest	$10.98	$14.10	5.1%	• ITCM continues to identify reliability-driven projects that are the vast majority of new investment. • ITCM has also identified over 50 projects that convert 34.5 kV facilities to 69 kV.
Mid-American	$2.85	$3.60	4.8%	• MEC has consistently invested in transmission over the past five years and is expected to continue to do so.
Entergy-LA	$3.60	$4.52	4.6%	• Entergy will accelerate storm hardening and climate resilience, including Ent.-LA.
Entergy MS	$5.90	$7.30	4.4%	• Entergy will accelerate storm hardening and climate resilience, including Ent.-MS.
Dairyland Power	$8.18	$9.80	3.7%	• DPC is expected to make the majority of investments over the forecast period. • NWEC is not expected to have significant investment.
CLECO	$2.74	$3.21	3.3%	• CLECO has consistently made significant investments over the past five years and has communicated that significant ongoing projects will fuel rate base growth in coming years.
Otter Tail	$3.30	$3.56	2.8%	• OTP forecasts lower annual capital expenditures than its historical five-year average over the next five years, with annual expenditures in the range of 50%-60% of its five-year average.
ATC	$5.20	$5.87	2.5%	• ATC's top 10 largest projects were 43% of the total capital budget in 2021 and were driven by asset renewal and reliability.
MN Power	$4.55	$5.14	2.5%	• MN Power states it is very conservative in forecasting capital expenditures.
SMMPA	$3.73	$4.22	2.5%	• SMMPA shares the zone with Rochester Public Utilities. Each TO led its respective segment (JAAs, Municipals) in investments over the past five years.
Entergy-AR	$4.15	$4.59	2.1%	• Entergy-AR's planned investments over the forecast period are much smaller than other Entergy operating companies
Average Annual Growth Rate of Joint Zones Above			**6.5%**	

7. Trends in MISO Transmission Projects

The forecast zonal rate increases above reflect a level of investment included in the MTEP Appendix A that remains strong and is heavily weighted toward the "Other" project category. Other projects are those that do not fall into categories such as a Multi-value Project, Market Efficiency, Baseline Reliability and Generator Interconnection. Appendix A includes projects formally recommended by MISO staff as the preferred solution to identified network needs and approved by the MISO Board of Directors.

In the MTEP20, 67% of the total project estimated costs included in Appendix A were categorized as Other projects designed to address local reliability issues, load growth or the age and condition of local zonal facilities. These Other projects are not competitively bid. The 340 Other projects totaled $2.8 billion in estimated project costs. In the MTEP20, Appendix A also included 75 Baseline Reliability projects totaling $755 million in estimated project costs and 100 Generator Interconnection projects totaling $606 million in estimated project costs.

77% of the total project estimated costs included in the MTEP Appendix A were categorized as "Other" projects.

The weighting towards the Other project category increased in the MTEP21 Appendix A. In the most recent MTEP, 77% of the total project estimated costs included in Appendix A were categorized as Other projects. The 257 Other projects totaled another $2.6 billion in estimated project costs on top of what was included in MTEP20. Thus, there is no indication that transmission owners are moving away from planning projects that fall into the Other project category. The MTEP21 Appendix A also included 61 Baseline Reliability projects totaling $462 million in estimated project costs and only 49 Generator Interconnection projects totaling $319 million, both categories are down from 2020.

The annual MTEP reports also include Appendix B, which contains projects that have been validated by MISO staff as preferred solutions to address network needs, but staff has deferred the final recommendation to a subsequent planning cycle. Appendix B is not simply a pipeline to Appendix A, because project solutions can change based on evolving conditions and network needs. Some Appendix B projects never obtain final approval due to a change in network needs or the development of a substitute solution. Projects in Appendix B are often listed without defined cost estimates because the projects are still undergoing planning and design.

However, the MTEP does not capture the universe of new transmission build in MISO each year. The MISO Business Practice Manual 020 also lists projects that transmission owners are not required to submit to the annual planning process. New projects in BPM 020 include those with the following characteristics:

- Do not represent a topology change, such as constructing a new circuit, tapping an existing circuit, or removing or retiring an existing circuit from the MISO planning model.
- Do not add new circuit breakers, upgrade an existing circuit breaker or change the electrical characteristics of an existing circuit breaker.
- Do not change a circuit rating.
- Involve like-for-like replacements with direct costs of less than $1 million.

Projects that meet these exclusion criteria would likely be categorized as Other projects if they were indeed submitted at all to the planning process. Therefore, this bucket of transmission projects would not change the overall dominance of the Other project category of investment in MISO in recent years.

The 2021 MISO systemwide average zonal rate grew at an eye popping 17.7% from 2020, compared with only a 1.5% increase from 2019 to 2020.

8. Transmission Rates Snap Back in 2021— MCR's Annual Transmission Rate Analysis by Zone

Each year, MCR reports the rate changes for most MISO pricing zones and the MISO systemwide average zonal rate in the most recent year and calculates the historical CAGRs by zone. The 2021 MISO systemwide average zonal rate grew at an eye popping 17.7% from 2020, compared with only a 1.5% increase from 2019 to 2020. The growth in this year's Schedule 9 zonal rates reflects capital additions, a MISO-wide load reduction of 4.1%, largely due to the pandemic;[15] and the end of the amortization of accumulated deferred income tax balances that have run their course. Thus, the growth in MISO zonal rates in 2021 primarily was due to the continued increase in transmission investment and a decline in load.

Zonal rates increased in 2021 across all the sampled MISO pricing zones (see Figure 8 on next page). At the low end of the growth rate range are the Dairyland, ATC and Cooperative Energy zones with annual growth rates of 4.2%, 6.1% and 6.8%, respectively. In stark contrast, Entergy New Orleans, Entergy MS and Entergy LA zones all topped the charts with rate increases of 43.2%, 34.8% and 34.4%, respectively. These IOU-dominated zones illustrate the snapback that rates experience as the refunds associated with the amortization of excess ADIT have worked their way through the formula rates. In addition, Entergy AR, Entergy LA and Entergy New Orleans had load reductions contributing to their large rate increases.

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[15] See MISO 2020 State of the Market Report prepared by the MISO Market Monitor, page 8. In the October 2021 Market Monitor report, Potomac Economics reports peak load increased by 2% over 2020 due to hotter temperatures and easing of Covid impacts.

Figure 8
Transmission Schedule 9 Network Rate Increases
2005-2021 MISO Average and Select Pricing Zones [16]

Index/Pricing Zone	$/kW/Month—Sch. 9					*% Change 2020-21*	Cumul % Change thru 2021	Compound Ann % Inc thru 2021
	2005	'10, '14	'19	'20	'21			
CPI								**2.4%**
MISO System Avg	1.51		3.40	3.45	4.07	**17.7%**	168.9%	***6.4%***
Otter Tail	3.39		*3.04*	*2.70*	*3.30*	**22.2%**	*-2.6%*	***-0.2%***
MDU	3.05		*2.65*	*2.58*	*3.06*	**18.9%**	*0.3%*	***0.0%***
Cleco		*1.92*	*2.31*	*2.43*	*2.74*	**12.6%**	*42.5%*	***3.3%***
NIPSCO	2.20		*2.78*	*3.46*	*4.02*	**16.2%**	*82.6%*	***3.8%***
S. IL Pwr Coop	2.20		*3.20*	*3.08*	*4.05*	**31.5%**	*84.6%*	***3.9%***
MidAmerican		1.82	2.21	2.39	2.85	**19.1%**	56.4%	***4.2%***
ITC	1.61		*2.66*	*2.74*	*3.13*	**14.1%**	*94.3%*	***4.2%***
Cooperative En.		*3.94*	*5.90*	*5.91*	*6.32*	**6.8%**	*60.3%*	***4.4%***
Hoosier	3.27		*5.69*	*5.66*	*6.62*	**16.9%**	*102.4%*	***4.5%***
Entergy New Orl		*1.28*	*0.76*	*1.58*	*2.26*	**43.2%**	*76.2%*	***5.3%***
Ameren-MO	0.83		*1.61*	*1.62*	*1.90*	**17.3%**	*128.8%*	***5.3%***
ATC	2.27		*4.71*	*4.90*	*5.20*	**6.1%**	*129.3%*	***5.3%***
NSP (Xcel)	1.87		*4.26*	*3.94*	*4.45*	**13.0%**	*137.9%*	***5.6%***
IP&L	0.79		*1.48*	*1.75*	*1.94*	**10.8%**	*145.3%*	***5.8%***
Entergy TX		*2.33*	*3.78*	*3.99*	*4.33*	**8.4%**	*85.7%*	***5.8%***
Duke-Indiana	1.25		*2.62*	*2.76*	*3.29*	**19.6%**	*163.6%*	***6.2%***
GRE	2.15		*6.19*	*4.62*	*5.81*	**25.8%**	*170.6%*	***6.4%***
Entergy LA		*1.81*	*2.53*	*2.68*	*3.60*	**34.4%**	*99.1%*	***6.5%***
MN Power	1.61		*3.83*	*3.91*	*4.55*	**16.6%**	*182.9%*	***6.7%***
Entergy MS		*2.68*	*452*	*4.38*	*5.90*	**34.8%**	*120.2%*	***7.4%***
Entergy AR		*1.85*	*3.46*	*3.46*	*4.15*	**20.1%**	*124.6%*	***7.6%***
Dairyland Power		3.55	7.43	7.85	8.18	**4.2%**	130.5%	***7.9%***
Vectren	0.90		*2.88*	*2.71*	*3.39*	**25.0%**	*277.6%*	***8.7%***
METC	0.98		*3.79*	*3.96*	*4.47*	**12.8%**	*356.3%*	***10.0%***
Ameren-IL	0.88		*3.44*	*3.38*	*4.16*	**23.2%**	*374.6%*	***10.2%***
ITC-Midwest	2.13		*9.68*	*9.55*	*10.98*	**15.0%**	*415.0%*	***10.8%***

[16] Source: MCR Analysis based on June 2005, 2010, 2014, 2019 through 2021 Attachment O Files. MEC and DPC began as TOs in 2010. MISO South zones began January 2014 based on 2013 rates and new rates went into effect June 1, 2014. MISO system average includes all zones.

Figure 9
Total Estimated Transmission Rate Increases [17]
MISO Average and Select Pricing Zones (Schedules 9, 26 and 26-A)
2005-2021

Index/Pricing Zone	**$/kW/Month**				***% Change 2020-21***	**Cumul % Change thru 2021**	**Compound Ann % Inc thru 2021**
	2005	***2010***	**2020**	***2021***			
CPI							***2.4%***
MISO System Avg	1.51		4.55	5.18	**13.9%**	343%	***8.0%***
MDU	3.05		*3.62*	*4.12*	**14.0%**	*135%*	***1.9%***
Otter Tail	3.39		*4.90*	*5.59*	**14.1%**	*165%*	***3.2%***
S. IL Power Coop	2.20		*3.12*	*4.11*	**31.5%**	*187%*	***4.0%***
Hoosier	3.27		*5.99*	*6.99*	**16.7%**	*214%*	***4.9%***
NIPSCO	2.20		*4.56*	*5.12*	**12.4%**	*233%*	***5.4%***
ITC	1.61		*3.72*	*4.11*	**10.3%**	*255%*	***6.0%***
MidAmerican		1.82	3.30	3.76	**13.8%**	107%	**6.8%**
ATC	2.27		*6.52*	*6.87*	**5.3%**	*303%*	***7.2%***
NSP (Xcel)	1.87		*5.45*	*6.04*	**10.8%**	*323%*	***7.6%***
Duke-Indiana	1.25		*3.67*	*4.26*	**16.2%**	*341%*	***8.0%***
Ameren-MO	0.83		*2.60*	*2.88*	**10.9%**	*346%*	***8.1%***
Dairyland Power		3.55	8.11	*8.47*	**4.4%**	*139%*	***8.2%***
IP&L	0.79		*2.67*	*2.87*	**7.5%**	*362%*	***8.4%***
GRE	2.15		*6.77*	*7.98*	**17.8%**	*372%*	***8.6%***
MN Power	1.61		*5.64*	*6.45*	**14.3%**	*400%*	***9.1%***
Vectren	0.90		*4.13*	*4.87*	**`18.0%**	*543%*	***11.2%***
ITC-Midwest	2.13		*10.82*	*12.29*	**13.7%**	*576%*	***11.6%***
Ameren-IL	0.88		*4.45*	*5.23*	**17.6%**	*597%*	***11.8%***
METC	*0.98*		*5.73*	*6.26*	**9.2%**	*639%*	***12.3%***

MCR

[17] Applies to MISO North only. Schedule 26 (recovered through Attachment GG) began in 2007 and Schedule 26-A (recovered through Attachment MM) began in 2012. 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.

Other IOU-dominated pricing zones also experienced very large rate increases in 2021; Vectren led the way with a 25% increase in its zonal rate, largely due to the addition of $31 million or a 6% increase in Vectren's gross transmission plant and an accompanying 2% decrease in zonal load. The Ameren IL zonal rate grew by 23.2%, mainly due to Ameren's addition of $589 million or a 19% increase in gross transmission plant. Otter Tail's zonal rate grew 22.2%, partially due to Otter Tail adding $61 million or 9% to their gross transmission plant recovered in the Attachment O. These large gross transmission plant additions result in added return on rate base and additional expenses to the ATRRs recovered in these pricing zones.[18] The Southern Illinois Power Cooperative ("SIPC") zone had a large rate increase in 2021 of 31.5% as SIPC's WSA and GPA allocators rose due to the shut down of the Marion Generating Plant, and their load decreased by a substantial 15%. There is a wide range of Schedule 9 (local) zonal rates with the high end occupied by ITC-Midwest at $10.98 per kW/month. At the other end of the range, Ameren-MO and Indianapolis Power & Light ("IP&L") enjoy the lowest zonal rates of $1.90 and $1.94 per kW/month. The MISO systemwide average zonal rate is $4.07 per kW/month compared to last year's average rate of $3.45 per kW/month, an increase of 17.7%.

The average combined Schedule 9, 26 and 26-A rate grew by 13.8% in 2021.

The steady impact of the cost-shared projects recovered in Schedules 26 and 26-A continues to add a layer onto the total zonal costs in MISO (see Figures 9 on page 21). The MISO systemwide average zonal rate combined with Schedule 26 and 26-A costs grew to $5.18 per kW/mo., a 13.9% increase in 2021 and an 8.0% CAGR since 2005. This growth compares with the Consumer Price Index CAGR of just 2.4% since 2005. The range in the combined Schedule 9, 26 and 26-A rate is flanked by ITC-Midwest ($12.29 per kW/mo.) at the high end and Ameren-MO and IP&L ($2.88 and $2.87 per kW/mo., respectively) at the low end. At 12.3%, METC has the highest CAGR in the combined Schedule 9, 26 and 26-A rates since 2005, followed by Ameren-IL at 11.8% and ITC-Midwest at 11.6% per year.

9. The Seven Benefits of Transmission Investing for Public Power and Cooperatives

In this environment of heavy transmission investment and escalating transmission rates, it makes sense for public power and cooperatives to understand how transmission investment can create value to help offset these escalating costs. (See Figure 10 on the next page for the seven benefits of transmission investing for public power and cooperatives.)

[18] Additional gross plant additions add more transmission depreciation expense, some incremental O&M and, in most cases, increase the gross plant allocator that allocates expenses like property taxes.

Figure 10

Benefits of Transmission Investing for Public Power and Cooperatives

1. Enhances reliability
2. Recovers transmission costs from all zonal load
3. Provides attractive returns to help offset rising transmission rates
4. Promotes comparable service
5. Meets load growth and promotes economic development
6. Ensures a “seat at the RTO table”
7. Provides lower transmission costs than the incumbent

1. Enhances reliability. The number one reason to invest in transmission is to enhance the reliability of members (for a JAA or G&T) or to enhance the reliability of customers (for a municipal or distribution cooperative). In order to move a proposed local project through MISO’s Transmission Expansion Planning process, the project must provide improvements consistent with the TO’s local planning reliability criteria and/or NERC reliability criteria. Municipals have the oldest transmission facilities of any segment, including IOUs, JAAs, G&Ts and distribution cooperatives; thus, there are opportunities to upgrade and expand their existing facilities to enhance reliability. See Section 10, Figure 30 for the average system age as shown by the ratio of net plant to gross plant for each segment.

2. Recovers transmission costs from all zonal load. If a TO resides in a JPZ, then customers other than their own can pay a large portion of their transmission costs. For example, 29 of the 33 municipals in MISO reside in JPZs and most are less than 5% of the total load in the zone. This means that in most cases, at least 95% of a municipal’s transmission costs are paid by other utility customers. Instead of paying for its own transmission costs, a TO in a JPZ can get a return on its investment, full recovery of depreciation and O&M, and a portion of A&G and payment in lieu of taxes or property taxes mostly paid for by other utility customers. This is the closest one can get to “having cake and eating it, too.”

3. Provides attractive returns that help offset rising transmission rates. The median municipal equity ratio in MISO is 88.8%,[19] so municipals using the conventional non-levelized (return on rate base) template can get a relatively high return on their investment. Combining the standard MISO 10.52% ROE (base ROE of 10.02% plus RTO adder of 50 basis points) with a high equity ratio yields a high overall return of about 9.6%.[20] This level of return is much higher than a municipal's cost of debt and is highly valued in today's low interest rate environment. Further, a formula rate helps to ensure full recovery of transmission costs and this level of return without the annual risk of a rate case.[21]

A 9.6% level of return is much higher than a Municipal's cost of debt.

4. Promotes comparable service. Investing in transmission provides the ability to receive comparable service to the service levels currently enjoyed by the load served by incumbent utilities. In fact, even the capability and intent of a JAA or G&T to make investment on behalf of its members provides leverage that can force the incumbent to make local investments, such as providing a second tap line to the incumbent's network, reconductoring a line with new structures, or upgrading the voltage level of a substation. Further, adding additional supply sources from another interconnection improves reliability and can provide increased access to renewables while potentially lowering congestion costs. If the incumbent in a JPZ knows the investment can be made by a JAA or G&T on behalf of their members, the incumbent often relents and prefers to make the investment itself (and claim the ATRR), because it knows the zonal rate will increase regardless of who makes the investment.

5. Meets load growth and promotes economic development. In order to meet load growth or even a shift in demand, a TO often must upgrade an existing substation or line or add new facilities. Likewise, in order to meet a large customer's expansion plans or attract a new large commercial or industrial customer, a local utility must be able to provide the appropriate voltage level, MW capacity and redundancy to ensure high levels of reliability. Moreover, new substation investment can lead to even more transmission line investment opportunities in the future as the utility can tie into even more substations. This "networking effect" can lead to higher levels of reliability as additional facilities are added.

6. Ensures a "seat at the RTO table." Being an active transmission investor also involves participating in MISO committees, yielding insights that a utility would not otherwise gain. Sitting on these committees also enables a utility

[19] Median equity ratio is based on 33 MISO municipals.

[20] Assuming embedded cost of debt of 2.83%, the median for MISO municipals with long term debt.

[21] As part of the annual review process, stakeholders can challenge cost inputs but not the formula itself. The MISO standard ROE can be challenged by filing a Section 206 complaint at FERC.

to provide more input into RTO policy and surrounding utility investments, to be more proactive in identifying required projects, and to make the contacts necessary to ensure its projects are approved through the MTEP.

7. Provides lower transmission costs than the incumbent. Many JAAs, G&Ts, distribution cooperatives and some municipals with lower equity ratios can invest in transmission at a lower cost than an incumbent IOU, thus having a lower impact on zonal rates. The ATRR cost of the typical IOU/Transco in MISO is about 25% higher than the typical G&T and about 19% more than the typical T&D cooperative.[22] Cooperatives have this cost advantage largely from being tax-exempt, typically having a lower equity ratio and often having a lower cost of debt through tax-exempt or federally backed financing. For example, G&Ts or distribution cooperatives using the Rural Utilities Service ("RUS") can currently borrow at about 1.74% and public power "A" rated tax-exempt debt costs only about 2.05% for 30-year debt.[23]

The ATRR cost of the typical IOU/Transco in MISO is about 25% higher than the typical G&T and about 19% more than the typical T&D cooperative.

[22] See MCR white paper, "The Cooperative Cost Advantage: Another Reason Why Cooperatives Should be Investing in Transmission," February 2021.
[23] Interest rates as of November 11, 2021.

Figure 11
Growth Trends in MISO TO Investment

	Last 6 Years	Last 3 Years	Last Year
MISO Transmission Investment	$22.4 billion	$11.7 billion	$3.9 billion
Total Gross Transmission Plant Growth	64.0%	25.5%	7.2%
Compound Annual Growth Rate of Gross Transmission Plant	8.6%	7.9%	7.2%

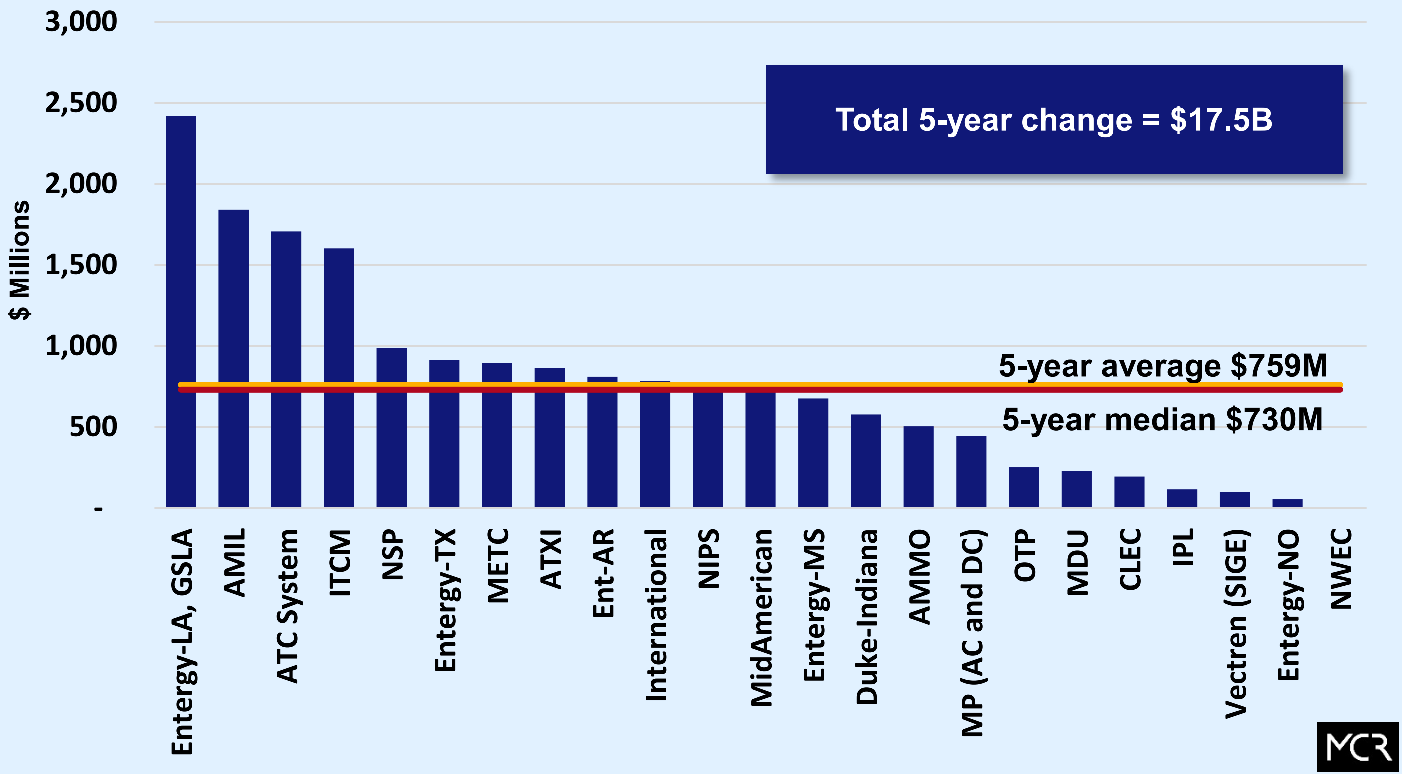
10. MCR's Annual Transmission Investment Analysis

Over the last six years, gross transmission plant has risen by a compound annual growth rate of 8.6%.

Strong MISO Transmission Investment Continues

MCR annually tracks the transmission investment and key metrics by industry segment; and as has been the case for many years now, transmission investment continues to be strong in MISO. The overall growth rate in gross transmission plant across all MISO transmission owners in 2021 was 7.2% compared to 7.7% in 2020 and 8.6% in 2019. Although this growth rate is down slightly from the past couple years, the transmission dollar investment in MISO continues to be strong. In 2021 gross transmission investment rose by $3.9 billion for all MISO TOs in the MCR Proprietary Transmission Investment & Load ("PTIL") database. This dollar increase is about the same as in 2020. Over the last six years, gross transmission plant has risen by a CAGR of 8.6%. Although slowing a bit over the last three years, investment has remained healthy with a CAGR of 7.9% (see Figure 11 above).

Figure 12
5-Year Change in Gross Transmission Plant Balance for MISO IOUs and Transcos (2016-2021)[24]



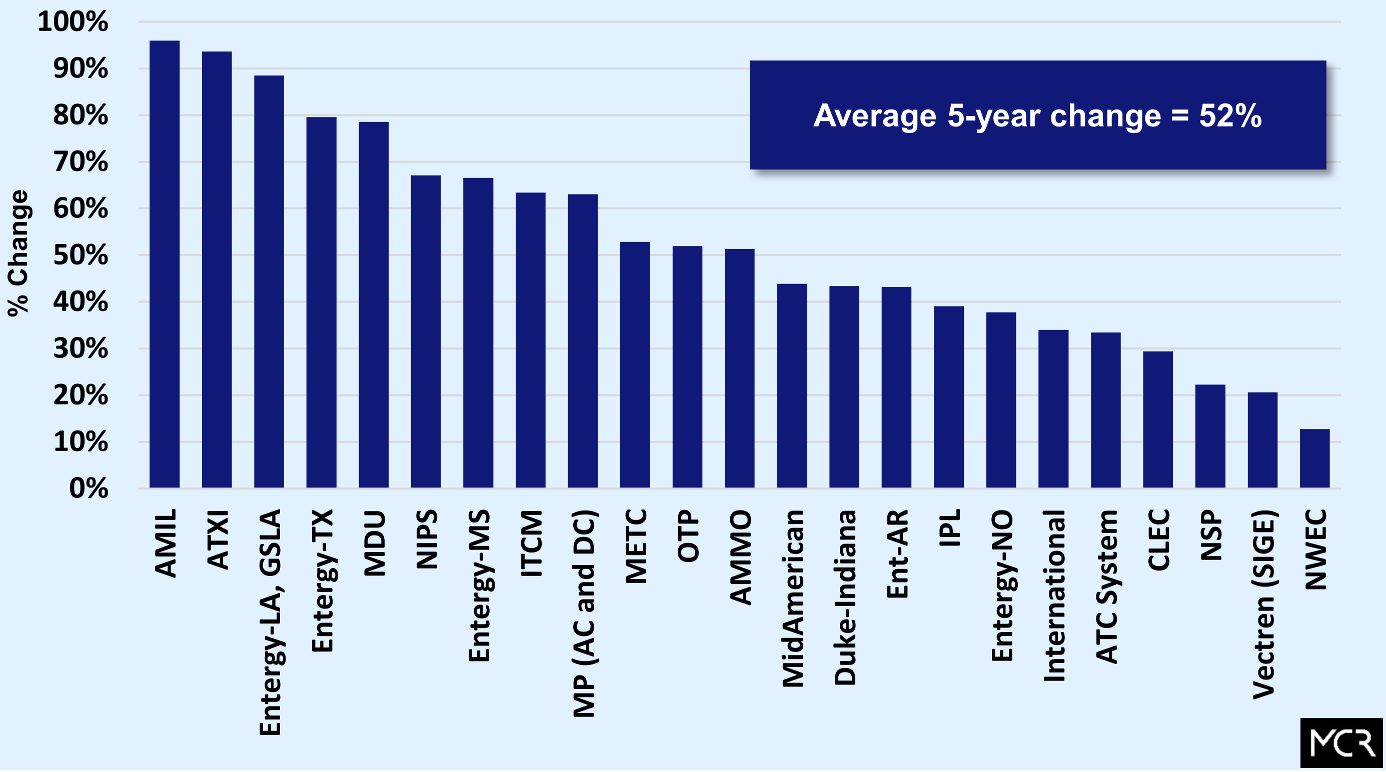
Which Transmission Owners Have Been Investing over the Last Five Years?

The change in gross transmission plant balances provides a strong proxy measure of the absolute levels of transmission capital investment for MISO's various transmission owners. MCR's PTIL database is updated each year with publicly-available transmission plant data, aggregated by five segments: IOU/Transcos, G&Ts, joint action agencies ("JAA's"), T&Ds, and Municipals.

The total change in gross transmission plant (see Figure 12 above) for MISO IOUs and Transcos was $17.5 billion over the last five years. The average change for the 23 IOUs and Transcos over the five years was $759 million (about $152 million per year), up slightly from last year's $741 million. Four IOU/Transcos had over $1.0 billion in transmission investment over the last five years.

[24] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os. Covers Schedule 9, 26 and 26-A investments. For those TOs with a projected test year, PTIL captures the change in projected data. For those companies using an historical test year, PTIL captures the change in previous end-of-year data. IOUs and Transcos are categorized together, because MISO Transcos are mostly owned by IOUs and/or are profit-making entities. Transmission gross plant compared rate year 2016 vs. rate year 2021 (i.e., the changes from 2016 to 2017, 2017 to 2018, 2018 to 2019, 2019 to 2020 and 2020 to 2021). Formula for investment = 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.

Figure 13
5-Year Percentage Change in Gross Transmission Plant Balance for MISO IOUs and Transcos (2016-2021)[25]



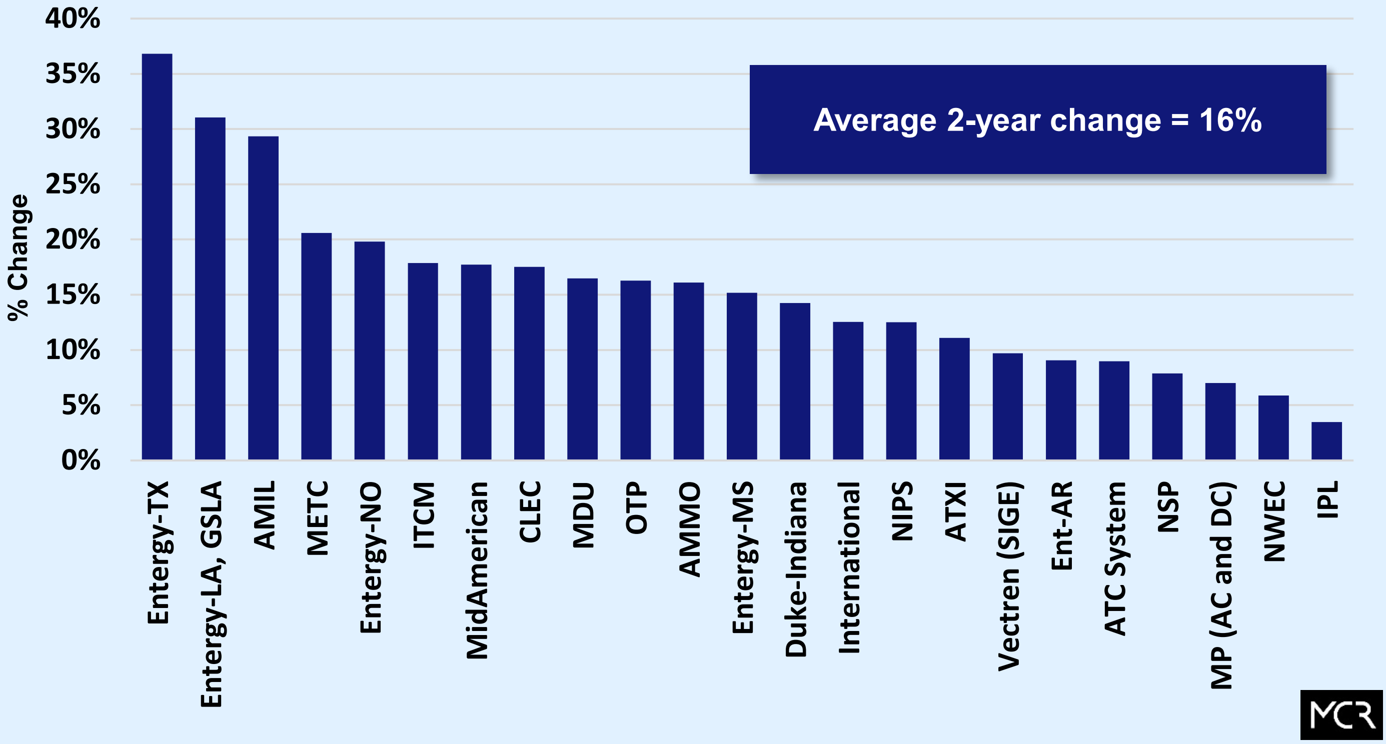
This $17.5 billion increase represented a 52% increase in transmission gross plant over the five years compared to a 55% five-year increase as of last year. This difference indicates that while the overall dollars invested increased, the segment's investment growth was slightly slower (see Figure 13). Ameren-Illinois ("AMIL") grew by a whopping 96% while Ameren Transmission Company of Illinois ("ATXI"), has grown by 94% over the last five years. Entergy-LA, Entergy-TX, and Montana Dakota Utilities ("MDU") showed five-year growth rates of 89%, 80% and 79%, respectively. At the low end of growth is NWEC with only a 13% change, Vectren at 21% and NSP at 22%.

The segment's median increase of 51% was nearly identical to the segment average and about equal to the 52% median increase over the previous five-year period. This continued strong 5-year growth is indicative of IOUs and Transcos continued high rates of overall transmission investment, which in turn, generate continued earnings growth. Despite ATC's relatively low growth of 33% over the last five years, it still had the third highest absolute level of investment at $1.7 billion due to its sheer size. Entergy-LA and Ameren-IL led the way at $2.4 billion and $1.8 billion, respectively.

[25] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os.

Figure 14

2-Year Percentage Change in Gross Transmission Plant Balance for MISO IOUs and Transcos (2016-2021)[26]



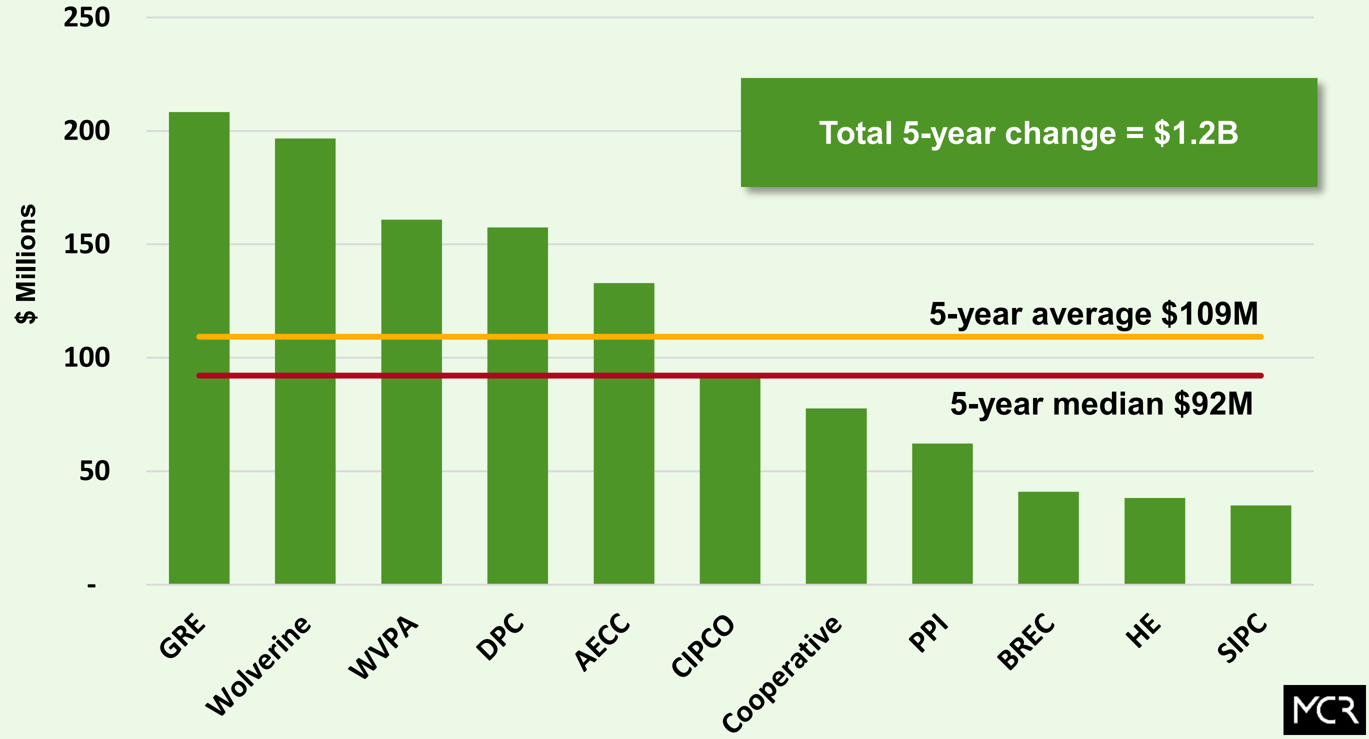
The past two years have shown similarly high levels of investment among the IOUs and Transcos, with an overall segment increase of 16% (see Figure 14). The segment median was 15%, indicating that the growth was widespread throughout the segment. The TOs with the largest percentage change through 2021 as compared to the ending 2019 balance were Entergy-TX at 37%, Entergy-LA at 31%, and AMIL at 29%.

Figures 15 through 26 on the following pages show the changes in gross transmission plant, both in dollar and percentage terms, over the last five years for MISO G&T, JAA, T&D, and Municipal TOs. MISO G&Ts have shown consistent investment levels in the five-year period through 2021 ($1.2 billion, see Figure 15 on the next page) which held steady for the five-year period ending 2020 ($1.2 billion). The median fell slightly from $101 million to $92 million for the five-year period ending 2021. Great River Energy ("GRE") at $208 million and Wolverine Power Cooperative ("WPC") at $197 million led the group this year, followed by Wabash Valley Power Alliance ("WVPA") at $161 million and Dairyland Power Cooperative ("DPC") at $157 million.

The overall five-year percentage change in gross transmission plant for all G&Ts remained steady at 34% this year with a median of 33%, down from last year's 40% (see Figure 16 on the next page). Arkansas Electric Cooperative Corporation ("AECC") led with a 102% increase followed by WVPA at 86% and WPC and Prairie Power ("PPI"), both at 70%.

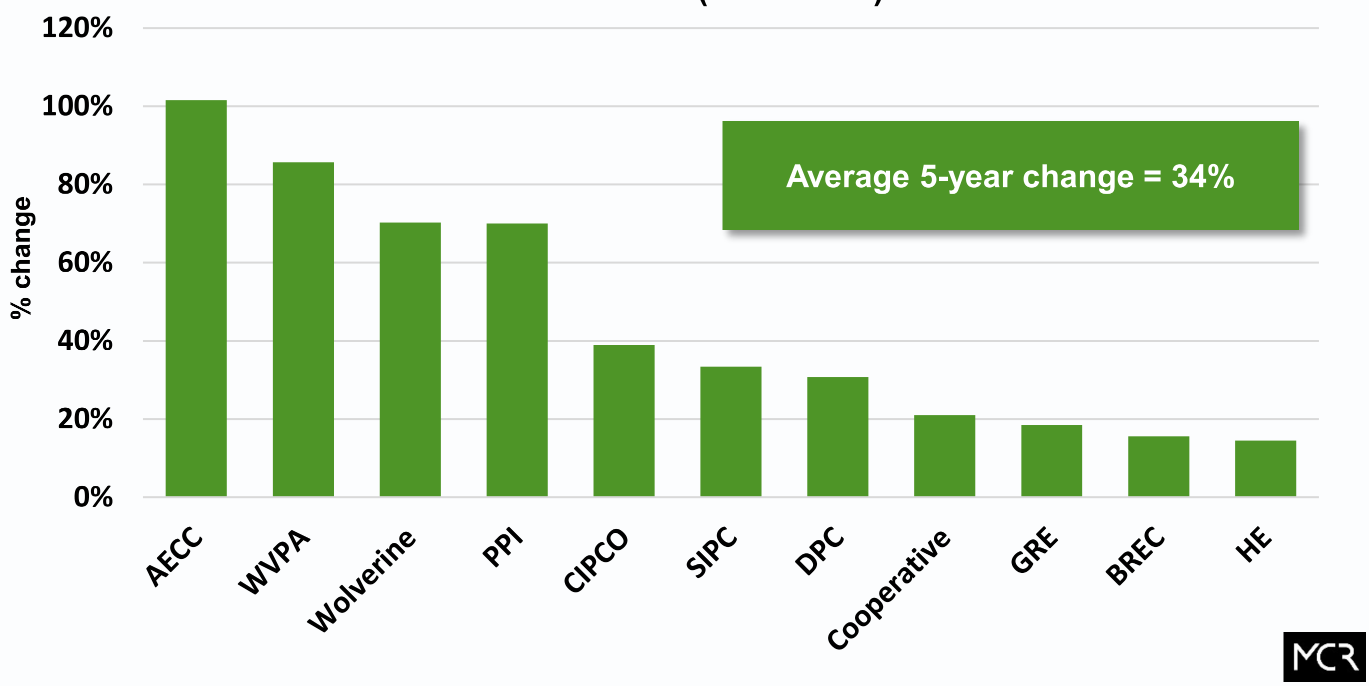
[26] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

Figure 15
5-Year Change in Gross Transmission Plant Balance for MISO G&Ts (2016-2021)[27]



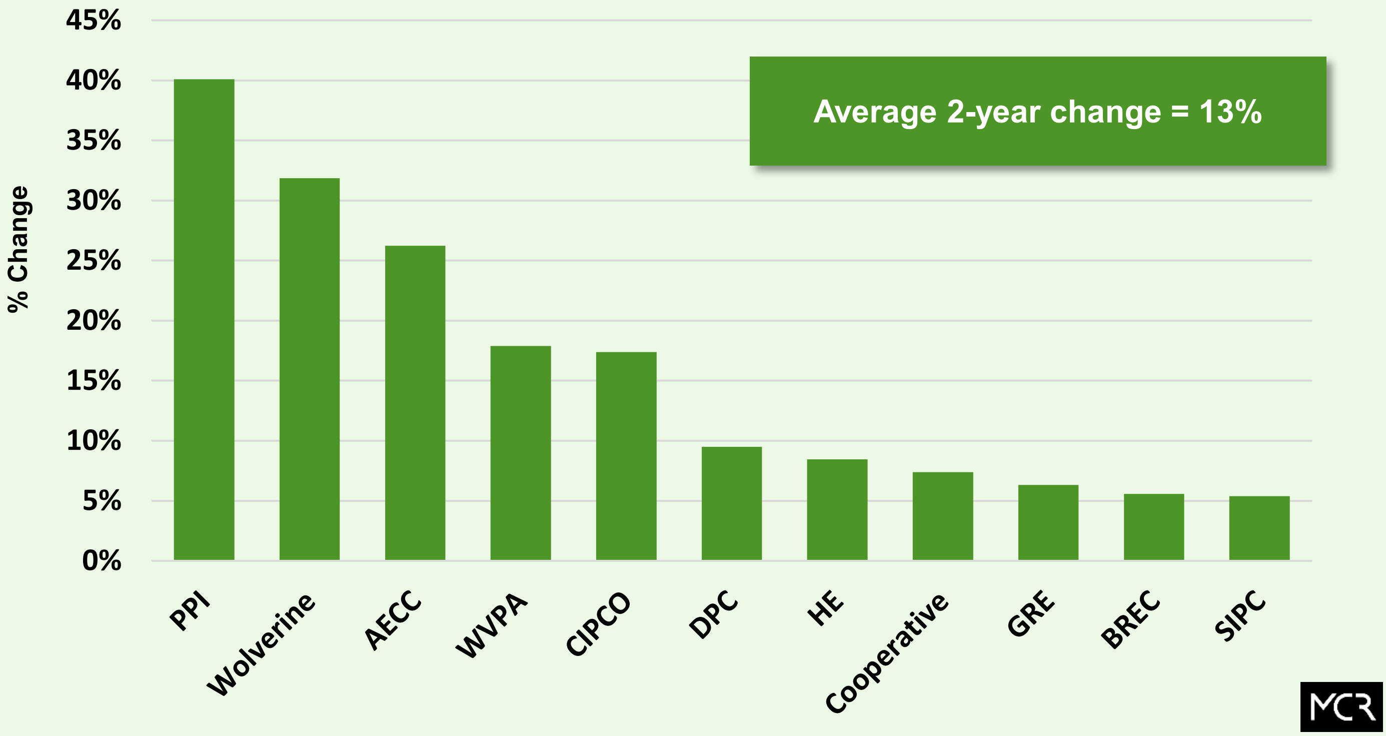
[27] Reflects the 10 MISO G&T transmission owners, plus CIPCO (which files an Attachment O but is not a MISO TO). Does not include Minnkota Power Cooperative (which is not a MISO TO and does not file an Attachment O).

Figure 16
5-Year Percentage Change in Gross Transmission Plant Balance for MISO G&Ts (2016-2021)[28]



[28] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os.

Figure 17
2-Year Percentage Change in Gross Transmission Plant Balance for MISO G&Ts (2016-2021)[29]



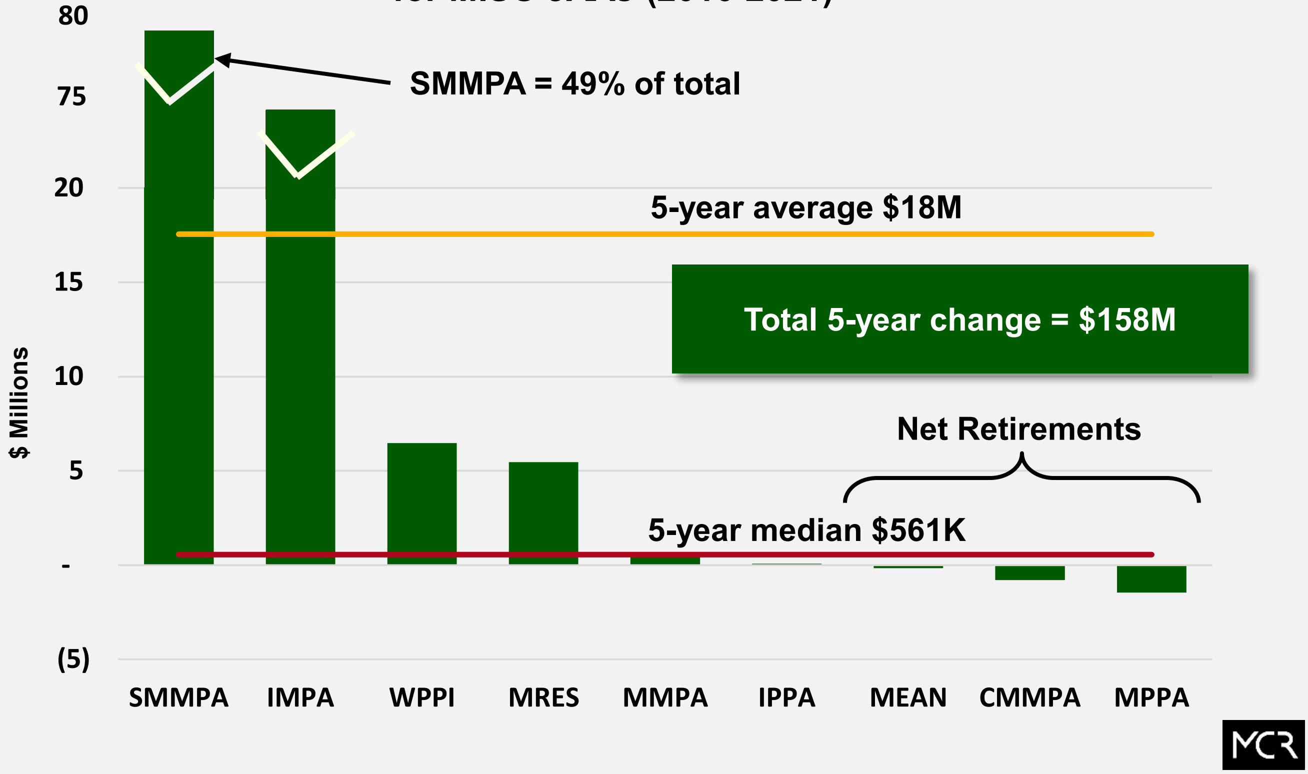
Though the G&T segment showed strong investment over the five-year period, its overall percentage change of 34% is well short of the 52% change of IOU/Transcos over the last five years.

Though the G&T segment showed strong investment over the five-year period, its overall percentage change of 34% is well short of the 52% change of IOU/Transcos.

The MISO G&Ts showed a 13% overall segment growth over the most recent two years compared to the prior two-year period ending 2020. PPI, WPC and AECC led with two-year growth rates of 40%, 32% and 26%, respectively (see Figure 17 above). The two-year G&T segment change of 13% still lags behind the IOU/Transco segment change of 16% for the same time period.

[29] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

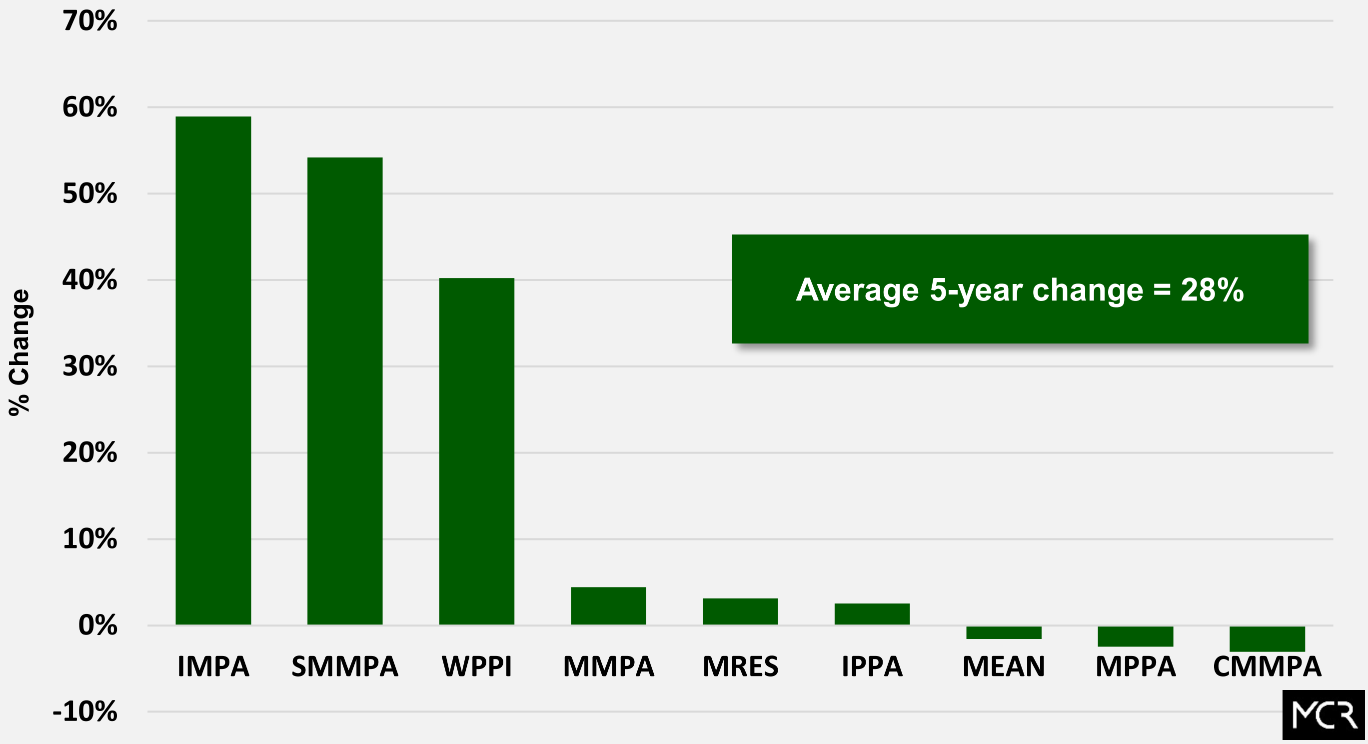
Figure 18
5-Year Change in Gross Transmission Plant Balance for MISO JAAs (2016-2021)[30]



MISO's JAA transmission owners increased their gross transmission plant by $158 million over the past five years (see Figure 18 above), down from an increase of $202 million for the five-year period ending last year. IMPA and SMMPA comprised about $148 million (94%) of the total $158 million increase. They were followed by WPPI Energy and Missouri River Energy Services ("MRES") at $6.5 million and $5.5 million, respectively. The remaining four JAAs had less than $1 million or had net retirements. The difference between the average ($18 million) and the median (only $561K) highlights the concentration in two of the JAAs.

[30] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

Figure 19
5-Year Change in Gross Transmission Plant Balance for MISO JAAs (2016-2021)[31]



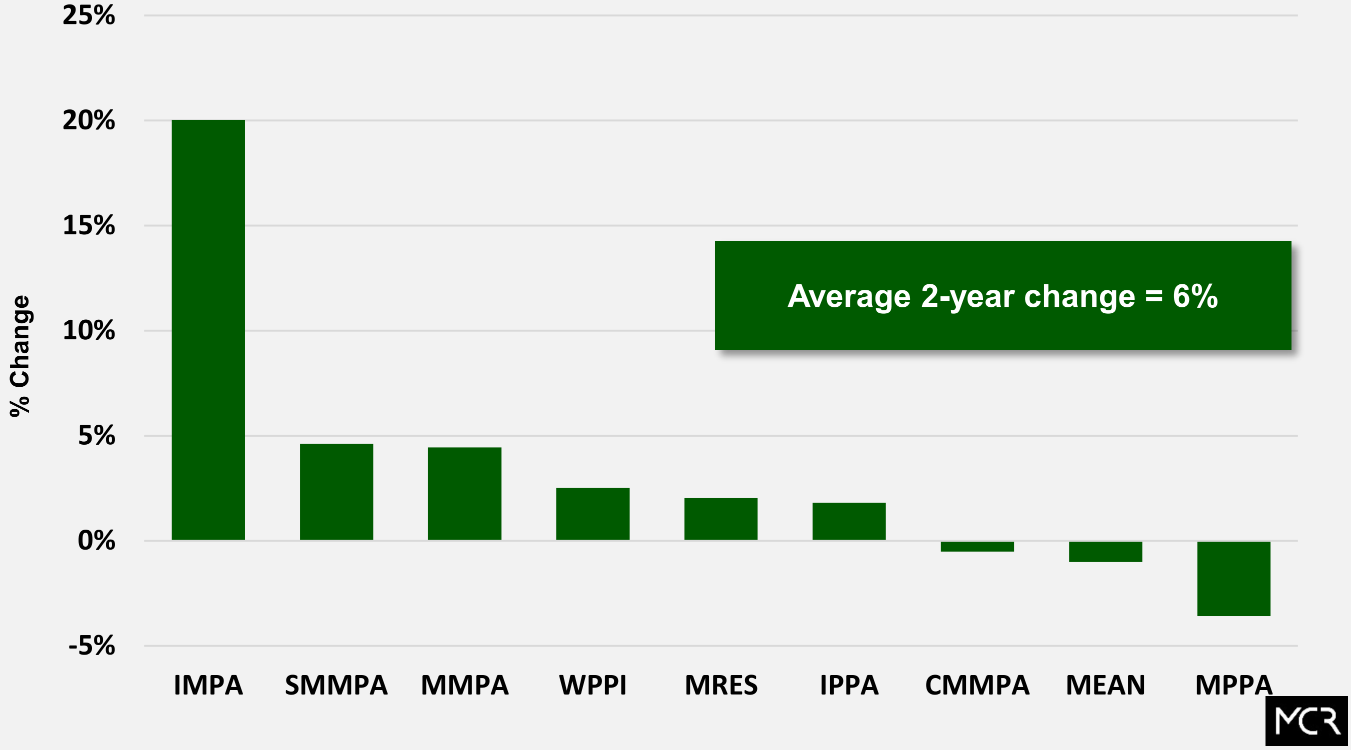
Three of the nine JAA TOs (IMPA, SMMPA, and WPPI) comprised nearly all of the growth with increases of 59%, 54% and 40% (see Figure 19 above). The remaining six JAA TOs were at 4% or less growth. This disparity is highlighted by the fact that the segment average five-year percentage increase was 28% but the median increase was only 3%.

The JAA segment's five-year investment continued to slow from prior five-year periods, largely reflecting the end of Capx2020 projects.

The JAA segment's five-year investment continued to slow from prior five-year periods (40% for the 5-year period ending in 2020 and 68% for the 5-year period ending in 2019), largely reflecting the end of Capx2020 projects.

[31] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

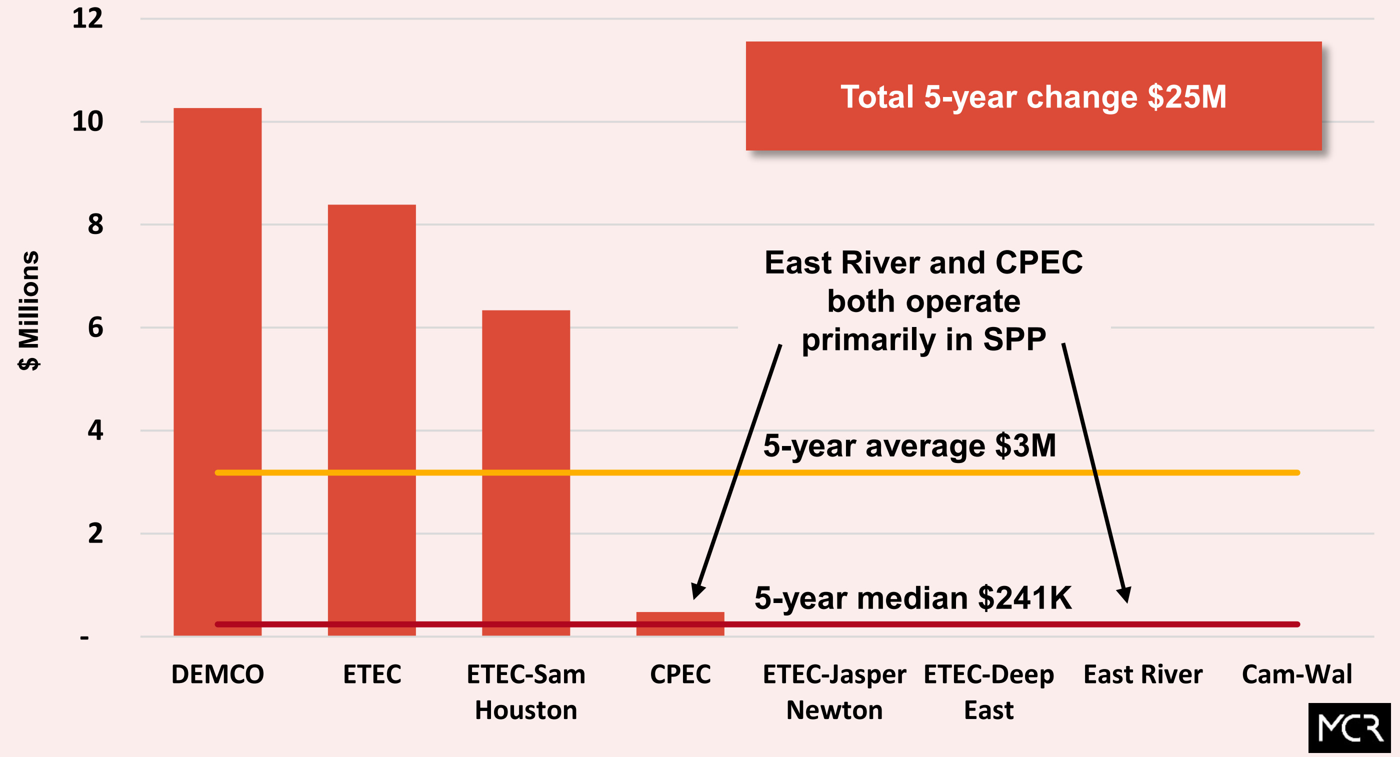
Figure 20
2-Year Change in Gross Transmission Plant Balance for MISO JAAs (2016-2021)[32]



The slowdown in transmission investment in the JAA segment is highlighted even further by examining the last two years of investment (see Figure 20 above). The segment increased by only 6%, down from the 9% growth for the two-year period ending 2020 and the 11% growth for the two-year period ending 2019. IMPA led the segment by far with a 20% increase over the two-year period. The median segment increase remained very low at just 2% and is indicative of continued low levels of investment from several JAAs.

[32] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

Figure 21
5-Year Change in Gross Transmission Plant Balance for MISO T&Ds (2016-2021)[33]

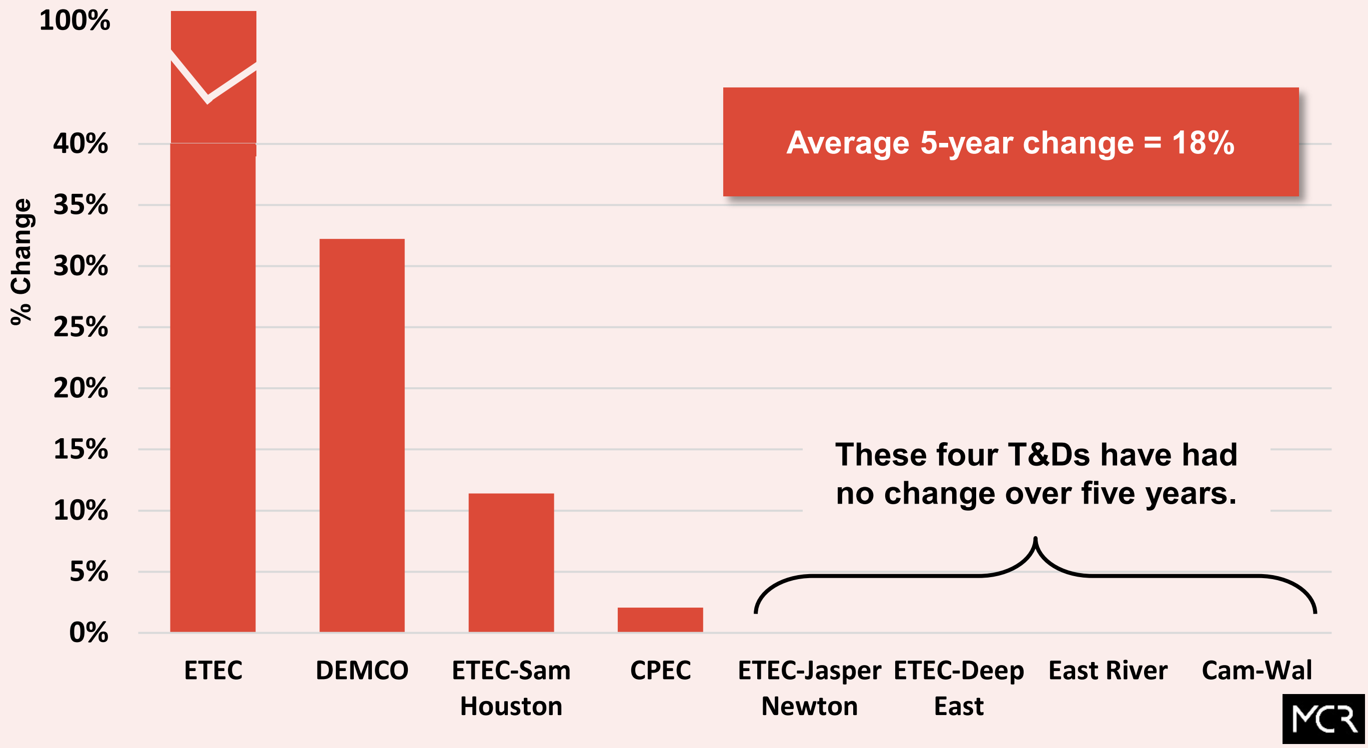


The T&D cooperative segment's overall five-year change in gross transmission plant totaled only $25 million, down from the $36 million in the prior five-year period (see Figure 21 above). DEMCO, East Texas Electric Cooperative ("ETEC") and ETEC-Sam Houston had the greatest dollar change over the five-year period with $10.3 million, $8.4 million and $6.3 million increases, respectively. The median was a mere $241K, reflecting that four T&D cooperatives did not increase their gross transmission plant balances over the last five years.

Note that East River and Central Power Electric Cooperative ("CPEC") are T&D cooperatives primarily in Southwest Power Pool ("SPP"), so the cooperatives' lack of investment in MISO is not in any way indicative of overall company transmission investments.

[33] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

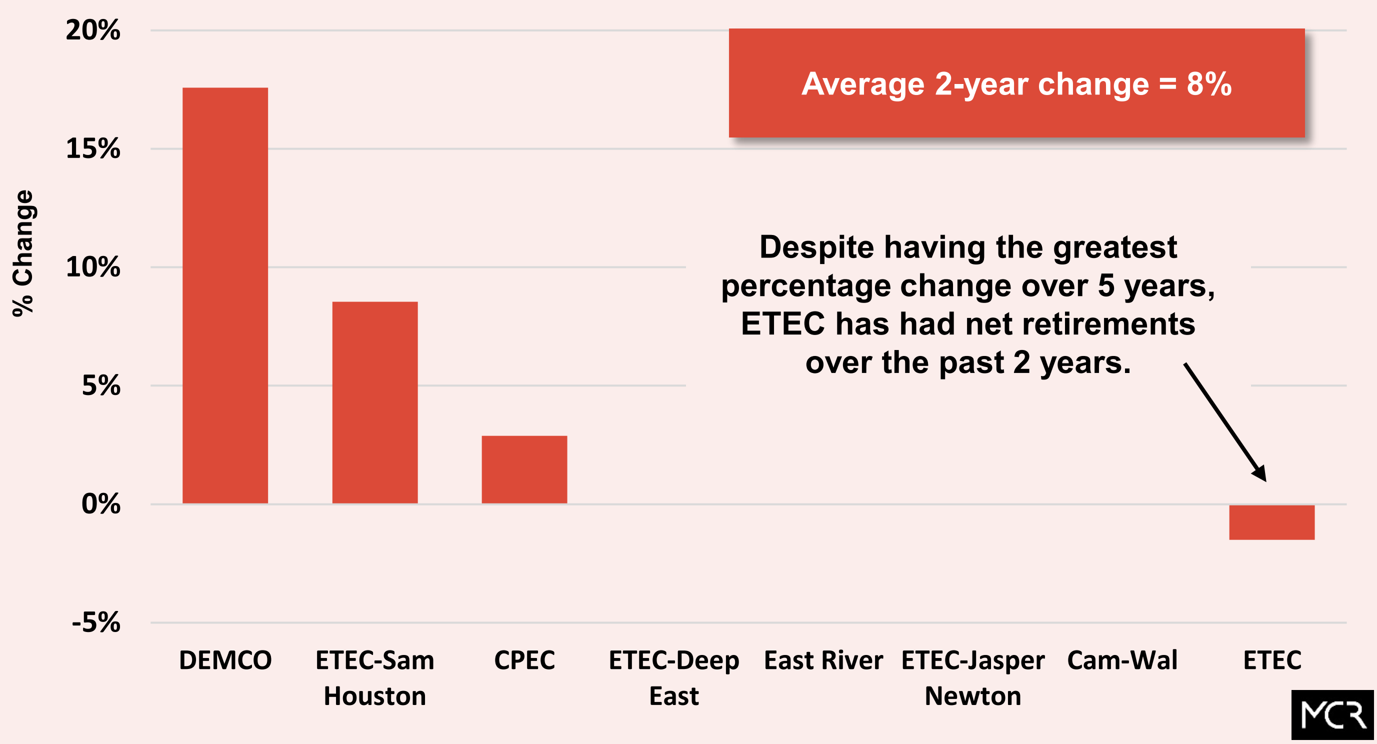
Figure 22
5-Year Percentage Change in Gross Transmission Plant Balance for MISO T&Ds (2016-2021)[34]



MISO T&Ds' five-year percentage change of 18% is the lowest of the five segments for 2021. The five-year percent change chart (Figure 22 above) is dominated by a 103% increase for ETEC due primarily to their merger with TEX-LA Cooperative. DEMCO showed five-year growth of 32% and Sam Houston at 11%. The dearth of investment for MISO T&Ds is evidenced by a median of only 1% growth over the entire five-year period.

[34] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

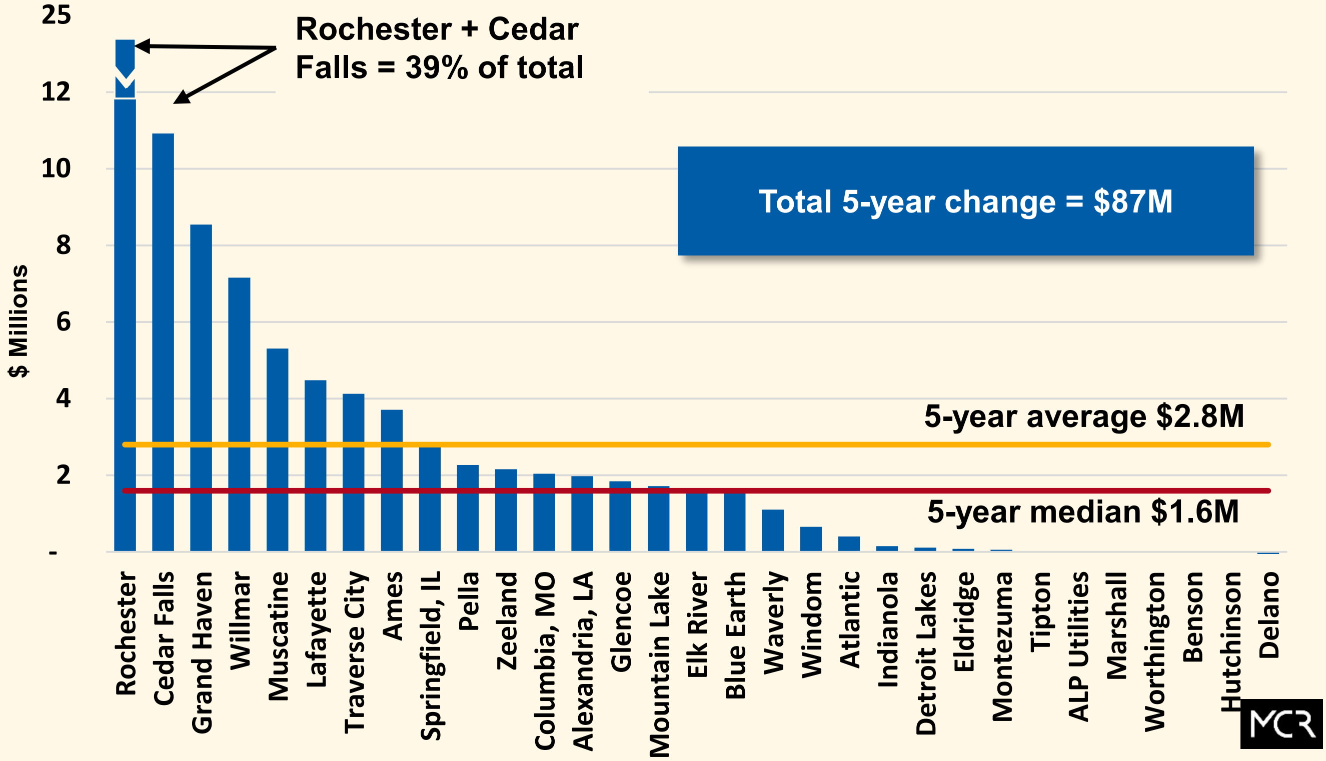
Figure 23
2-Year Percentage Change in Gross Transmission Plant Balance for MISO T&Ds (2016-2021)[35]



The investment for the T&D segment over the most recent two-year period, grew by only 8% with DEMCO and Sam Houston showing growth of 18% and 9%, respectively (see Figure 23 above). The median percentage change was 0%, highlighting again the lack of widespread transmission investment in this segment.

[35] Source: MCR PTIL database based on June 2019-2021 MISO Attachment Os.

Figure 24
5-Year Change in Gross Transmission Plant Balance for MISO Municipals (2016-2021)[36]



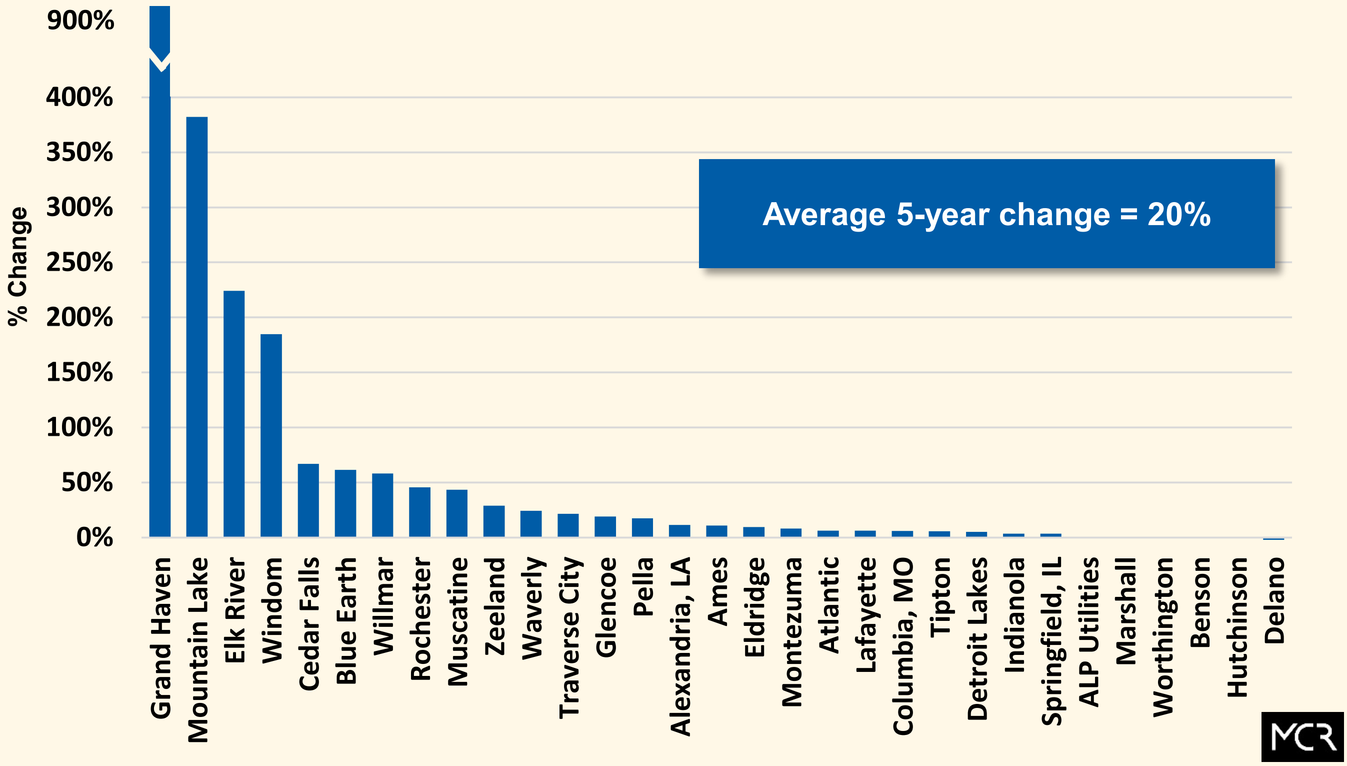
This year, there was less concentration of Municipal investment as the difference between the average and median narrowed.

MISO Municipal transmission owners had a five-year overall change in gross transmission plant of $87 million (see Figure 24 above), down significantly from $103 million and $114 million in the prior two five-year periods. The top investors in transmission were Rochester, MN; Cedar Falls, IA; Grand Haven, MI; Willmar, MN; Muscatine, IA; Lafayette, LA; Traverse City, MI; and Ames, IA. Grand Haven has gone from near last in transmission investment level three years ago to one of the top Municipals through their replacement and expansion of their transmission system.

On the positive side, this year there was less concentration of Municipal investment as the difference between the average and median narrowed--from a $3.3 million average and $1.5 million median last year to a $2.8 million average and $1.6 million median in the most recent five-year period.

[36] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os. Does not include cities of Henderson, KY and Breckenridge, MN which do not have sufficient years of data.

Figure 25
5-Year Percentage Change in Gross Transmission Plant Balance for MISO Municipals (2016-2021)[37]

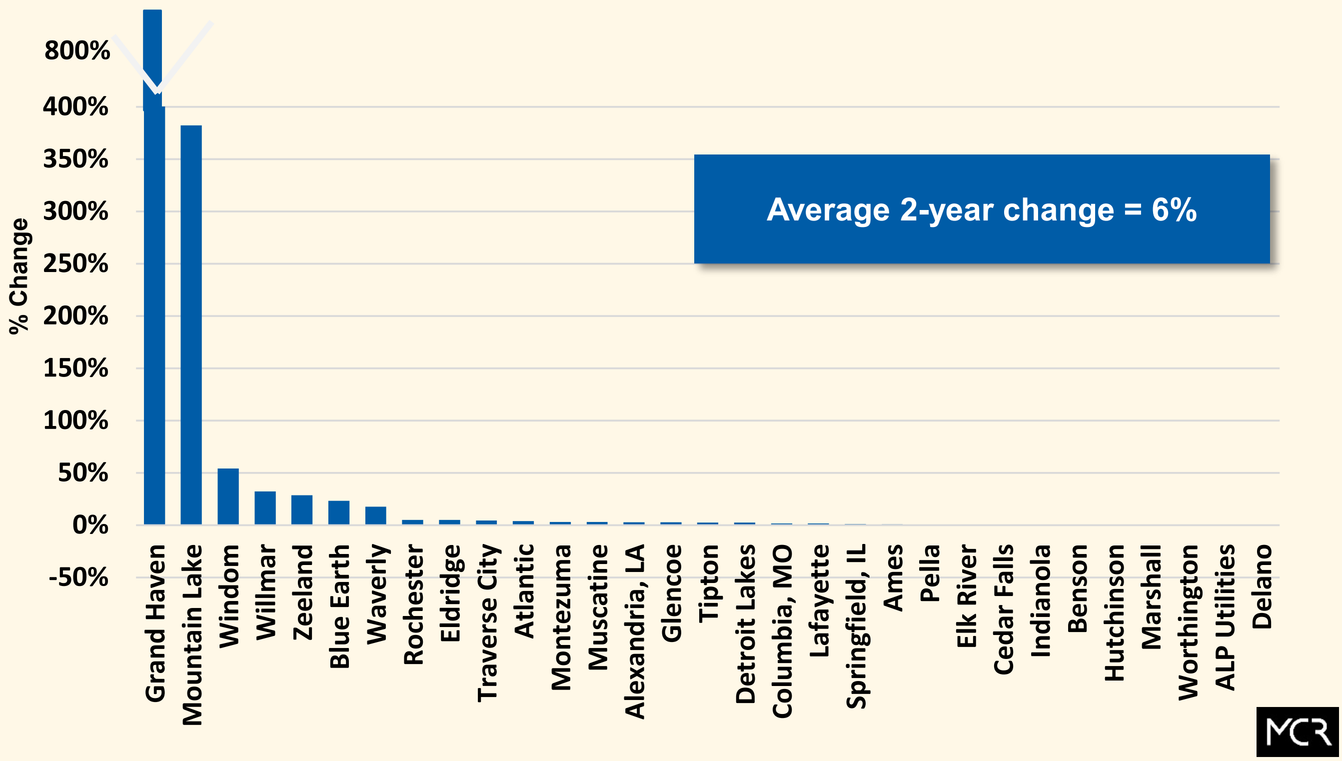


The five-year percentage change for MISO Municipals was 20% (see Figure 25 above), down from 25% and 35% during the prior two 5-year periods. Grand Haven had the largest percentage increase over the period (921%) followed by Mountain Lake (382%), Elk River (224%) and Windom (185%). Still, nearly half (15) of the 31 Municipals had five-year percentage increases of less than 10% over the last five years, indicating that there remains substantial investment potential for Municipals, particularly in the replacement/upgrade of their transmission facilities.

Nearly half of the 31 Municipals had five-year percentage increases of less than 10% in the last five years.

[37] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os.

Figure 26
2-Year Change in Gross Transmission Plant Balance for MISO Municipals (2016-2021)[38]



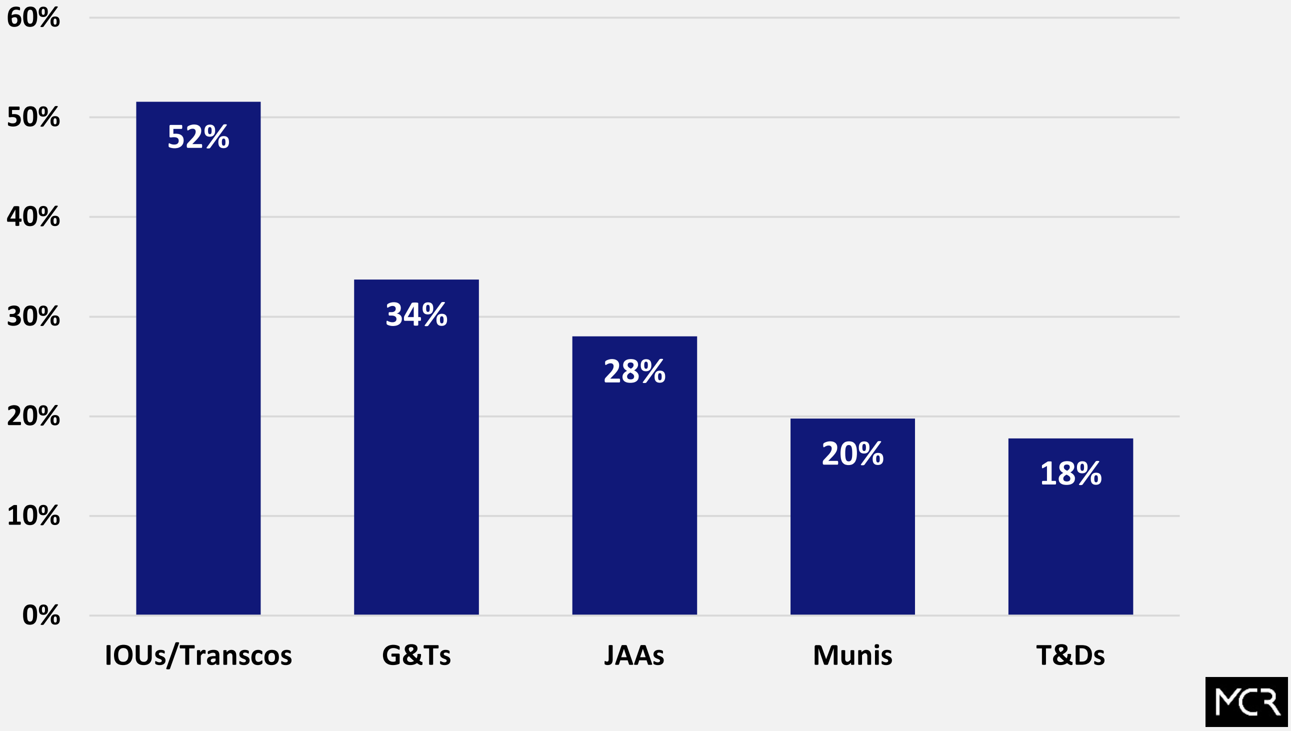
This lack of investment by Municipals is particularly perplexing because 27 of these 31 Municipals are in joint pricing zones.

When looking at the percentage change over the last two years only, Grand Haven (853%), Mountain Lake (382%) Windom (54%), Willmar (32%) Zeeland, MI (29%) and Blue Earth MN (23%) led the Municipal segment.

Overall, however, the segment had a weighted average increase of just 6% (see Figure 26 above) over the two-year period, just above the T&D cooperative segment and identical to last year's change. A surprising 20 of the 31 Municipals had a two-year change in transmission gross plant of less than 3%, indicating that most Municipals are not consistently investing in, or replacing their aging transmission systems. This lack of investment by Municipals is particularly perplexing because 27 of these 31 Municipals are in joint pricing zones, where the vast majority of the costs are paid for by customers other than their own.

[38] Source: MCR PTIL database based on June 2016-2021 MISO Attachment Os.

Figure 27
5-Year Percentage Change Compared to 2015 Ending Balance for MISO Transmission Owner Segment[39]



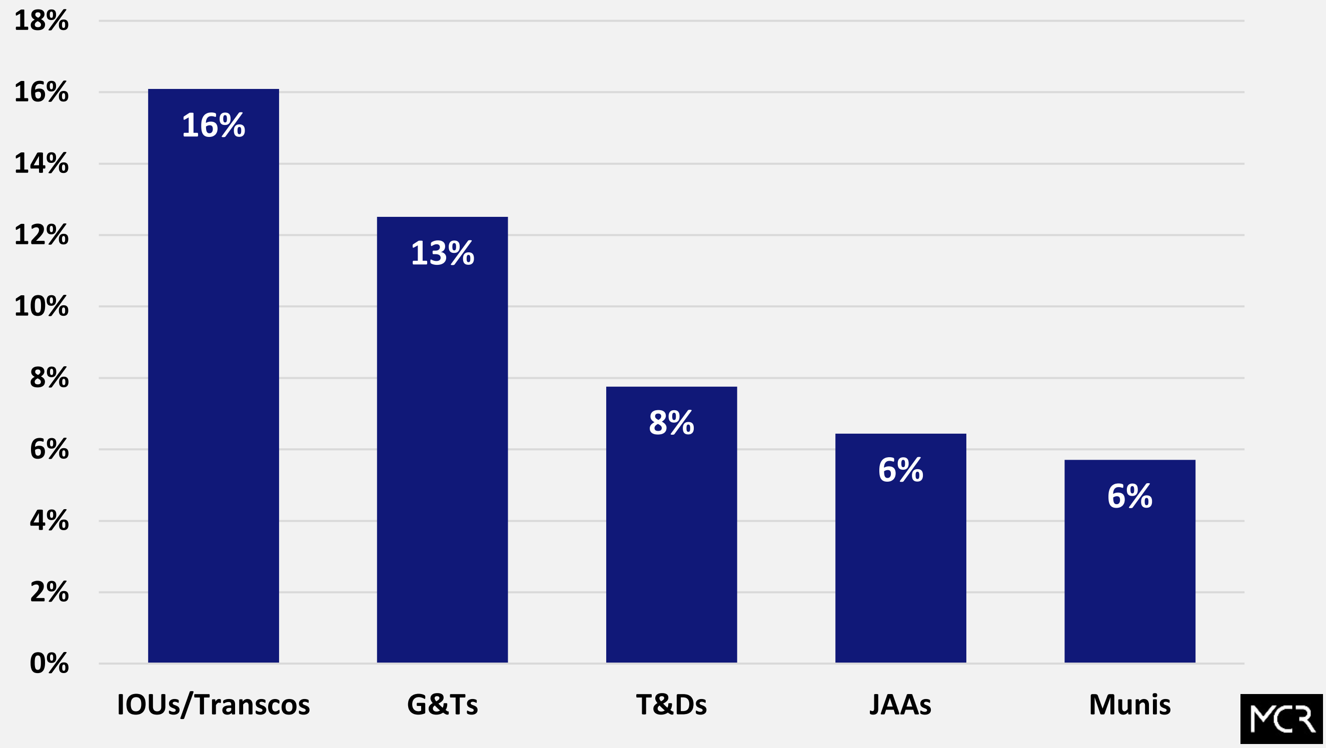
What is the Difference in the Growth Rate of the Groups?

Figures 27 and 28 summarize the five- and two-year growth rates exhibited by each segment. Over the last five years, IOU/Transcos far outpaced the rest of the segments with an increase of 52%. This compares with 55% last year. G&Ts showed an increase of 34% (compared to last year's 35%) followed by JAAs at 28% (vs. 40% last year), Municipals at 20% (vs. 25% last year) and T&D cooperatives at 18% (vs. 29% last year). JAAs experienced the largest decline compared to last year's five-year change.

IOU/Transcos far outpaced the rest of the segments with an increase of 52%.

[39] Source: June 2016-2021 MISO Attachment Os, which show gross transmission plant. Represents weighted averages for each group. Companies must be in entire 5-year period to be included.

Figure 28
2-Year Percentage Change Compared to 2018 Ending Balance for MISO Transmission Owner Segment[40]



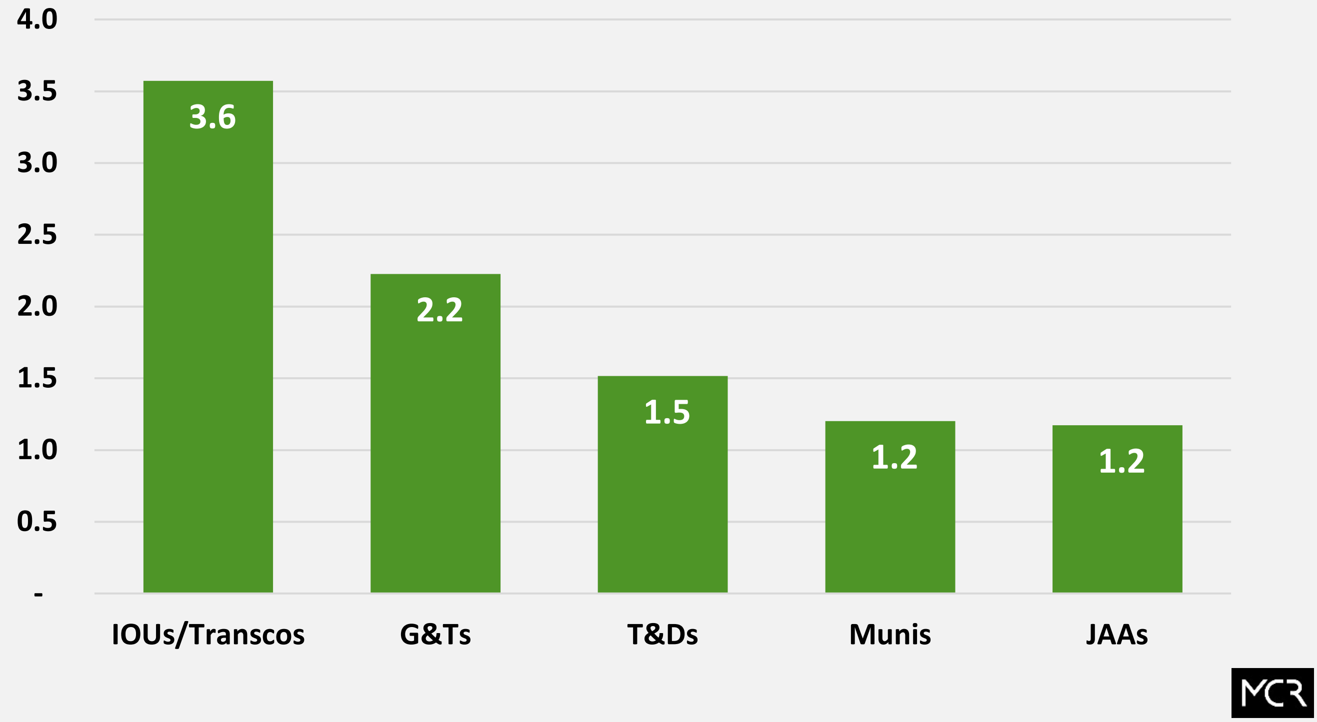
Every segment experienced a decrease in this transmission to depreciation ratio.

The two-year percentage increases are not much different than the increases seen in last year's study. Figure 28 above shows IOU/Transcos had a 16% five-year growth rate (vs. 18% last year) and G&Ts came in at 13% (vs. 11% last year). The two-year growth rate for JAAs was at 6% (down from 9%) and Municipals saw a 6% change, which stayed the same as last year. T&Ds rose from a 2% change last year to this year's 8%.

Figure 29 on the next page shows MCR's change in gross transmission plant to depreciation expense metric over the most recent two years, which quantifies how fast each segment is investing relative to transmission depreciation expense; it is a measure of investment intensity. Every segment experienced a decrease in this transmission to depreciation ratio versus the two-year period ending last year, indicating the pace of investment is slowing

[40] Source: June 2019-2021 MISO Attachment Os, which show gross transmission plant. Represents weighted averages for each group.

Figure 29
Change in Gross Transmission Plant Balance Compared to Depreciation Expense for MISO Transmission Owners (2019-2021)[41]



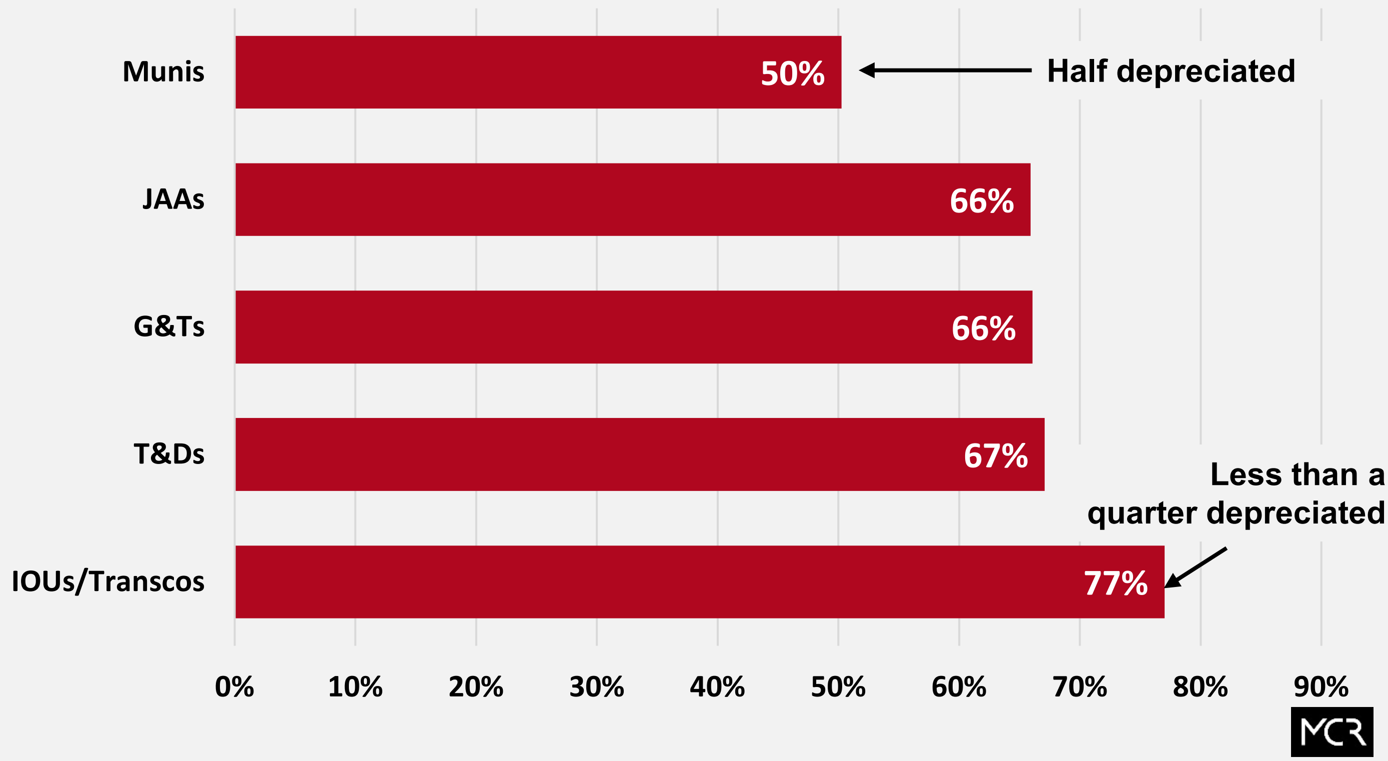
a bit. MISO IOU/Transcos made transmission investments at an average rate of 3.6 times transmission depreciation expense, down from a rate of 4.2 times during the two-year period ending last year—but still a very healthy investment rate. Of the 23 IOU/Transcos, only IPL (0.7) and NWEC (0.9) had a ratio of less than one. G&Ts had average ratio of 2.2, down slightly from 2.3 last year. It is noteworthy that all 11 G&Ts had transmission investment to deprecation ratios greater than one, indicating solid and widespread investment in that segment. The T&D segment had a ratio of 1.5 times depreciation expense down from last year's 1.9. JAAs had a rate of 1.2, down considerably from the 2.8 last year; and Municipals were also at 1.2, down from 1.7 last year.

All 11 G&Ts had transmission investment to deprecation ratios greater than one.

In dramatic contrast to the IOU/Transco and G&T segments, over the last two years, eight of nine JAAs, six of eight T&Ds, and 22 of the 31 Municipals had ratios less than one, indicating that they have not been investing at a level to at least replace their depreciation expense.

[41] Source: June 2019-2021 MISO Attachment Os. For those TOs using the cash flow template, depreciation expense was estimated based on Attachment O data and the annual financial statements. Represents weighted averages for each group. Shows total change in transmission gross plant in last two years divided by two years of depreciation expense.

Figure 30
2021 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO Owners of Transmission[42]



Which Transmission Owners Have the Newest Plant?
The ratio of net transmission plant to gross transmission plant provides a view of the average age of each segment's transmission plant, with higher percentages indicating newer plant. IOU/Transcos have the newest transmission assets with their combined net transmission plant equaling 77% of their gross transmission plant (see Figure 30 above), the same as in 2020. T&Ds have the second newest plant on average with 67%, becoming slightly newer than last year's 64%; G&Ts held steady at 66% with JAAs down slightly at 66% from 67% last year. Municipals, on average, aged slightly with a 50% ratio versus 52% last year and 53% in 2019.

It is interesting to see that despite some noteworthy investments mentioned previously, Municipal systems, on average, are getting older rather than newer, as defined by this metric. By contrast, IOU/Transcos and G&Ts are investing at robust rates and staying at the same level of net plant to gross plant.

[42] Source: June 2021 MISO Attachment Os. Percentages in graph 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 31
2021 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO IOUs and Transcos[43]

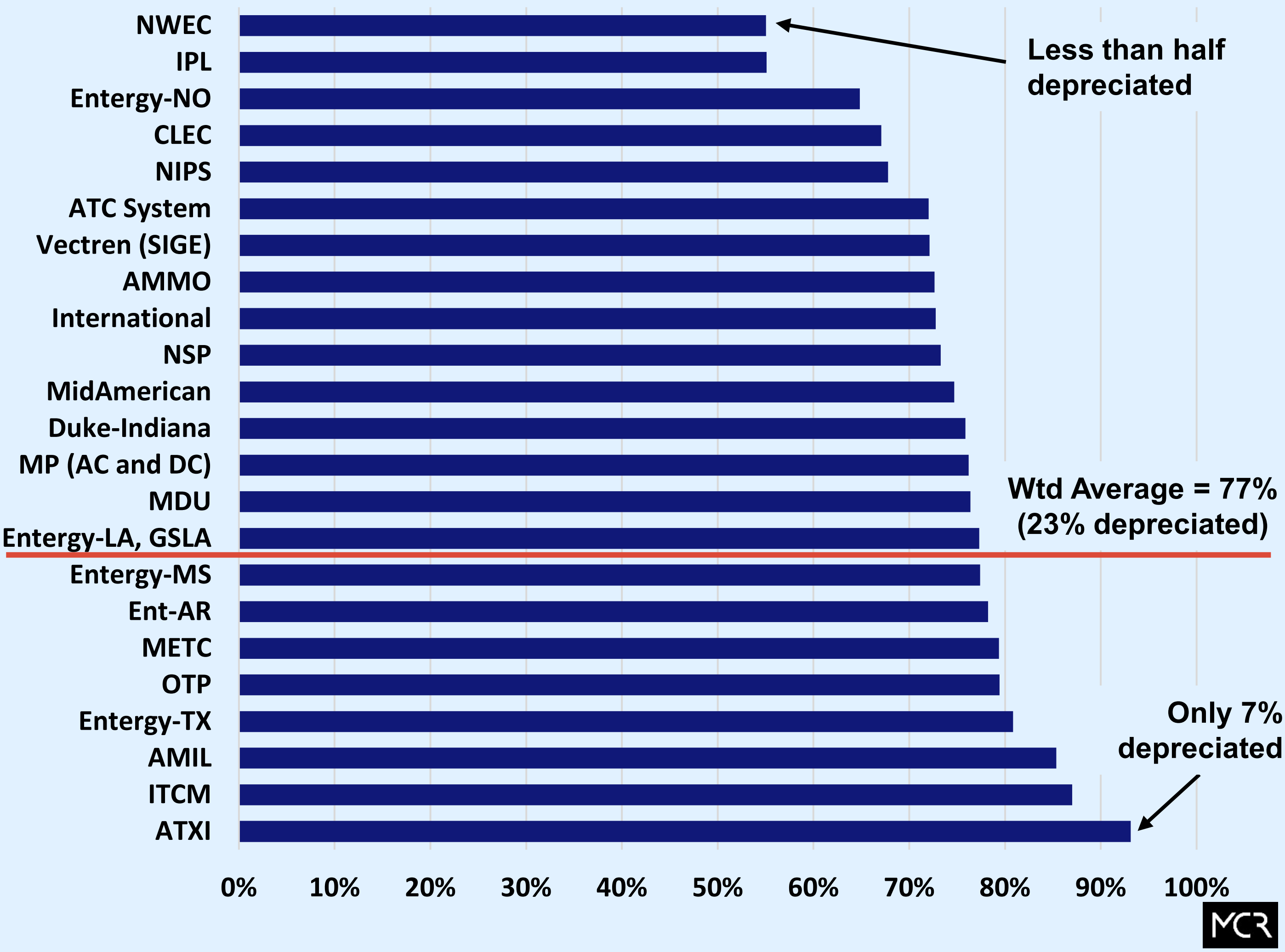
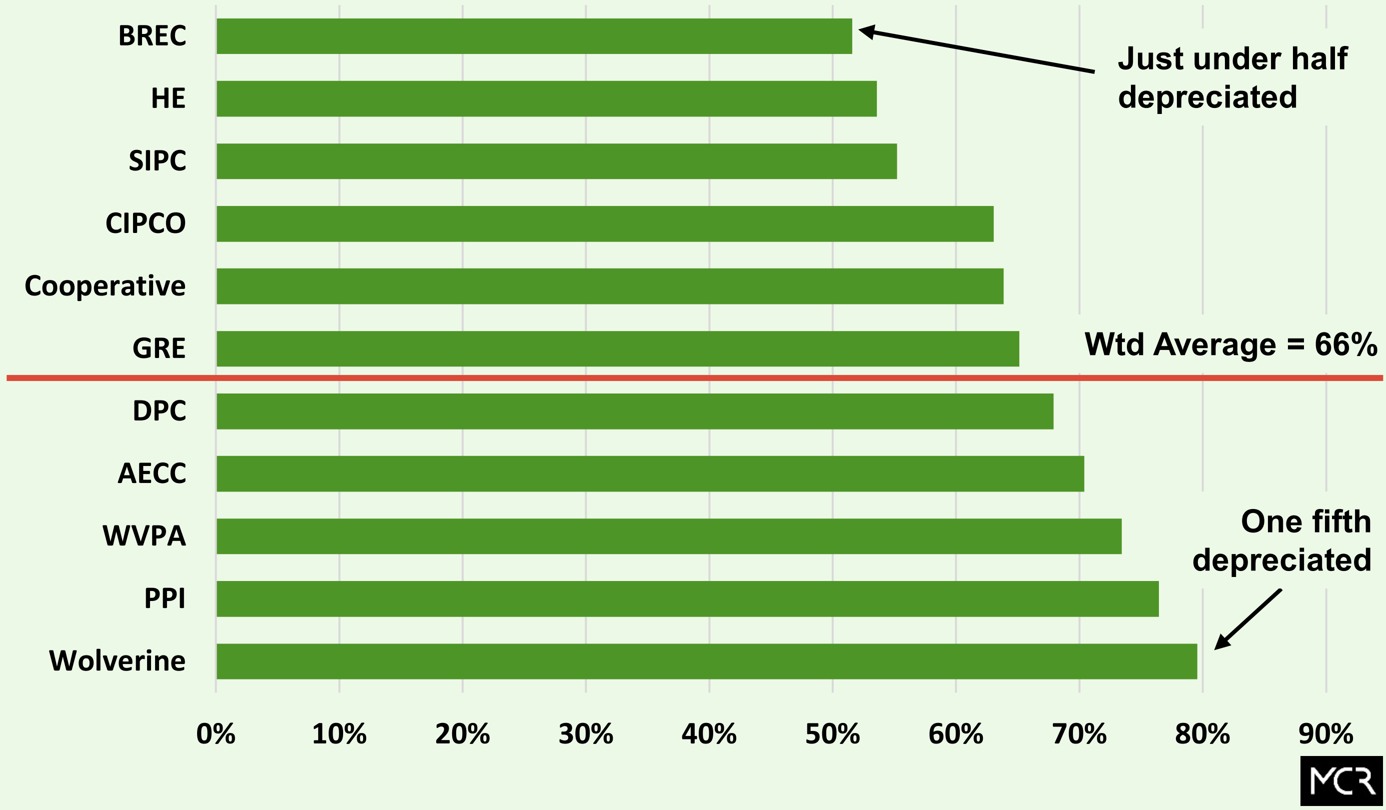


Figure 31 shows the detail of net transmission plant as a percent of gross transmission plant for each IOU/Transco. Two Transcos, ATXI and ITC-Midwest ("ITCM"), continue to lead the group with 93% and 87%, respectively. AM-IL follows at 85% and Entergy-TX at 81%. Minnesota Power ("MP") has had the largest consistent increases from year-to-year, jumping from 67% in 2019 to 73% in 2020 and by three more percentage points to 76% in 2021. It's important to note that while the average asset age of many TOs in the IOU/Transcos segment is relatively new, there is still room for many IOU/Transcos to invest considerable amounts. As discussed previously, the age of facilities is just one of a myriad of reasons for investing in transmission. Given that transmission investment provides relatively high returns, it will continue to be an earnings driver coveted by the investment community.

[43] Source: June 2021 MISO Attachment Os.

Figure 32
2021 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO G&Ts[44]



For G&Ts, Wolverine, PPI and WVPA have the newest transmission plant on average, whereas Big Rivers Electric Corporation ("BREC"), Hoosier Energy ("HE") and SIPC have the oldest transmission plant (see Figure 32 above). PPI jumped three points from 73% to 76%, reflecting their continued recent investment. Many G&Ts still have room to upgrade facilities, but the lack of investment by four G&Ts with the most depreciated assets may be influenced by the issue discussed previously in Section 2 of single member zones vs. joint zones. That is, BREC, SIPC, Hoosier, and CIPCO have little/no other loads in their zones/areas to share in their costs.

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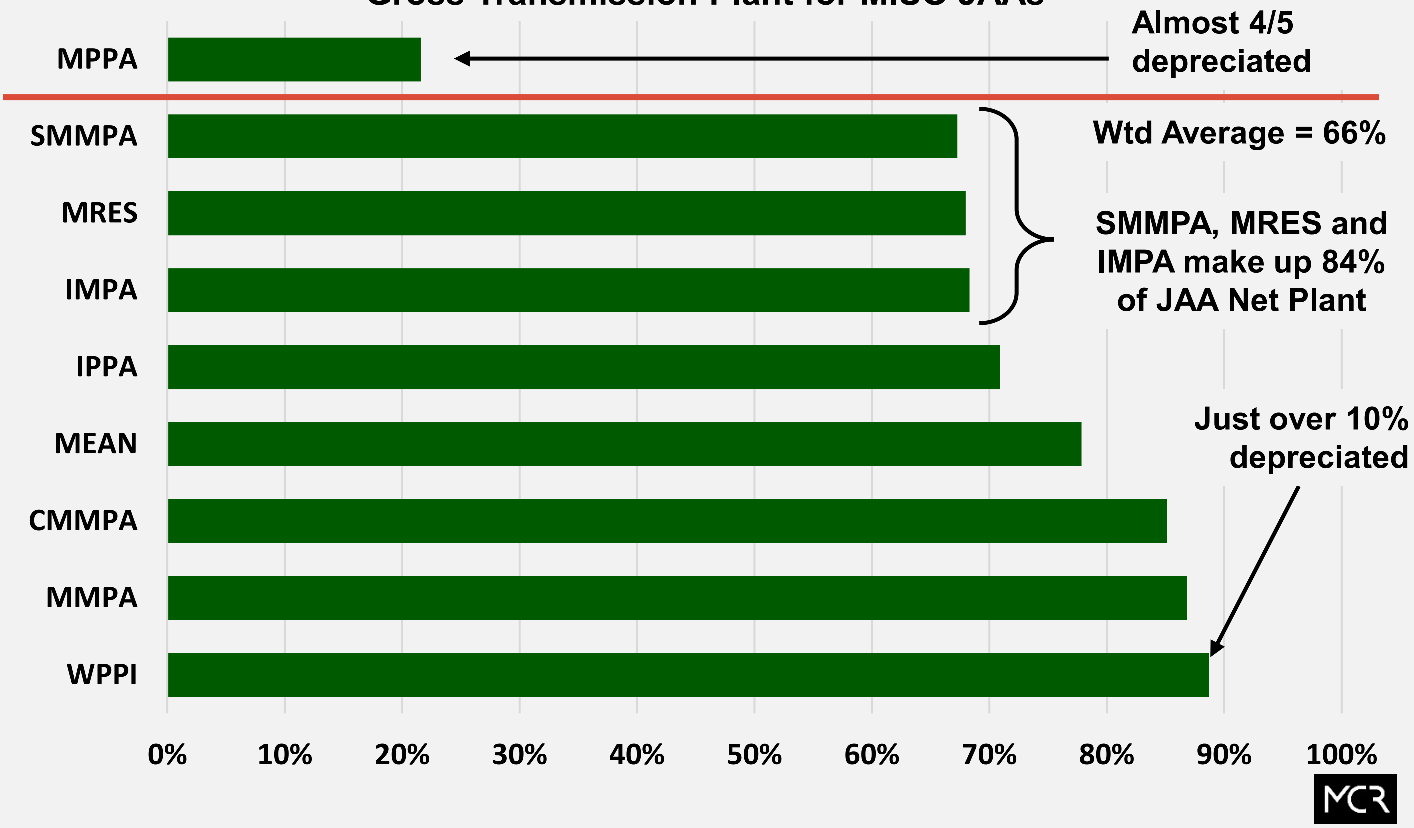
[44] Source: June 2021 MISO Attachment Os.

Figure 33
2021 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO JAAs[45]



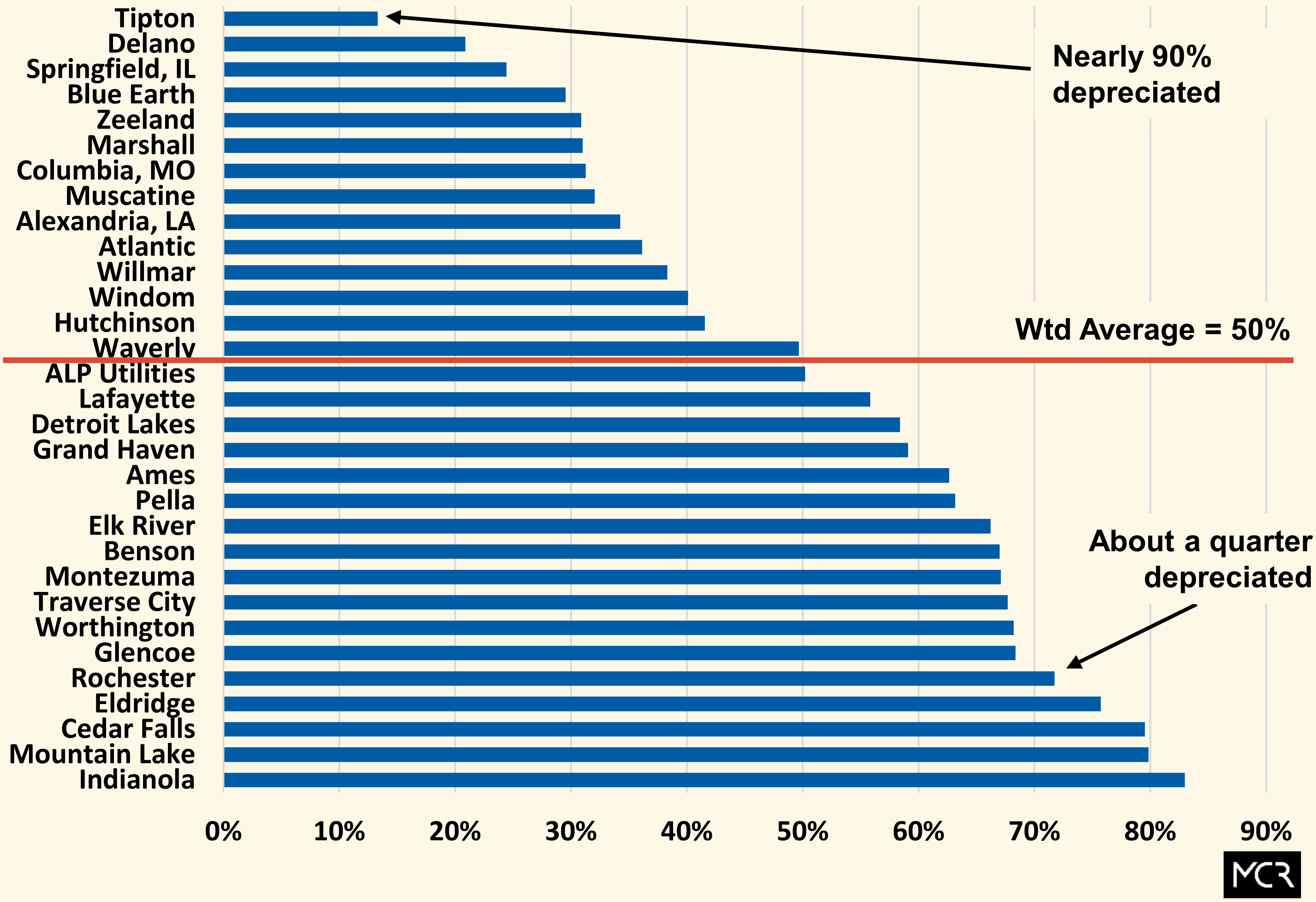
The JAA segment's transmission assets have a weighted average ratio of 66% (see Figure 33 above), the same as the G&T segment and meaningfully older than the IOU/Transco segment. WPPI Energy has the newest set of transmission assets with a net plant to gross plant ratio of 89%. On the other hand, Michigan Public Power Agency ("MPPA") has the oldest transmission with a ratio of 22%, down from 27% last year.

All JAAs had stayed the same or had a drop in their net plant to gross plant ratio, indicative of the lower level of segment investment this past year. This reinforces that the slowdown in JAA transmission investment noted in the last two years continues.

[45] Source: June 2021 MISO Attachment Os.

Figure 34

2021 Net Transmission Plant as a Percent of Gross Transmission Plant for MISO Municipals[46]



28 of the 31 Municipals have older transmission facilities than the IOU/Transco average of 77%.

The 2021 net plant to gross plant ratios in the Municipal segment continue to show a wide variability in average age of facilities among cities. The segment weighted average ratio was 50% (see Figure 34 above), down from 52% in 2020. Cities with the newest systems, including Indianola (83%), Cedar Falls (80%) and Mountain Lake (80%), were vastly newer than those with the oldest systems such as Tipton (13%), Delano (21%), Springfield, IL (24%), Blue Earth (30%), Marshall, MN (31%), Zeeland (31%), Colombia, MO (31%)., Muscatine (32%) and Alexandria, LA (34%).

Despite some progress, the weighted average net to gross plant ratio for Municipals of 50% is much older than the IOU/Transco average of 77%. In fact, 28 of the 31 Municipals have older transmission facilities than the IOU/Transco average of 77%. This continues to raise the prospect that many Municipals are facing the possibility of replacing or upgrading their facilities in the near future in order to maintain and/or improve their levels of reliability.

[46] Source: June 2021 MISO Attachment Os.

Figure 35
Comparison of Change in Gross Transmission Plant Balance to Current Load Ratio Share for MISO IOU/Transcos, G&Ts, T&Ds, and Municipals (2018-2020)[47]

	2-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	7,115	92.6%	86,699.7	86.0%
G&Ts	530	6.9%	11,001.6	10.9%
T&Ds	12	0.1%	941.3	1.0%
Municipals	28	0.4%	2,148.3	2.1%
Total	7,685	100.0%	100,790.9	100.0%

MCR

Which Groups are Investing Commensurate with their Load?

Investment by each segment in the sample over the past two years has not been aligned with each segment's share of MISO load. Investment over the two-year period totaled $7.68 billion in the IOU/Transcos, G&Ts, T&Ds, and Municipal segments (see Figure 35 above), which is roughly the same as last year's two-year total of $7.76 billion. Over the past two years, IOU/Transcos are responsible for $7.1 billion, which amounts to 92.6% of the total investment. Compared to having 86.0% of the total load across these segments, IOU/Transcos are significantly overinvested relative to peers. G&Ts, T&Ds, and Municipals, by contrast, are each significantly underinvested relative to load: G&Ts had 6.9% of total investment versus 10.9% of load; T&Ds had 0.1% of total investments versus 1% of load (severely underinvested); and Municipals had 0.4% of investments versus 2.1% of load, also significantly underinvested over the last two years. This is a similar picture for T&Ds and Municipals to last year's version of the table whereas G&Ts have narrowed the investment gap a bit.

G&Ts, T&Ds, and Municipals are each significantly underinvested relative to loads.

[47] Source: June 2019-2021 MISO Attachment Os. Load may be adjusted where the G&T's load is in multiple pricing zones, but the reported load reflects only one 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 joint action agencies (most JAAs do not have load themselves and their member's load is addressed in the Municipal group). 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 Municipal's load was 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. Includes Minnesota Power AC and DC load.

Figure 36
Comparison of Total Gross Transmission Plant Balance to Current Load Ratio Share for MISO IOU/Transcos, G&Ts, T&Ds, and Municipals (2020)[48]

	Existing Gross Transmission Plant ($ Millions)	% of Total Gross Plant Change	Estimated 12 CP Load (MWs)	Estimated % of Total Load
IOU, Transcos	51,201.4	90.4%	86,699.7	86.0%
G&Ts	4,766.8	8.4%	11,001.6	10.9%
T&Ds	162.3	0.3%	941.3	1.0%
Municipals	525.0	0.9%	2,148.3	2.1%
Total	56,655.5	100.0%	100,790.9	100.0%

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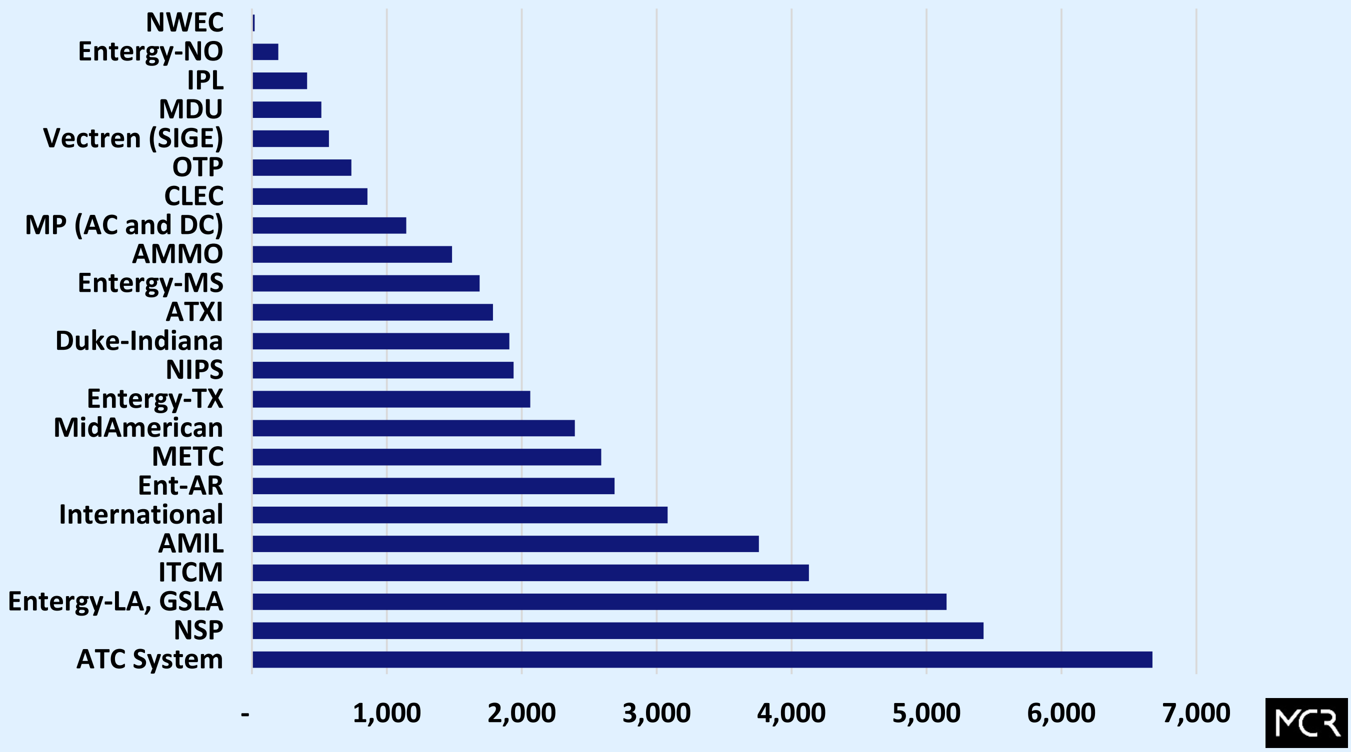
What is the Current Level of Assets Compared to Load?
Despite still being underinvested, the investment-share dynamic among the various segments is better when comparing 2021 gross transmission plant in service to load ratio share. IOU/Transcos remain overinvested, with 90.4% of gross transmission plant versus 86.0% of the load (see Figure 36 above). G&Ts, T&Ds, and Municipals are underinvested relative to load, which is consistent with many of the metrics we discussed in prior pages. However, the gap is not as dramatic as compared to Figure 35 on the previous page.

[48] Source for asset data: June 2021 MISO Attachment Os.

Figure 37
2021 Gross Transmission Plant Balance for MISO IOU/Transcos[49]



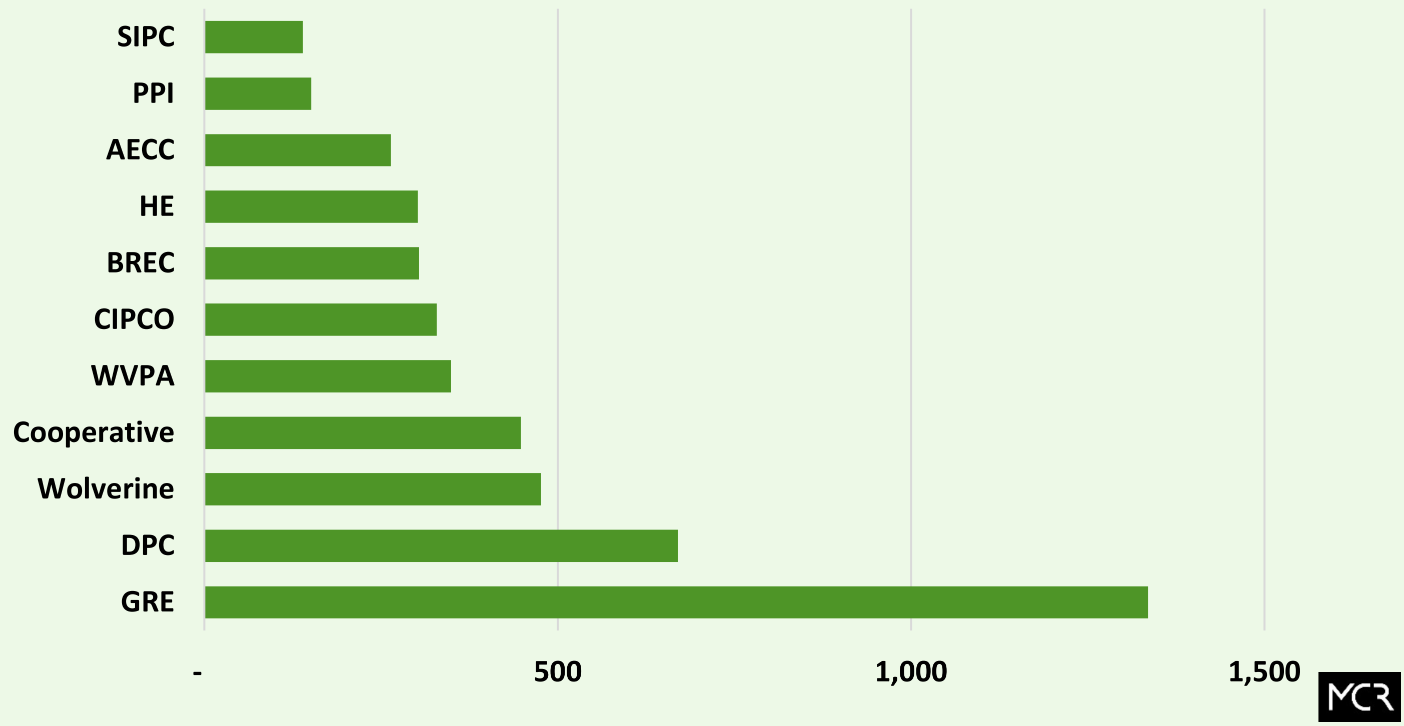
Who are the Largest Transmission Owners in MISO?
Each segment has transmission owners that dominate by size and are therefore responsible for a large portion of ATRR. Figures 37 through 41 present the size of MISO transmission owners in each segment, ranked by the total company gross transmission plant as reported on 2021 Attachment Os.

As shown in Figure 37 above, ATC is the largest of all IOU/Transcos with $6.67 billion (up from $6.43 billion last year), followed by NSP at $5.42 billion (up from $5.20 billion) and Entergy-LA at $5.15 billion (up 14% from $4.52 billion in 2020). Given Entergy's pledge to increase the resilience of its T&D system in the face of more frequent hurricanes, we would expect Entergy-LA to surpass NSP as soon as next year. Given the heavy investment we've seen across the segment and large percentage increases over the last five- and two-year periods, the IOU/Transco segment is growing even larger relative to the rest of the segments in MISO.

The G&T segment's largest TO remains Great River Energy with 2021 gross transmission plant of $1.36 billion, which is twice the size of DPC, the second largest G&T. DPC has gross transmission plant of $670 million. Wolverine, with its heavy recent investment and high growth rates, follows DPC at $476

[49] Source for all TO transmission gross plant charts: June 2021 MISO Attachment Os.

Figure 38
2021 Gross Transmission Plant Balance
for MISO G&Ts



million. Cooperative Energy is the fourth largest G&T in transmission assets with $448 million (see Figure 38 above).

Figure 39 on the next page shows the large disparity between the largest joint action agencies and the smallest. On the upper end are SMMPA ($221 million), IMPA ($189 million) and MRES ($180 million). These top three are many multiples the size of smaller JAAs like IPPA ($3.0 million), MEAN ($10.4 million) and MMPA ($13.2 million). This disparity between the largest and smallest JAAs is growing: the largest three JAAs were responsible for nearly all of the segment investment in the past year.

In the T&D segment, ETEC-Sam Houston is the largest player at $62 million of gross transmission plant followed by DEMCO at $42 million (see Figure 40 on the next page).

The Municipal segment, of course consists of various sized TOs and thus has the most striking difference between the largest and smallest gross transmission plant (see Figure 41 on page 54). The cities of Springfield ($83 million), Lafayette ($77 million), and Rochester ($74 million) account for 45% of the total gross transmission plant for the segment (the same as last year). In spite of the dominance by these three cities, we are seeing a wider group of Municipals sharing the segment's investments, but the investment is not as consistent each year as the IOU/Transco and G&T segments.

Figure 39
2021 Gross Transmission Plant Balance for MISO JAAs

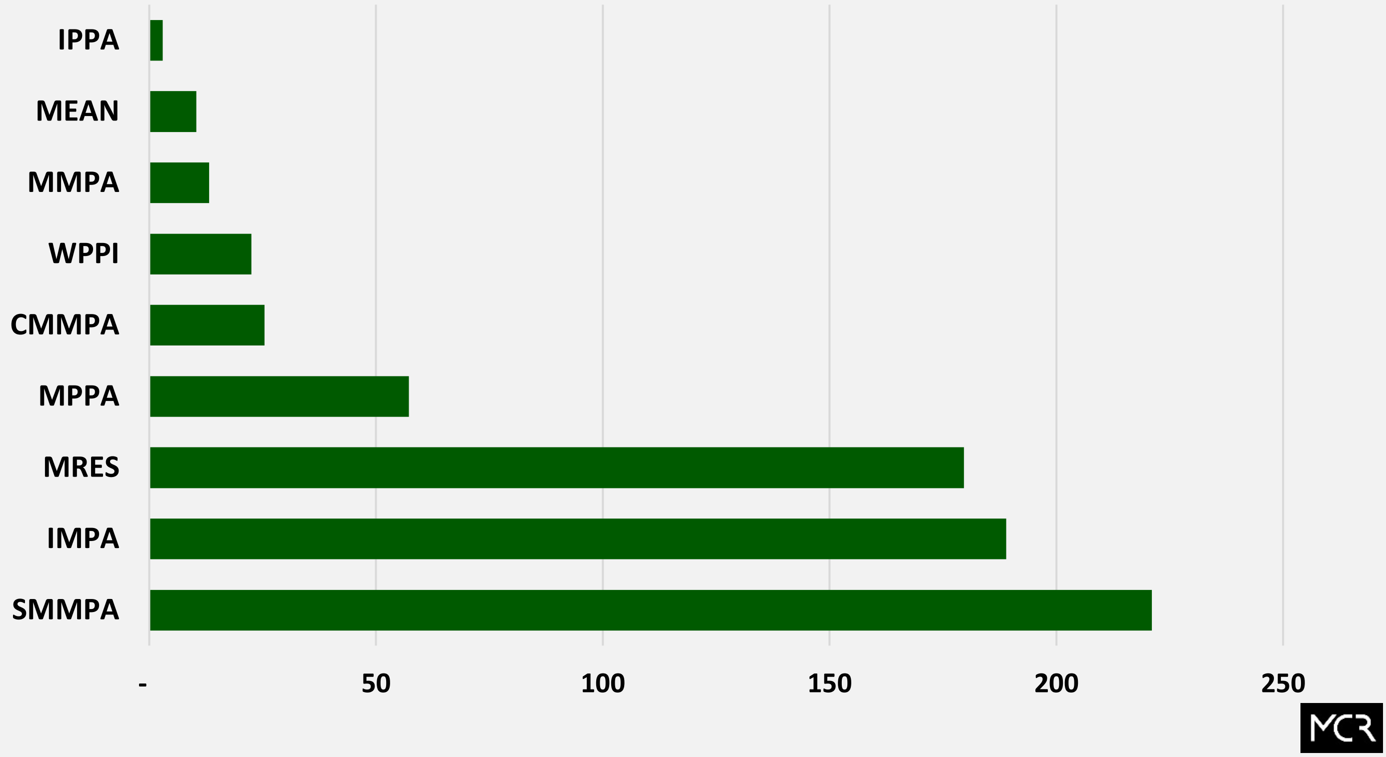


Figure 40
2021 Gross Transmission Plant Balance for MISO T&Ds

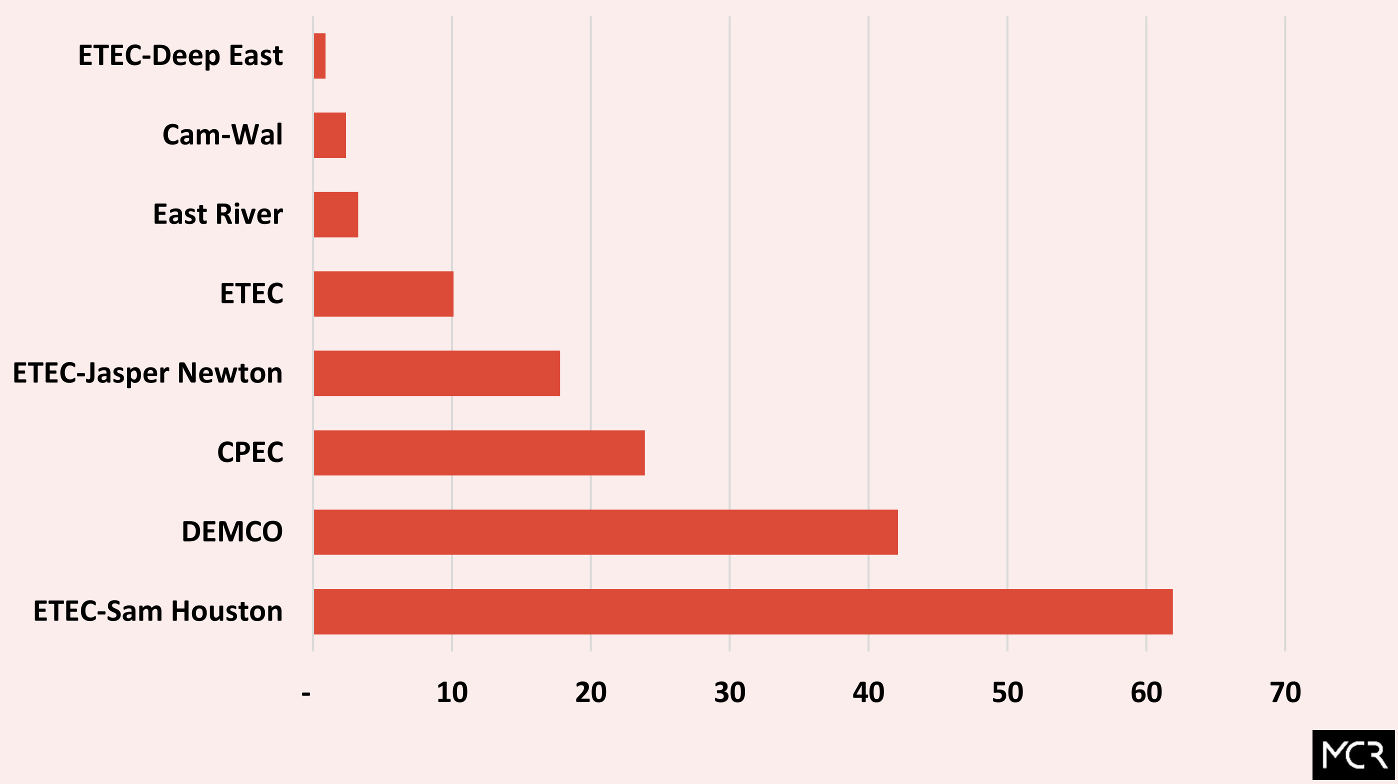
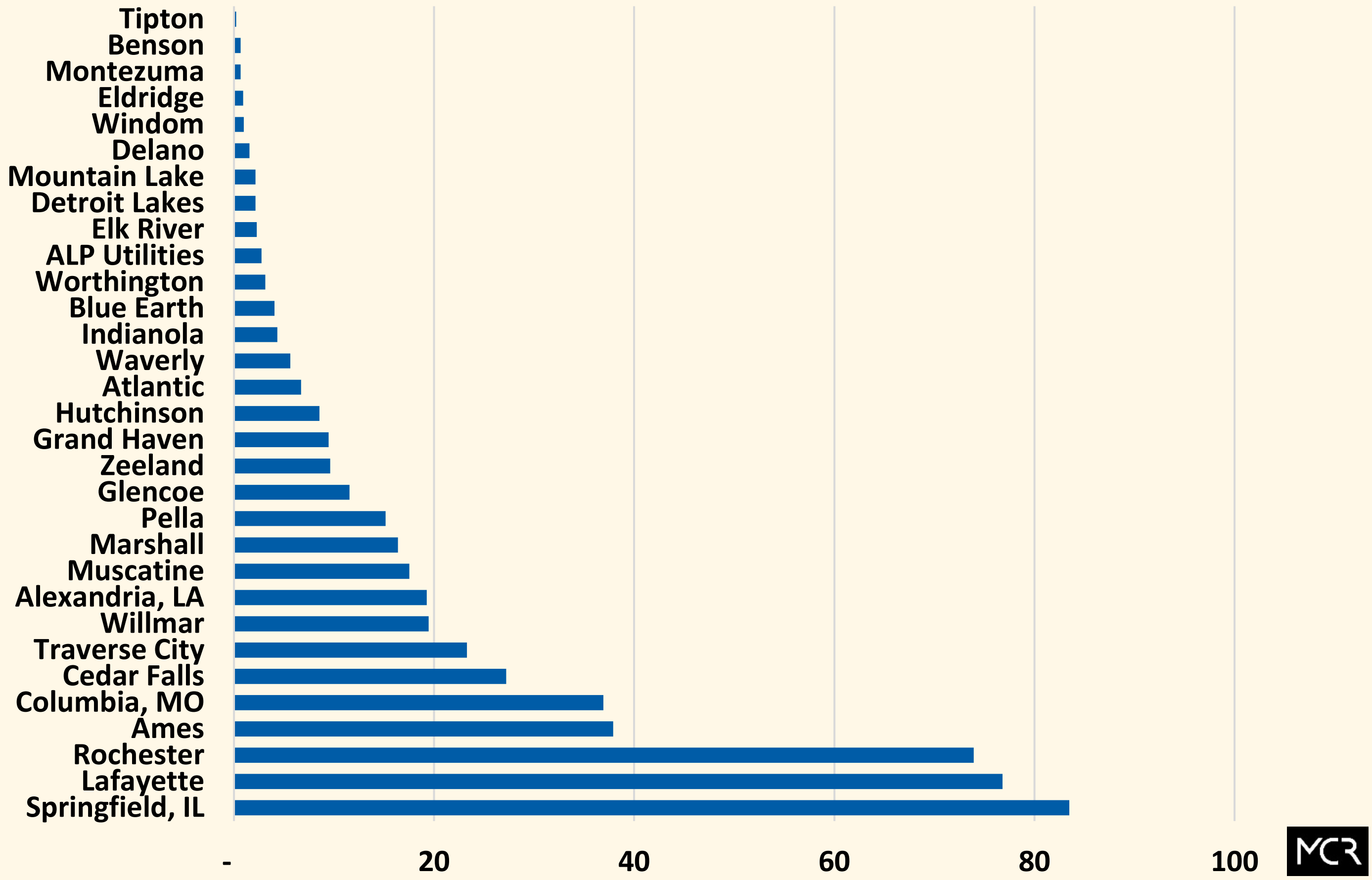


Figure 41
2021 Gross Transmission Plant Balance for MISO Municipals



11. Viewing Transmission Differently

The MISO transmission rate express train had previously slowed, but all indications are that it has picked up and will continue to increase at a healthy pace. As IOUs and Transcos in MISO continue to invest in transmission to drive their earnings growth and social, political, and regulatory trends are favorable to transmission investment, transmission rates will continue to increase. As a municipal or cooperative in a joint pricing zone, the most effective way to mitigate these transmission rate increases is to develop a business plan that identifies and invests in transmission projects to enhance the reliability for your customers and the broader network. Additionally, existing TOs must optimize their existing Attachment O transmission formula rate to maximize transmission revenue. Instead of transmission rates being a source of irritation to Boards and secondary to generation, municipals and cooperatives must view transmission as a business that provides opportunities for an additional stream of revenue while also enhancing the reliability of the system.

MCR Transmission Strategy Overview

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

Transmission Rate and Cost Analysis

- **Formula rate review for existing transmission owners.** MCR conducts reviews of transmission formula rates, (MISO Attachment O and SPP/PJM Attachment H) to substantiate costs and optimize revenue.
- **Development of annual transmission revenue requirements ("ATRR") for new transmission owners.** MCR develops cost data to support full RTO revenue recovery for new transmission owners ("TOs"), which involves, for example, developing MISO's Attachment O, and Attachment H in SPP and PJM. In addition, MCR develops and reviews client updates to annual formula rates and defends client updates against challenges from neighboring utilities, as appropriate.
- **Review/Challenge to incumbent formula rate costs.** MCR reviews neighboring IOU utility transmission costs or RTO cost calculations to ensure transmission charges are appropriate.
- **Staff education workshops on formula rates.** MCR conducts workshops to educate client staff on formula rates and the implications of business changes on ATRR.

FERC Filings

- **Section 205 rate filings and testimony.** MCR provides expert FERC testimony for Section 205 rate filings, including new ATRR filings related to joining an RTO. Our expertise includes testimony and formula rate template development/changes.
- **Transmission incentive rate filings and testimony.** MCR provides analytics, formula rates and testimony for transmission incentives rate applications to FERC. This includes requests for hypothetical capital structure, CWIP, abandoned plant and regulatory asset.
- **Cost of capital expert testimony.** MCR provides expert testimony and analytics to support proposed cost of capital for new and existing formula rates for public power and cooperatives, including margin requirement, ROE and capital structure.
- **Intervention and settlement support.** MCR provides our clients analytical and intervention response support during intervention, settlement, mediation and hearings.

MCR Transmission Strategy Overview
(continued)

Strategic Economic Analysis

- **Development of transmission business plans.** MCR works with clients to define transmission-related issues, goals and strategies, including providing analytic support.
- **Economic evaluation of new transmission projects.** MCR analyzes cash flows of proposed transmission projects. MCR's Transmission Project Evaluation Tool™ highlights how value is created under various cost allocation and recovery scenarios and helps prioritize capital.
- **RTO membership evaluations.** MCR conducts economic analysis using MCR's RTO Evaluation Model™ to assess whether to become a transmission owner in an RTO.
- **Analysis of joint zone investment and 7-factor tests.** MCR provides analytical support to support assets qualifying under the FERC 7-factor test and in negotiations with incumbents on the appropriate share of eligible transmission investment in a joint pricing zone, including the review of joint pricing zone agreements.
- **Analysis of the potential purchase or sale of assets.** MCR conducts strategic and financial analysis related to value created from buying or selling transmission facilities. MCR provides various valuation techniques to assess the market value of transmission assets.

Transmission Cost/Rate Competitiveness

- **Peer cost comparisons by FERC account.** MCR conducts transmission cost comparisons with peer utilities by FERC account for transmission owners to identify potential areas warranting cost reduction and/or differences in the recording of costs.
- **Rate strategy and transmission revenue forecasting.** MCR develops forecasts of ATRR and transmission rates for its clients to assess their rate competitiveness and better understand the levers to manage future rate increases. ATRR forecasts are developed under various transmission investment scenarios. Analyses also include evaluating generator interconnection investment options such as utility-funded and customer-funded investment.
- **Transmission capital investment and metric comparisons.** MCR maintains a proprietary database of transmission capital investment, load and comparative cost metrics for TOs and industry segments in various RTOs. This information provides analytical support in cost competitive analyses, MCR expert testimony in FERC filings and in negotiations with incumbents on the appropriate share of transmission investment in a joint pricing zone.

MCR Transmission Strategy Practice Leadership

Jim Pardikes is a Vice President at MCR and leads the Transmission Strategy Practice. He has 35 years of experience consulting to the utility industry. His expertise includes asset eligibility, asset valuation, and expert testimony for Section 205 and incentive filings, including cost of capital. Jim regularly presents to Boards and senior teams and has written extensively on the drivers of transmission investments and the case for transmission incentives. Jim can be reached in the office at 847-504-2549, on mobile phone at 847-226-2084, or by email at jpardikes@mcr-group.com.

"Jim has a way of getting to the core concept; he's able to present it in a way that's understandable. He has a confidence when he's presenting, which is quite valuable." —Transmission Planning Manager, G&T

Ron Kennedy is a Director with MCR. He has over 20 years of experience in consulting to the utility industry. His expertise includes formula rates, Section 205 rate filings, rate incentives, evaluation of RTO membership, asset valuation, asset eligibility and financial evaluation of transmission projects. Ron is experienced in presenting to executive teams and Boards of Directors. Ron can be reached at rkennedy@mcr-group.com.

"Ron knows those FERC accounts like the back of his hand." —Vice President, JAA

Chris Nagle is a Manager with MCR. He has 14 years of experience in transmission, rates and regulatory affairs. His MCR expertise includes conducting reviews of formula rates, developing new formula rates/testimony, asset valuation and evaluating economics of transmission projects. His previous experience includes rate development and cost allocation for a multi- jurisdictional electric utility, including testifying as an expert witness before various PSCs. Chris can be reached at cnagle@mcr-group.com.

"Chris is incredibly responsive and knows what questions to ask." —GM, Municipal

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