UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentive Policy	))	 Docket No. PL19-3-000

INITIAL COMMENTS OF GRIDLIANCE

GridLiance Holdco, LP[1] submits the following comments on behalf of its wholly owned subsidiaries GridLiance West Transco LLC, GridLiance High Plains LLC, and GridLiance Heartland LLC (together, GridLiance) in response to the Notice of Inquiry (NOI) issued by the Federal Energy Regulatory Commission (FERC or Commission) on March 21, 2019.[2] These comments focus primarily on two issues discussed in the NOI – Joint Ownership and Transcos – and offer specific recommendations for reforms on these topics for the Commission's consideration based on GridLiance's transmission development experience and demonstrated commitment to transmission investment.

I. EXECUTIVE SUMMARY

- <u>FERC should offer a new Joint Ownership Incentive</u> in furtherance of its longstanding policy goals of (a) attaining greater levels of non-public utility participation in grid expansion projects and a deeper pool of transmission investors; and (b) promoting an expanded RTO footprint leading to a more reliable transmission grid and a more competitive wholesale market.
    - The Commission should establish a new Joint Ownership Incentive under sections 219 (Order No. 679[3]) or 205 of the Federal Power Act (FPA), awarded on a project-specific basis to jurisdictional utilities and non-public utilities that partner on new transmission projects that meet two objective, pre-defined criteria: (1) have been approved by a Commission-approved regional or local transmission planning process; and (2) that are at least 15% owned, in aggregate, by non-public utilities.

[1] A portfolio company of Blackstone Energy Partners, GridLiance is an independent transmission company formed to partner, through its subsidiaries in California ISO (CAISO), Midcontinent ISO (MISO), and Southwest Power Pool (SPP), with electric cooperatives, municipally-owned electric utilities, joint action agencies, and renewable energy developers to identify and develop transmission solutions to meet its partners' ownership, capital investment, and reliability goals.

[2] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019).

[3] *Promoting Transmission Investment through Pricing Reform,* Order No. 679, FERC Stats. & Regs. ¶ 31,222 (Order No. 679), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

- o Projects that satisfy these criteria will not only advance worthy Commission policy goals, but also deliver significant benefits to non-public utility partners (and their customers) and enhance the overall reliability and resilience of the grid.
  - As proposed, the new incentive adder would only apply to: (1) Newly constructed projects, as well as to upgrade projects where existing facilities are re-constructed and/or renovated, that meet the proposed eligibility criteria as an incentive to spur needed investment with non-public utility partners; and (2) A partner's portion of jointly owned projects.

- FERC should maintain the Transco Adder under Order No. 679 in recognition (a) of the abundant evidence that the Transco business model provides clear, concrete benefits to ratepayers that more than offset the costs to ratepayers of the increased returns authorized through the Commission's Transco Adder, as demonstrated empirically herein, and (b) the incentive adder award fairly balances the need for new transmission facilities and investor expectations with the Commission's obligation to ensure rates are just and reasonable, as GridLiance West's experience in CAISO shows.

- FERC's approach to awarding the Transco Adder, including allowing active ownership of a Transco by market participants and applying the Adder to all of an eligible Transco's transmission plant based upon whether the applicant qualifies under the independence standard for a Transco, incentivizes transmission development and efficient operation of the grid and should continue unchanged.

II. COMMENTS

A. A New, Project-Specific Joint Ownership Incentive Should Be Available to Promote Beneficial Joint Transmission Investment

In furtherance of its longstanding policy of promoting expanded joint ownership opportunities for non-public utilities, the Commission should establish a new Joint Ownership Incentive under FPA sections 219 (Order No. 679) or 205, awarded on a project-specific basis to jurisdictional utilities and non-public utilities that partner on new transmission projects that meet two objective, pre-defined criteria: (1) have been approved by a Commission-approved regional or local transmission planning process; and (2) that are at least 15% owned, in aggregate, by non-public utilities. Projects that satisfy these criteria will not only advance worthy Commission policy goals, but also deliver significant benefits to non-public utility partners (and their customers) and enhance the overall reliability and resilience of the grid.

Equally important, GridLiance is not advocating that the Joint Ownership Incentive be applied to existing assets that it or other jurisdictional utilities may acquire. Rather, GridLiance is proposing that the new ROE incentive adder apply only to newly constructed projects, as well as to upgrade projects where existing facilities are re-constructed and/or renovated,[4] that meet the proposed eligibility criteria as an incentive to spur needed investment with non-public utility partners. The Incentive would only apply to a partner's portion of jointly owned projects. Likewise, each project partner would be expected to obtain cost recovery through its respective formula rates.

As demonstrated below, GridLiance's proposed incentive promises to provide an effective vehicle for promoting expanded joint ownership opportunities for non-public utilities, directly meeting the Commission's longstanding public policy goals of (a) attaining greater levels of non-public utility participation in grid expansion projects and a deeper pool of transmission investors; and (b) promoting an expanded RTO footprint leading to a more reliable transmission grid and a more competitive wholesale market. Likewise, by creating additional opportunities for non-public utilities to make transmission investments at their desired levels, this incentive is designed to counter the financial impediments to transmission investment by non-public utilities and to provide additional benefits. Specifically, it offers a cost-effective means of addressing non-public utilities' record of suboptimal transmission investment, scarcity of capital, and their desire to invest in and co-own revenue-enhancing transmission projects to partially offset increasing transmission rates. Additionally, for non-public utilities with aging networks, it promotes enhanced system reliability by directly incentivizing a willing partner such as GridLiance to pursue joint development opportunities that stand to increase the reliability of a non-public utility's system in a more cost-effective manner than the non-public utility could likely achieve on its own. Finally, it provides important pro-competitive benefits for customers, such as (a) fostering a more competitive environment providing a competitive alternative to the incumbent utility; (b) promoting greater non-public utility

[4] In Order No. 679, the Commission makes clear that "new investment in existing facilities will be eligible for incentive-based rate treatments. Order No. 679 at P 56.

participation in RTO competitive transmission processes; and (3) promoting increased reliability at a lower cost per investment. Finally, it delivers significant benefits when the proposed eligibility criteria are met.

1. Non-Public Utilities Recent History of Under-Investment in Transmission

GridLiance commissioned MCR Performance Solutions, LLC (MCR) to better understand, from an analytical standpoint, the state of transmission investment among non-public utilities, focusing on investment levels of transmission-owning municipal utilities (municipals) and transmission-owning generation and transmission electric cooperatives (G&Ts, or cooperatives) in MISO and SPP relative to IOUs and transmission-only companies (IOU/Transcos) over the past five years. The prepared direct testimony of Mr. James Pardikes, attached hereto and marked as ***Attachment A***, presents the results of MCR's empirical analysis, which is based on their Proprietary Transmission Investment and Load (PTIL) Database[5] of transmission investment data, metrics, and related reports for IOU/Transcos,[6] G&T, and Public Power[7] for various RTOs covering the last five years. MCR's database only includes utilities that have transferred their transmission assets to MISO and SPP and file an Attachment O or Attachment H cost template, respectively, to obtain revenue recovery, primarily because standardized transmission cost data is not available for entities that are not TOs.[8] The investment data for MISO and SPP is based on the

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[5] MCR's PTIL Database includes utilities that file Attachments O or H formula rates and placed their transmission assets under the MISO or SPP tariff. It does not include recently admitted G&Ts who have less than three years of investment data and transmission and distribution (T&D) cooperatives due to their limited sample size and in some cases, limited years of investment data.

[6] IOUs and Transcos are categorized together because the MISO and SPP Transcos are either profit-making entities and/or owned by IOUs or their holding companies.

[7] The PTIL Database includes new municipal entrants to MISO and SPP who had limited years of Attachments O or H data, *i.e.*, in MISO three municipals had four years of investment data and five municipals had three years of investment data. All SPP municipals are based on four years of investment data because most joined SPP in 2015.

[8] For example, there are still many municipals in the MISO footprint that own transmission assets (*e.g.*, 69 kV or above) or are contemplating new/upgraded transmission that do not file an Attachment O and thus published, standardized transmission cost data is not available for these utilities. Given the large and diversified sample of 31 municipals in MISO who do file an Attachment O and the 18 municipals in SPP who file an Attachment H formula rate, this data sample provides a good proxy for all municipals in the MISO and SPP footprints, recognizing the size of the entire municipal market in the MISO and SPP footprint is even larger than the 48 tracked in MCR's PTIL Database.

change in the gross transmission plant balances reported in the MISO Attachment O and SPP Attachment H formula rate schedules[9] that are used to calculate each TO's annual transmission revenue requirement, which in turn is fed into the calculation of the zonal rate for each pricing zone. Using the change in gross transmission plant as reported by each TO in the Attachments O and H provides a consistent basis and a good proxy[10] for the levels of transmission capital investment for IOU/Transcos, G&Ts, and Public Power. The PTIL Database includes estimated load data for each of the TOs obtained from various sources.[11]

MCR found that despite the Commission's encouragement of joint ownership arrangements to date, many municipals and at least some cooperatives, particularly those that are transmission-dependent on their host (often an IOU) incumbent transmission owner (TO) for transmission service (TDNPUs),[12] have been investing in transmission at far lower rates and operate generally older systems than their IOU/Transco counterparts in MISO and SPP, indicating that many of these entities (a) lack the means and/or the opportunity to maintain their systems comparably to IOU/Transcos in MISO and SPP, and may be facing obstacles to planning and investing at their desired levels, and (b) have increased outage

[9] The database utilized the July MISO Attachment Os from 2013-2018. The MISO Attachment O is a cost template that provides a structured and consistent approach for how TOs report and recover the costs of their transmission-related assets and expenses. The Attachment O is filed each year by each TO and determines the transmission revenue to be recovered from MISO ratepayers. The database utilized the most recent SPP Attachment H formula rate templates posted as of June 14, 2019, thus the SPP Attachment H data covers 2014-2019.

[10] Formula for investment in each year per the Attachment O/Attachment H = change in company gross transmission plant + change in construction work in progress (CWIP) in rate base. The reported change in the transmission gross plant balance in the Attachment O/Attachment H includes the net effect of any retirements, adjustments, and transfers. Transfers could, for example, include a reclassification of distribution plant as transmission. Capital expenditures reported in the FERC Form 1 or RUS Form 12 for any given year will likely be different than the change in gross transmission plant reported in the Attachments O or H, because of any retirements, adjustments, and transfers. Further, the Attachments O and H require the plant to be in rate base, so any CWIP capital expenditures not yet in rate base is not included the data.

[11] Sources for estimated load data may include, for example, the MISO Attachment O, SPP Attachment H, FERC Form 1 wholesale load data, Energy Information Administration (EIA) annual reports for municipals, and/or other public sources.

[12] TDNPUs are defined here as non-public utilities such as municipals and cooperatives that either: a) do not own transmission lines, b) own radial lines, or (c) own looped facilities that are not integrated into the regional system.

exposure when compared to the rest of the MISO and SPP systems and could benefit from the increased system redundancy and off-system access to the broader wholesale market that comes from additional transmission investment.

With respect to MISO specifically, MCR found that the municipal segment in MISO is investing in transmission at significantly lower rate than their IOU/Transco counterparts.[13] In fact, according to Mr. Pardikes, most municipals in MISO have made very little investment in transmission over the last five years.[14] This disparity is well illustrated by several objective measures presented in Mr. Pardikes' testimony, which includes the following findings:

- The average transmission investment over the past five years as a percent of transmission gross plant balance, a good indicator of investment *pace*, was nearly three times lower for municipals than for IOU/Transcos.[15]
- The five-year growth of transmission gross plant for municipals (18%) was nearly four times lower than for IOU/Transcos (66%).[16]
- Municipals have a much lower investment *intensity* level than other segments based on a ratio of their investment to depreciation expense.[17]
- The age of municipal facilities is older than those of IOU/Transcos and getting older, as indicated by the ratio of net transmission plant to gross transmission plant, which provides an indicator of which segments have the "newest" aggregate transmission facilities.[18]
- Municipals are underinvested in transmission relative to their load ratio share.[19]

Although the MCR municipal sample only included those municipals that placed their transmission assets under the MISO tariff and filed Attachment Os, there are other municipals who own some

[13] Pardikes Testimony at P 7.

[14] *Id*. at P 8-9.

[15] *Id*. at PP 10-11.

[16] *Id.* at PP 8-9.

[17] *Id.* at PP 11-12.

[18] *Id.* at P 12.

[19] *Id.* at PP 13-14.

transmission but are not yet in MISO and could benefit from additional transmission investment. Based on the above factors, Mr. Pardikes concludes that many municipals and G&Ts in MISO are facing the possibility of needing to replace/upgrade or expand their facilities in the near future to ensure continued or enhanced service reliability for their customers.[20]

With respect to SPP specifically, MCR found that the municipal segment in SPP is investing in transmission at significantly lower rate than the other segments.[21] In fact, according to Mr. Pardikes, just like their counterparts in MISO, most municipals in SPP have made very little investment in transmission over the last four years.[22] This disparity is well illustrated by several objective measures presented in Mr. Pardikes' testimony, which includes the following findings:

- The percentage change in gross transmission plant over the comparison period is much lower for municipals than for the other segments.[23]
- Municipals have a much lower investment intensity level than the other segments based on a ratio of their investment to depreciation expense.[24]
- The age of municipal and G&T transmission facilities is older than those of IOU/Transcos, as indicated by the ratio of net transmission plant to gross transmission plant.[25]
- Municipals are severely underinvested in transmission relative to their load ratio share.[26]

Given these factors, Mr. Pardikes similarly concludes that many municipals in SPP and, to a lesser extent, cooperatives are facing the possibility of needing to replace/upgrade or expand their facilities in the near future to ensure continued or enhanced service reliability for their customers.[27]

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[20] *Id*. at P 14.

[21] *Id*. at P 15.

[22] *Id*. at P 16.

[23] *Id.* at P 18.

[24] *Id.* at PP 18-19.

[25] *Id*. at P 19-20.

[26] *Id.* at PP 20-21.

[27] *Id*. at P 20.

Looking at the combined results for MISO and SPP, MCR's analysis clearly shows that municipal and cooperative investment is lagging behind IOU/Transcos and that both segments are showing signs of aging transmission infrastructure in these RTOs. As detailed below, MCR attributes their relative lack of investment to various factors at play for non-public utilities that are systematically limiting their investment.[28] Many of the same impediments to investing are applicable to those municipals who are TOs in an RTO and those not currently in the RTO.

2. Many Non-Public Utilities Lack Comparable Means and/or Opportunity to Plan for and Invest in Transmission at Their Desired Levels

Their lack of relative transmission investment compared to IOU/Transcos, coupled with aging transmission systems, indicate that many municipals and some cooperatives in MISO and SPP lack the means and/or the opportunity to maintain their systems comparably to their IOU/Transco counterparts, and may be facing obstacles to planning and investing at their desired levels. For example, many smaller municipals and cooperatives in MISO[29] and SPP[30] remain connected to their region's integrated system by lower-voltage radial transmission lines, which inherently provide less reliable service. These exist due to past supply arrangements, where the municipal or cooperative system acquired power from its local host incumbent TO, often an IOU. As Mr. Pardikes explains, many TDNPUs want to increase ownership in transmission rather than having their investment needs met by their host incumbent TO.[31] As described below, while there is interest on the part of many of these non-public utilities to develop and own transmission, there are a number of institutional obstacles and resource barriers that limit their ability to

[28] *Id*. at P 23.

[29] Prime examples include Highland, Illinois; Mascoutah, Illinois; and Rolla, Missouri.

[30] Prime examples include Tri-County Electric Cooperative, Inc., and People's Electric Cooperative in Oklahoma and municipals Duncan, Oklahoma; Frederick, Oklahoma; Hope, Arkansas; Marlow, Oklahoma; Pratt, Kansas; and Wellington, Kansas.

[31] Pardikes Testimony at P 26.

participate in transmission development and planning on a comparable basis as their IOU/Transco counterparts.

a. IOU Non-Native Loads Are Often at a Transmission Planning Disadvantage Relative to IOU Retail Customers

A disparity persists today in how transmission upgrades for non-native (wholesale) loads served by IOUs are typically planned (and paid for) in RTOs relative to the IOU's own native (retail) load. In GridLiance's experience, dating back to their historical supply arrangements, many IOU non-native loads, such as TDNPUs, often have radial, low-voltage connections to the broader regional network. In SPP, Tri-County Electric Cooperative, Inc., People's Electric Cooperative, and the municipal members of Oklahoma Municipal Power Agency and Kansas Power Pool, such as Duncan, Oklahoma and Wellington, Kansas, respectively, are prime examples. While there are instances when such design satisfies a specific entity's needs, these connections are generally "weak" and have associated reliability concerns when that entity does not have an alternative service path. By contrast, a town of similar size and load characteristics that is served by the same host IOU would likely have looped service and experience relatively fewer reliability concerns. As Mr. Pardikes explains, the lack of transmission planning comparability that IOU non-native loads experience stems from the asymmetrical way upgrades that provide networked access for an IOU's non-native load customers served by radial lines are treated relative to an IOU's native load customers served off a similar line under North American Electric Reliability Corporation (NERC) transmission planning standards.[32]

As a practical matter, the disparity described above means IOU non-native load customers are often exposed to higher costs and lower reliability than similarly situated IOU retail customers who happen to be served by an IOU via networked facilities. This is not "comparable" transmission service that all retail

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[32] *Id* at PP 24-25. *See* NERC Transmission System Planning Performance Requirements TPL-001-4, Table 1, footnote 12. *See* also Section III-2, available at https://www.nerc.com/files/TPL-001-4.pdf.

customers rightly deserve. Grid reliability and resilience should not depend on who provides the wholesale and retail service to an end-user if their circumstances are otherwise similar. However, as Mr. Pardikes notes, having a competitive alternative to the IOU, such as an independent Transco partnering with the TDNPU on new joint investment, leads to more innovative and cost-effective solutions for the TDNPU and enhanced reliability for that entity's system and the regional network.[33] Without remedial action from the Commission, such as enabling GridLiance's proposed Joint Ownership Incentive, this disparity will likely continue, leaving IOU non-native load customers above at a transmission planning disadvantage.

b. Non-Public Utilities Often Face Acute Barriers to Pursuing Their Own Investments

Aside from the lack of transmission planning comparability described above, there are a variety of other reasons why many municipals and some cooperatives, especially TDNPUs, in the MISO and SPP footprint have relatively low investment levels, ranging from entity-specific circumstances and financial factors to systemic barriers to pursuing their own investments. Specific reasons include: (1) tariff rules which favor the incumbent TO or having a traditional reliance on their host incumbent TO;[34] (2) thinly staffed resources;[35] (3) low level of risk tolerance;[36] (4) constraints/competition for capital and potential regulatory burden associated with investment;[37] (5) reluctance to join an RTO;[38] and (6) a reluctance on the host incumbent TO to "accept" the transmission assets of a new non-public into its RTO pricing zone.[39] Reliance on the host incumbent TO to provide for non-public utilities' transmission reliability needs can leave TNDPUs vulnerable to delays as the incumbent will often control the timeline and transmission

[33] *Id*. at PP 26, 41.

[34] *Id.* at PP 27-28.

[35] *Id.* at PP 28-29.

[36] *Id.* at PP 30-31.

[37] *Id.* at P 31.

[38] *Id.* at PP 32-33.

[39] *Id.* at PP 33-35.

designed may prioritize the incumbents' system rather than enhance the TDNPU's system. Further, when a TDNPU relies on a third-party to address its transmission service needs over developing such capabilities in-house, both parties' resources are naturally dedicated elsewhere to higher priority business needs. By removing these traditional impediments to investing, including working within the RTO planning process, and providing ample capital and planning resources focused on the transmission business, a Joint Ownership Incentive directly incentivizes investment in both local/zonal and competitive regional projects at their desired levels.

3. The Proposed Incentive Reasonably Advances the Commission Stated Goal of Promoting Increased Joint Transmission Investment

Considering the various factors that have discouraged non-public utility investment in FERC-jurisdictional transmission over the years, the proposed Joint Ownership Incentive is consistent with promoting needed capital investment in electric transmission infrastructure, developing a more robust transmission grid, increasing reliability, and in general, advancing fulfillment of the goals articulated in Order No. 679 and FPA section 219. As described below, Commission policies that are designed to help non-public utilities overcome obstacles to transmission investment at their desired levels, such as GridLiance's proposed Joint Ownership Incentive, are, in effect, policies aimed at increased reliability and a deeper pool of transmission investors, both worthy public policy goals recognized by the Commission.

a. The Commission Has Historically Recognized the Value of Joint Ownership, Even Inviting the Proposed Incentive

GridLiance's proposed Joint Ownership Incentive is supported by Commission policy and precedent dating back more than 13 years, as the Commission has recognized the potential benefits of engaging non-public utility participation in new transmission joint ownership arrangements, and consequently invited industry – on several occasions – to propose ratemaking incentives that would facilitate these goals.

In 2006 in Order No. 679, the Commission considered the available avenues for encouraging non-public utility participation in new transmission projects. Intervenors in that proceeding set forth a variety of policy reasons to encourage new transmission development by non-public utilities, such as: (1) lowering project costs by virtue of non-public utilities' ability to fund projects with tax-free debt;[40] (2) promoting competition by expanding the pool of development participants;[41] (3) mitigating the conflict between transmission investment and vertically-integrated utilities' interests in underinvesting to preserve their generation market share;[42] and (4) providing non-public utilities with greater access to information about transmission availability, thereby reducing opportunities for discrimination.[43] The Commission not only recognized the benefits attendant to joint development projects, but specifically encouraged non-public utilities' participation in transmission development, stating:

> We agree with comments that public power participation can play an important role in the expansion of the transmission system…. We want to encourage public power participation in new transmission projects.[44]

A few years later, in Order No. 890, and more recently in Order No. 1000, the Commission once again addressed the prospect of joint ownership favorably, stating:

> there are benefits to joint ownership of transmission facilities, particularly large backbone facilities, both in terms of increasing opportunities for investment in the transmission grid, as well as ensuring nondiscriminatory access to the transmission grid by transmission customers.[45]

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[40] Comments of American Municipal Power-Ohio Inc. (AMP) at P 5 (filed January 11, 2006; National Rural Electric Cooperatives Association Order No. 679 Comments at P 41 (filed January 11, 2006).

[41] Comments of AMP at P 3 (referring to comments of Transmission Access Policy Study Group).

[42] *Id*. at P 4.

[43] *Id.*

[44] Order No. 679 at P 354.

[45] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 776 (2011) citing Order No. 890 at P 593, *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

Indeed, the significant benefits associated with joint ownership has spurred the Commission at various times to invite incentive proposals that will accomplish that goal, such as GridLiance's proposed Joint Ownership Incentive.[46] In Order No. 679, the Commission stated:

> to the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project. <u>Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants</u>.[47] (Emphasis added)

On rehearing, in Order No. 679-A, the Commission further stated that non-public utilities "can plan an important role in expansion of the transmission system" and reiterated its willingness to "look favorably on an incentive request that includes public power joint ownership."[48] Most recently, in 2015 the Commission acknowledged the value of enlisting joint investment by twice inviting a then-GridLiance subsidiary Transco, South Central MCN, to propose an incentive "tailored to encouraging public power participation in new transmission projects."[49] GridLiance is proposing in this proceeding that the Commission do just that.

b. Establishing the Proposed Incentive Furthers the Commission's Stated Goals

If approved by the Commission, a Joint Ownership Incentive would ease financial obstacles to beneficial transmission investment for non-public utilities, thus promoting increased non-public utility investment, a deeper pool of investors, and enhanced reliability and market efficiency. This includes

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[46] The proposed Joint Ownership Incentive is further consistent with other efforts by the Commission to promote non-public utility investment beyond the Order No. 679 rulemaking, such as by permitting non-public utilities in MISO to utilize the same rate of return as IOUs and granting other incentives, such as hypothetical capital structure and regulatory assets, to non-public utilities.

[47] Order No. 679 at P 354.

[48] Order No. 679-A at PP 100, 102.

[49] *South Central MCN LLC*, 153 FERC ¶ 61,099 at P 69 (2015) (*South Central*); *order on reh'g,* 154 FERC ¶ 61,271 (*South Central Rehearing*) (finding, in both orders, that SCMCN "could propose an incentive under Order No. 679 tailored to encouraging Public Power and Cooperative participation in new transmission projects.").

addressing the needs of TDNPUs and integrating them into an RTO network, as appropriate. Broader non-public utility participation provides benefits to the region as a whole by encouraging development in areas of the RTO footprint that may not otherwise be accessible. Likewise, by expanding opportunities for joint regional transmission projects, the resulting expansion of the RTO footprint supports the Commission's efforts to promote wholesale market competition.

Further, a Joint Ownership Incentive is consistent with past Commission actions to date[50] granting rate incentives to non-public utilities in MISO encouraging joint ventures with public utilities, such as CapEx2020[51] in the upper Midwest. However, those incentives were associated with larger regional backbone projects with higher risks/challenges. The joint investment projects involving IOUs, G&Ts, JAAs, and municipals have traditionally been more regional and became less frequent with the onset of FERC Order No. 1000. There has been and continues to be a void in the market as smaller transmission projects have not received their due attention as indicated by the lack of municipal investment in MISO.[52] Providing a Joint Ownership Incentive provides a financial inducement to address this void in the market to remove the impediments discussed above to a non-public utility investing in order to enhance the reliability of the local and regional network.

A Joint Ownership Incentive is also consistent with the long-held Commission goal of the economic benefits of an RTO and a broader RTO footprint.[53] Moreover, it provides a vehicle to address the important

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[50] *See* Pardikes Testimony at PP 36-37.

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

[52] Pardikes Testimony at P 37.

[53] *See*, *e.g.*, FERC Order No. 2000.

public policy goal of ensuring the efforts to expand the nation's transmission grid appropriately include all stakeholders including the historically underrepresented non-public utility sectors, in both the planning and ownership of new facilities.[54] Finally, as noted above, a Joint Ownership Incentive is consistent with the Commission's policy and precedent of encouraging joint investment in transmission projects, including its 2015 invitation to GridLiance to propose an incentive under Order No. 679 based on facilitating the participation of non-public utilities in new transmission projects.[55]

4. The Proposed Incentive Cost-Effectively Addresses Non-Public Utilities' Suboptimal Transmission Investment Level, Financing Impediments, and Reliability Needs

A Joint Ownership incentive cost-effectively addresses non-public utilities' record of suboptimal investment, scarcity of capital, and desire to invest in and co-own revenue-enhancing transmission projects to partially offset their increasing transmission rates. By removing the traditional impediments to investing including scarce capital and planning resources, a Joint Ownership Incentive directly incentivizes planning and investment in both local/zonal and regional projects at their desired levels.[56] For instance, a Joint Ownership Incentive would provide an attractive way for non-public utilities to jointly bid for competitive projects in ISO/RTO Order No. 1000 Competitive Transmission Processes. Mr. Pardikes testifies that the Commission's effort to bring specific investment opportunities directly to non-public utilities in this manner reasonably addresses a common frustration that his clients express to him about the lack of viable means for them to identify, properly define, and participate in new transmission projects that meet their needs.[57] It provides a customized approach that incentivizes all types of new transmission investment of potential

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[54] Pardikes Testimony at P 39.

[55] *South Central* at P 69 (citing Order No. 679, at P 354); *South Central Rehearing* at P 26 (citing Order No. 679, at PP 354-355) (finding, in both orders, that SCMCN "could propose an incentive under Order No. 679 tailored to encouraging Public Power and Cooperative participation in new transmission projects.").

[56] Pardikes Testimony at P 40.

[57] *Id*.

interest to prospective partners and ensures non-public utilities support and participation to strengthen the grid.[58] Additionally, for TDNPUs with aging networks, it helps promote enhanced reliability and grid resilience by incentivizing a willing public utility partner like GridLiance to pursue joint development opportunities that provide lower cost reliability and resilience solutions that a typical non-public utility could likely achieve on its own.

5. The Proposed Incentive Provides Important Pro-Competitive Benefits for Consumers

As discussed below, GridLiance's proposed Joint Ownership Incentive also provides a variety of pro-competitive benefits for customers, including fostering a more competitive environment providing a third-party alternative to the incumbent TO, thereby enabling the non-public utility to be an owner rather than a renter. In addition, by expanding opportunities to co-invest in RTO regional projects, it promotes a broader RTO footprint that includes more non-public utility systems with its attendant reliability and planning benefits.[59] Likewise, it facilitates greater non-public utility participation in RTO competitive transmission processes. As mentioned previously, most non-public utilities cannot effectively participate in MISO's and SPP's Order No. 1000 Competitive Transmission Process on their own due to the prohibitively intensive resource and financial commitment needed to realistically pursue these types of projects. A Joint Ownership Incentive directly incentivizes a prospective public utility partner to commit the necessary staffing and financial resources to identify, design, gain RTO approval, and construct various projects to enhance the reliability of the non-public utility's transmission network. Likewise, because it would also be available to the non-public utility partner, the incentive similarly incentivizes a prospective non-public utility partner to coordinate with the public utility and commit to the effort.

[58] *Id*.

[59] *Id.* at P 41.

Finally, a Joint Ownership Incentive provides additional benefits to all RTO customers more generally. By encouraging additional non-public utility participation in projects, a Joint Ownership Incentive can promote increased reliability at a lower cost per investment.[60] As previously discussed, many non-public utilities have lower revenue requirements per mile of transmission investment than IOUs/Transcos because they do not pay income taxes and often have lower debt costs due to tax-exempt or government-backed financing. Thus, compared to a non-public utility relying solely on meeting their reliability needs from their incumbent TO, a Joint Ownership Incentive is consistent with advancing regulatory goals by reducing the transmission cost of RTO ratepayers to fund necessary investment in the grid through the lower revenue requirements of non-public utilities.[61]

6. The Proposed Incentive Promotes Public Policy and Delivers Significant Benefits When the Proposed Eligibility Criteria Are Met

Again, GridLiance is proposing that the Commission establish a new Joint Ownership Incentive to be awarded on a project-specific basis to jurisdictional utilities and non-public utilities that partner on new transmission projects that meet two objective, pre-defined criteria: (1) have been approved by a Commission-approved regional or local transmission planning process; and (2) are at least 15% owned, in aggregate, by non-public utilities.

Equally important, GridLiance is not advocating that the Joint Ownership Incentive be applied to existing assets that it or other jurisdictional utilities may acquire. Rather, GridLiance is proposing that the new ROE incentive apply only to newly constructed projects, as well as to upgrade projects where existing facilities are re-constructed and/or renovated,[62] that meet the proposed eligibility criteria as an incentive to spur needed investment with non-public utility partners. The Incentive would only apply to a partner's

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[60] *Id.* at P 42.

[61] *Id.*

[62] In Order No. 679, the Commission makes clear that "new investment in existing facilities will be eligible for incentive-based rate treatments. Order No. 679 at P 56.

portion of jointly owned projects. Likewise, each project partner would be expected to obtain cost recovery through its respective formula rates.

a. Projects Eligible for the Incentive Must Be Approved by a Commission-Approved Regional or Local Transmission Planning Process

GridLiance's proposal ensures that the Joint Ownership Incentive will be applied to only projects that have been well-vetted and found to be well-justified. Each of the proposed projects will have gone through a Commission-approved planning process and been approved in order to eligible for incentives. This guards against projects that are unneeded and applies the same rules to approving projects as any other TO in the RTO.[63]

b. Projects Eligible for the Incentive Must Have in Aggregate 15% or More in Ownership Interests Held by Non-Public Utilities

GridLiance's proposed 15% eligibility threshold strikes the appropriate balance between safeguarding against gaming and inadvertently systematically excluding those smaller TDNPUs who could benefit the most from the Joint Ownership Incentive. Under the proposal, public utilities like GridLiance would be directly incentivized to work with the broadest pool of potential non-public utility investors, many of which would not have the capital to invest in projects at higher levels. Thus, a 15% investment threshold ensures that non-public utilities are involved at material levels in applicable projects, thus substantially increasing their investment levels in transmission from historically low levels.[64] This threshold is also generally consistent with non-public utility ownership percentages of several of the well-known prior MISO joint projects that were part of the CapX2020 consortium.[65]

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[63] Pardikes Testimony at P 43.

[64] *Id*. at P 43.

[65] *Id.* at PP 44-45.

In MCR's experience, the typical transmission project for a municipal can range from $5 million-$20 million, more than the existing total gross transmission plant of many municipals in MISO and SPP and multiples of their typical annual investment levels.[66] The recent median annual investment of municipals in MISO is only about $110,000 per year and about $100,000 per year in SPP.[67] A 15% investment in a $10 million project represents a dramatic increase in the documented investment levels of many municipal utilities in MISO and SPP. A 15% joint investment with a single municipal city in a local/zonal high-voltage project that costs $10 million would require an investment of $1.5 million by the non-public utility partner(s) in order for a public utility like GridLiance to qualify for the Joint Ownership Incentive. At 15 times the medial annual historical municipal investment, this threshold could still be a stretch, but in MCR's experience, a $1.5 million transmission investment (15% of $10 million) by a single municipal utility may still be financially within reach for many smaller municipals willing to invest in a transmission project, whereas a full $10 million investment likely would not be.[68]

At the same time, setting the threshold level well above 15% could cause those smaller non-public utilities that could most benefit from the opportunities created by the proposed Joint Ownership Incentive to be unintentionally excluded. Using the same $10 million project example above, if the aggregate threshold for the Joint Ownership Incentive were set at 25%, a public utility like GridLiance may need to partner with multiple municipals to reach the minimum threshold of $2.5 million. Given the added transaction costs associated with such a multi-party venture, setting the threshold too high could systematically discourage public utilities from pursuing smaller non-public utilities.[69] This rationale is even more applicable with

[66] *Id.* at P 46.

[67] *Id.*

[68] *Id.* at PP 46-47.

[69] *Id* at P 46.

regard to projects in the MISO Competitive Transmission Process, which applies to projects with regional cost allocations that will generally be bigger and even more expensive.[70]

B. The Transco Business Model Continues to Produce Meaningful Benefits for Consumers to Merit an Incentive Adder

1. Commission Policy and Precedent Support Incentive Rate Treatment

In Order No. 679, the Commission established the "Transco Adder" incentive after concluding that the benefits of independent, transmission-only companies were sufficient to justify additional costs to customers and thus merited a ROE adder.[71] The Commission explained that the Transco business model particularly deserves incentive rate treatment because of the "proven and encouraging track record of Transco investment in transmission infrastructure," the singular focus on transmission investment by transmission-only companies, the elimination of competition for capital between generation and transmission investments, and access to capital markets."[72] The Commission observed that the Transco business model responds more rapidly and precisely to market signals, and thus satisfies FPA section 219 because the Transco business model promotes increased investment in new transmission, which in turn reduces costs and increases customers.[73] To promote the formation of Transcos and attract investment after the Transco is formed, Commission policy offers an ROE incentive to companies that qualify.[74] The Commission continues to recognize that the Transco business model promotes consumer benefits sufficient to justify an ROE adder.[75] In its most recent order[76] addressing the subject, the Commission

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[70] *Id.*

[71] Order No. 679 at P 226.

[72] *Id*. at PP 222-224.

[73] *Id.* at P 224.

[74] *Id*. at P 221.

[75] *Consumers Energy Company et al. v. International Transmission Company et al*., 165 FERC ¶ 61,021 (2018) at P 73.

[76] *Id.*

acknowledged that its "current policy" is that a "fully independent transmission company can receive a 50 basis point Transco Adder, citing *NextEra Energy Transmission New York, Inc.* and *GridLiance West Transco LLC.*[77] By continuing to provide a Transco Adder, the Commission encourages the Transco business model and promotes the corresponding reliability and economic benefits it provides.

2. Recent Empirical Evidence Shows the Value of the Transco Business Model in Promoting Transmission Development

Despite the Commission's past support for the Transco business model by authorizing recovery of a Transco Adder, GridLiance is aware that some questions have arisen as to the effectiveness of the adder in providing "meaningful benefits to consumers." In particular, Commissioner Glick opined in his concurrence in the *GridLiance West* order that: "It is certainly not clear that Transcos are superior to other public utilities that can and do invest in transmission facilities—including competitively developed transmission facilities—or that awarding Transcos a higher ROE actually leads to greater transmission investment."[78] Notwithstanding Commissioner Glick's comments, there is abundant evidence that that the Transco business model provides clear, concrete benefits to ratepayers that more than offset the costs to ratepayers of the increased returns authorized through the Commission's Transco Adder rate incentive.

To address Commissioner Glick's concerns, GridLiance engaged MCR to explore empirically the value of the Transco business model in promoting transmission development relative to investment levels of vertically-integrated utilities. In particular, MCR used various objective metrics to analyze the transmission investment levels of Transcos and IOUs over the last six years where the comparison would be the most meaningful, such as in MISO and SPP, the two RTOs where Transcos are most prevalent. These metrics included the following:

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[77] *NextEra Energy Transmission New York, Inc.* 162 FERC ¶ 61,196 at PP 48-52 (2018) (*NEET NY*), and *GridLiance West Transco LLC*, 164 FERC ¶ 61,049 at PP 40-46 (2018) (*GridLiance West*).

[78] *GridLiance West* at P 2.

- Percentage change in gross transmission plant for the past six years;[79]

- Percentage change in gross transmission plant for the most recent three years;

- Investment to depreciation intensity ratio over the last six years, which provides insight into the *rate* at which transmission owners are investing to replace transmission plant as it depreciates. A ratio of one means that transmission investment is replacing transmission plant as it becomes depreciated;

- The median investment to median gross transmission plant ratio over the last six years, which measures the *pace* and *consistency* of investment;[80] and

- The average annual dollar investment, which captures the absolute *size* of the investment. This equals the total dollar change in gross transmission plant over the six years divided by six years.

The results of MCR's empirical analysis are attached hereto as ***Attachment B***.[81] In summary, MCR found that the Transco segment in MISO and SPP has been investing in transmission plant over the last six years at a higher rate than their IOU counterparts, which MCR attributed to the inherent benefits of the Transco business model and the incentives put in place by the Commission, including the Transco ROE Adder for certain Transcos based on their relative independence.[82]

In particular, when analyzing the metrics on a median basis, the data show that the relative Transco investment rate has exceeded that of their IOU counterparts for four of the five metrics analyzed:

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[79] 2019 gross plant minus 2013 gross plant divided by 2013 gross plant.

[80] This metric represents the ratio of the median dollar investment over the six-year timeframe to the median gross transmission plant over the same period. This metric measures the pace and consistency of investment by adjusting for one-time large investments. This metric is then discussed two ways: 1) the median of the sampled companies in the segment (that is, the median of these eight ratios for Transcos and median of the 25 IOUs; and 2) the simple average of the eight Transcos and the simple average of the 25 IOUs.

[81] *The Transco Model is Working*, June 2019, prepared for GridLiance by MCR Performance Solutions (MCR Transco Report). Annual transmission investment figures were calculated by taking the difference between each TO's reported gross transmission plant from year-to-year plus the change in construction work in progress (CWIP). These gross transmission plant figures were used as a proxy for each company's annual transmission capital investment and were then aggregated by each segment (*i.e.*, eight Transcos in MISO and SPP and 25 IOUs in MISO and SPP) to determine segment-wide figures. From this data, key metrics were calculated by segment to gauge the level of relative transmission investment to make comparisons of the relative propensity to invest between the Transco and IOU segments.

[82] MCR Transco Report at P 2.

- The median percentage change in gross transmission plant for the eight TOs in the Transco segment was 83% for the six-year period, versus 66% for the 25 TOs in the IOU segment;

- When looking at only the last three years of investment, the median percentage change in gross transmission plant was 25% for the Transco segment versus 28% for the IOU segment;

- The median Transco segment investment to depreciation expense intensity ratio was 553% compared to 434% for the IOU segment;

- The ratio of the median investment to median gross transmission plant balance for Transcos was 8% compared to 7% for the IOU segment;[83] and

- The median average annual dollar investment for the Transco segment was $160.3 million compared to $111.5 million for the IOU segment.

These median metrics paint a general picture of Transcos investing more heavily in transmission than IOUs. Furthermore, when looking at the metrics on an average (rather than median) basis, the advantage to the Transco segment is even more pronounced with all five metrics favoring the Transco segment:

- The Transco segment had an average[84] 344% overall percentage change in gross transmission plant over the last six years, compared to 77% for IOUs; when looking at only the last three years, the Transco segment had an average 36% change in gross transmission plant from 2016 to 2019,[85] compared to 28% for IOUs.

- The average investment to depreciation expense intensity ratio for the Transco segment from 2013 to 2019 was 748%, versus 428% for IOUs;

- The average of the median investment to median gross plant ratios for the Transco segment was 14% compared to 8% for the IOU segment; and

- The average annual dollar investment by Transcos over the six-year period was $185.1 million, versus $129.1 million for IOUs.

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[83] The median of the list of companies' ratios in each segment (median investment over the six years divided by median gross plant balance over the six years).

[84] All averages are simple averages of the companies in the sample. On a weighted average basis, Transcos still maintain their advantage over IOUs. On a weighted average basis: the percentage change over six years for Transcos is 91% compared to IOUs' 75%; the investment to depreciation ratio is 494% vs. 433% for IOUs, and the median investment to median gross plant balance ratio is 9% for Transcos vs. 8% for IOUs.

[85] The 2016 to 2019 gross transmission plant data produces three years of investment data, *i.e.*, the change in transmission gross plant from 2016 to 2017, 2017 to 2018 and 2018 to 2019.

Even when "outliers" such as Ameren Transmission Company of Illinois[86] and American Transmission Company[87] are removed, the story of higher Transco investment remains the same. Thus, as shown herein, the Transco business model has been very successful in promoting transmission investment and the corresponding reliability and economic benefits it provides consumers and should continue to be encouraged by FERC in order to sustain the high levels of investment demonstrated by Transcos in MCR's analysis. In explaining MCR's results, the report's author, Mr. Jim Pardikes, MCR's VP, Transmission, concludes that the key to Transcos' superior investment levels in these RTOs is their management's focus on transmission as a singular business function and ready access to capital, both hallmarks of the Transco business model.[88] In short, as demonstrated above, MCR's empirical analysis clearly shows that the Transco business model meaningfully promotes transmission development and the consumer benefits it provides to merit an incentive adder.

3. The Transco Adder is Working and Should be Continued

As discussed below, the Commission's Transco incentives, such as providing a hypothetical capital structure, establishing a regulatory asset for Transcos, and providing a Transco Adder for more independent Transcos, combined with the inherent benefits of the Transco business model described above, have effectively incentivized forming Transcos and their elevated levels of transmission investment and should be continued. The Transco Adder has provided an additional financial inducement for new, more independent Transcos like NextEra Energy Transmission New York and GridLiance West LLC to

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[86] Much of the difference in the average figures is driven by Ameren Transmission Company of Illinois (ATXI), which has an exceptionally high percentage growth in investment of 1,902%, due to starting from a relatively small gross transmission dollar base of $63.4 million combined with completing large capital projects. Even without ATXI, however, all the average metrics still show Transco investment outpacing IOU investment.

[87] The MCR Transco Report at P 6 (describing how some of the metrics for American Transmission Company, the largest TO in both the Transco and IOU segments by measure of gross transmission plant, are comparatively low for the Transco segment and clearly bring down the Transco segment metrics.)

[88] *Id.* at P. 7-8.

enter the market in recent years and dedicate the capital and resources to proactively identify projects that enhance the reliability of the network, as Mr. Pardikes notes.[89]

GridLiance West's experience is particularly instructive of the positive role the Transco Adder plays in furthering the Commission's Order No. 679 and Energy Policy Act of 2005 goals. It is also indicative of the improved responsiveness to transmission market needs and other benefits that the Transco business model provides customers. By incentivizing the formation of entities like GridLiance West singularly focused on transmission ownership, operation, and expansion, the Adder meaningfully facilitates a deeper pool of transmission investors, advancing a long-running Commission objective. GridLiance West's acquisition of the high-voltage transmission system of Valley Electric Transmission Association LLC (Valley) in 2017 and GridLiance West's subsequent pursuit of transmission investments benefitting CAISO customers that would not have been pursued otherwise, such as its Sloan Canyon upgrade project, is an early example of the benefit of an independent Transco acquiring assets from a small non-profit utility more focused on meeting its retail customer needs. Likewise, GridLiance West's Sloan to Mead project, the first CAISO economic project specifically addressing congestion for exports, not simply imports, is a testament to the added value of the Transco business model as CAISO almost certainly would not have authorized the project but for GridLiance West's demonstration that the CAISO Tariff did, indeed, support looking at export congestion. Both the Sloan Canyon and Sloan to Mead projects will benefit CAISO ratepayers by enhancing reliability and reducing congestion, with demonstrable net savings. GridLiance West's very formation and ability to attract capital to finance incremental transmission investments such as these projects have been and continue to be directly facilitated by the Transco Adder.

Another benefit of the Transco Adder is demonstrated by the value GridLiance West is providing California customers by influencing how Nevada-based renewables connected to the CAISO-controlled grid

[89] *Id.* at P 8.

are treated in the California Public Utilities Commission (CPUC) Integrated Resource Plan (IRP) proceedings. GridLiance West's service territory is rich with the potential for cost-effective solar development. Relatively small transmission build-out projects are needed to realize the net benefits of these resources in support of California's goals to reduce greenhouse gases, but the benefits from relying on Southern Nevada solar significantly outweigh the costs. GridLiance West was the first to identify that the CPUC's IRP model failed to recognize that Nevada resources interconnected to its system are, in fact, CAISO grid resources. Previously, the model erroneously assigned wheeling charges to those resources, making them less economic. GridLiance West is now working with the CPUC and CAISO to ensure the IRP modeling efforts properly account for these benefits to ensure the most cost-effective resources are allocated to the benefit of California consumers.

As noted, the IRP effort is part of GridLiance West's efforts to identify various transmission solutions to enable the state of California to achieve its greenhouse gas emissions goals more cost effectively. Without GridLiance West's participation in the IRP, low-cost Nevada renewables might not have been accurately modelled in the CPUC's and the CAISO's planning. GridLiance West's focus on transmission planning to benefit all CAISO ratepayers exceeds the purposes that Valley had when it owned the same assets and is indicative of how Transco ownership of assets previously owned by small not-for-profit utilities in any location can provide benefits. This is thus one example of the importance of the Commission's overarching goals in incentivizing the Transco business model.

At the same time, the Transco Adder fairly balances the need for new facilities and investor expectations with the Commission's obligation to ensure rates that are just and reasonable. While the Transco Adder provides significant benefits to a start-up Transco like GridLiance West as described above, its impact to CAISO customers is negligible[90] and will produce more than sufficient benefits to justify the

[90] For the 2018 rate year, GridLiance West's transmission revenue requirement (TRR) constitutes less than one percent of the $2.4 billion CAISO Transmission Access Charge (TAC). Adding the 50 bp ROE

associated cost impact to customers. For these reasons, the Commission's incentive policy to encourage Transco formation is working and should be continued on a case-by-case basis to ensure future robust transmission investment.

4. The Commission's Approach to Awarding the Transco Adder Incentivizes Transmission Development and Efficient Operation of the Grid and Should Continue Unchanged.

The Commission's policy[91] of allowing active ownership of a Transco by market participants to be eligible for a Transco Adder, is solid and should remain unchanged. Assertions that Transcos affiliated with market participants are insufficiently independent, and thus that eligibility for the incentive should be restricted to only those entities that are fully independent of market participants, are baseless and ignore the recent precedent in *NEET NY,*[92] which reiterated the Commission's view, expressed in Order No. 679, that a transmission-only company may be affiliated with market participants. In *NEET NY*, the Commission stated that stand-alone transmission companies even with active affiliation with a market participant are eligible for the incentive to the extent they can show why such affiliation "does not affect the integrity of its investment planning, capital formation, and investment processes or how its business structure provides support for transmission investments in a way similar to the structure of non-affiliated Transcos …."[93] Such demonstrations are appropriately fact-specific and the requisite showing is best determined based on the record in individual proceedings.[94] For these reasons, the Commission should continue to apply the

adder granted to GridLiance West boosts its TRR and CAISO's TAC by less than $400,000 and adds about ten cents to CAISO's 11.27994 $/MWh TAC rate.

[91] Order No. 679 at P 201 (The definition of Transco the Commission established in Order No. 679 "does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and distribution facilities.").

[92] *NEET NY* at P 51.

[93] *Id.* at P 50 (quoting Order No. 679 at P 240).

[94] *GridLiance West* at P 17 (Applying its *NEET NY* precedent, the Commission more recently found that based on the record in that proceeding that GridLiance West LLC had similarly "demonstrated that its relationship with its affiliates will not affect the integrity of GridLiance West's investment, planning, capital

standards articulated in *NEET NY* on a case-by-case basis when evaluating whether a Transco is sufficiently independent from market participants to merit an incentive.

Likewise, the Commission's practice of awarding the Transco Adder based upon whether the applicant qualifies under the independence standard for a Transco rather than on a particular project is similarly sound and should continue unchanged. Like the RTO Adder, the Transco Adder differs from the risk-based incentives FERC sometimes grants to encourage new transmission investment in particularly difficult and risky situations. When authorized for new investment, a risk-based incentive generally applies only to the investment in specific new projects. In contrast, the Transco Adder is an incentive available only for independent transmission companies and is intended to be an incentive to encourage a particular *business model*, rather than address the risks associated with a specific project. Further, as MCR concluded, the benefits of the Transco business model (*e.g.*, increased competition, ready access to capital, more responsiveness and innovative market solutions, improved asset management) extend to all of a Transco's investments rather than a particular project.[95] Further, these characteristics are systemwide benefits inherent in the Transco business model and sustain over time.[96] Additionally, awarding a Transco Adder on a project-by-project basis is impractical and unnecessarily burdensome as having to make a filing at FERC each time a Transco makes a project would slow down the investment process, effectively diminishing one of the advantages of a Transco, its market responsiveness.[97] For these reasons, the Transco Adder should apply to all of an eligible Transco's transmission plant rather than awarded on a project-by-project basis.

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formation, and investment processes" and that GridLiance West can "operate independently from its affiliated marketing interests located inside and outside the CAISO region.").

[95] MCR Transco Report at P 9.

[96] *Id.*

[97] *Id.* at P 10.

Additionally, requiring an entity seeking a Transco incentive to provide information demonstrating anything other than that it qualifies under the independence standard and how its benefits are expected to occur would run counter to longstanding Commission policy and its recent *NEET NY* precedent.[98] Since the Commission began approving independence incentives under FPA section 205 before Order No. 679, it has consistently declined to require the project-specific showing required for incentives other than the RTO Adder. As the Commission stated in *NEET NY,[99]* a Transco adder under Order No. 679 is not based on the specific risks or benefits of an applicant's project but based upon whether the applicant qualifies under the independent standard for a Transco and "continues to provide the benefits which we are trying to incentive[ize]." The Commission recently reiterated that the Transco Adder is similar to the RTO Adder in that eligibility is based on an objective criterion: independence.[100] Protestors argued that the adder should be separately justified based on criteria beyond independence to show that the adder is needed for the particular entity, but the Commission rejected those arguments and clarified that further justification is not required. Specifically, the Commission found that:

> Similar to the Commission's recent finding with respect to the RTO Adder for the MISO Transmission Owners, we find that utilities are eligible for the Transco Adder if they can demonstrate their status as Transcos. Applicants need not provide additional justification as to the necessity or benefits of the incentive or pass a cost-benefit analysis.[101]

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[98] *NEET NY* at P 52 (quoting Order No. 679 at PP 65 and 226); *Midcontinent Indep. Sys. Operator, Inc*. 150 FERC ¶ 61,252 (2015) (*ITC Midwest*) at P 46 *(*finding that "utilities are eligible for the Transco Adder if they can demonstrate their status as Transcos. Applicants need not provide additional justification as to the necessity or benefits of the incentive or pass a cost-benefit analysis.") (internal citations omitted).

[99] *NEET NY* at P 24 (citing and quoting Order No. 679 at PP 65, 226 ("[C]ontinuing to allow a Transco, over the long-term, to receive an incentive ROE for all of its facilities that recognizes its increased transmission investment only makes sense if the Transco continues to provide the benefits which we are trying to incentive.")).

[100] *ITC Midwest* at P 46.

[101] *Id.* at P 47.

Finally, the Commission's policy and precedent[102] of applying the Transco Adder generically to an eligible Transco's rate-based assets, not just to new investment, is equally sound and should similarly continue unchanged. Because it is the *business model* that is incentivized under the Commission's policies, whether the Transco invests in a new or upgraded project or buys existing transmission, the benefits of the Transco business model still apply.[103] In fact, the Commission has long permitted application of the incentive to both acquired and existing assets, as well as new construction and has consistently recognized the benefits of transferring transmission assets from a transmission owner affiliated with market participants to an independent Transco. In an early pre-Order No. 679 order specifically approving applying the Transco Adder to jurisdictional assets acquired from a market participant, the Commission found that the "transfer of transmission facilities to an independent entity is one of the most effective means of separating transmission interests from generation interests and achieving independence through a for-profit transmission company."[104] More recently, in *StarTrans*, the Commission approved an incentive ROE associated with a Transco's acquisition of high-voltage transmission facilities from a California municipal utility because Transcos "have demonstrated an inclination to react more rapidly to market signals indicating when and where transmission investment is needed," emphasizing that "Transcos' for-profit nature, combined with a transmission-only business model, enhances asset management and access to capital markets and provides greater incentives to develop innovative services."[105] Other existing Transcos granted incentives by the Commission have accomplished their

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[102] *ITC Great Plains, L.L.C.*, 126 FERC ¶ 61,223 (2009) (*ITC Great Plains*) at P 96 ("…because the two purchased substations will be under the functional control of SPP and since we find that ITC Great Plains merits the 100 basis points return on equity for independence, we find that it is appropriate to grant these return on equity incentives for the two purchased substations.").

[103] *Id*.

[104] *ITC Holdings Corp*., 102 FERC ¶ 61,182 (2003) (*ITC Holdings*) at PP 1,68 (approving transfer of jurisdictional assets and 100 basis point adder).

[105] *StarTrans IO, L.L.C.*, 122 FERC ¶ 61,306 (2008) (*StarTrans*) at PP 19, 28, *order on rehearing*, 130 FERC ¶ 61,209 (2010); *order denying rehearing*, 133 FERC ¶ 61,154 (2010).

growth and investment activities through a combination of acquisition and development activities, further demonstrating that the Commission's policy is sound and should continue unchanged.

III. SPECIFIC NOI QUESTIONS

A. Joint Ownership

Question 50: Are there barriers to non-public utilities' ownership of transmission facilities?

As discussed above in detail in section II.A.2, their lack of relative transmission investment compared to IOU/Transcos, coupled with aging transmission systems, indicate that many municipals and at least a few cooperatives in MISO and SPP lack the means and/or the opportunity to maintain their systems comparably to their IOU/Transco counterparts, and may be facing obstacles to planning and investing at their desired levels. The disparity in investment levels likely stems from several institutional obstacles and resource barriers that limit their ability to participate in transmission development and planning on a comparable basis as their IOU/Transco counterparts. As GridLiance documents in testimony from Mr. Jim Pardikes accompanying these comments, there are a variety of reasons why many municipals and some cooperatives, especially TDNPUs, in the MISO and SPP footprint have relatively low investment levels, ranging from entity-specific circumstances and financial factors to systemic barriers to pursuing their own investments. Specific reasons include: (1) tariff rules which favor the incumbent TO or having a traditional reliance on their host incumbent TO;[106] (2) thinly staffed resources;[107] (3) low level of risk tolerance;[108] (4) constraints/competition for capital and potential regulatory burden associated with investment;[109] (5)

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[106] Pardikes Testimony at PP 27-28.

[107] *Id.* at PP 28-29.

[108] *Id.* at PP 30-31.

[109] *Id.* at P 31.

reluctance to join an RTO;[110] and (6) a reluctance on the host incumbent TO to "accept" the transmission assets of a new non-public into its RTO pricing zone.[111]

In particular, As Mr. Pardikes points out, some non-public utilities have constrained capital investment budgets, for example, by their need to maintain their credit rating and debt service coverage, or their bonding authority and amount of tax-exempt financing capacity.[112] Further, within a municipal, there is often competition among the various business segments for limited capital. Potential transmission projects (which can be costly relative to municipals' total capital budgets) have to compete with generation and distribution projects in the electric utility and with other municipal business segments that require capital, such as water, wastewater treatment, natural gas, telecom, and district heating. In addition, the sheer legal, financial, and regulatory requirements of issuing debt can discourage a municipal from financing a new project.

Question 51: Should the Commission consider granting incentives to promote joint ownership arrangements with non-public utilities, and if so, how?

As demonstrated in section II.A. above, in furtherance of its longstanding policy of promoting a expanded joint ownership opportunities for non-public utilities, the Commission should establish a new Joint Ownership Incentive under FPA sections 219 (Order No. 679) or 205, awarded on a project-specific basis to jurisdictional utilities and non-public utilities that partner on new transmission projects that meet two objective, pre-defined criteria: (1) have been approved by a Commission-approved regional or local transmission planning process; and (2) that are at least 15% owned, in aggregate, by non-public utilities. Projects that satisfy these criteria will not only advance worthy Commission policy goals, but also deliver

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110 *Id.* at PP 32-33.

111 *Id.* at PP 33-35.

112 Pardikes Testimony at P 32.

significant benefits to non-public utility partners (and their customers) and enhance the overall reliability and resilience of the grid.

Equally important, GridLiance is not advocating that the Joint Ownership Incentive be applied to existing assets that it or other jurisdictional utilities may acquire. Rather, GridLiance is proposing that the new ROE incentive apply only to newly constructed projects, as well as to upgrade projects where existing facilities are re-constructed and/or renovated,[113] that meet the proposed eligibility criteria as an incentive to spur needed investment with non-public utility partners. The Incentive would only apply to a partner's portion of jointly owned projects. Likewise, each project partner would be expected to obtain cost recovery through its respective formula rates.

As detailed above, GridLiance's proposed incentive promises to provide an effective vehicle for promoting expanded joint ownership opportunities for non-public utilities, directly meeting the Commission's longstanding public policy goals of (a) attaining greater levels of non-public utility participation in grid expansion projects and a deeper pool of transmission investors; and (b) promoting an expanded RTO footprint leading to a more reliable transmission grid and a more competitive wholesale market. Likewise, by creating additional opportunities for non-public utilities to make transmission investments at their desired levels, this incentive is designed to counter the financial impediments to transmission investment by non-public utilities and to provide additional benefits. Specifically, it offers a cost-effective means of addressing non-public utilities' record of suboptimal transmission investment, scarcity of capital, and their desire to invest in and co-own revenue-enhancing transmission projects to partially offset increasing transmission rates. Additionally, for non-public utilities with aging networks, it promotes enhanced system reliability by directly incentivizing a willing partner such as GridLiance to pursue joint development opportunities that

[113] In Order No. 679, the Commission makes clear that "new investment in existing facilities will be eligible for incentive-based rate treatments. Order No. 679 at P 56.

stand to increase the reliability of a non-public utility's system in a more cost-effective manner than the non-public utility could likely achieve on its own. Finally, it provides important pro-competitive benefits for customers, such as (a) fostering a more competitive environment providing a competitive alternative to the incumbent utility; (b) promoting greater non-public utility participation in RTO competitive transmission processes; and (3) promoting increased reliability at a lower cost per investment. Finally, it delivers significant benefits when the proposed eligibility criteria are met.

B. Transcos

Question 57: Does the Transco business model continue to provide sufficient benefits to merit transmission incentives? What information should an entity seeking a Transco incentive provide to demonstrate sufficient benefits?

Yes. As demonstrated above in section II.B., the Transco business model continues to provide sufficient benefits to merit transmission incentives and should be continued. Likewise, as explained in section II.B.4. above, consistent with longstanding Commission policy and precedent, an entity seeking a Transco incentive should not be required to provide information demonstrating anything other than that it qualifies under the independence standard and how its benefits are expected to occur.[114] Since the Commission began approving independence incentives under FPA section 205 before Order No 679, it has consistently declined to require the project-specific showing required for incentives other than the RTO Adder. As the Commission recently stated in *NEET NY,*[115] a Transco adder under Order No. 679 is not based on the specific risks or benefits of an applicant's project but based upon whether the applicant qualifies under the independent standard for a Transco and "continues to provide the benefits which we are trying to incentive[ize]." The Commission recently reiterated that the Transco Adder is similar to the RTO

[114] *See, e.g.*, MCR Transco Report at P 9.

[115] *NEET NY* at P 24 (citing and quoting Order No. 679 at PP 65, 226 ("[C]ontinuing to allow a Transco, over the long-term, to receive an incentive ROE for all of its facilities that recognizes its increased transmission investment only makes sense if the Transco continues to provide the benefits which we are trying to incentive.")).

Adder in that eligibility is based on an objective criterion: independence.[116] Protestors argued that the adder should be separately justified based on criteria beyond independence to show that the adder is needed for the particular entity, but the Commission rejected those arguments and clarified that further justification is not required. Specifically, the Commission found that:

> Similar to the Commission's recent finding with respect to the RTO Adder for the MISO Transmission Owners, we find that utilities are eligible for the Transco Adder if they can demonstrate their status as Transcos. Applicants need not provide additional justification as to the necessity or benefits of the incentive or pass a cost-benefit analysis.[117]

Question 58: Should the Transco incentive remain available to Transcos that are affiliated with a market participant? If so, how should the Commission evaluate whether a Transco is sufficiently independent to merit an incentive?

Yes. As explained above in II.B.4., the Commission's policy[118] of allowing active ownership of a Transco by market participants to be eligible for a Transco Adder, is solid and should remain unchanged. Assertions that Transcos affiliated with market participants are insufficiently independent, and thus that eligibility for the incentive should be restricted to only those entities that are fully independent of market participants, are baseless and ignore the recent precedent in *NEET NY*,[119] which reiterated the Commission's view that a transmission-only company may be affiliated with market participants. In *NEET NY*, the Commission stated that stand-alone transmission companies even with active affiliation with a market participant are eligible for the incentive to the extent they can show why such affiliation "does not affect the integrity of its investment planning, capital formation, and investment processes or how its business structure provides support for transmission investments in a way similar to the structure of non-

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[116] *ITC Midwest* at P 46.

[117] *Id.* at P 47.

[118] Order No. 679 at P 201 (The definition of Transco the Commission established in Order No. 679 "does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and distribution facilities.").

[119] *NEET NY* at P 51.

affiliated Transcos …."[120] Such demonstrations are appropriately fact-specific and the requisite showing is best determined based on the record in individual proceedings.[121] For these reasons, the Commission should continue to apply the standards articulated in *NEET NY* on a case-by-case basis when evaluating whether a Transco is sufficiently independent from market participants to merit an incentive.

Question 59: Should a Transco incentive be awarded on a project-by-project basis?

No. As explained in II.B.4. above, consistent with longstanding Commission policy and its recent *NEET NY* precedent,[122] the Transco incentive should continue to be awarded based upon whether the applicant qualifies under the independence standard for a Transco and not on a project-by-project basis. Further, like the RTO Adder, the Transco Adder differs from the risk-based incentives FERC sometimes grants to encourage new transmission investment in particularly difficult and risky situations. When authorized for new investment, a risk-based incentive generally applies only to the investment in specific new projects. In contrast, the Transco Adder is an incentive available only for independent transmission companies and is intended to be an incentive to encourage a particular *business model*, rather than address the risks associated with a specific project. Further, the benefits of the Transco business model (*e.g.*, increased competition, ready access to capital, more responsiveness and innovative market solutions, improved asset management) extend to all of a Transco's investments rather than a particular project.[123] Further, these characteristics are systemwide benefits inherent in the Transco business model

[120] *Id.* at P 50 (quoting Order No. 679 at P 240).

[121] *GridLiance West* at P 17 (Applying its *NEET NY* precedent, the Commission more recently found that based on the record in that proceeding that GridLiance West LLC had similarly "demonstrated that its relationship with its affiliates will not affect the integrity of GridLiance West's investment, planning, capital formation, and investment processes" and that GridLiance West can "operate independently from its affiliated marketing interests located inside and outside the CAISO region.").

[122] *NEET NY* at P 52 (quoting Order No. 679 at PP 65 and 226); *ITC Midwest* at P 46 (finding that "utilities are eligible for the Transco Adder if they can demonstrate their status as Transcos. Applicants need not provide additional justification as to the necessity or benefits of the incentive or pass a cost-benefit analysis.") (internal citations omitted).

[123] MCR Transco Report at P 9.

and sustain over time.[124] Additionally, awarding a Transco Adder on a project-by-project basis is impractical and unnecessarily burdensome as having to make a filing at FERC each time a Transco makes a project would slow down the investment process, effectively diminishing one of the advantages of a Transco, its market responsiveness.[125] For these reasons, the Transco Adder should apply to all of eligible Transco's transmission plant rather than based on a particular project.

Question 60: Should the Transco incentive exclude assets that a Transco buys, rather than develops?

No. As explained above in II.B.4., because it is the *business model* that is incentivized under the Commission's policies, the Transco incentive has should continue to be applied generically to a Transco's rate-based assets, not just to new investment. Whether the Transco invests in a new or upgraded project or buys existing transmission, the benefits of the Transco business model still apply.[126] As noted above, Commission policy and precedent[127] similarly support not limiting application of the incentive to specific assets. In fact, the Commission has long permitted application of the incentive to both acquired and existing assets, as well as new construction and has consistently recognized the benefits of transferring transmission assets from a transmission owner affiliated with market participants to an independent Transco. In an early pre-Order No. 679 order specifically approving applying the Transco Adder to jurisdictional assets acquired from a market participant, the Commission found that the "transfer of transmission facilities to an independent entity is one of the most effective means of separating transmission interests from generation interests and achieving independence through a for-profit

[124] *Id.*

[125] *Id*. at P 10.

[126] *Id*.

[127] *ITC Great Plains* at P 96 ("…because the two purchased substations will be under the functional control of SPP and since we find that ITC Great Plains merits the 100 basis points return on equity for independence, we find that it is appropriate to grant these return on equity incentives for the two purchased substations.").

transmission company."[128] More recently, in *StarTrans*, the Commission approved an incentive ROE associated with a Transco's acquisition of high-voltage transmission facilities from a California municipal utility because Transcos "have demonstrated an inclination to react more rapidly to market signals indicating when and where transmission investment is needed," emphasizing that "Transcos' for-profit nature, combined with a transmission-only business model, enhances asset management and access to capital markets and provides greater incentives to develop innovative services."[129] Other existing Transcos granted incentives by the Commission have accomplished their growth and investment activities through a combination of acquisition and development activities, further demonstrating that the Commission's policy is sound and should continue unchanged.

IV. CONCLUSION

WHEREFORE, for the reasons set forth above, GridLiance respectfully requests that the Commission consider these comments in any actions or decisions taken pursuant to this docket.

Respectfully submitted,

Beth Emery

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June 26, 2019

[128] *ITC Holdings* at PP 1, 68 (approving transfer of jurisdictional assets and 100 basis point adder).

[129] *StarTrans* at PP 19, 28.

Attachment A

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentive Policy	)	DOCKET NO. PL19-3-000

PREPARED BY

JAMES PARDIKES

Vice President, Transmission Strategy

MCR Performance Solutions, LLC

On Behalf of

GridLiance Holdco, LP

6/26/19

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is James Pardikes. I am a Vice President and head of the Transmission Strategy Practice at MCR Performance Solutions (MCR). MCR is a management consulting firm that provides a wide range of services to the utilities industry. I have been employed by MCR since 2001. My present business address is 155 North Pfingsten Road, Suite 155, Deerfield, IL 60015.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of GridLiance Holdco, LP (GridLiance).

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS HEAD OF THE TRANSMISSION STRATEGY PRACTICE AT MCR.

A. I lead transmission-related projects for MCR's clients. Over the last 12 years, I have advised non-public utilities (*e.g.*, electric cooperatives, municipals, joint action agencies), in the MISO and SPP regions on a variety of transmission strategy and capital planning matters and testified in front of the Commission on numerous occasions.[1]

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

I am supporting GridLiance's comments in this proceeding. My testimony addresses the merits of the Joint Ownership incentive adder discussed in the NOI. I will discuss the benefits expected from the Commission's creation of a new properly tailored, project-specific Joint Ownership Incentive adder (Joint Ownership Incentive), drawing on: (1) the

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[1] Please see https://www.mcr-group.com/transmission/what-we-do/ for a list of FERC Dockets in which I have provided direct testimony and my experience statement.

existing transmission systems and levels of investment of transmission-owing municipal utilities (municipals) and transmission-owning generation and transmission electric cooperatives (G&Ts, or cooperatives) in MISO and SPP relative to investor-owned utilities and transmission companies (IOU/Transcos); (2) how non-public utilities, particularly those that are transmission dependent on their host incumbent transmission owner (TO), often an IOU, for transmission service (TDNPUs)[2] lack comparable means and/or opportunity to plan for and invest in local transmission projects at their desired levels; (3) how GridLiance's proposed Joint Ownership Incentive reasonably advances the Commission's stated policy goal of promoting increased joint transmission investment; (4) why GridLiance's proposed Joint Ownership Incentive effectively addresses non-public utilities' suboptimal transmission investment, financing impediments, and reliability needs; (5) how GridLiance's proposed Joint Ownership Incentive provides important pro-competitive benefits; and (6) how GridLiance's proposed Joint Ownership Incentive promotes public policy and delivers significant benefits when the proposed eligibility criteria are met.

III. <u>SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I have found that significant public policy benefits could be realized by halting the historic and ongoing trend of many non-public utilities investing at a lesser level than IOUs and Transcos. To achieve this, the Commission should authorize a new, project-specific financial incentive geared specifically to promoting joint ownership arrangements with non-public utilities. More specifically:

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[2] TDNPUs are defined here as non-public utilities such as municipals and cooperatives that either: a) do not own transmission lines, b) own radial lines, or c) own looped facilities that are not integrated into the regional system.

(1) Despite the Commission's encouragement of joint ownership arrangements to date, many municipals and some cooperatives have been investing in transmission at far lower rates and operate generally older systems than their IOU/Transco counterparts in MISO and SPP, indicating that these entities (a) lack the means and/or the opportunity to maintain their systems comparably to IOU/Transcos in MISO and SPP, and may be facing obstacles to investing at their desired levels, and (b) may have increased outage exposure when compared to the rest of the MISO and SPP systems and could benefit from the increased system redundancy and off-system access to the broader wholesale market that comes from additional transmission investment;

(2) Granting a new, clearly-defined Joint Ownership Incentive, such as that proposed by GridLiance in this proceeding, promises to provide an effective vehicle for promoting enhanced joint transmission investment, directly meeting the Commission's longstanding public policy goals of (a) attaining greater levels of non-public utility participation in grid expansion projects and a deeper pool of transmission investors; and (b) promoting an expanded regional transmission organization (RTO) footprint leading to a more reliable transmission grid and a more competitive wholesale market;

(3) By creating additional opportunities for non-public utilities to make transmission investments at their desired levels, this incentive is designed to counter the financial impediments to transmission investment by non-public utilities and to provide additional benefits. Specifically, it promises to cost-effectively address non-public utilities' record of suboptimal transmission investment, scarcity of capital, and their desire to invest in and co-own revenue-enhancing transmission

projects to partially offset increasing transmission rates. Additionally, for non-public utilities with aging networks, it promotes enhanced system reliability by directly incentivizing a willing partner such as GridLiance to pursue joint development opportunities that stand to increase the reliability of a non-public utilities' system in a more cost-effective manner than the non-public utility could likely achieve on its own;

(4) Additionally, GridLiance's proposed Joint Ownership Incentive provides important pro-competitive benefits for customers, such as (a) fostering a more competitive environment providing a competitive alternative to the incumbent utility; (b) promoting greater non-public utility participation in RTO competitive transmission processes; and (3) promoting increased reliability at a lower cost per investment; and

(5) Finally, the incentive delivers significant benefits when the proposed eligibility criteria are met. I recommend that the Commission establish a Joint Ownership Incentive, under sections 219 (Order No. 679) or 205 of the Federal Power Act (FPA), awarded on a project-specific basis to public utilities and non-public utilities that partner on new transmission projects that meet two objective, pre-defined criteria:

(1) Have been approved through a Commission-approved regional or local transmission planning process; and

(2) Are at least 15% owned, in aggregate, by non-public utilities.

IV. A NEW, PROJECT-SPECIFIC JOINT OWNERSHIP INCENTIVE SHOULD BE AVAILABLE TO PROMOTE JOINT TRANSMISSION INVESTMENT FOR THE GREATER BENEFIT OF THE GRID

1. Many Non-Public Utilities in MISO and SPP Have Historically Under-Invested in Transmission

Q. PLEASE EXPLAIN MCR'S CAPABILITIES WITH REGARD TO ANALYZING TRANSMISSION INVESTMENT LEVELS IN MISO AND SPP.

A. MCR's Proprietary Transmission Investment and Load (PTIL) Database[3] was developed by MCR and is a proprietary database of transmission investment data, metrics, and related reports for IOU/Transcos,[4] G&Ts, and municipals and Joint Action Agencies (Public Power)[5] for various RTOs covering the last five years. The investment data for MISO and SPP is based on the change in the gross transmission plant balances reported in the MISO Attachment O and SPP Attachment H formula rate schedules[6] that are used to calculate each TO's annual transmission revenue requirement, which in turn is fed into the calculation of the zonal rate for each pricing zone. Using the change in gross transmission plant as reported by each TO in the Attachments O and H provides a consistent basis and

[3] MCR's PTIL Database includes utilities that file Attachments O or H formula rates and placed their transmission assets under the MISO or SPP tariff. It does not include recently admitted G&Ts who have less than three years of investment data and transmission and distribution (T&D) cooperatives due to their limited sample size and in some cases, limited years of investment data.

[4] IOUs and Transcos are categorized together because the MISO and SPP Transcos are either profit-making entities and/or owned by IOUs or their holding companies.

[5] The PTIL Database includes new municipal entrants to MISO and SPP who had limited years of Attachments O or H data, *i.e.*, in MISO three municipals had four years of investment data and five municipals had three years of investment data. All SPP municipals are based on four years of investment data because most joined SPP in 2015.

[6] The database utilizes the July MISO Attachment Os from 2013-2018. The MISO Attachment O is a cost template that provides a structured and consistent approach for how TOs report and recover the costs of their transmission-related assets and expenses. The Attachment O is filed each year by each TO and determines the transmission revenue to be recovered from MISO ratepayers. The database utilizes the most recent SPP Attachment H formula rate templates posted as of June 14, 2019, thus the SPP Attachment H data covers 2014-2019.

a good proxy[7] for the levels of transmission capital investment for IOU/Transcos, G&Ts, and Public Power. The PTIL Database includes estimated load data for each of the TOs obtained from various sources.[8]

Q. DOES THE DATA INCLUDE UTILITIES THAT HAVE TRANSMISSION ASSETS BUT HAVE NOT TRANSFERRED THESE FACILITIES TO MISO OR SPP?

A. No. The data only includes utilities that have transferred their transmission assets to MISO and SPP and file an Attachment O or Attachment H cost template, respectively, to obtain revenue recovery, primarily because standardized transmission cost data is not available for entities that are not TOs.[9] Those within the MISO and SPP footprint provide a more than sufficient sample size for my review.

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[7] Formula for investment in each year per the Attachment O/Attachment H = change in company gross transmission plant + change in construction work in progress (CWIP) in rate base. The reported change in the transmission gross plant balance in the Attachment O/Attachment H includes the net effect of any retirements, adjustments, and transfers. Transfers could, for example, include a reclassification of distribution plant as transmission. Capital expenditures reported in the FERC Form 1 or RUS Form 12 for any given year will likely be different than the change in gross transmission plant reported in the Attachments O or H, because of any retirements, adjustments, and transfers. Further, the Attachments O and H require the plant to be in rate base, so any CWIP capital expenditures not yet in rate base is not included the data.

[8] Sources for estimated load data may include, for example, the MISO Attachment O, SPP Attachment H, FERC Form 1 wholesale load data, Energy Information Administration (EIA) annual reports for municipals, and/or other public sources.

[9] For example, there are still many municipals in the MISO footprint that own transmission assets (*e.g.*, 69 kV or above) or are contemplating new/upgraded transmission that do not file an Attachment O and thus published, standardized transmission cost data is not available for these utilities. Given the large and diversified sample of 31 municipals in MISO who do file an Attachment O and the 18 municipals in SPP who file an Attachment H formula rate, this data sample provides a good proxy for all municipals in the MISO and SPP footprints, recognizing the size of the entire municipal market in the MISO and SPP footprint is even larger than the 48 tracked in the PTIL Database.

a. MISO

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING INVESTMENT LEVELS FOR VARIOUS MISO SEGMENTS.

A. The findings from MCR's PTIL data indicate that the municipal segment in MISO is investing in transmission at a significantly lower rate than the G&T segment and at a much lower rate than the IOU/Transco segment.

(1) Most municipals have made very little investment in transmission over the last five years (See Figure 1).

(2) The percentage change in transmission investment over the last five years, as indicated by the five-year average transmission investment as a percent of average gross transmission balance, a good indicator of investment *pace*, was nearly three times lower for municipals than for the other segments.

(3) The cumulative five-year percentage increase in investment (*i.e.*, growth in gross transmission plant over five years) for municipals was nearly four times lower than for IOU/Transcos.

(4) Municipals have a much lower investment *intensity* level than other segments based on a ratio of their investment to depreciation expense.

(5) The age of municipal and G&T transmission facilities is older than those of IOU/Transcos, as indicated by the ratio of net transmission plant to gross transmission plant.

(6) Municipals and G&Ts are underinvested in transmission relative to their load ratio share.

Given these factors, many municipals and G&Ts in MISO are facing the possibility of needing to replace/upgrade or expand their facilities in the near future to ensure continued or enhanced service reliability for their customers.

Q. OVER THE LAST FIVE YEARS, PLEASE DESCRIBE THE LEVEL OF TRANSMISSION INVESTMENT IN MISO AND HOW IT COMPARES AMONG THE SEGMENTS.

A. The change in gross transmission plant (a proxy for investment) for 23 MISO IOUs[10] and Transcos was $15.8 billion over the last five years. The average five-year change for the IOU/Transco segment was $686 million ($15.8 billion ÷ 23 entities) with a median of $702 million, or about $140 million per year. This compares to G&Ts that had a total five-year dollar change of nearly $1.2 billion,[11] $312 million for the Joint Action Agency (JAA) segment,[12] and $112 million for municipals, with the municipal data indicating that much of this investment is concentrated in just a few municipals, with many reflecting zero or minimal investment (see Figure 1).[13]

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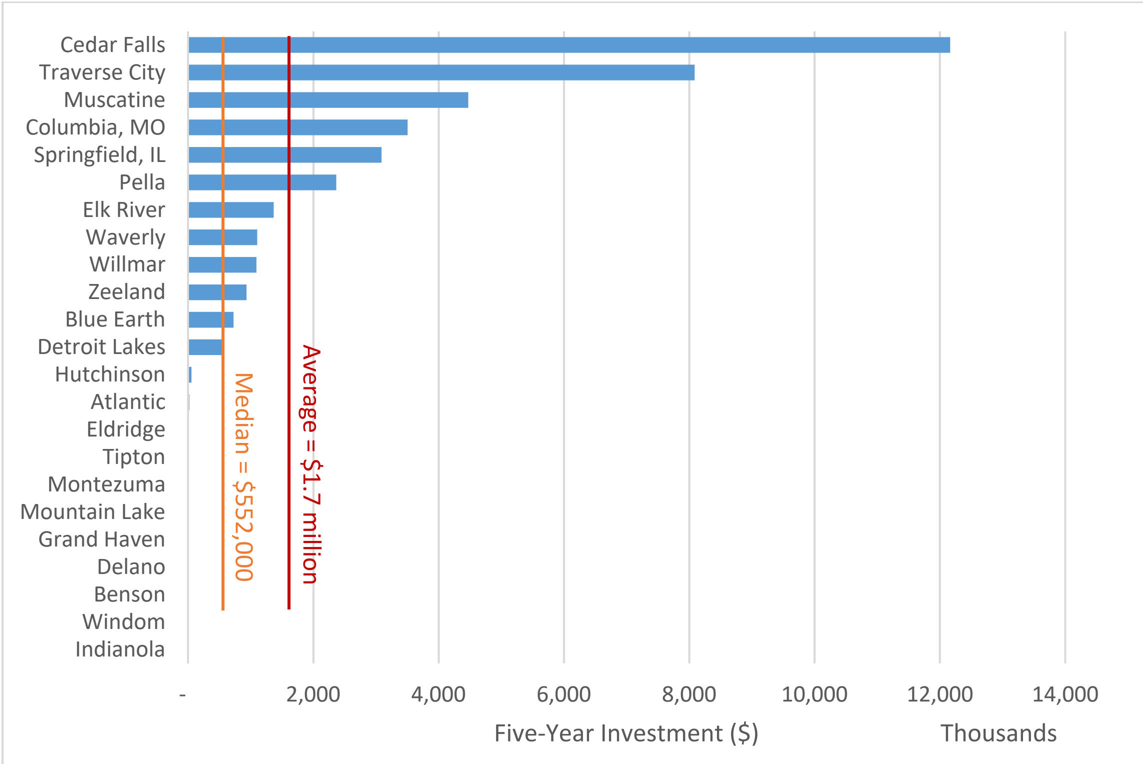
[10] This figure does not include Consumers Energy because it had less than three years of investment data.

[11] The five-year average for the 12 G&Ts was $97 million ($1.17 billion ÷ 12) with a median of $76 million (approximately, $15 million per year). Thus, the median annual investment for a MISO IOU/Transco of $140 million is over nine times the G&T median of $15 million.

[12] The average five-year change for the JAA segment was about $35 million ($312 million ÷ 9) with a median of only about $15 million, or about $3 million per year. Of those seven JAAs who had the full five years of investment data in the Attachment O, the five-year average investment was $39 million with a median of about $11 million.

[13] Figure 1 shows the five-year change in gross transmission plant of $39 million for the 23 municipals with a complete five years of data in MISO; it shows that the larger municipals such as Cedar Falls and Traverse City dominated the total investment for the segment. To highlight the concentration in a few municipals, the five-year average of the 23 municipals with all five years of data was about $1.7 million with a median of only about $552,000 with many municipals having little or no investment at all. For all 31 municipals, the total change was $111.6 million, and the average was higher at $3.6 million mostly due to large projects for Rochester and Ames who entered during the study time frame. The median remained at $552,000 for those with all five years of data, with many municipals having little or no investment.

Figure 1: Five-Year Transmission Investment by MISO Municipals



Q. WHAT IS THE DIFFERENCE IN THE TRANSMISSION INVESTMENT GROWTH RATES OF THE MISO SEGMENTS OVER THE PAST FIVE YEARS?

A. Table 1 shows the percentage increase in transmission gross plant of each of the segments over the five-year period using 2013 as a base. JAAs lead the segments with an 82% increase,[14] IOU/Transcos follow with a 66% increase, and G&Ts' transmission

[14] Although the JAA segment has shown considerable growth, a large portion of this growth is from projects that are regional 345-kV backbone projects in the upper Midwest, including the CapX2020 projects that mostly do not directly support local reliability needs of their member municipals at lower voltages. Similarly, a portion of the G&T growth was due to these same CapX2020 projects. The final CapX2020 project involving JAAs or G&Ts went into service in 2016; thus, transmission investment growth by the MISO JAA and G&T segments has since fallen off. These large backbone projects were planned prior to FERC Order No. 1000 and no new CapX2020-sponsored projects are planned as part of the existing MISO Transmission Expansion Plan (MTEP). This above figure excludes CMMPA and WPPI Energy, which did not have the full five years of data. When including all nine JAAs regardless of when they entered MISO, the percentage increase for JAAs rises from 82% to 94%.

plant grew by 42%, followed by municipals at 18%.[15] When looking at the last three years only, the leading segment changed positions with IOU/Transcos growing by 33%, followed by JAAs at 28%, G&Ts at 22%, and municipals again, at only 18%. In both time periods, the growth of G&Ts and municipals lagged IOU/Transcos by a considerable margin.

Table 1
MISO Change in Investment by Segment
2013 to 2018

MISO Transmission Segment	5-Year $ Cumulative Change in Transmission Investment for Segment ($Thousands)	% Change in Investment, 2013 to 2018
IOU/Transcos	$ 15,787,578	66%
G&Ts	$ 1,167,852	42%
JAAs	$ 270,720	82%
Municipals	$ 39,009	18%

What is also revealing is a review of the average transmission investment of each segment over the last five years as a percentage of their average gross transmission plant balance over the same timeframe (See Table 2 below). This metric is a good indicator of investment *pace*. The average transmission investment as a percentage of gross plant for municipals was only about 16.4%, and about 32.6% for G&Ts, compared to IOU/Transcos, which increased their transmission plant at a much higher 48.1%. Like the IOU/Transcos, JAAs also showed a robust investment pace in this timeframe of 52.9%.[16]

[15] This calculation excludes Ames, Glencoe, Lafayette, and Worthington, which had four years of investment data from the Attachment O, and Alexandria, ALP, Marshall, and Rochester, which had three years of investment data from the Attachment O. When including all municipals, regardless of when they entered MISO, the percentage increase rises to 51% largely due to Ames and Rochester, which both had large projects during the timeframe.

[16] This figure excludes CMMPA and WPPI Energy, which had four and three years of Attachment O investment data, respectively, and thus did not have the full five years of data. When including all nine JAAs including CMMPA and WPPI Energy, the percentage was similar at 56.7%.

Table 2
5-Year Average Annual Dollar Change in MISO Investment as a Percent of Average Gross Transmission Balance

MISO Transmission Segment	5-Year Average Annual $ Change in Transmission Investment for Segment ($Thousands)	Average 5-Year Gross Transmission Plant Balance for Segment ($Thousands)	% Change in Average Investment over Average Gross Plant Balance
IOU/Transcos	$ 686,416	$ 1,427,761	48.1%
G&Ts	$ 97,321	$ 298,912	32.6%
JAAs	$ 38,674	$ 73,113	52.9%
Municipals	$ 1,696	$ 10,326	16.4%

Q. WHAT OTHER METRICS DID YOU CONSIDER WHEN LOOKING AT THE INVESTMENT INTENSITY OF MISO TRANSMISSION OWNERS?

A. Another indicator of the level of investment *intensity* for the various segments is the ratio of transmission investment to transmission depreciation expense over the last five years and the last two years. A ratio of one means that transmission investment is replacing transmission depreciation expense. When one considers, however, that new investment is in more recent dollars, whereas depreciation expense is, on average, in much "older" dollars (*e.g.*, 10 to 20 years old), a ratio of one may not even be sufficient for maintenance, let alone expand or enhance, a TO's transmission system.

Q. WHAT WAS SIGNIFICANT ABOUT THE COMPARISONS OF INVESTMENT INTENSITY RATIOS?

A. Over the last five years, MISO IOU/Transcos made transmission investments at a healthy average rate of 4.7 times their transmission depreciation expense, with not a single TO at a ratio of less than one. Over that same period, JAAs invested at 4.3 times their depreciation expense; G&Ts at 2.6 times; and municipals at 0.7 times.[17] With the lowest

[17] Based on the last two years, the ratios are 4.3 for IOU/Transcos and 2.2 for municipals (based on the full sample of 31 municipals). On a median basis, however, the IOU/Transco median is

ratio, the municipal data also reflects investment concentration in only a few entities, as only eight of 23 municipals with the full five years of data showed transmission investment greater than their depreciation expense with a ratio of 1.0 or greater, and the median is a mere 0.3.

Q. ARE THERE OTHER INDICATORS THAT INDICATE THE VARIOUS MISO SEGMENTS HAVE BEEN INVESTING IN TRANSMISSION AT DIFFERENT RATES?

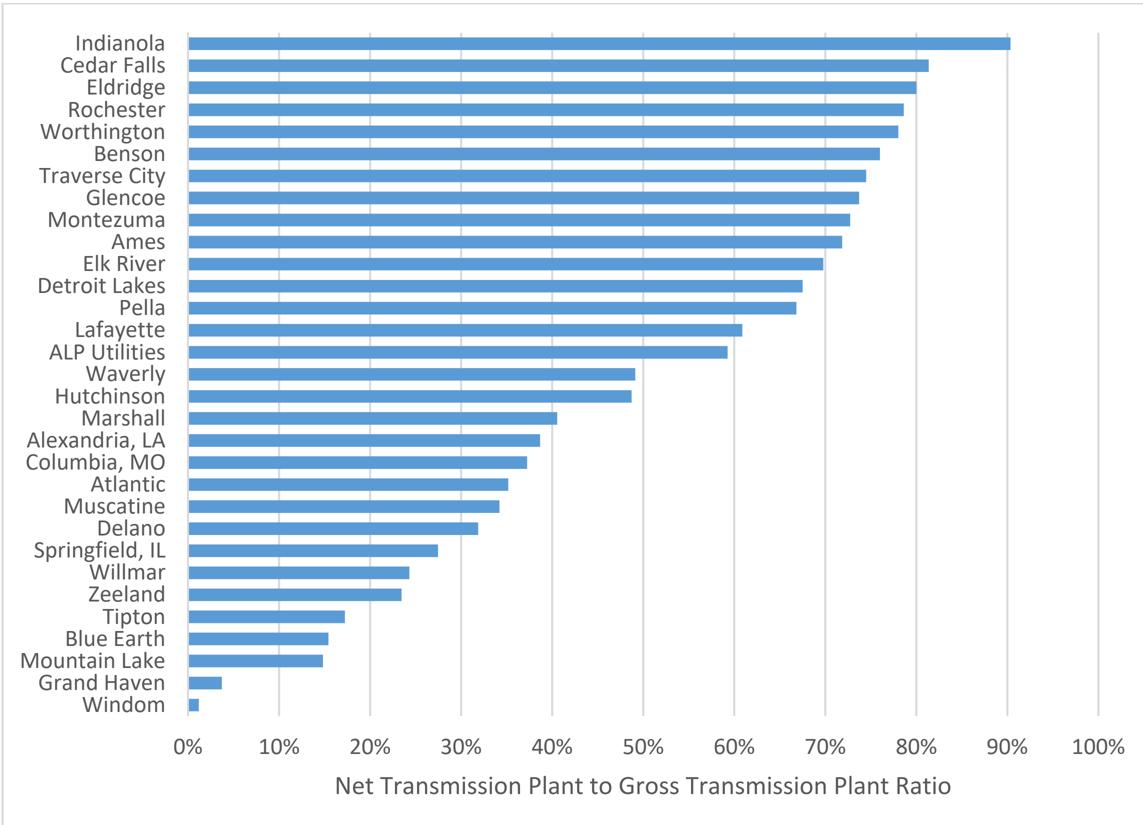
A. Yes. Analyzing the 2018 net transmission plant to gross transmission plant ratio provides an indicator of which segments have the "newest" aggregate transmission facilities. Generally speaking, the higher the ratio, the newer the plant, on average.[18] IOU/Transcos, as a group, have the newest transmission assets with their combined net transmission plant equaling 75% of their gross transmission plant. The comparable 2017 and 2016 percentages were 73% and 72%, indicating that on average, transmission is younger for the IOU/Transco segment and getting younger. On average, JAAs and G&Ts are lower than IOU/Transcos at 68% and 66%, respectively. This is unchanged from 2016 for G&Ts, and JAAs were slightly lower in 2016 at 67%. Municipals have the oldest transmission plant with a net plant to gross plant ratio of 54%, nearly half depreciated on average, unchanged from 2016. There is large variability in the net plant to gross plant ratio for municipal transmission facilities with 13 out of 31 municipals having plant that is over 60% depreciated (*i.e.*, a ratio of net plant to gross plant of less than 40%)—see Figure 2. This

4.8 and only 0.1 for municipals. The municipal disparity between the weighted average of 2.2 and the median of 0.1 highlights the concentration of investment in a few municipals.

[18] There are differences among TOs in the depreciation rate, which can affect comparisons of the ratios.

calculation reinforces the idea that many municipals and cooperatives in MISO are facing the possible need to replace/upgrade their facilities in the near future.

Figure 2: Net Transmission Plant to Gross Transmission Plant Ratio for MISO Municipals



Q. HOW DO THE VARIOUS MISO SEGMENTS COMPARE IN THEIR PORTION OF TOTAL INVESTMENT RELATIVE TO THEIR LOAD RATIO SHARE?

A. MCR compiled estimated load data for each of the TOs in the sample in order to compare the change in each segment's transmission investment to their load ratio share of the total IOU/Transco, G&T, and municipal load in the sample.[19] Per Table 3 below, MISO G&T and municipals in the sample are investing at a lower rate than IOU/Transcos relative to their load. Focusing on investment over the last five years, G&Ts represent an estimated

[19] JAAs are not included because they generally are not retail load serving entities—the end-use load resides with their municipal members.

11% of the total 2018[20] MISO load for IOU/Transcos, G&Ts, and municipals in the sample, but only represent about 7% of the new transmission investment. Similarly, municipals represent about 2% of the total IOU/Transco, G&T and municipal load in the sample, but represent less than 1% of the new transmission investment over the last five years. This overall finding is consistent with the various metrics discussed above that show municipals and G&T cooperatives in MISO are investing at significantly lower rates than IOU/Transcos. In some instances, the IOU/Transco transmission investment total can include investments designed to serve load that is not captured in the IOU/Transco estimated 12 CP load in the table below. These instances are precisely the issue that GridLiance's business model seeks to address.

Table 3[21]
Comparison of Change in Gross Transmission Plant Balance to
Current Load Ratio Share for MISO IOU/Transcos, G&Ts, and Municipals (2013-2018)[22]

MISO Transmission Segment	5-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	$ 15,787.6	92.5%	87,664.5	86.6%
G&Ts	$ 1,167.8	6.8%	11,367.9	11.2%
Municipals	$ 111.6	0.7%	2,204.5	2.2%
Total	*$ 17,067.0*	*100.0%*	*101,236.9*	*100.0%*

[20] The change in the investment data over the last three years is shown relative to the latest single year of load data available (which is usually 2018).

[21] Table 3 is not intended to account for total MISO load because not all load serving entities are included in the sample comprising each segment and T&D cooperatives are not included. The investment and load data are only for those TOs in the sample.

[22] Sources: July 2015-2018 MISO Attachment Os for gross plant balance data. Load may have been adjusted upward where the G&T's load is in multiple pricing zones, but the reported 12-month coincident peak load only reflects the G&T's load in their own pricing zone. Sources also include MCR estimates based on FERC Form 1, page 400, column e, "firm service for self" and RUS Form 12. 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 estimated 12-month coincident peak load.

b. SPP

Q. WHAT SEGMENTS WERE ANALYZED IN THE SPP ANALYSIS?

A. The three segments in the SPP investment analysis were IOU/Transcos, G&Ts, and Municipals. JAAs and T&D cooperatives were not included due to the small segment size and/or limited number of years of investment data. The analysis covers the last five years of investment data from 2014 to 2019.[23]

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING INVESTMENT LEVELS FOR VARIOUS SPP SEGMENTS.

A. The findings from MCR's PTIL data indicate that the municipal segment in SPP is investing in transmission at a significantly lower rate than the IOU/Transco and G&T segments:

(1) Most municipals have made very little investment in transmission over the last four years (see Figure 3).

(2) The percentage change in gross transmission plant over the comparison period is much lower for municipals than for the other segments.

(3) Municipals have a much lower investment intensity level than the other segments based on a ratio of their investment to depreciation expense.

(4) The age of municipal and G&T transmission facilities is older than those of IOU/Transcos, as indicated by the ratio of net transmission plant to gross transmission plant.

[23] MCR completed the SPP analysis in June 2019 and thus used the 2019 postings of Attachment H data that were posted by early June 2019. Empire District had not posted as of June 14, 2019 so their 2019 data was estimated based on the last three years. By contrast, MCR completed the MISO analysis earlier in 2019. At that time, 2019 Attachment O data was not available for all companies, so the analysis was based on the five years of Attachment O ending 2018.

(5) Municipals and G&Ts are underinvested in transmission relative to their load ratio share.

Given these factors, in SPP many municipals and, to a lesser extent, cooperatives are facing the possibility of needing to replace/upgrade or expand their facilities in the near future to ensure continued or enhanced service reliability for their customers.

Figure 3: Four-Year Transmission Investment by SPP Municipals

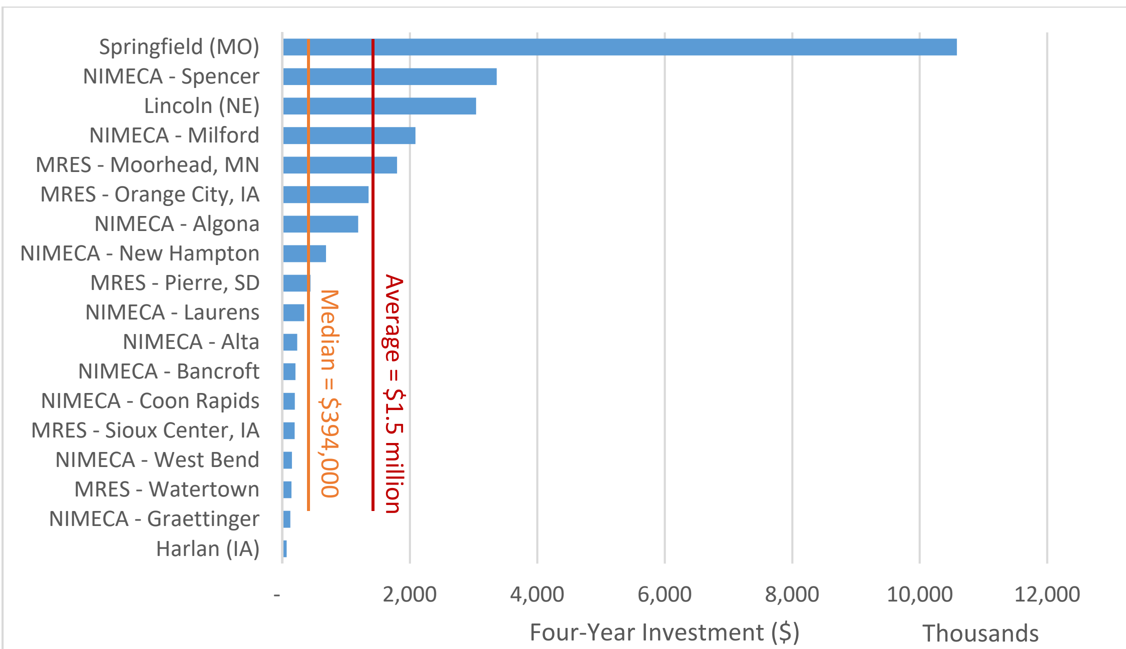


Figure 3 shows that the last four years of investments by SPP municipals has been concentrated among a few players. The highest investing municipal Springfield, Missouri had investments of more than double the next highest municipal, and only five of the 18 municipals had investments above the average of the segment. To highlight this concentration, the average investment of the municipal segment over the last four years was $1.5 million whereas the median was only $394,000.

Q. OVER THE LAST FIVE YEARS, PLEASE DESCRIBE THE LEVEL OF TRANSMISSION INVESTMENT IN SPP AND HOW IT COMPARES AMONG THE SEGMENTS.

A. Table 4 shows the G&T segment had the greatest investment change at an average of 72%, followed by IOU/Transcos at 54%, and municipals at only 6%.[24] Municipal investment lags the IOU/Transco and G&T segments over the comparison period[25] and in each individual year throughout the period, demonstrating that relatively low levels of investment has been and continues to be an issue for most municipals.[26] The cumulative segment investment over the five-year period for IOU/Transcos in SPP of about $4.3 billion is about 4.7 times G&Ts' segment total change of $919 million. Municipals collectively invested only about $26 million over their four-year time period.

Table 4
SPP Change in Investment 2014 to 2019

SPP Transmission Segment	5-Year[27] $ Cumulative Change in Transmission Investment for Segment ($Thousands)	% Change in Investment, 2014 to 2019
IOU/Transcos	$ 4,289,689	54%
G&Ts	$ 918,791	72%
Municipals[28]	$ 26,210	6%

[24] Represents the weighted average percentage increase for the segment. On a simple average basis, however, the sequence changes: the simple average percentage increase for IOU/Transcos is 66%, G&Ts 54%, and municipals 26%. The municipal simple average is higher due to relatively high percentage increases for three smaller municipals: Milford (106%), Spencer (74%), and Orange City (73%). On a median basis, the median percentage increase over the comparison period is 42% for G&Ts, 41% for IOU/Transcos, and 15% for municipals.

[25] The comparison period for the SPP data is the five years ending 2019 for IOU/Transcos and G&Ts. Municipals, however, are based on four years of data as most SPP municipals filing formula rates entered SPP in 2015.

[26] A JAA of a municipal may invest in transmission but often these investments are more regional and higher voltage and less likely to directly impact the lower voltage facilities of the local municipals.

[27] Municipal change is four years, measured from 2015 through 2019 due to lack of data in 2014. Most municipals in the sample entered SPP in 2015.

[28] Municipals have a much lower percentage change (on a weighted average, simple average or median basis) even after considering the percentage change is over four years rather than the five years for IOU/Transcos and G&Ts.

Similar results can be seen in Table 5, which compares the investment growth by segment to each segment's average gross transmission balance over the comparison period. G&Ts led the group with a 55% change, followed by IOU/Transcos at 42%, and municipals lagging significantly at 1%.

Table 5
5-Year Average Annual Change in SPP Investment as a Percent of Average Gross Transmission Balance

SPP Transmission Segment	5-Year Average[29] Annual $ Change in Transmission Investment for Segment ($Thousands)	Average 5-Year Gross Transmission Plant Balance for Segment ($Thousands)	% Change in Average Investment over Average Gross Plant Balance
IOU/Transcos	$ 4,289,689	$ 12,008,705	42%
G&Ts	$ 918,791	$ 1,677,457	55%
Municipals	$ 26,210	$ 2,249,112	1%

Q. WHAT OTHER METRICS DID YOU CONSIDER WHEN LOOKING AT THE INVESTMENT INTENSITY OF THE SPP SEGEMENTS?

A. As described previously in the MISO analysis, another indicator of the level of investment intensity for the segments is the ratio of transmission investment to transmission depreciation expense. A ratio of one means that transmission investment is replacing transmission depreciation expense.

Q. WHAT WAS SIGNIFICANT ABOUT THE COMPARISONS OF INVESTMENT INTENSITY RATIOS?

A. Over the comparison period, SPP IOU/Transcos are making transmission investments at a healthy average rate of 3.6 times their transmission depreciation expense, with only one

[29] Municipal change is four years, measured from 2015 through 2019 due to lack of data in 2014. Most municipals filing formula rates entered SPP in 2015.

TO at a ratio of less than one.[30] G&Ts in SPP invested at a robust 4.7 times their depreciation expense whereas municipals were at only 0.5 times. When looking at this ratio over the last two years only, the IOU/Transco segment is at a ratio of 2.9, G&Ts at 4.9, and municipals at only 0.6. Moreover, the municipal data shows only three of 18 municipals showed transmission investment greater than their depreciation expense, whereas eight of the 10 IOU/Transcos and six of the seven G&Ts had a ratio greater than 1.0.

Q. ARE THERE OTHER INDICATORS THAT INDICATE THE VARIOUS SEGMENTS HAVE BEEN INVESTING IN TRANSMISSION AT DIFFERENT RATES?

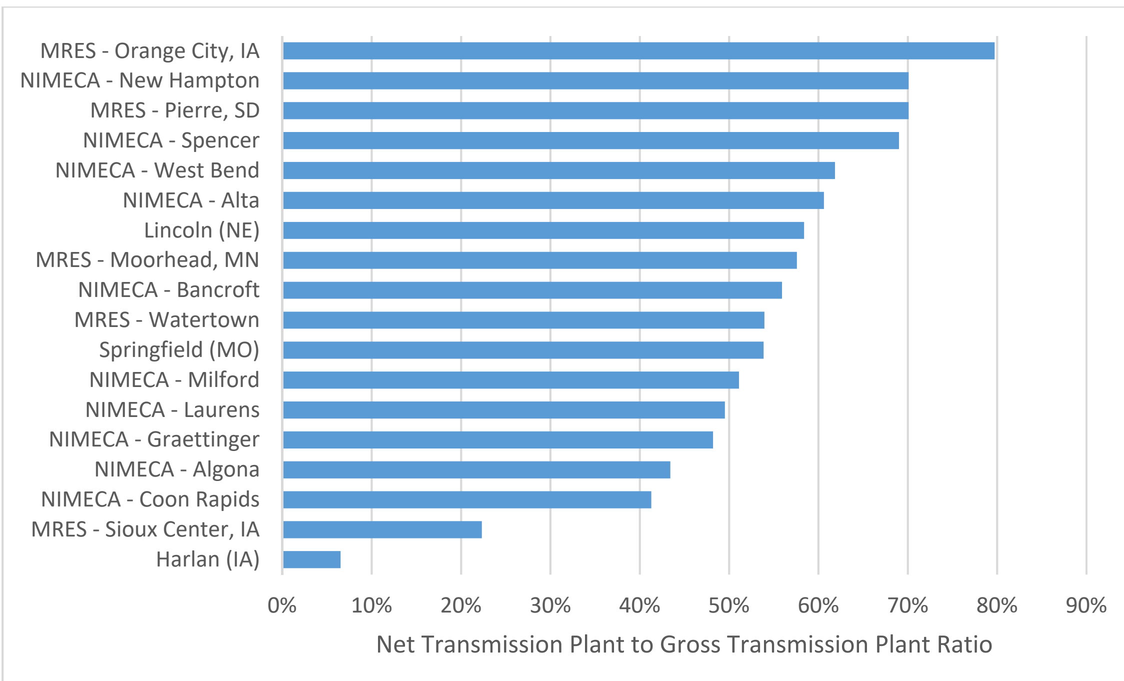
A. Yes. The ratio of net transmission plant to gross transmission plant provides an indicator of which segments have the "newest" plant in SPP. On average, TOs with higher ratios tend to have newer transmission plant.[31] The IOU/Transco segment in SPP has the newest transmission assets as of 2019 with a net plant to gross plant ratio of 78%, or 22% depreciated. This ratio is unchanged from 2016. G&Ts have the next greatest 2019 net transmission plant to gross transmission plant ratio of 69%, significantly up from 60% in 2016. This increase in the ratio is consistent with the G&T's relatively high percentage change in gross plant and their high investment to depreciation ratio over the last five years discussed previously. In stark contrast, municipals have the oldest plant on average, with a ratio of just 57%, down from the 2016 ratio of 60%. The decline in the municipals' ratio from 2016 to 2019 indicates that the segment's transmission plant is

[30] NorthWestern Corporation had an investment to depreciation expense ratio less than one (0.8) over the last five years.

[31] There are differences among TOs in the depreciation rate, which can affect age comparisons of the ratios. For example, G&Ts borrowing from the RUS, oftentimes have higher depreciation rates than IOUs. Under this case, the relative age of these G&Ts may be actually older compared to IOUs.

getting older, and that municipals are not investing at a rate great enough to maintain the average age of transmission plant, yet alone modernize their systems. Of the 18 municipals in the sample, only a single municipal had plant newer than the IOU/Transco segment average of 78% (see Figure 4 on next page).[32] This calculation reinforces the idea that many municipals and some cooperatives in SPP are facing the prospect of replacing/upgrading their transmission facilities in the near future.

Figure 4: Net Transmission Plant to Gross Transmission Plant Ratio for SPP Municipals



Q. HOW DO THE SPP SEGMENTS COMPARE IN THEIR PORTION OF TOTAL INVESTMENT RELATIVE TO THEIR LOAD RATIO SHARE?

A. MCR compiled estimated load data for each of the TOs in the SPP sample to compare the change in each segment's transmission investment to their load ratio share of the total IOU/Transco, G&T, and municipal load in the sample. Per Table 6 below, SPP municipals

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[32] Orange City, Iowa has a 2019 net transmission plant to gross transmission plant ratio of 80%.

in the sample are investing at a much lower rate than IOU/Transcos and G&Ts relative to their load. Based on investment over the comparison period, IOU/Transcos were responsible for about 81.9% of the total new transmission investment but represent only an estimated 77.0% of the total 2018[33] SPP load for the IOU/Transcos, G&Ts, and municipals in the sample. Similarly, G&Ts represent about 18.0% of the sample's load but invested a lesser 17.6% of new investment. Although G&Ts have made significant progress in recent years, they still are underinvested in transmission assets relative to their load ratio share. On the other hand, municipals represent about 5.0% of the total IOU/Transco, G&T, and municipal load in the sample, but were responsible for just 0.5% of the new transmission investment over the last four years.[34] That is, municipals in the sample are severely underinvested relative to their load ratio share. This overall finding is consistent with the metrics discussed above that show SPP municipals are significantly underinvesting compared to G&Ts and IOU/Transcos.

In some instances, the IOU/Transco transmission investment total can include investments designed to serve load that is not captured in the IOU/Transco estimated 12 CP load in the table below. These instances are precisely the issue that GridLiance proposed Joint Ownership Incentive is seeking to address. By expanding joint ownership opportunities, a Joint Ownership Incentive stands to enable municipals to increase their own transmission investment to better meet their specific reliability needs and utilize the

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[33] The change in the investment data over the last five years is shown relative to the latest single year of load data available (which is usually 2018).

[34] As previously discussed, the municipal data reflects four years of data. If one were to extrapolate the four years of data to five years of data using the four-year average as the fifth year (*i.e.*, $26.2M/4 = $6.55M), the 0.5% figure would increase to 0.6%.

revenue from their assets to help mitigate rate increases in the zone that they often face regardless of whether they are a TO or not.

Table 6[35]
Comparison of Change in Gross Transmission Plant Balance to Current Load Ratio Share for SPP IOU/Transcos, G&Ts, and Municipals (2014-2019)[36] [37]

SPP Transmission Segment	5-Year[38] 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	$ 4,289.7	81.9%	26,454.9	77.0%
G&Ts	$ 918.8	17.6%	6,191.9	18.0%
Municipals	$ 26.2	0.5%	1,718.2	5.0%
Total	*$ 5,234.7*	*100.0%*	*34,365.0*	*100.0%*

c. Generalizations Based on Combined MISO and SPP Results

Q. WHAT FINDINGS AND CONCLUSIONS CAN YOU DRAW FROM COMPARING THE RESULTS FROM YOUR MISO AND SPP ANALYSES?

A. It is overwhelmingly clear that municipals are investing at a far lesser rate than IOU/Transcos and G&Ts in both MISO and SPP. Municipals' low investment is apparent across all the metrics analyzed, showing the widespread and significant nature of the

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35 Table 6 is not intended to account for total SPP load because not all load serving entities are included in the sample comprising each segment and T&D cooperatives are not included. The investment and load data are only for those TOs in the sample.

36 SPP municipal figures calculated for four years, 2015 – 2019 due to many municipals entering SPP in 2015.

37 Sources: 2014-2019 SPP Attachment Hs for gross plant balance data. Load may have been adjusted upward where the G&T's load is in multiple pricing zones, but the reported 12-month coincident peak load only reflects the G&T's load in their own pricing zone. Sources also include MCR estimates based on FERC Form 1, page 400, column e, "firm service for self" and RUS Form 12. The source of load data (12 CP) for most municipals is the Attachment H. In some cases, where a TO's load is not reported in its Attachment H, the TO's load was estimated based on publicly available sources and adjusted with a 75% factor to obtain 12-month coincident peak load.

38 SPP municipal figures calculated for four years, 2015 – 2019.

relative lack of investment. Though G&Ts fared better in SPP, they too lagged the investment levels of IOU/Transcos in MISO, and show signs of aging transmission infrastructure in both MISO and SPP. Given the large and diversified sample of 31 municipals in MISO who do file an Attachment O and the 18 municipals in SPP who file an Attachment H formula rate, this data sample provides a good proxy for all municipals in the MISO and SPP footprints, recognizing the size of the entire municipal market in the MISO and SPP footprint is even larger than the 48 tracked in this analysis. I conclude that there are factors at play for non-public utilities that are systematically limiting their investment. Many of the same impediments to investing are applicable to those municipals who are TOs in an RTO and those not currently in the RTO. I discuss these factors below.

2. Many Non-Public Utilities Lack Comparable Means and/or Opportunity to Plan for and Invest in Transmission at Their Desired Levels

Q. WHAT ARE THE IMPLICATIONS OF LOWER NON-PUBLIC UTILITY INVESTMENT AND AN AGING SYSTEM?

A. Their lack of relative transmission investment compared to IOU/Transcos, coupled with aging transmission systems, indicate that many municipals and some cooperatives lack the means and/or the opportunity to maintain their systems comparably to their IOU/Transco counterparts in MISO and SPP and may be facing obstacles to planning and investing at their desired levels. In MISO, municipals are about 46% depreciated whereas in SPP, they are about 43%. This compares to 25% and 22% depreciated for IOU/Transcos in MISO and SPP, respectively. In addition, this suggests that many municipals and some cooperatives in MISO and SPP, particularly TDNPUs, have increased outage exposure when compared to the rest of the MISO and SPP systems and could benefit from the increased system redundancy and off-system access to the broader wholesale market that comes from additional transmission investment. These entities[39] must rely on their radial feeds to connect to the MISO and SPP network, making them dependent on those connections to access the regional network.

Q. DO YOU BELIEVE CUSTOMERS OF SMALL NON-PUBLIC UTILITIES ARE GENERALLY AT A TRANSMISSION PLANNING DISADVANTAGE RELATIVE TO IOU CUSTOMERS?

A. In my experience, IOU non-native (wholesale) loads are often at a transmission planning disadvantage relative to IOU native (retail) loads. These entities can have radial, lower-voltage transmission lines that interconnect their systems with the broader regional integrated network. Radial lines tend to predominate in areas served with low population densities, *i.e.*, small cities and rural electric cooperatives. When their retail customers are served from transmission lines that are not looped with other facilities or are served from facilities weakly connected to the integrated bulk system, their customers are left without service redundancies and, in the case of radial facilities, an alternative path. In contrast, a town of similar size and load characteristics that is served by a host IOU as its native load would more likely have looped service and thus be subject to relatively fewer reliability concerns.

The lack of transmission planning comparability that exists stems from the asymmetrical way in which transmission upgrades for non-native loads served by IOUs are typically planned (and paid for) in an RTO relative to the IOU's own native load under North American Electric Reliability Corporation (NERC) transmission planning criteria.

[39] Prime examples in SPP include municipals Duncan, Oklahoma; Frederick, Oklahoma; Hope, Arkansas; Marlow, Oklahoma; Pratt, Kansas; and Wellington, Kansas and Oklahoma cooperatives Tri-County Electric Cooperative, Inc. and Peoples' Electric Cooperative. Prime examples in MISO include municipals Highland, Illinois; Mascoutah, Illinois; and Rolla, Missouri.

Under NERC standards,[40] loss of up to 25 MW of load is considered an acceptable loss and up to 75 MW could be considered acceptable under some limited circumstances. Thus, RTOs do not "see" a reliability issue and their plans would not require an upgrade, such as adding facilities to "loop" that load to the transmission network to improve reliability. From the IOU's perspective, there has been little incentive to change that paradigm. Wholesale cities[41] and Oklahoma cooperatives like Tri-County Electric Cooperative, Inc. and Peoples' Electric Cooperative that are served by radial feeders are considered a single meter, notwithstanding that hundreds or thousands of retail customers are behind that meter. As a result, a transmission project to provide an alternative interconnection point and/or to loop each of the transmission assets of such entities, even if desirable to the city or cooperative to provide greater reliability, greater access to alternative suppliers, or to attract new load (particularly industrial) to the area, would not be scored highly under the NERC transmission planning criteria. Thus, the IOU (which might be competing for new industrial load itself) may be less likely to propose such a project. As importantly, the RTO planning process would not require a reliability solution.

By contrast, the same IOU could view quite differently a radial line serving its native load, including a similarly situated city in which the IOU itself has hundreds or thousands of customer meters and to which it has an interest to attract load growth. Even if the loss of an IOU's load served by that radial line is deemed "acceptable" under applicable planning criteria, as a practical matter, the IOU and its state commission

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[40] *See* NERC Transmission System Planning Performance Requirements TPL-001-4, Table 1, footnote 12. *See* also Section III-2, available at https://www.nerc.com/files/TPL-001-4.pdf.

[41] Prime examples include Duncan, Oklahoma; Frederick, Oklahoma; Hope, Arkansas; Pratt, Kansas; and Wellington, Kansas in SPP and Rolla, Missouri; Highland, Illinois; and Mascoutah, Illinois in MISO.

overseeing the IOU's retail service could view the loss of those customers as a reliability concern and the IOU would likely propose a project to improve reliability. For example, the standard measures for outages, SAIDI and SAIFI,[42] would not drive action by the IOU for loss of a single wholesale city (that itself has thousands of retail meters) but could precipitate action to loop service for thousands of retail meters in its own service territory. An independent Transco partnering with non-public utilities provides a valuable competitive alternative that provides enhanced reliability to the municipal's system and the regional network. Having a competitive alternative to the incumbent leads to more innovative and cost-effective solutions for the non-public utility.

Q. ARE NON-PUBLIC UTILITIES GENERALLY SATISFIED WITH THEIR LEVELS OF INVESTMENT IN TRANSMISSION?

A. Many non-public utilities, particularly TDNPUs, want to increase ownership in transmission rather than having their investment needs met by incumbent TO, most often an IOU. They desire to be an owner rather than a "renter." In addition to enhancing reliability and promoting wholesale competition in their area, investing in and co-owning revenue-enhancing transmission projects allows these entities: (1) an opportunity to partially offset rising RTO network transmission rates through a return on their investment; and (2) the ability to provide their own customers comparable levels of reliability to what their host IOU currently provides its own retail customers, but at a reduced cost, due to their tax-exempt status (no state or federal income taxes and often a lower cost of debt) and their ability to design infrastructure for their specific needs.

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[42] The System Average Interruption Duration Index (SAIDI) is the average outage duration for each customer served. The System Average Interruption Frequency Index (SAIFI) is the average number of interruptions that a customer would experience. Both measures are used as reliability indicators.

Q. BASED ON YOUR EXPERIENCE, WHAT ARE SOME OF THE COMMON REASONS WHY NON-PUBLIC UTILITY TRANSMISSION INVESTMENT HAS BEEN COMPARATIVELY LOW IN MISO AND SPP?

A. Based on my extensive experience with existing and former Public Power and cooperative clients in the MISO and SPP footprint (TOs and non-TOs), there are a variety of reasons why many municipals and some cooperatives, especially TDNPUs, in the MISO and SPP footprint have relatively low investment levels, ranging from entity-specific circumstances and financial factors to systemic barriers to pursuing their own investments. In short, these entities generally lack the means, the opportunity, or both, to pursue new transmission investments on their own. Specific reasons include: (1) tariff rules which favor the incumbent TO or having a traditional reliance on their host incumbent TO; (2) thinly staffed resources; (3) low level of risk tolerance; (4) constraints/competition for capital and potential regulatory burden associated with investment, and in some cases, (5) a reluctance to join an RTO; and (6) a reluctance of the host incumbent TO to "accept" the transmission assets of a new non-public utility into its RTO pricing zone. I will address each one in turn.

Q. WHY DO TARIFF RULES FAVOR THE INCUMBENT?

A. Irrespective of their interest or financial capability, non-public utilities that do not own transmission can be largely foreclosed under RTO tariff-based right of first refusal (ROFR) policy and Order No. 1000 from pursuing system reinforcements on their own because construction rights to build reliability upgrades/expansions to existing transmission facilities in the incumbent's service territory are reserved to the incumbent TO. For example, per the MISO Transmission Owner's Agreement, ownership of new transmission lines typically falls to the owner of the existing substation within MISO that a proposed new line interconnects, as the right to build projects not subject to MISO's Order No. 1000 competitive process generally belong to the incumbent TOs to which the new transmission line will interconnect.[43]

Even where they have ROFRs of their own, however, a transmission-owning non-public utility in the MISO footprint may elect to continue to rely on the nearby incumbent TO for the reasons discussed further below such as insufficient level of resources, risk aversion, and limited capital. Regarding competitively-bid projects, as discussed further below, most non-public utilities cannot effectively participate in MISO's and SPP's Order No. 1000 Competitive Transmission Process on their own due to the prohibitively intensive resource and financial commitment needed to realistically pursue these types of projects, with an uncertain outcome.

Q. HOW DO STAFFING LEVELS AFFECT THE LEVEL OF NON-PUBLIC UTILITY TRANSMISSION INVESTMENT?

A. Smaller non-public utilities, particularly TDNPUs, are often not staffed for complex transmission planning and generally lack dedicated transmission planning and engineering capabilities. Some municipals receive planning and engineering assistance from a JAA,

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[43] *See* Midcontinent Independent System Operator, Inc./MISO Rate Schedules, MISO Transmission Owners Agreement, Appendix B – Planning Framework 33.0.0, Section VI, *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1229. (stating that "[e]xcept for facilities that are Competitive Transmission Projects as defined in the Tariff and subject to the transmission developer selection process set forth in Attachment FF, Section VIII of the Tariff or Baseline Reliability Projects as defined in the Tariff located in more than one pricing zone: (i) ownership and the responsibility to construct facilities which are connected to a single Owner's system belong to that Owner, and that Owner is responsible for maintaining such facilities: (ii) ownership and the responsibilities to construct facilities which are connected between two (2) or more Owners' facilities belong equally to each Owner, unless such Owners otherwise agree, and the responsibility for maintaining such facilities belongs to the Owners of the facilities unless otherwise agreed by such Owners; and (iii) ownership and the responsibility to construct facilities which are connected between an Owner(s)' system and a system or systems that are not part of MISO belong to such Owner(s) unless the Owner(s) and the non-MISO party or parties otherwise agree, however, the responsibility to maintain the facilities remains with the Owner(s) unless otherwise agreed.").

but many others do not, or the assistance is not sufficient. Smaller municipals often only employ a single planning engineer; typically, that person is focused largely on planning for the utility's existing facilities with a particular focus on their distribution system needs. However, planning and building transmission projects requires dedicated transmission planning capabilities, which in turn requires additional, specialized engineering personnel who know their electric utility and surrounding interconnected transmission systems. To be in a position to build transmission instead of relying on a neighboring incumbent TO in MISO, a municipal's additional staff would need to be sufficient to properly propose a required local transmission project to the RTO and ensure it is approved as part of the RTO's transmission expansion plan and oversee its development and construction.

Q. HAVE NON-PUBLIC UTILITIES BEEN ABLE TO PARTICIPATE IN THE MISO AND SPP PLANNING PROCESS AT A LEVEL CONSISTENT WITH IOU/TRANSCOs?

A. No. Non-public utilities, especially TDNPUs, often lack realistic means and resources to identify and properly define transmission projects that will enhance their systems, whether it be jointly with the neighboring incumbent TO (often an IOU), a Transco or by themselves. To the extent solutions are put forth that provide benefits for TDNPU systems, the solutions oftentimes are designed by the incumbents, and with the incumbents' systems and customers primarily in mind. This can be disadvantageous because TDNPUs pay for what may be less optimal solutions for their systems and it keeps them as "renters" paying the incumbents' revenue requirement rather than being owners of transmission and receiving revenue themselves. Ultimately, this harms all retail customers because non-public utilities often can invest in transmission at a reduced cost to the RTO ratepayer due to their tax-exempt status (no state or federal income taxes) and access to less expensive capital (typically a lower cost of debt).

Q. PLEASE DESCRIBE HOW THEIR LOW LEVEL OF RISK TOLERANCE HAS IMPACTED NON-PUBLIC UTILITY TRANSMISSION INVESTMENT.

A. There are unique financial, political, and regulatory risks associated with a non-public utility permitting, developing, and constructing a transmission project on its own. When one considers that the median municipal existing <u>total</u> gross transmission asset balances are only $5.6 million in MISO and $3.6 million in SPP respectively, new transmission projects can be relatively expensive for the typical municipal. In my experience, typical projects can range from $5 million-20 million,[44] often have high public visibility, and have long lead times with uncertain completion dates and budgets. The potential of having to absorb stranded costs of an uncompleted transmission project or one that is completed with substantial cost overruns has financial, rate, political, and personal ramifications for municipal utilities and their management. These types of risks can place the local community spotlight on individuals within the utility. In addition, TDNPUs who own a *de minimis* amount of transmission can trigger new NERC compliance obligations, such as reporting, training, and operator staffing requirements, as well as exposure to potential NERC infraction penalties, if these entities were to undertake the responsibilities

[44] Project capital cost estimate are based on MCR general client experiences. Project capital cost can vary widely depending on the type of project (substation, new line, upgrade, single vs. double circuit, topography and right of way requirements, interconnection requirements) and the voltage level (69kV, 115 kV, 138 kV, 161 kV). MISO publishes project cost estimation data for 69kV to 161 kV projects. For example, MISO estimates that the capital cost per mile for a double circuit 138 KV transmission line is about $2.0-$2.9 million (varies by state). The estimated 138 kV substation cost ranges from $2.3 million to add a line to an existing substation and up to $7.8 million to build a new substation. *See* pages 54-55 of the MISO Transmission and Substation Project Cost Estimation Guide for MTEP 2018, *available at* https://cdn.misoenergy.org/Transmission-and-Substation-Project-Cost-Estimation-Guide-for-MTEP-2018144804.pdf.

associated with planning, permitting, building, and owning new higher-voltage transmission lines.[45]

Q. PLEASE DESCRIBE HOW THERE CAN BE COMPETITION FOR LIMITED AMOUNT OF CAPITAL.

A. For some non-public utilities, their capital investment budgets can be constrained, for example, by their need to maintain their credit rating and debt service coverage, or their bonding authority and amount of tax-exempt financing capacity. For example, within a municipal, there is often competition among the various business segments for limited capital. Potential transmission projects (which can be costly relative to municipals' total capital budgets) have to compete with generation and distribution projects in the electric utility and with other municipal business segments that require capital, such as water, wastewater treatment, natural gas, telecom, and district heating. FERC has recognized the competition for capital in a typical integrated utility as one basis for providing incentives for transmission–only utilities.[46] Similar internal competition also exists for municipals that typically have to operate multiple utility business segments. In addition, the substantial financial and legal/regulatory information associated with issuing new debt can discourage some smaller municipals from making large capital investments.

Q. HOW HAS THEIR RELUCTANCE TO JOIN RTOs AS TOs IMPACTED THE LEVEL OF NON-PUBLIC UTILITY TRANSMISSION INVESTMENT?

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45 In the absence of an exemption, transmission facilities of at least 100 kV are subject to NERC compliance.

46 *See Promoting Transmission Investment through Pricing Reform,* Order No. 679, 116 FERC ¶ 61,057, at P 224 (2006). ("By eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed.").

A. MCR has conducted numerous economic evaluations for our public power and cooperative clients who have contemplated joining an RTO as a TO. In our experience and research, a small- to mid-sized utility joining an RTO as a TO can require an additional two- to four-person staff, measured in full-time equivalent hours.[47] This can translate into a significant increase in labor expense for entities that often have limited distribution and transmission staff personnel. For non-public utilities that have decided not to focus on transmission investment for the reasons explained above,[48] there is no compelling reason to incur the costs associated with hiring, training, and retaining this incremental headcount. In addition to any incremental increase in direct labor costs, joining an RTO can require significant management attention, particularly preparing for membership and during the initial year.

In addition to staffing issues, other concerns associated with joining an RTO can involve, for example, the need to transition to recording costs in accordance with FERC's Uniform System of Accounts. Municipals must follow Government Accounting Standards Board accounting. For many municipals, having to also report by FERC accounting requirements would require considerable added effort and cost. Often times, municipals do not have accounting systems that provide a clean historical costing of their assets. Even if they do, these systems may not easily differentiate transmission and distribution, may not break out transmission associated with a generating plant, or may not include certain capital costs of a transmission asset, such as right-of-way acquisition or engineering.

[47] The incremental number of staff may be smaller if the utility is a market participant and is already actively involved in market transactions. Required municipal staffing can also be lower if the municipal utility is a member of joint action agency that performs some RTO duties on behalf of its members or contracts certain tasks out to third parties.

[48] *See* upcoming discussion about how some municipals attempt to work with neighboring incumbents.

Similarly, on the expense side, it is very common for municipals to have recorded transmission and distribution expenses together, so both the processes and systems would need to change when joining an RTO. These staffing and management resource requirements, systems, and accounting issues can make becoming a transmission-owning member of an RTO a daunting prospect. This reluctance to join an RTO, and thus not being able to obtain cost recovery through the RTO tariff, places the cost of building new transmission for a non-public utility solely on the utility's customers, even though the addition of such transmission may also enhance the reliability of the broader region. When not part of an RTO, the prospect of a non-public utility's own customers absorbing the full direct rate impact of transmission investment can discourage that municipal from investing in its existing transmission system. Thus, the regional system loses the enhanced reliability and footprint benefit of having both a large portion of non-public utility's existing transmission assets in the RTO for optimal operations and planning and proposing prospective new projects and placing upgrades and solutions into the regional transmission network that are focused on their systems.

Q. PLEASE EXPLAIN WHY THERE IS OFTEN A RELUCTANCE ON THE PART OF A HOST INCUMBENT TRANSMISSION OWNER TO "ACCEPT" THE TRANSMISSION ASSETS OF A NEW NON-PUBLIC UTILITY INTO ITS PRICING ZONE AND THE IMPLICATIONS FOR NON-UTILITY INVESTMENT.

A. Initially, many RTO pricing zones had single or few participants in the zone. The emergence of the joint pricing zone following the Commission's *Wolverine* decision[49] in 2004/2005 led to the emergence of joint pricing zones which are very common today in

[49] *Midwest Independent Sys. Operator, Inc*, 106 FERC ¶ 61,219 (2004) (*Wolverine*).

MISO and in SPP. In a joint pricing zone, the costs of upgrades are zonally shared among the customers of all utilities' customers in the pricing zone. Wholesale customers outside of an RTO are often assessed their load ratio share of zonal facilities while also bearing the entire cost of their own facilities and despite important Commission rulings such as its *Prairie Power* decision,[50] there can still be subtle resistance when new utilities want to integrate their networked facilities into the RTO. There is a natural resistance for a host incumbent TO to keep the costs of new players out of the zone because it raises the costs to the incumbent's native load. Thus, a host incumbent TO has an incentive to keep the radial facilities of its imbedded wholesale customers out of the host TO's transmission network. Thus, there is no incentive for the incumbent to work with its wholesale customers with radial facilities to loop their radial facilities. This is contributing to the lack of investment by municipals and some cooperatives. If the wholesale customer's facilities were networked, they would then likely qualify under the Commission's 7-factor test as transmission and be recoverable in the zonal rates and thus, increase the rates to the incumbent's native load.

Looping largely radial-only connections to the broader regional grid can enhance grid reliability and resilience, *e.g.*, by providing geographic diversity that lessons the impact of a single disturbance on the existing radial lines that principally serve these class of customers, thereby lessoning the potential for loss of load and helping assure overall system reliability and/or facilitating the delivery of power on a system-wide basis.

To address this tendency to exclude facilities that could be networked and enhance reliability, the Commission can best promote comparable reliability and resilience

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[50] *Prairie Power v. Ameren Services Company, Ameren Illinois Company and Ameren Transmission Company of Illinois*, 144 FERC ¶ 61,193 (2013) (*Prairie Power*).

by promoting widespread looping of radial lines predominantly serving incumbent non-native loads. To promote looping, the Commission should continue to reinforce that the costs of newly networked transmission facilities integrated into an RTO are included in RTO zonal rates on a comparable basis as RTO-controlled facilities serving incumbent native load. The principle of non-discrimination dictates no less. Further, planning criteria should evolve to ensure comparable service so currently non-networked transmission facilities are planned to be networked to benefit all customers served by the grid. Consistent with promoting this comparability, the Commission can approve this Joint Ownership Incentive to encourage the looping of existing radial lines and a more reliable transmission network.

Q. PLEASE DESCRIBE HOW THESE FACTORS COVERED ABOVE CAN RESULT IN A RELIANCE ON THE INCUMBENT AND MANAGEMENT ATTENTION AND UTILITY RESOURCES BEING FOCUSED ON AREAS OTHER THAN TRANSMISSION INVESTMENT.

A. The factors discussed above of tariff rules favoring the incumbent, thinly staffed resources, risk aversion to high visibility projects, constrained capital, a reluctance to join the RTO, and disincentives to an incumbent TO accepting the transmission facilities of a new RTO member in the incumbent's pricing zone can result in a reliance on the host incumbent to provide for the non-public utilities' transmission reliability needs. However, this solution can leave non-public utilities, especially TDNPUs, vulnerable to delays as the incumbent will often control the timeline and transmission designed may prioritize the incumbents' system rather than enhance the TDNPU's system. When a TDNPU relies on a third party like its host incumbent to address its transmission service needs over developing such capabilities in-house, both parties' resources are naturally dedicated elsewhere to higher priority business needs.

3. GridLiance's Recommended Joint Ownership Incentive Is Just and Reasonable

Q. WHY DO YOU BELIEVE GRIDLIANCE'S PROPOSED JOINT OWNERSHIP INCENTIVE IS JUST AND REASONABLE?

A. In my experience, GridLiance's recommended Joint Ownership Incentive is just and reasonable under either FPA section 205 or 219 (Order No. 679) based on the greater benefits it would provide to the transmission system. More specifically, GridLiance's proposal: (1) advances the stated public policy goals of the Commission of (a) attaining greater levels of non-public power participation in new transmission investment and a deeper pool of transmission market participants, and (b) promoting an expanded RTO footprint leading to a more reliable transmission grid and a more competitive wholesale market; (2) is consistent with the Commission's policies and regulatory authority; (3) is designed to counter the financial impediments to transmission investment for non-public utilities; (4) offers important pro-competitive benefits; and (5) and delivers additional benefits when the proposed eligibility criteria are met. I will discuss each in turn.

4. A Proposed Joint Ownership Incentive Furthers the Commission's Stated Policy of Promoting Increased Joint Transmission Investment

Q. HAS THE COMMISSION GRANTED INCENTIVES CONSISTENT WITH ENCOURAGING NON-PUBLIC UTILITY INVESTMENT IN TRANSMISSION?

A. Yes. In accordance with Order No. 679, the Commission has encouraged transmission investment by non-public utilities by granting transmission rate incentives, such as a hypothetical capital structure, to numerous non-public utilities in MISO, including Dairyland Power Cooperative (three times), Central Minnesota Municipal Power Agency (CMMPA) and WPPI Energy (twice for each), and Missouri River Energy Services.[51] It also has approved the establishment of a regulatory asset to CMMPA, and on two occasions to WPPI Energy. It also consistently approved an incentive to recover abandoned plant for these entities. All of these incentives were granted for joint projects that involved non-public utility joint ownership with IOUs. In many cases, these incentives were instrumental to the entity's decision to join MISO or to invest in the relevant project.

Q. HAVE THESE INCENTIVES YOU DISCUSS APPLIED TO SMALLER NON-PUBLIC UTILITIES?

A. No. The incentives for joint ownership to date has been in larger regional backbone projects (*e.g.*, CapX2020 in the upper Midwest)[52] with higher risks/challenges. These joint investment projects involving IOUs, G&Ts, JAAs, and municipals have traditionally been more regional and became less frequent with the onset of FERC Order No. 1000. There has been and continues to be a void in the market as smaller transmission projects have not received their due attention as indicated by the lack of municipal investment in MISO.

Q. ARE THESE EFFORTS AT ENCOURAGING JOINT INVESTMENT VALUABLE?

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[51] *See WPPI Energy*, 141 FERC ¶ 61,004, P 32; *Midcontinent Indep. Sys. Operator, Inc.*, (Central Minnesota Municipal Power Agency), 145 FERC ¶ 61,263, P 25; *Dairyland Power Coop.*, 142 FERC ¶ 61,100, P 27 (2013); *Mo. River Energy Servs*., 138 FERC ¶ 61,045, P 37 (2012*); Dairyland Power Coop*., 152 FERC ¶ 61,019, P22 (2015); *WPPI Energy*, 151 FERC ¶ 61,246, P 22 (2015). *WPPI Energy*, Docket No. ER16-744-000 (delegated letter order) (March 29, 2016); *Central Minnesota Municipal Power Agency*, 134 FERC ¶ 61,115, P 31 (2011), *Central Minnesota Municipal Power Agency*, 145 FERC ¶ 61,300 (2013), 149 FERC ¶ 61,226 under Docket No. ER14-246 (2014 Settlement).

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

A. Yes. Encouraging greater transmission investment by non-public utilities is consistent with promoting capital investment in electric transmission infrastructure, developing a more robust transmission grid, increasing reliability, and in general, advancing fulfillment of the goals articulated in Order No. 679 and FPA section 219.

As I explained above, many non-public utilities, particularly TDNPUs, face substantial local transmission planning/expansion challenges. Commission policies that are designed to help these entities overcome such obstacles are, in effect, policies aimed at increased reliability and a deeper pool of transmission investors.

Q. HOW DOES ESTABLISHING A JOINT OWNERSHIP INCENTIVE FURTHER THE COMMISSION'S STATED GOALS OF PROMOTING INCREASED JOINT TRANSMISSION INVESTMENT?

A. A Joint Ownership Incentive eases financial obstacles to transmission investment for non-public utilities, thus promoting increased non-public utility investment, a deeper pool of investors, and enhanced reliability and market efficiency. This includes addressing the local reliability needs of smaller municipals and electric cooperatives with radial, lower-voltage systems and integrating them into an RTO/ISO network, when possible. Broader non-public utility participation provides benefits to the region as a whole by encouraging development in areas of the ISO/RTO footprint that may not otherwise be accessible. Likewise, by expanding opportunities for joint regional transmission projects, the resulting expansion of the ISO/RTO footprint supports the Commission's efforts to promote wholesale market competition.

Establishing a Joint Ownership Incentive is also consistent with the long-held Commission goal of the economic benefits of an RTO and a broader RTO footprint.[53] Moreover, it provides a vehicle to address the important public policy goal of ensuring the efforts to expand the nation's transmission grid appropriately include all stakeholders including the historically underrepresented non-public utility sectors, in both the planning and ownership of new facilities.

Q. IS A JOINT OWNERSHIP INCENTIVE CONSISTENT WITH THE COMMISSION'S POLICIES AND REGULATORY AUTHORITY?

A. Yes. As noted above, a Joint Ownership Incentive is consistent with the Commission's policy and precedent of encouraging joint investment in transmission projects, including its 2015 invitation to GridLiance to propose an incentive under Order No. 679 based on facilitating the participation of non-public utilities in new transmission projects.[54]

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[53] *See*, *e.g.*, FERC Order No. 2000, pages 255-256. The six benefits of a broader RTO footprint of utilities and transmission assets include:
1) Making accurate and reliable ATC determinations: An RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.
2) Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.
3) Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.
4) Offering transmission service at non-pancaked rates: Competitive benefits result from eliminating pancaked transmission rates within the broadest possible energy trading area.
5) Improving Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.
6) Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient if planned and coordinated over a larger region.

[54] *South Central MCN LLC*, 153 FERC ¶ 61,099 at P 69 (2015) (citing Order No. 679, at P 354) (*South Central*); *order on reh'g*, 154 FERC ¶ 61,271 at P 26 (citing Order No. 679, at PP 354-355) (finding, in both orders, that SCMCN "could propose an incentive under Order No. 679 tailored to encouraging Public Power and Cooperative participation in new transmission projects.").

A Joint Ownership Incentive can be justified under either FPA sections 219 (Order No. 679) or 205. The Commission has similarly approved ratemaking incentives under FPA section 205, rather than Order No. 679, where the incentive would further a public policy goal but would apply to projects not-yet-identified.[55]

5. The Proposed Incentive Cost-Effectively Addresses Non-Public Utilities' Suboptimal Transmission Investment Level, Financing Impediments, and Reliability Needs

Q. HOW DOES A JOINT OWNERSHIP INCENTIVE ADDRESS THE FINANCIAL IMPEDIMENTS TO TRANSMISSION INVESTING FOR NON-PUBLIC UTILITIES?

A. A Joint Ownership Incentive directly incentivizes planning and investment in both local/zonal and competitive regional projects at non-public utilities' desired levels by removing the traditional impediments to investing including scarce capital and planning resources. The Commission's effort to bring specific investment opportunities directly to non-public utilities in this manner reasonably addresses a common frustration that my clients express to me about the lack of viable means for them to identify, properly define, and participate in new transmission projects that meet their needs. It provides a customized approach that incentivizes all types of new transmission investment of potential interest to prospective partners and ensures non-public utilities support and participate to strengthen the grid.

Q. HOW DOES A JOINT OWNERSHIP INCENTIVE HELP NON-PUBLIC UTILITIES ADDRESS THEIR RELIABILITY NEEDS?

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[55] *See South Central* at PP 24, 37(citing Order No. 1000-A) (granting hypothetical capital structure and regulatory asset incentives on a non-project specific basis, finding that granting the regulatory asset under section 205 "furthers the Commission's policy goal of facilitating the participation of nonincumbent transmission developers in the Order No. 1000 competitive solicitation process, thereby encouraging competition," and granting the hypothetical capital structure on the same grounds.)

A. As previously mentioned, the typical transmission project for a municipal can range from $5 million-$20 million, more than the existing total gross transmission plant of many municipals in MISO and SPP and multiples of their typical annual investment levels. For non-public utilities with aging networks, a Joint Ownership Incentive directly incentivizes a willing public utility partner, such as an independent Transco like GridLiance, to pursue joint development opportunities that stand to increase the reliability of a non-public utility's system in a more cost-effective manner than the entity could likely achieve on its own. Thus, a Joint Ownership Incentive is likely to make the financing hurdle noted above more manageable. By virtue of jointly participating in a project with a public utility such as GridLiance, non-public utilities will have greater access to the skill sets and processes necessary to design and construct important transmission projects.

6. The Proposed Incentive Provides Important Pro-Competitive Benefits for Consumers

Q. PLEASE SUMMARIZE SOME OF THE PRO-COMPETITIVE BENEFITS ASSOCIATED WITH A JOINT OWNERSHIP INCENTIVE

A. As discussed above, GridLiance's proposed Joint Ownership Incentive will foster a more competitive environment providing a competitive alternative to the incumbent TO. This leads to lower-cost, more innovative solutions and allowing the non-public utility to be an owner rather than renter. In addition, these joint investments promote a broader RTO footprint that includes more non-public utility systems with its attendant reliability and planning benefits.

Q. WILL A JOINT OWNERSHIP INCENTIVE ALSO PROMOTE GREATER NON-PUBLIC UTILITY PARTICIPATION IN ISO/RTO COMPETITIVE TRANSMISSION PROCESSES?

A. Yes. As mentioned previously, most non-public utilities cannot effectively participate in MISO's and SPP's Order No. 1000 Competitive Transmission Process on their own due to the prohibitively intensive resource and financial commitment needed to realistically pursue these types of projects. A Joint Ownership Incentive provides the financial inducement for the public utility to commit the necessary staffing and financial resources to identify, design, gain RTO approval, and construct various projects to enhance the reliability of the transmission network. A Joint Ownership Adder would also be available to the non-public utility partner and provides them a similar inducement to coordinate with the public utility and commit to the effort.

Q. DOES A JOINT OWNERSHP INCENTIVE PROVIDE ADDITIONAL BENEFITS TO ALL ISO/RTO CUSTOMERS MORE GENERALLY?

A. Yes. By encouraging additional non-public utility participation in projects, a Joint Ownership Incentive can promote increased reliability at a lower cost per investment. As previously discussed, many non-public utilities have lower revenue requirements per mile of transmission investment than IOU/Transcos because they do not pay income taxes and often have lower debt costs due to tax-exempt or government-backed financing. Thus, compared to a non-public utility relying solely on meeting their reliability needs from their incumbent TO, a Joint Ownership Incentive is consistent with advancing regulatory goals by reducing the transmission cost of RTO ratepayers to fund necessary investment in the grid through the lower revenue requirements of non-public utilities.

7. The Proposed Incentive Promotes Public Policy and Delivers Significant Benefits When the Proposed Eligibility Criteria Are Met

Q. WHAT IS YOUR VIEW ON GRIDLIANCE'S PROPOSED REQUIREMENT OF APPROVAL BY A COMMISSION-APPROVED REGIONAL OR LOCAL TRANSMISSION PLANNING PROCESS?

A. By proposing projects through a Commission-approved regional or local transmission planning process, this prevents the partners from constructing unnecessary projects and expecting cost recovery with the Joint Ownership Incentive. The stakeholders are given an opportunity to provide input to the planning process and discuss the proposed project that would receive the Joint Ownership incentive.

Q. WHAT IS YOUR VIEW ON GRIDLIANCE'S PROPOSED 15% THRESHOLD ELIGIBILITY REQUIREMENT OF NON-PUBLIC UTILITY PARTICIPATION FOR A JOINT OWNERSHIP INCENTIVE?

A. I think it is a reasonable level because the 15% minimum aggregate ownership criteria:

(1) provides assurance that non-public utilities are involved at material levels in applicable projects, thus substantially increasing their investment levels in transmission from historically low levels;

(2) acts as a safeguard against abuse so that public utilities like GridLiance cannot game the incentive by offering non-public utility partners *de minimus* investment opportunities, *e.g.*, 1%, in order to trigger the incentive's application;

(3) provides incentive to public utilities like GridLiance to work with the broadest pool of potential non-public utility investors, many of which are small and would not have the capital to invest in projects at higher levels; and

(4) helps ensure the non-public utility investment level in a local/zonal joint project is substantial yet is not so high as to systematically exclude smaller municipals.

Q. IS GRIDLIANCE'S PROPOSED 15% MINIMUM OWNERSHIP CRITERION FOR A JOINT OWNERSHIP INCENTIVE CONSISTENT WITH PREVIOUS JOINT INVESTMENTS OF WHICH YOU ARE FAMILIAR?

A. Yes. MCR has directly supported various non-public utility TOs in MISO in their transmission incentive rate filings for their joint investment with IOUs covering six separate joint transmission projects. Each of the non-public utility incentive requests associated with these projects involved MISO TOs and the incentive requests were approved by the Commission. Four of these six joint projects are part of the CapX2020 consortium. The average (and median) collective non-public utility ownership of these six projects that we have supported with incentive filings is 21.7% and 18.4%, respectively, with three of the projects in the range of 9% to 13% (see Table 7 below).[56] The minimum aggregate partner ownership threshold of 15% proposed by GridLiance therefore is generally consistent with non-public utility ownership percentages of these well-known prior MISO joint projects.

[56] Similarly, the Commission has approved various IOU transmission incentive filings for IOU participants for the same CapX2020 joint projects. IOU participants for these same projects have included, for example, *Allete/Minnesota Power* 133 FERC ¶ 61,270 (2010); *Otter Tail Power* 137 FERC ¶ 61,255 (2011); *and Xcel Energy Services, Inc*. 121 FERC ¶ 61,284 (2007).

Table 7

Select MISO TO Joint Investment Projects Approved in FERC Orders for Public Power and G&T Incentives--Percentage Ownership[1]																
	IOU/Transco Transmission Owner in MISO							Public Power/G&T Transmission Owner in MISO								
MISO Joint Project	**CapX 2020 Project**	**Xcel**	**Otter Tail Power**	**ATC**	**ITC-Midwest**	**MN Power**	**IOU Total**	**GRE**	**MRES**	**CMMPA**	**SMMPA, SMMPA WI**	**DPC**	**RPU**	**WPPI**	**Public Power, G&T Co-op Total**	**Total**
Hampton-Rochester-La Crosse[2]	Yes	64.0%					64.0%				13.0%	11.0%	9.0%	3.0%	**36.0%**	100.0%
Hampton to Brookings[3]	Yes	72.1%	4.1%				76.2%	16.5%	5.1%	2.2%					**23.8%**	100.0%
Fargo-St. Cloud-Monticello[4]	Yes	36.1%	13.2%			14.7%	64.0%	25.0%	11.0%						**36.0%**	100.0%
Big Stone to Brookings[5]	Yes	37.5%	50.0%				87.5%	8.2%	2.5%	1.8%					**12.5%**	100.0%
Briggs Substation to North Madison Substation[6]	No	37.0%		50.0%			87.0%				6.5%	5.0%		1.5%	**13.0%**	100.0%
Cardinal-Hickory Creek[7]	No			45.5%	45.5%		91.0%					9.0%			**9.0%**	100.0%
Average							78.3%								**21.7%**	
Median							81.6%								**18.4%**	

Notes and Sources:
Note 1: Percentage ownerships were estimates at the time of the incentive filings; actual percentages may have changed based on final project agreements
Note 2: Dairyland Power Cooperative, Docket No. EL13-19-000, 11/9/2012, page 4; 142 FERC ¶ 61,100, 2/8/2013. Also, WPPI Energy, Docket No. EL12-67,5/9/2012, page 9; 141
Note 3: Central Minnesota Municipal Power Agency, Docket. No. EL38-02, 134 FERC ¶ 61,115, 2/15/2011
Note 4: Missouri River Energy Services, Docket No. EL11-45-000, 6/15/2011; 138 FERC ¶ 61,045, 1/20/2012 and Application to the North Dakota Public Service Commission for a
Note 5: Central Minnesota Municipal Power Agency, Docket. No. ER13-2468, 9/27/2013, Exhibit CMMPA-15 page 4; 145 FERC ¶ 61,263, 12/19/2013
Note 6: Dairyland Power Cooperative, Docket No. 15-1689; FERC ¶ 61,019 1/7/2015, P. 4. Also, WPPI Energy, Docket No. EL12-67, 4/21/2015, Exhibit WPPI-1, page 7; 151 FERC ¶
Note 7: Cardinal-Hickory Creek, Docket No. ER18-193-000 FERC 161 FERC ¶ 61,301, pages 1, 9 and 10.
Additional Note: The CapX2020 Bemidji-Grand Rapids project is not included in this list because Minnkota Power Cooperative is not a MISO TO, did not receive incentives and MCR did not support this project with an incentive filing. The public power participation was Minnkota 31.5% and Great River Energy 13%.

Q. WHY SHOULD A NON-PUBLIC UTILITY OWNERSHIP THRESHOLD FOR QUALIFYING FOR A JOINT OWNERSHIP INCENTIVE NOT BE SET GREATER THAN 15%?

A. Setting the threshold at too high a level can discourage participation by non-public utilities. A 15% threshold level of non-public utility participation in a joint project with a public utility like GridLiance is appropriate because it helps ensure that the broadest possible pool of such entities participate and benefit from co-development arrangement, including the smaller municipals which are in most need for transmission investment. Again, from my experience, radial and low-voltage connections are especially prevalent amongst smaller non-public utilities.

Further, the recent median annual investment of municipals in MISO is only about $110,000 per year and about $100,000 per year in SPP.[57] In direct contrast, as previously mentioned, MCR's experience indicates that the typical investment level for the types of projects that may be needed for many municipals is about $5 million-$20 million Thus, for example, if the aggregate threshold for the Joint Ownership Incentive were set at 25% on a $10 million project, a public utility like GridLiance may need to partner with numerous municipal utilities to reach the minimum threshold of $2.5 million municipal ownership in this example. The public utility and each partner would have to review and negotiate the project documents, educate the partners' boards of the arrangement, and gain agreement from their respective stakeholders. These logistics could take an inordinate amount of time, effort, and cost. Thus, setting the threshold too high could systematically discourage public utilities from pursuing smaller non-public utilities. This rationale is even more applicable with regard to projects in the RTO competitive transmission processes, which applies to projects with regional cost allocations that will generally be bigger and even more expensive.

In contrast, a 15% joint investment with a single municipal utility in a local/zonal high-voltage project that costs $10 million would require an investment of $1.5 million by the non-public utility partner(s) in order for a public utility like GridLiance to qualify for the Joint Ownership Incentive. This threshold could still be a stretch – it is about 15 times the

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[57] In MISO, the median investment over the five-year period was $550,000, or $110,000 per year. In SPP, the median investment over the four-year period studied was $394,000, or nearly $100,000 per year.

median annual historical municipal investment. But, based on my experience, a $1.5 million transmission investment (15% of $10 million) by a single municipal may still be financially within reach for many smaller municipals willing to invest in a transmission project, whereas a full $10 million investment likely would not be. Thus, a 15% aggregate threshold for the Joint Ownership Incentive safeguards against gaming and helps ensure the non-public utility investment level in a local/zonal joint project is substantial yet is not so high as to systematically exclude smaller municipals.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment B

The Transco Model is Working

Prepared for
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MCR

The Transco Model is Working

Executive Summary

MCR Performance Solutions (“MCR”) compared investment levels of standalone transmission companies (“Transcos”) and investor-owned utilities (“IOUs”) in MISO and SPP over the last six years using various metrics to determine whether Transcos invest at a higher propensity than IOUs. The analysis shows that from 2013 to 2019, Transcos indeed invested at a higher rate than IOUs in these RTOs. MCR attributes the substantial investment levels for Transcos to its business model and the incentives put in place by Federal Energy Regulatory Commission (“FERC”), including the Transco return on equity (“ROE”) adder for certain Transcos based on their relative independence. By continuing to award incentives including a Transco ROE adder (“Transco Adder”), FERC continues to encourage the Transco business model and promote the corresponding reliability and economic benefits it provides.

Introduction

GridLiance Holdco, LP engaged MCR to analyze the transmission investment differences between IOUs and Transcos over the past six years where the comparison would be the most meaningful, such as across MISO and SPP, the two RTOs where Transcos are particularly prevalent. Additionally, MCR was asked to comment on the reasons for the potential differences as well as opine on the relative value of the Transco Adder and the merits of the Commission’s current approach to awarding the incentive. In particular, MCR sought to answer the following questions:

- Do Transcos in SPP and MISO invest in transmission at a higher rate than IOUs)?
- If so, what factors contribute to that difference?
- Should FERC continue to offer the Transco Adder incentive?
- Should the Commission adjust its current approach to awarding the Transco Adder?

To answer the first question, MCR developed an analysis in its Proprietary Transmission Investment & Load (“PTIL”) database[1] comparing investment levels of Transcos to IOUs from 2013-2019 in a combined MISO and SPP data set. The annual transmission investment figures were calculated by taking the difference between each transmission owner’s (“TO’s”) reported gross transmission plant from year-to-year plus the change in construction work in progress (“CWIP”). These gross transmission plant figures were used as a proxy for each company’s annual transmission capital

[1] See the section titled, About MCR’s Proprietary Transmission Investment & Load Database, on page 10 to learn more about the companies included in the database and the years for which data was collected.

investment,[2] and were then aggregated by each segment (*i.e.*, eight Transcos in MISO and SPP and 25 IOUs in MISO and SPP) to determine segment-wide figures. From this data, key metrics were calculated by segment to gauge the level of relative transmission investment to make comparisons of the propensity to invest between the Transco and IOU segments. These metrics included the following:

- Percentage change in gross transmission plant for the past six years;[3]
- Percentage change in gross transmission plant for the most recent three years;
- Investment to depreciation intensity ratio over the last six years, which provides insight into the rate at which transmission owners are investing to replace transmission plant as it depreciates. A ratio of one means that transmission investment is replacing transmission plant as it becomes depreciated;
- The median investment to median gross transmission plant ratio over the last six years, which measures the pace and consistency of investment;[4] and
- The average annual dollar investment, which captures the absolute size of the investment. This equals the total dollar change in gross transmission plant over the six years divided by six years.

Results from the PTIL database investment figures and the metrics developed from the figures can be found in Table 1 below.

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[2] Formula for investment in each year per the Attachment O and Attachment H = change in company gross transmission plant + change in CWIP in rate base. The reported change in the transmission gross plant balance in the MISO Attachment O or SPP Attachment H formula rate cost templates include the net effect of any retirements, adjustments and transfers. Transfers could, for example, include a reclassification of distribution plant as transmission. Capital expenditures reported in the FERC Form 1 for any given year will likely be different than the change in gross transmission plant reported in the Attachment O / Attachment H, because of any retirements, adjustments, and transfers. Further, the Attachment O / Attachment H requires the plant to be in rate base, so any CWIP capital expenditures not yet in rate base are not included the Attachment O / Attachment H data.

[3] 2019 gross transmission plant minus 2013 gross transmission plant divided by 2013 gross transmission plant.

[4] This metric represents the ratio of the median dollar investment over the six-year timeframe to the median gross transmission plant over the same period. This metric measures the pace and consistency of investment by adjusting for one-time large investments. This metric is then discussed two ways: 1) the median of the sampled companies in the segment (that is, the median of these eight ratios for Transcos and median of the 25 IOUs; and 2) the simple average of the eight Transcos and the simple average of the 25 IOUs.

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Table 1
Results of PTIL Database and Metrics

Transmission Segment	6-Year % Change in Transmission Gross Plant	3-Year % Change in Transmission Gross Plant	6-Year Investment to Depreciation Expense Intensity Ratio	6-Year % Median Investment to Median Transmission Gross Plant	Average Annual $ Change in Transmission Investment ($M)
Transcos					
Median	83%	25%	553%	8%	$160,288
Average	344%	36%	748%	14%	$185,123
IOUs					
Median	66%	28%	434%	7%	$111,460
Average	77%	28%	428%	8%	$129,093

Transco Investment vs. IOU Investment

When analyzing the metrics on a median basis, the data show that the relative Transco investment rate has exceeded that of IOUs for four of the five metrics:

- The median percentage change in gross transmission plant for the eight TOs in the Transco segment was 83% for the six-year period, versus 66% for the 25 TOs in the IOU segment;
- When looking at only the last three years of investment, the median percentage change in gross transmission plant was 25% for the Transco segment versus 28% for the IOU segment;
- The median Transco segment investment to depreciation expense intensity ratio was 553% compared to 434% for the IOU segment;
- The ratio of the median investment to median gross transmission plant balance for Transcos was 8% compared to 7% for the IOU segment;[5] and

[5] The median of the list of companies' ratios in each segment (median investment over the six years divided by median gross plant balance over the six years).

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The Transco Model is Working

- The median average annual dollar investment for the Transco segment was $160.3 million compared to $111.5 million for the IOU segment.

These median metrics paint a general picture of Transcos investing more heavily in transmission than IOUs. Furthermore, when looking at the metrics on an average (rather than median) basis, the advantage to the Transco segment is even more pronounced with all five metrics favoring the Transco segment:

- The Transco segment had an average[6] 344% overall percentage change in gross transmission plant over the last six years, compared to 77% for IOUs; when looking at only the last three years, the Transco segment had an average 36% change in gross transmission plant from 2016 to 2019,[7] compared to 28% for IOUs.
- The average investment to depreciation expense intensity ratio for the Transco segment from 2013 to 2019 was 748%, versus 428% for IOUs;
- The average of the median investment to median gross plant ratios for the Transco segment was 14% compared to 8% for the IOU segment; and
- The average annual dollar investment by Transcos over the six-year period was $185.1 million, versus $129.1 million for IOUs.

Much of the difference in the average figures is driven by Ameren Transmission Company of Illinois ("ATXI"), which has an exceptionally high percentage growth in investment of 1,902%, due to starting from a relatively small gross transmission dollar base of $63.4 million combined with completing large capital projects. Even without ATXI, however, all the average metrics still show Transco investment outpacing IOU investment. The following statistics show the impacts of removing ATXI from the Transco sample:

- The average six-year percentage change in investment decreases from 344% to 121%, which is still higher when compared to 77% for IOUs. When looking at just the most recent three years, the average change in investment decreased from 36% to 31% compared to 28% for IOUs;

[6] All averages are simple averages of the companies in the sample. On a weighted average basis, Transcos still maintain their advantage over IOUs. On a weighted average basis: the percentage change over six years for Transcos is 91% compared to IOUs' 75%; the investment to depreciation ratio is 494% vs. 433% for IOUs, and the median investment to median gross plant balance ratio is 9% for Transcos vs. 8% for IOUs.
[7] The 2016 to 2019 gross transmission plant data produces three years of investment data, *i.e.*, the change in transmission gross plant from 2016 to 2017, 2017 to 2018 and 2018 to 2019.

- The average investment to depreciation expense intensity ratio decreases from 748% to 513% compared to 428% for IOUs;
- The average median investment to median gross plant ratio decreases from 14% to 9% compared to 8% for IOUs; and
- The average annual dollar investment decreased from $185.1 million to $167.6 million, compared to $129.1 million for IOUs.

So, even after removing ATXI from the sample, all metrics show Transcos invest at a higher rate than IOUs when measuring the metrics on an average basis.

Additionally, American Transmission Company ("ATC") is one of the largest and most well-established Transcos in MISO. In fact, ATC is the largest transmission owner in both the Transco and IOU segments by measure of gross transmission plant; however, some of ATC's metrics are comparatively low for the Transco segment:

- ATC had an overall change in gross transmission plant of just 51% for the time period, compared to the Transco segment median of 83%;
- ATC's investment to depreciation intensity ratio was only 253%, versus the Transco median of 553%; and
- ATC's median investment to median gross plant ratio was 6% compared to the Transco median of 8%.

Given these figures, it is clear that ATC brings down some of the Transco segment metrics. However, ATC's lower metrics are not surprising given its dominant size. ATC has nearly $6 billion of gross transmission plant, which makes it the largest TO in the combined sample of Transcos and IOUs. ATC's considerable size makes it unlikely that it could grow at a comparable rate to smaller, less established peers. Despite these three relatively low metrics, however, ATC continues to be a very heavy investor in transmission. In fact, its 2019 investment of approximately $396 million is the largest in the Transco segment and was second only to Entergy Louisiana across all transmission owners. ATC's average change in investment of $350 million per year over the last six years is nearly double the Transco average of $185 million. This high level of ATC investment is projected to decline only slightly as ATC's 10-year investment plan shows a total transmission investment of $3.1 billion, or about $310 million per year.[8]

[8] See page 2 of ATC's 2018 Summary Report: 10-Year Transmission System Assessment. $3.1 billion is the midpoint of the $2.8 billion–$3.4 billion 10-year investment range.

Thus, the segment metrics show an even greater advantage to the Transco segment over the IOU segment when ATC is removed from the calculations. When excluding ATC, the metrics show:

- The median Transco segment investment growth over the six-year period increases from 83% to 100%;
- The median of the Transco segment investment to depreciation intensity ratios increases from 553% to 626%; and
- The ratio of the median investment to median gross transmission plant balance for Transcos increases from 8% to 10%.

Thus, in summary, the investment metrics indicate that the Transco segment has been investing in transmission plant over the last six years at a higher rate than the IOU segment. When measured on a median basis, the metrics favor the Transcos. When measured on an average basis, the advantage to Transcos increases. Even when “outliers” such as ATXI and ATC are removed, the story of higher Transco investment remains the same.

The Transco Business Model

We now know the answer to the question, “Do Transcos in SPP and MISO invest in transmission at a higher rate than IOUs?” is an affirmative yes. We’d now like to consider what factors contribute to that difference. One place to start is the Transco business model, which encourages increased investment in transmission capital projects as compared to the IOU business model. I believe there are two key characteristics of the Transco business model that allow them to invest at a greater rate than IOUs:

- Management’s focus on transmission as a singular business function; and
- Ready access to capital.

Unlike IOUs or other utilities that own assets across multiple utility functions, Transcos focus solely on building and operating transmission plant. Transco personnel gain an in-depth expertise from running a transmission business. This concentrated attention affords management the opportunity to focus their efforts and resources on proactively identifying and designing capital projects that increase grid reliability, interconnect with new generation projects, and reduce congestion. This focus coincides with a formula rate model that encourages rate base investment to generate earnings.

Because management’s efforts are dedicated to transmission, a Transco’s capital budget tends to be less constrained as compared to an IOU. By virtue of establishing a Transco (whether an affiliate of an IOU or an independent Transco), there is an acknowledgement and readiness that ample capital will be required to fund growth. Further, many Transcos are funded by well-known firms (e.g., private equity firms) with ready access to capital, so financing can be more readily available compared to IOUs where there is often more competition for capital between other utility functions, such as generation and distribution.

Further, some Transcos' business models proactively seek out opportunities to partner with other segments (*e.g.*, municipals) to enhance their partner's reliability. Municipals, for example, tend to have much lower relative levels of investment[9] than other segments, as MCR has chronicled separately for GridLiance). By providing a competitive alternative to the local IOU incumbent, some more nimble and independent Transcos can provide municipals and cooperatives a more innovative, cost-effective solution to local reliability issues. This emphasis of proactively seeking investment opportunities with potential partners can lead to higher levels for investment for Transcos.

In addition, with their singular focus on transmission investment, Transcos are typically more willing to take the risk and considerable effort of bidding on competitively solicited RTO-sponsored projects under FERC Order 1000. These bids bring high risks due to the large numbers of bidders, the substantial required resources and investment to bid, and design a bid that often assumes the risk of construction cost overruns. However, with their ready availability of capital and dedicated resources, Transcos are well-suited to compete for these competitive projects.

Transmission Incentives Including Transco ROE Adders

In our experience, transmission incentives, such as providing a hypothetical capital structure, establishing a regulatory asset for Transcos and providing a Transco Adder for more independent Transcos, have contributed to forming Transcos and their elevated levels of transmission investment. We have witnessed how the Transco Adder has provided an additional financial inducement for new, more independent Transcos like NextEra Energy Transmission New York and GridLiance West to enter the market in recent years and dedicate the capital and resources to proactively identify transmission projects that enhance reliability of the network. As demonstrated herein, the Transco business model, along with these attractive incentives, has been successful in promoting transmission investment and enhanced reliability, and should continue to be encouraged by FERC in order to sustain the high levels of investment demonstrated by Transcos.

The independent Transco business model continues to provide sufficient benefits consistent with the public interest, such as increased competition, improved responsiveness to transmission market needs, ready access to capital, and improved asset management, to merit an incentive. The Independent Transco model provides a well-financed, competitive alternative to incumbent TOs.

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[9] For example, lower investment relative to their load ratio share.

The Transco Model is Working

Independent Transcos have a singular focus on identifying and pursuing projects that enhance the reliability of the transmission grid, both at the local level and at the regional level through Order No. 1000 competitive projects. This additional competitive force in the market tends to drive down costs for competitively-bid projects through lower bids and construction cost caps/controls.[10]

Awarding a Transco Adder Based on Relative Independence

The Transco Adder should continue to be awarded to Transcos based on their relative independence, relying on the same sufficiently independent criteria[11] FERC relied on in its 2018 *NextEra Energy Transmission New York* order.[12] For example, the Commission should not preclude a Transco Adder incentive simply because a Transco has an affiliate in the same RTO. The awarding of a Transco Adder should be case specific and be based on how relevant the existence of an affiliate is to the Transco's level of independence in its RTO. Further, the Commission's policy articulated in the recent *ITC* order[13] of awarding a Transco Adder up to a maximum of 50 basis points based on their relative independence is sound policy (ITC was awarded 25 basis points). The independent Transco business model should continue to be encouraged through the Transco Adder.

A more independent Transco seeking an ROE Adder incentive should be required to provide information demonstrating how its benefits are expected to occur, such as how it will be a positive competitive influence in the marketplace, why its business model is more responsive to transmission market needs in its RTO(s) and how its asset management processes can more effectively manage capital and O&M costs. For example, an independent Transco can play an important role in an RTO by providing a competitive alternative to the incumbents both for local projects and competitively-bid projects.

The Transco Adder Should Apply to All Transco Assets Rather than Specific Projects

FERC's incentive policy to encourage Transco formation is working and should be continued to ensure future robust transmission investment. The Transco Adder should apply to all of an independent Transco's transmission plant rather than based on a particular project. The benefits of the Transco business model (*e.g.*, increased competition, ready access to capital, more responsive and innovative market solutions, improved asset management) extend to all a Transco's investments rather than a particular project. These characteristics are systemwide benefits inherent in the Transco model and sustain over time.

[10] See, for example, the two MISO competitively bid projects, Duff-Coleman and Hartburg-Sabine Junction, both had construction cost caps and other forms of cost controls.
[11] The level of independence with regard to investment planning, capital formation, business structure and potential conflicts of interest relative to ownership percentage and location of affiliate assets.
[12] *NextEra Energy Transmission New York, Inc*. 162 FERC ¶ 61,196 (2018).
[13] *Consumers Energy Company et al. v. International Transmission Company et al*., 165 FERC ¶ 61,021 (2018).

The Transco Model is Working

The Transco Adder differs from the risk-based project incentives FERC sometimes grants to encourage new transmission investment in more challenging projects. The Transco Adder is an incentive available only for independent transmission companies and is intended to be an incentive to encourage a particular business model, rather than address the risks associated with a specific project. Thus, like the RTO Adder that a Transco would receive for its participation in an RTO, the Transco Adder should apply to all of the assets of an eligible Transco, rather than applying just to a specific project like a risk-based incentive, which is justified by the attributes of a specific project.

Further, having to make a filing at FERC each time a Transco makes an investment in a project slows down the investment process, effectively diminishing one of the advantages of a Transco, its market responsiveness. Moreover, it diverts away important resources and creates unnecessary additional regulatory filing and intervention costs for the Transco that can drive up costs in the pricing zone for all customers.

The Transco Adder Should Apply to Both Purchased Existing Assets and New Investment

Whether the Transco invests in a new or upgraded project or buys existing transmission, the benefits of increased competition, improved responsiveness to transmission market needs, ready access to capital, and improved asset management still apply. A Transco purchasing existing assets can lead to enhanced reliability of the network as a Transco will actively work within the RTO planning process to identify cost-effective opportunities for upgrades or expansions. These opportunities could include, for example, converting existing radial facilities to networked transmission, thus enhancing the reliability of the network. Thus, purchased assets of a more independent Transco should also be eligible for the Transco Adder.

Incentives are Working

In summary, the investment metrics in our analysis indicate that the Transco segment in MISO and SPP has been investing in transmission plant over the last six years at a higher rate than the IOU segment. FERC's incentives, including the Transco Adder, combined with the inherent benefits of the Transco business model, have been very successful to date in encouraging transmission investment and should be continued.

About MCR's Proprietary Transmission Investment & Load Database

MCR has developed and maintained transmission-related investment, load, and related metrics for MISO and SPP transmission owners in its Proprietary Transmission Investment and Load database. In order to qualify for the sample in this analysis of Transcos and IOUs, a TO in MISO and SPP had to have filed transmission formula rates for the time period of 2013 through 2019, which provides six years of investment data. Based on this criterion, eight Transcos and 25 IOUs across MISO and SPP were included in the sample.[14] This data is sourced from publicly available transmission formula rates (Attachment O in MISO and Attachment H in SPP).[15]

About the Author

Jim Pardikes is a Vice President at MCR Performance Solutions, LLC ("MCR") and leads the Transmission Strategy Practice. MCR is a management consulting firm in Deerfield, Illinois that focuses exclusively on the utility industry. Jim has 33 years of experience consulting to the utility industry, including public power, generation and transmission cooperatives, independent transmission developers and investor-owned utilities. His expertise includes transmission formula rate and cost analysis, FERC filings and strategic economic analysis. Jim has provided expert testimony in many FERC filings across a broad number of topics including transmission incentives, cost of capital and formula rates. Since 2007, Jim has led over 185 client transmission engagements in MISO, Southwest Power Pool and PJM Interconnection. Jim has extensive experience facilitating client working teams and presenting to executive management and Boards of Directors. Previously, Jim was a Senior Manager in Accenture's energy practice and a Vice President with CSC Planmetrics (now CSC Consulting), where he specialized in wholesale energy marketing.

Also contributing to this report for MCR were Ron Kennedy, Director, Chris Nagle, Lead Consultant and Nilsa Sweetser, Consultant.

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[14] The eight Transcos are: AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc and AEP Southwestern Transmission Company, Inc), ITC Great Plains, KCP&L's Greater Missouri Operations Company, American Transmission Company (ATC), Ameren Transmission Company of Illinois (ATXI), ITC International, ITC Midwest and Michigan Electric Transmission Company (METC).

The 25 IOUs are: AEP (Public Service Company of Oklahoma and Southwestern Electric Power Company), Empire District, Kansas City Power & Light, Oklahoma Gas & Electric, Southwestern Public Service Company, NorthWestern Energy (South Dakota), Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy), Ameren-Illinois, Ameren-Missouri, Duke-Indiana, Indianapolis Power & Light, Minnesota Power, Montana-Dakota Utilities, Northern States Power, Northern Indiana Public Service (NIPSCO), Otter Tail Power, Vectren, MidAmerican Energy, Northwestern Wisconsin Electric Company, CLECO, Entergy-Arkansas, Entergy-Mississippi, Entergy-Texas, Entergy-Louisiana and Entergy-New Orleans.

[15] The 2019 Empire District data was estimated by MCR as it had not been posted as of the cutoff date of the study of June 14, 2019. The 2019 investment was estimated based on the average investment of the prior three years combined with ratios applied for accumulated depreciation and depreciation expense.

Document Content(s)