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INVESTMENTS IN TRANSMISSION

PRESENTATION OUTLINE AND SUMMARY

ROBERT A. JABLON
robert.jablon@spiegelmcd.com

DANIEL H. SILVERMAN
daniel.silverman@spiegelmcd.com

SPIEGEL & MCDIARMID LLP

1333 New Hampshire Avenue, NW
Washington, DC 20036
Phone: 202.879.4000
Fax: 202.393.2866

www.spiegelmcd.com

INVESTMENTS IN TRANSMISSION

BY ROBERT A. JABLON AND DANIEL H. SILVERMAN

PRESENTATION OUTLINE AND SUMMARY

I. The Central Minnesota Municipal Power Agency ("CMMPA") and Midwest Municipal Transmission Group ("MMTG") have achieved a notable success that may benefit APPA members broadly. As a result of FERC cases and settlements, they have resolved all major issues so that CMMPA can invest in the CapX Brookings transmission line and receive fair cost recovery. CapX is a consortium of Upper Midwest utilities that is constructing major new Midwest transmission.

II. CMMPA and MMTG have created a path which APPA members and others can use to invest in future transmission projects.

III. CMMPA is a municipal power agency. Members can participate in agency power supply and transmission activities on a project by project basis. CMMPA also allows both members and non-members to invest in individual projects through CMMPA. Thus, CMMPA is financing Brookings transmission investments for both its own members who want to participate and for MMTG members as well. It is also acting as a Midwest Independent Transmission System Operator ("MISO") Transmission Owner for those who desire. MISO pays cities for their transmission investments only through MISO Transmission Owners.

IV. MMTG was formed by the Minnesota Municipal Utilities Association ("MMUA"), CMMPA, and the Iowa Association of Municipal Utilities ("IAMU") in 2001 when investor-owned utilities and others tried to freeze smaller municipal systems out of participation in Upper Midwest transmission. Its purpose was to allow small upper Midwest Cities to be transmission owners and to be compensated for their transmission on the same terms as dominant transmission owners. MMTG still has this purpose. It was also formed to promote necessary transmission development and reasonable transmission rates and terms. It still has these purposes.

V. CMMPA/MMTG have achieved:

a. The right to invest in the Brookings Project. They had to overcome extensive opposition to obtain transmission grid ownership rights and to invest in CapX. This took FERC filings, orders, testimony, negotiations, settlements, FERC Commissioner meetings and other efforts;

b. Entitlements to use of a 50 percent hypothetical capital structure (treating half CMMPA's capital as equity for CMMPA's MISO Annual Transmission Revenue Requirement ("ATRR"), even though CMMPA is financing its Brookings investments with debt). Thus, if CMMPA borrows money to finance Brookings at 5percent, it gets paid by MISO for half of its Brookings investment at its 5 percent cost of debt and the other half at the standard MISO equity rate of return of 12.38 percent (or the applicable amount at the time);

c. Entitlements to seek cost recovery if Brookings is canceled without CMMPA fault. This is a generally allowed, but very important, FERC incentive for new transmission construction. Applicants for incentive rates, including cancelation protection, must ask for them and get them approved. They must justify the incentives and demonstrate that their transmission projects are not routine;

d. The right to 100 percent construction work in progress ("CWIP") incentive rate. This gives CMMPA the right to collect its capital construction costs currently**.** Again, this is a standard incentive, but it has to be Commission approved. Note that in CMMPA's case, CMMPA is using a regulatory asset account for current expense amounts;

e. The ability to include its operations and maintenance and administrative and general costs incurred beginning January 1, 2007 in a regulatory asset account to be recovered over a five year period when Brookings goes on line. CMMPA will earn an equity return on its Brookings investments, including full returns on regulatory asset account balances applying a 50 percent equity capital structure accrued beginning January 16, 2012. Regulatory Asset Order, cited below at P 22. Although CMMPA's costs included in the regulatory asset account are subject to review when they are put into rates, all outstanding cost issues have been settled and FERC has approved CMMPA's categories of costs that CMMPA/MMTG requested be includable in the regulatory asset account; and

f. Reasonable assurances of fair cost recovery. Outstanding cost issues have been settled and, as is stated above, FERC has approved CMMPA's categories of costs that CMMPA/MMTG requested be includable in the regulatory asset account. Under CMMPA/MMTG's settlement, CMMPA's costs will be reviewed by MISO annually. Therefore, when CMMPA/MMTG applies for FERC for cost approval, they will have had the categories of costs approved and their particular costs reviewed; and

VI. Key CMMPA/MMTG decisions: *Cent. Minn. Mun. Power Agency*, 134 FERC ¶ 61,115 (2011) ("Incentive Rates Order"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 135 FERC ¶ 61,131 (2011) ("Section 205 Order") ; *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶61,186 (2011) ("Clarification Order"); *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,021 (2012) ("Regulatory Asset Order").

VII. Why is it important that we can invest?

a. Transmission rates will be high.

i. New investments.

ii. FERC allows high rates.

iii. We pay 12.38 percent equity rate of returns or the prevailing equity return when we use transmission.

iv. We pay for others' incentives.

b. Offset future transmission rates which are expected to increase dramatically due to ramp-up in transmission expansion; owning vs. renting.

c. Math is compelling.

i. If a city borrows $1 at 5 percent, its cost of borrowed capital is 5 cents. If it collects 12.38 percent on half of it, it earns 8.69 cents. This can yield millions of dollars. It is an instance of where cities (rightfully so) are not disadvantaged.

ii. CMMPA Example: If it does not make investments, it pays transmission rates that include the 12.38 percent MISO investor-owned utilities' equity rate of return, federal income tax allowances, and all of the high costs that are included in an IOUs' corporate salary structure and rates. By investing, it is able to offset these costs by obtaining owners' profits. FERC has recognized this offset. (Incentive Rates Order at P 31. "[A]llowing Central Minnesota to receive a revenue requirement for the Brookings Project that reflects the higher capital costs of the investor-owned utilities' will offset the Midwest ISO transmission rates that its members pay, which largely reflect those investor-owned utilities' higher capital costs, thereby allowing Central Minnesota and its members to effectively reduce their future transmission rates to reflect their lower capital costs to mitigate their investment risks associated with the project.")

d. Participation gives knowledge.

i. Obtain valuable knowledge and expertise.

ii. Greater knowledge and involvement in transmission planning at a time when one can act to protect against harm.

e. Ownership lets cities into the club.

f. It is the right thing to do.

i. Transmission investment is needed;

ii. Cities carry their weight

iii. Doing so may give indirect benefits.

g. Participation in transmission planning.

h. Serves the public interest.

VIII. For APPA members other than CMMPA/MMTG, there is now a reasonable assurance that they can invest in future transmission and anticipate full cost recovery, including reasonable returns, without facing the hurdles that CMMPA/MMTG had to overcome. Smaller systems can invest in transmission on the same basis as investor-owned utilities ("IOUs") with confidence of cost recovery. CMMPA/MMTG have thus set a path for municipals to obtain transmission investment cost recovery.

IX. The significance of what CMMPA and MMTG have achieved can be measured against the opposition that they faced. CMMPA, MMTG and other APPA members will not likely face similar hurdles on their investing in new projects. Fundamentally, they reinforced that municipals can invest in transmission on the same basis as IOUs**.**

i. Initially, many opposed MMTG members' ability to invest. They were not initially included in CapX or its predecessor, TRANSLink. It took great effort for them to successfully obtain investment rights. (See above.)

ii. Even after CMMPA/MMTG were allowed to invest, as a general principle, MidAmerican Energy and MISO opposed municipals receiving an equity rate of return when MMTG sought transmission rate credits for their transmission under Section 30.9 of the MISO tariff. *Midwest Indep. Transmission Sys. Operator, Inc.*,128 FERC ¶ 61,047, P 24 (2009) (municipals "entitled to earn equity returns at the same rate as other Transmission Owners…. network customers receiving credits for their integrated facilities under section 30.9 …should… be able to earn equity returns as do Transmission Owners.") If we had lost this case, we would have expected others to have taken similar positions elsewhere to deny or limit municipal equity returns on their CapX and other transmission investments.

iii. Otter Tail objected to CMMPA/MMTG's ability to use a hypothetical capital structure to give CMMPA the same percentage of equity as the IOUs. CMMPA debt finances. (See above.) Although the cities and the public in the cities have the same risks in investing in transmission as investor owned utilities, if cities that debt finance cannot be treated as if they have equity, they will earn no or minimal equity returns on their investments. If we finance with borrowed money and have zero equity, but MISO allows a 12.38% equity return, they earn zero times 12.38% = 0.

iv. MISO and/or others fought us on costs every step of the way.

v. MISO accepts the investor-owned utilities' financial statements and financial filings to FERC – the Form 1s – as correct on the basis that they are audited and follow the FERC Uniform System of Accounts.

1. As municipals, CMMPA and its members follow state accounting as is legally required. (Governmental Accounting Standards Board or "GASB".
2. Therefore, MISO would not assume the accuracy of their cost accounting, although CMMPA reconciled its costs to the Uniform System of Accounts.
3. This led to CMMPA and its member cities being asked many hundreds of questions and being subject to strict scrutiny, with examinations of items of less than $100 that could have no impact on MISO rates. Such scrutiny would appear to conflict the Federal Power Act because its jurisdiction over most municipals is limited to ensuring that

regional transmission organization and jurisdictional rates are just and reasonable. *See Federal Power Act* § 201f, 16 U.S.C. 824(f); *Pacific Gas & Electric Co. v. FERC*, 306 F.3d 1112, 1114 (D.C. Cir. 2002) ("FERC may analyze and consider the rates of non-jurisdictional utilities to the extent that those rates affect jurisdictional transactions.").

4. Claims were made that because CMMPA did not own existing transmission, although its members did, it was not responsible for the grid and, therefore, could not charge its transmission planning or overhead expenses in MISO rates. If CMMPA went to the same planning meeting for the same purpose as another MISO Transmission Owner, the other owner could include its costs in MISO rates, but CMMPA could not include its similar costs in such rates. This was regardless of allegations that to be recognized as a MISO Transmission Owner, CMMPA (and others) had to participate in planning. CMMPA/MMTG paid for other owners' costs through MISO transmission rates.

5. Claims were also made that CMMPA could not charge the same expenses in MISO rates that others were charging – and for which CMMPA/MMTG paid in MISO transmission rates – because CMMPA costs are paid by its member cities. Before CMMPA gets external financing, its members are the source of its funds (*i.e.,* investments) that it cannot recover through MISO transmission rates.

6. MISO Transmission Owners argued that CMMPA could not charge operations and maintenance/administrative and general costs before April 1, 2010, when its members' transmission (unrelated to Brookings) was integrated into MISO. CMMPA started incurring Brookings costs in 2006 and was allowed the January 1, 2007 date that it requested. Regulatory Asset Order at P 26 .

vi. CMMPA/MMTG have now resolved all these problems.

b. What is the basis for believing that CMMPA/MMTG's orders and settlement are likely to protect others? A number of FERC decisions nails down CMMPA/MMTG's entitlements, thereby stating FERC policy and establishing precedent, practically if not technically (because settlements were approved).

i. Incentive rates decisions granted CMMPA a hypothetical capital structure; construction work in progress, plant abandonment protections.

ii. Decisions on regulatory asset accounts.

iii. FERC people indicated informally that CMMPA/MMTG decisions are a model.

iv. Although FERC reviews just and reasonableness when CMMPA takes assets out of regulatory asset accounts to places them in rates when Brookings is put into service, FERC Orders accept the categories of costs that CMMPA can put into service.

v. Settlement Agreement – provides an annual review of costs making FERC approval for CMMPA/MMTG more likely; others can adopt similar categories and cost principles.

X. Even with transmission rate incentives, public power transmission investments are generally substantially rate reducing for consumers because, among other reasons, their debt costs are often lower than investor owned utilities; they do not pay or include federal income tax costs in rates and their costs are often lower than those of investor owned utilities. CMMPA/MMTG Answers to Protests and Motions of the Midwest Independent Transmission System Operator, Inc., the Midwest ISO Transmission Owners, Xcel Energy Services, Inc. and Consumers Energy Company and Motion for Leave to File 2, 13, 14, 31-32, 45 (and references cited therein), Mar. 23, 2011, *Midwest Indep. Transmission Sys. Operator, Inc.,* Docket No. ER11-2700, *et. al.,* eLibrary No. 20110323-5115.

XI. Problems and Questions Facing New Municipal Transmission Investments.

a. There is pressure on hypothetical capital structure equity amounts– Commissioner Norris dissent in Incentive Rates Order.

b. Others have asked for amounts giving less than parity with investor-owned utilities.

c. Solutions – justify that amounts chosen are necessary for municipal participation approval.

i. Necessary for financing – coverage.

ii. Equities – we have same risks.

iii. Show transmission is less costly for everyone with our participation.

d. Line abandonment – if not one's fault, incentive allows inclusion of costs in rates.

e. Subsequent review of rates.

f. Accounting and FERC Form 1 filing issues.

g. Do we want a regulatory asset account?

h. IOU arguments that we should have our own pricing zone.

XII. FERC Staff conference availability.

XIII. Municipal non-jurisdictional status filing issues. (Regional Transmission Organization or jurisdictional Transmission Provider can file.)

FERC TRANSMISSION RATE INCENTIVES

I. Legal Background

a. Legal Sources

i. Section 1241 of the Energy Policy Act of 2005 enacted new Federal Power Act ("FPA") Section 219.

ii. FPA Section 219: "the Commission shall establish, by rule, incentive-based . . . rate treatments . . . for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." *Id*. § 219(a), 16 U.S.C. § 824s(a).

iii. The statute seeks to promote "capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, *regardless of the ownership of the facilities*[,]" FPA § 219(b)(1), 16 U.S.C. § 824s(b)(1) (emphasis added), including providing "a return on equity that attracts new investment in transmission facilities[.]" FPA § 219(b)(2), 16 U.S.C. § 824s(b)(2).

iv. Order No. 679 (18 CFR § 35.35(d))[1]: Incentive-based rate treatment for transmission infrastructure investment. Order No. 679 specified that "to the extent allowed under our jurisdiction, a public power entity should have the same opportunity afforded to jurisdictional entities to recover costs related to new transmission investment," barring inconsistent treatment. Order No. 679, P 356.

v. FERC case law generally supports municipal investment opportunities. Incentive Rates Order at P 19, n. 23 (citing Order No. 679, P 354). Citing Order No. 679 the Commission has recognized that "encouraging public power participation in such projects is consistent with the goals of section 219 of the FPA by encouraging a deep pool of participants." Incentive Rates Order at P 19 n.23, P 32.

b. Qualifying for incentives in general

i. Applicants must demonstrate that the facility is needed to maintain reliability or reduce congestion.

ii. Applicants must show a nexus between the requested incentives and the investments that are being made. This test requires "applicants to

[1] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *clarified*, 119 FERC ¶ 61,062 (2007).

demonstrate that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project." Order No. 679-A, P6. In practice, this test considers, among other things, whether the projects at issue are routine and whether they present special risks and challenges. *Xcel Energy Servs. Inc.*, 121 FERC ¶ 61,284, PP 54-56 (2007); *Great River Energy*, 130 FERC ¶ 61,001, PP 30-31 (2010); *Otter Tail Power Co.*, 129 FERC ¶ 61,287, PP 28-29 (2009).

1. Projects having multiple owners are considered a risk factor favoring the grant of incentives.
2. Being subject to multiple jurisdictions' approvals is also considered a risk.

iii. Resulting rates after incentives must be just and reasonable.

iv. Requests, taken as a whole, must be justified. The total incentive package must not be more than is necessary to encourage transmission construction and to achieve non-discrimination and lack of preference.

v. Rebuttable Presumption: If an applicant satisfies certain conditions, "its project will be afforded a rebuttable presumption that it qualifies for transmission incentives[,]" meaning that it is needed to ensure reliability or reduce congestion. Order No. 679, P 57; Order No. 679-A, P 41.

1. Projects that result from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found acceptable to the Commission. Order No. 679-A, P 43.
2. Projects that have received construction approval from an appropriate state commission, agency or state siting authority, so long as that authority considered whether the project ensures reliability or reduces congestion. *See* Order No. 679-A, P 49.

c. Overview of Available Incentives. *See* Order No. 679, PP 84-178.

i. Overall rate of return

1. Rate of return on equity
2. Hypothetical capital structure

ii. 100 percent construction work in progress.

iii. Recovery of prudently incurred pre-commercial costs.

iv. Plant abandonment protection.

v. Deferred cost recovery;

vi. Accelerated depreciation for rate recovery.

vii. Other important rate treatments include use of a forward-looking test year.

d. Overall Rate of Return

i. Determined by return on equity (“ROE ”) and Capital Structure: The overall rate of return obtained by a utility is determined by its weighted average cost of capital, which is the weighted sum of the cost of debt and the return on equity.

ii. Weighted Average Cost of Capital = (ROE 12.38% x % of Equity on Balance Sheet) + (Actual Enterprise Cost of Debt x % of Long Term Debt on Balance Sheet).

iii. As can be seen from the formula for weighted average cost of capital, two different incentives affect the overall rate of return allowed by FERC for a transmission project. The first is simply the FERC allowed rate of return on equity. The currently allowed standard equity rate of return in MISO transmission rates is 12.38 percent, but additional incentive rates of return may be allowed. The second question is whether FERC will allow the utility to use a hypothetical capital structure for ratemaking purposes, or instead will require the utility to use its actual ratio of debt to equity as its capital structure for determining the overall rate of return. The first of these questions is determined largely by the nature of the transmission project. The second is very important for some municipal investments in Regional Transmission Organization (“RTO”) transmission projects.

iv. Return on Equity

1. What is it?

(a) ROE is the profit that a utility is allowed to earn on the portion of its transmission investment that is financed through equity, as opposed to debt.

(b) Under Order No. 679, FERC grants enhanced base ROE “sufficient to attract capital.” This means that FERC will engage in the usual Discounted Cash Flow analysis to determine the ROE “zone of reasonableness,” but for those projects that qualify for an incentive ROE, FERC “will provide ROEs at the upper end of the zone of reasonableness.” Order No. 679, P 93.

(c) In addition to this incentive base ROE for qualifying projects, FERC also provides discrete additional incentive ROE “adders” for specific types of projects and project participants.

(d) Transco ROE incentive. *See* Order No. 679, P 221.

(e) Transmission Organization ROE incentive: An adder available to utilities that join and/or continue to be a member of an Independent Transmission Operator (“ISO”), Regional Transmission Organization, or other Commission-approved Transmission Organization. *See* Order No. 679,P 326; Order No. 679-A, P 86.

2. Advantages of seeking an incentive rate of return on equity

(a) Creates a higher revenue stream from the RTO which can be used to reduce rates for customers.

(b) Helps increase the hedging value of transmission investments in RTOs by increasing the proportion of the Annual Transmission Revenue Requirement ("ATRR") for the project collected by the investor.

3. Disadvantages of asking for incentive rate of rate of return on equity

(a) If one requests incentives, other stakeholders may contest the request at FERC, which can lead to increased legal costs for investing in the project.

(b) A major argument in favor of municipal transmission participation is that it is rate reducing; requesting incentive ROEs may reduce the persuasiveness of arguments regarding the advantages of municipal participation.

(i) One possible exception is where Project Co-owners are seeking the same incentive ROE, in which case it can potentially be defended on the basis of parity and non-discrimination.

(c) Many public utilities are transmission dependent, and thus have an interest in keeping transmission rates reasonable.

(d) There are compelling policy arguments that the current ROEs being granted to transmission owning utilities are higher than necessary to obtain transmission development, given the current economic climate and cost of equity capital.

(e) FERC requires that the total package of incentives must be reasonable in light of the "demonstrable risks or challenges faced by the applicant in undertaking the project." Order No. 679-A, P 6. "If some of the incentives in the package reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE." Thus requesting ROE adders may reduce one's ability to demonstrate need for other incentives as well. Order No. 679-A, P 6.

(f) ROE incentives above the already allowed 12.38 percent may be inequitable or against consumers' interests.

4. What did CMMPA/MMTG do?

(a) CMMPA/MMTG and other Brookings co-owners requested the regular MISO equity return of 12.38 percent for their transmission investments and did not ask for additional ROE adders, although such adders were potentially available.

v. Hypothetical capital structure

1. What is it and how does it work?

(a) Generally, in the equation above describing overall rate of return, FERC uses a utility's actual capital structure, *i.e.*, its actual proportion of debt and equity to calculate an overall rate of return.

(b) However, FERC recognizes that "[e]ach project or company may have unique financial and cash flow requirements, and a rigid approach to acceptable capital structures could threaten the viability of some projects." Order No. 679, P 123.

(c) Thus, if granted the hypothetical capital structure incentive, FERC allows applicants to file a weighted average cost of capital based on a proposed hypothetical capital structure.

2. Advantages of requesting a hypothetical capital structure

(a) Municipal entities generally finance capital investments such as large transmission projects either primarily or exclusively by issuing bonds and other debt. As a result, many such utilities' balance sheets reflect a high percentage of debt and a smaller percentage of equity. Thus, unless they use a hypothetical capital structure, many APPA members' actual capital structure will reflect either 100 percent or very high debt ratios, and 0 percent or very low equity ratios. This is particularly true for joint action agencies, such as CMMPA, that may have a zero or close to a 0 percent equity.

(b) The result is that even incentive ROEs will have little effect on the return that such (but not all) public power utilities will earn on a new transmission through a FERC formula rate unless they can apply a hypothetical capital structure.

(c) If a utility has a 0 percent equity ratio, its overall rate of return will simply be equal to its cost of debt.

(i) For example, 12.38% ROE * 0 = 0.

(d) The higher the percentage of an Applicant's Annual Transmission Revenue Requirement is to all pricing zone participants' ATRR, the more that Applicant may be able to accept a reduced hypothetical equity capital structure and therefore a lower equity rate of return. (An entity that contributes 100 percent of zonal revenues receives 100 percent of the benefit of reduced rates; an entity that contributes one percent pays 99 percent of its transmission rates to cover others' costs and receives a one percent advantage from reduced rates.)

(e) Because transmission projects in RTOs are generally funded primarily by investor owned utilities with substantial equity capital, transmission customers, including APPA members, pay rates that include substantial equity returns.

(f) Public power entities usually represent only a small fraction of the overall financing of a large RTO transmission project, such as CapX projects in most pricing zones (although Great River Energy is dominant in its zone). As a result, if public power entities use their actual capital structure for ratemaking, their investment will not effectively hedge their transmission costs. Their ATRR will simply cover their cost of debt for financing the project, leaving little left over to hedge rates set predominantly by the investor owned utilities' overall rate of return and other IOU costs.

(g) Such public power entities likely cannot finance without the protection of equity returns and adequate coverage.

(h) If a utility's goal is to effectively hedge increasing transmission rates, if that utility has a high debt-equity ratio, it likely *must* use a hypothetical capital structure. Even with a hypothetical capital structure of 50 percent equity, a public power utility will likely have a lower ATRR for the same transmission investment as an IOU because of its lower debt, taxes, and other costs. As a result, fully hedging transmission costs by equalizing revenue and expenditures will likely require more than a load ratio share transmission investment (although above load-ratio ratios could require taxable financing).

(i) For these reasons, being granted a hypothetical capital structure can be crucial to municipals justifying and receiving local approvals and financing for municipal transmission investments.

3. Possible reasons for requesting a more conservative hypothetical capital structure (*i.e.,* lower hypothetical equity ratio) than regional transmission organization investor owned utilities' average or than dominant neighboring investor-owned utilities or transmission project co-owners:

(a) If allowed in inappropriate circumstances, hypothetical capital structures can lead to higher transmission rates.

(b) For this reason, APPA originally opposed hypothetical capital structures in general in the Order No. 679 incentive rates rule-making proceeding, arguing that they "could result in a windfall to public utilities by increasing actual return far in excess of the Commission's allowed return on equity." Order No. 679, P 127.

(c) Commissioner Norris' dissent in the Incentive Rates Order, if adopted by the Commission, would establish a very high bar for justifying a hypothetical capital structure.

(i) Commissioner Norris approaches the hypothetical capital structure incentive from a basic cost of service theory.

(ii) "[CMMPA] asks us to ignore these different characteristics, which make it less costly for [CMMPA] to finance its investment, and to instead consider [CMMPA] as if it were similarly situated to the investor-owned utilities co-sponsoring the Brookings Project." Incentive Rates Order at 61,524.

(iii) "Simply put, cost recovery should be based on the costs that each transmission owner actually incurs, not the costs that its neighboring transmission owners incur." *Id.*

(iv) Norris's dissent suggests he is open to hypothetical capital structures, but would implement a higher evidentiary threshold: "Central Minnesota's proposal also stands in stark contrast to the hypothetical capital structure incentive that the Commission granted co-owner Great River for the same Brookings Project.[2] While both entities have similar levels of actual equity, Great River provided evidence to demonstrate that it needed a 20 percent hypothetical equity level for 10 years in order to protect its financial integrity and maintain its credit rating." *Id.* (emphasis omitted).

(d) The more aggressive the hypothetical capital structure requested, the less APPA members can argue that their transmission investments are cost-reducing generally to consumers.

(e) Specifically, many of the justifications for an aggressive hypothetical capital structure, *e.g.*, one approximating the actual capital structure of an IOU, are less compelling when the public power entity has a dominant load ratio share in its zone, or when the project will be used predominantly by the public power entity's own ratepayers.

4. Reasons to request a more aggressive hypothetical capital structure:

(a) Norris's dissent is not controlling law. A majority of FERC Commissioners approved CMMPA's request for a 50 percent equity hypothetical capital structure by a 4-1 vote; Commissioner Norris approved general application of the 12.38 percent equity rate of return. *Accord, Citizens Energy*

[2] *Great River Energy*,130 FERC ¶ 61,001 (2010).

Corp., 129 FERC ¶ 61,242 (2009) (approving 50 percent debt, 50 percent equity hypothetical capital structure).

(b) As discussed above, it is very difficult for APPA members that have less than average equity (*e.g.,* through retained earnings) to effectively hedge increasing transmission costs without approval of a hypothetical capital structure. Even with a 50 percent equity capital structure, many APPA members will not fully hedge transmission costs if their investments only reflect load ratio share.

(c) Municipal systems pay transmission rates that predominantly include IOU returns based on above 50 percent equity amounts.

(d) Hypothetical capital structures are a means of allowing cities equity returns and/or coverage, which allow them to raise capital to support projects.

(e) Ultimate owners of municipal systems that invest – cities and the public – have similar risks as IOU shareholders; moreover, to the extent that IOU equity returns include a component for the risks and benefits of ownership, cities and the public have similar risks and entitlements.

(f) The public, which owns municipal utilities, if anything, probably has higher costs of money than investor owned utility shareholders.

(g) A more aggressive (higher) capital structure may be necessary to encourage municipal participation and to support municipal financing.

(h) Lower amounts than neighboring IOUs would be discriminatory. Municipals should not be discriminated against merely because they have a different mode of financing.

5. Arguments public power entities may use to justify a hypothetical capital structure covering the entire period of financing:

(a) The utility must demonstrate in its application that the hypothetical capital structure incentive is needed to promote investment consistent with the goals of FPA Section 219. Order No. 679, P 123. Like other incentives, this incentive requires satisfying the "nexus test" by showing that the requested hypothetical capital structure is "tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project." Order No. 679-A, P 21.

(b) There are a number of reasons why this is applicable for public power entities. Public power entities that are considering transmission investments should consider these justifications when requesting a hypothetical capital structure.

(c) In light of the concerns raised in Norris's dissent, it is important for APPA members and public power applicants generally to stress the advantages to consumers from municipal investments in transmission. In particular, that municipal investments, even with an aggressive hypothetical structure, are cost reducing.

(i) *See* Jim Pardikes & Ron Kennedy, *Going on the Offensive to Counter Dramatic Increases in Transmission Rates*, MCR Performance Solutions, Jun. 2012, *available at* http://www.mcr-group.com/index.jsp?whitepaper=383&pnav=5&pnav=5&tag=83. Mr. Pardikes and Mr. Kennedy advised CMMPA/MMTG and participated in the Brookings cases and negotiations.

(d) It is also important to stress the reasons why a hypothetical capital structure may be *necessary* for municipal participation in transmission investments.

(i) Cities must generally back stop debt financing with guarantees of payment. *See* Incentive Rates Order at P 32 ("The Commission expects that granting the requested hypothetical capital structure here will assist Petitioners in attracting financing and will encourage Petitioners and their members to invest further in the Brookings Project or future transmission expansion projects."). Cities cannot raise money without coverage – essentially comparable rates of return to investor-owned utilities.

(ii) A hypothetical capital structure may be necessary to generate enough cash flow to satisfy lenders. *See* Incentive Rates Order at P 31 ("This would decrease cash flow and hamper Central Minnesota's ability to make payments on its debt.").

(iii) A hypothetical capital structure may be necessary to secure a lower interest rate on debt financing, which is cost reducing. *See* Incentive Rates Order at P 31 ("[A]pproving the hypothetical capital structure for the entire period of debt financing will benefit [CMMPA]'s credit rating and allow it to receive more advantageous financing terms, which will lower its borrowing costs and decrease the total cost of its investment in the Brookings Project.").

(iv) For joint action agencies and generation and transmission cooperatives, as well as individual municipalities, a hypothetical capital structure may be necessary to get members or municipalities to join projects; entities generally will not invest if they cannot receive returns substantially above their cost of debt.

1. Hypothetical capital structures "can be especially important for projects with a diverse set of sponsors, some of which have different capital structures…" Order No. 679, P 131.

(e) Arguments based on equity

(i) Cities should get same returns as investor-owned utilities and others whose ATRR for the project will be included in rates, otherwise cities' ratepayers will effectively end up subsidizing other utilities. *See* Incentive Rates Order at P 32 ('[A hypothetical capital structure] will allow Petitioners to receive returns comparable to those of investor-owned utilities that are investing in the Brookings Project.").

(ii) Without a hypothetical capital structure, public power entities will pay investor-owned utilities transmission rates without being able to offset those increased rates using their own investment – they will be forced to be renters rather than owners, and will not be able to effectively hedge their transmission costs. *See* Incentive Rates Order at P 31 ("[A]llowing [CMMPA] to receive a revenue requirement for the Brookings Project that reflects the higher capital costs of the investor-owned utilities' will offset the Midwest ISO transmission rates that its members pay, which largely reflect those investor-owned utilities' higher capital costs, thereby allowing Central Minnesota and its members to effectively reduce their future transmission rates to reflect their lower capital costs to mitigate their investment risks associated with the project.").

(iii) A denial of a hypothetical capital structure may result in undue discrimination – it penalizes public power entities for their business model (relying on debt rather than equity). Public power entities face the exact same risks as IOUs when they invest in the same projects, thus in order to encourage and sometimes even allow their participation, they should be paid comparable overall rates of return.

6. Other legal considerations

   (a) The utility must provide its transmission investment plan and explain the specific projects to which the proposed hypothetical capital structure will apply. Order No. 679, P 123.

   (b) Duration of Hypothetical Capital Structure

      (i) In some cases, the Commission has required that an actual capital structure be adopted after construction is complete. Generally, in such cases Applicants were private corporations that could replace debt with equity upon the transmission in service date, and under these circumstances longer periods were not justified. *See, e.g.*, *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, P 119 (2009) ("[W]e find that Pioneer did not provide a sufficient nexus for the use of a hypothetical capital structure once the project is completed."). Pioneer's pleadings did not explain why a hypothetical capital structure was required after the project was completed, stating only that "[a]s the Project progresses, Pioneer will require significant borrowings as well as additional capital contributions from its Members."[3] Similarly, in *Tallgrass*, the Commission required that the applicant adopt an actual capital structure on completion of the project *as the applicant stated it would do* in its pleading. *Tallgrass Transmission*, 125 FERC ¶ 61,248 (2008). Commission also denied the Nevada Hydro Company's request for a three-year period regardless of construction time on the ground that it had made "no attempt to show why a three-year moratorium is necessary." *Nevada Hydro Co.*, *Inc.*,122 FERC ¶ 61,272, P 52 (2008).

      (ii) However, many of these arguments do not apply to APPA members, who generally cannot replace debt with equity in this way, and who rely on debt financing throughout the life of the project.

      (iii) The arguments described above support the application of hypothetical capital structure at least through the period during which the project is being

[3] Pioneer Transmission, LLC's Request for Acceptance of a Formula Rate and Rate Incentives 47, Oct. 15, 2008, Docket No. ER09-75-000, eLibrary No. 20081015-4004.

financed or the life of the project, not simply during the construction period.

(iv) Furthermore, in other transmission investments by municipal entities using 100 percent debt financing, the Commission has approved a hypothetical capital structure for the financing period for the project. *See, e.g.*, *Citizens Energy Corp.*, 129 FERC ¶ 61,242 (2009) (approving 50 percent debt, 50 percent equity hypothetical capital structure to be applied for 30 year financing period).

7. What did CMMPA do?

   (a) CMMPA originally requested a hypothetical capital structure of 55 percent equity, 45 percent debt, but then modified its proposal to 50 percent equity, 50 percent debt in a settlement, which was accepted by FERC.

   (b) Time period – CMMPA allowed 30 years based on the life of its anticipated bond issuances. Incentive Rates Order at PP 28, 31, 33.

8. Recent Precedent on Hypothetical Capital Structures: Approvals for predominantly debt-financed/municipal/ G&T Cooperative investments.

   (a) *See City of Vernon, California*, 109 FERC ¶ 63,057, P 110-119 (2004), *aff'd*, 111 FERC ¶ 61,092 (2005) (45.8 percent equity).

   (b) *Citizens Energy Corp.*, 129 FERC ¶ 61,242 (2009) (approving 50 percent equity, 50 percent debt hypothetical capital structure to be applied for 30 year financing period).

   (c) *Mo. River Energy Servs.,* 138 FERC ¶ 61,045 (2012) (approving 45 percent equity, 55 percent debt, to be applied for 33 year financing period).

   (d) *Great River Energy*, 130 FERC ¶ 61,001 (2010) (20 percent equity, 80 percent debt, to be applied until 2020, but note that it is dominant in its zone).

   (e) On May 10, 2012, WPPI Energy filed a petition for a declaratory order requesting a hypothetical capital structure with 45 percent equity.

e. 100 percent CWIP and Pre-Commercial Expenses

i. What is it and how it works

1. Generally expenses can be capitalized and included in rate base only when the plant goes into commercial operation, *i.e.,* when the plant becomes "used and useful." Order No. 679 n.70.

2. This incentive allows an applicant to include 100% of costs incurred for construction work in progress in rate base immediately.
3. CWIP provides for an early return on capital invested in new plant.
4. As an alternative, FERC also allows the applicant to expense "rather than capitalize pre-commercial operations costs associated with new transmission investment in order to relieve the pressures on utility cash flows associated with transmission investment programs." Order No. 679 P 103.
5. These pre-commercial expenses "include all expenditures for, preliminary surveys, plans and investigations, made for the purpose of determining the feasibility of utility projects and costs of studies and analyses mandated by regulatory bodies related to plant in service." Order No. 679 n. 82.

ii. Advantage of asking for 100% CWIP

1. Provides cash flow during construction.
2. Usually need positive Transmission Plant Allocator (*i.e.,* existing Transmission Plant in service in regional transmission organization footprint) to recover costs. CWIP returns are exempt from this requirement.

iii. Special requirements for filing for 100% CWIP

1. "[A]ppropriate for large new investments or in situations … where denying such an incentive would adversely affect the utility's ratings." Order No. 679 P 117.
2. Generally not a controversial incentive.
3. Need to demonstrate that either due to construction time or some other reason, there will be a substantial delay before project can go into service.
4. Should show CWIP is a timing difference, but over its life cycle, consumers would benefit.
5. Filing needs to avoid double counting with current rate collections, including allowance for funds during construction. *See, e.g.,* Order No. 679-A P 114.

f. Recovery of Costs of Abandoned Facilities

i. What is it and how does it work:

1. Many transmission projects involve risks outside the control of the developer, for example:

(a) Generation developers' decision to terminate development of potential resource;

(b) Difficulty obtaining state or local siting approvals.

2. If granted this incentive, the applicant is allowed to recover 100 percent of prudently incurred costs associated with abandoned transmission projects in transmission rates if such abandonment is outside the control of management. *See* Order No. 679 at 163.

ii. Advantages to requesting Plant Abandonment Recovery

1. Protects the investor against the sometimes substantial risk that the transmission project could be abandoned, leading to the non-recovery of costs.
2. Disadvantages to requesting Plant Abandonment Recovery

(a) Because FERC evaluates the nexus requirement for the full package of incentives, the lower risk from abandoned plant protection "may warrant a lower ROE than would otherwise be the case without this assurance." Order No. 679 at P 167.

iii. Very important, but not controversial, for incentive rates eligible projects.

g. Deferred cost recovery

i. What is it and how does it work:

1. Enables utility to defer costs that would otherwise be unrecoverable in rate base and amortize expenses once the asset goes into service.
2. Traditionally offered to investor-owned utilities subject to a retail rate freeze.
3. Can be accounted for as a regulatory asset under FERC's Uniform System of Accounts.
4. FERC treats this as a rate incentive, although regulatory asset accounts have been allowed before Order No. 679 and in non-transmission contexts.

h. Accelerated depreciation used for rate recovery.

i. What is it and how does it work:

1. Normally, FERC allows transmission plant to be depreciated over a 30 year period.
2. This incentive allows a utility to expense and recover transmission investment over an accelerated timeframe, as short as 15 years or less, depending on the circumstances.

ii. Advantages of asking for Accelerated Depreciation

1. Improves cash flow.
2. Better positions utilities for longer-term transmission investments.

iii. Disadvantages of asking for Accelerated Depreciation

1. Less overall return on investment because amortize rate base faster.

i. Other important rate treatments include potential use of a forward-looking test year.

II. Other issues

a. Ability of municipals to invest.

i. FERC refuses to order, although possible in individual cases.

ii. FERC must consider antitrust principles. *Gulf States Utils. Co. v. FPC*, 411 U.S. 747 (1973). Note *American Needle, Inc. v. National Football League*, No. 08-661 (U.S. May 24, 2010), providing that joint action among NFL and teams could give rise to liability, which has regional transmission organization analogy. FERC failed to adopt argument in *City of Pella, Iowa* v. *Midwest Independent Transmission System Operator, Inc. and MidAmerican Energy Company*, 134 FERC ¶ 61,081 (2011) at P 108. ("Commission does not have jurisdiction to determine violations of the antitrust laws and is not strictly bound to the dictates of these laws. Thus, Pella's claims… more appropriately addressed in other forums.")

iii. Other Potential Remedies: Antitrust – Joint action. Where joint investments or combined action through ISOs may have a Section One antitrust claim. American Needle Inc. v. NFL, No. 08-661 U.S. 1 (May 24, 2010); *Associated Press v. United States*, 326 U.S. 1 (1945); *United States v. Terminal R.R. Ass'n*, 224 U.S. 383 (1912); *Gamco, Inc. v. Providence Fruit & Produce Bldg*., 194 F.2d 484 (1st Cir. 1952). *See Verizon Communications Inc. v. Law Offices of Curtis V. Trinko*, 540 U.S. 398, 410 n.3 (2004) ("*Trinko*") ("[*C*]*oncerted* action…presents greater anticompetitive concerns and…simply requir[es] that the outsider be granted nondiscriminatory admission to the club." Emphasis in original).

iv. Section Two - (monopolization). *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973) – but see, *e.g., Trinko, supra.,* at 410 n.3.

v. Refusal to deal cases have been weakened. *See, e.g., Trinko, supra.,* at 407-11; *Bell Atlantic Corp. v. Twombly*, 550 U.S. 544 (2007) (legitimate business purpose in refusing to deal to avoid competition); *Pac. Bell Tel. Co. v. Linkline Commc'n, Inc.*, 555 U.S. 438 (2009) (limiting applicability of *United States v. Aluminum Co. of America*, 148 F.2d 416 (2d Cir. 1945)).

1. May have to show a transmission market or, at minimum, that ownership rights are essential and controlling Transmission Owner dominance in generation and sales markets. *See Spectrum Sports, Inc. v. McQuillan,* 506 U.S. 447 (1993).
2. Courts will defer to FERC. *See Trinko; Credit Suisse Sec. (USA) LLC v. Billing*, 551 U.S. 264, 283 (2007).
3. State antitrust laws may afford state for relief.
4. Joint filings in court and at FERC are possible.

5. Federal Trade Commission ("FTC") may afford relief under Section 5 of the FTC Act, making unfair trade practices unlawful. FTC Act § 5, 15 U.S.C. § 45.

vi. Advantages to our participation.

1. May help obtain public support (or reduce opposition) for projects as well as eliminating or reducing our own grounds for opposition.
2. Spread costs/risks – we reduce costs.
   (a) But investor-owned utilities may want profits from investing.
3. Regulatory support for joint participation. [See above].

vii. MMTG got CapX participation rights through FERC filings; MidAmerican Energy agreed to our ownership as a result of a market rates settlement and after Commission filings and conferences.

b. Ability of municipals to obtain recovery of comparable costs to incumbent Transmission Owners.

i. Regulatory asset account requirements and treatment as incentive. *See* Section 205 Order at P 21. *Accord*, *e.g., Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, P 84 (2009) (Pioneer was authorized "to accrue a carrying charge on the regulatory asset from the date of this order until the regulatory asset is included in rate base. Once the regulatory asset is included in rate base, Pioneer will be able to earn a return on the unamortized balance . . . ."); *Green Power Express LP*, 127 FERC ¶ 61,031, P 59 (2009) ("authorization to create the initial regulatory asset" to "allow Green Power to defer recovery of pre-construction costs, as well as start-up and development costs, and, to the extent Green Power has customers to assess those costs, recover them later.").

1. CMMPA needed to collect its Brookings pre-construction costs and transmission expenses.
2. Because it owned no existing transmission (although its members did), CMMPA had no MISO transmission rates on file under which it could collect them.
3. For the most part, FERC said that these costs could not be collected currently; therefore, they had to be cumulated in a regulatory asset account to be collected when Brookings comes on line.
4. Three categories of applicable costs – pre-Brookings operational expenses (that is, Operations and Maintenance/Administrative and General directly related to Brookings); general transmission expenses (*e.g.,* planning, examination of potential projects, related administrative), and construction work in progress. One way to collect non-capitalized expenses would have been to collect them currently through MISO rates. However, FERC disallowed this for entity that did not currently own transmission so costs had to be recovered, if at

all, through a regulatory asset account. Section 205 Order at P 24, 29. Others argued that because CMMPA had no transmission asset to operate, it could not properly record labor or any other expense to the transmission accounts until we had existing physical assets. *Id.* Inability to charge implicates not only O&M labor expenses, but also A&G expenses, which are allocated applying a wage salary allocator. (CMMPA/MMTG members did have such assets.)

5. Use of a regulatory asset account costs consumers more than allowing O&M/A&G expenses to be collected currently (because in that way a return on deferred cumulated amounts would not be charged) and would have given the Transmission Owner applicant current cash flow – but FERC ordered cost recovery only through a regulatory asset account regardless.

6. CMMPA can collect such costs through a regulatory asset account. Section 205 Order at P 29, n.49, citing *Green Power Express, LP,* 127 FERC ¶ 61,031, PP 107-109 (2009); Regulatory Asset Order at P 21; Clarification Order at P 8 ("use of a regulatory asset is an option available to CMMPA in order to recover certain O&M and A&G costs that are otherwise unrecoverable with a transmission plant allocator of zero . . . .").

7. Technical issue – entities can include O&M/A&G costs in current MISO rates based upon their Transmission Plant Allocator.

    (a) Transmission Plant Allocator's purpose is to allocate transmission costs to MISO only for transmission that is within MISO's footprint.

    (b) If an entity does not already own transmission within MISO, it therefore has a zero Transmission Plant Allocator.

    (c) Some advanced the argument that non-existing owners were not responsible for the grid and, therefore, were not entitled to O&M/A&G costs, such as planning expenses – these were just like costs that other MISO Transmission Owners included in their costs and MISO rates.

    (d) FERC: disallows adjusting Transmission Plant Allocator to allow new transmission owners to collect O&M/A&G currently. Section 205 Order at P 23, 38.

    (e) Thus, the solution is to have a regulatory asset account; costs collected with a return, when the asset goes on line. *Id.*

8. Delays in current costs recovery reduce cash flow, but if the costs can be financed, new transmission owners can earn a return on the cumulated, deferred amounts.

9. Municipals or other systems should determine if they prefer having a regulatory asset account to current recovery; if they do, they should

request a regulatory asset account as an incentive or otherwise. If a system wants to request regulatory asset, it should do so as soon as possible to enable it to accumulate carrying costs –retroactive approval of carrying costs may not be approved. Regulatory Asset Order at P 37.

10. If a system can own qualifying transmission assets in any amount, it will have a positive Transmission Plant Allocator and would be entitled to immediate cost recovery.
11. It matters who owns transmission (a separate entity, power supply agency, member), as this affects whether one will be deemed to have current transmission assets.
12. Under regulatory asset, FERC will review costs when costs are taken out of the regulatory asset account and amortized in rates. Regulatory Asset Order at PP 4, 25, 27. (*Id.*, P 25. "While we provide CMMPA with the ability to create the regulatory asset account to record Brookings Project pre-commercial operations and transmission-related expenses as a regulatory asset, CMMPA must make a section 205 filing to demonstrate that the expenses included in the regulatory asset account were prudently incurred and are just and reasonable."); Clarification Order at 9.

ii. Pre-filing meetings, conferences, opinions, etc. are available.

iii. Cost Acceptance.

1. MISO accepts investor-owned utilities costs based on their certified Form 1's as valid.
2. CMMPA followed state mandated GASB accounting with a cross walk reconciliation with Uniform System of Accounts.
3. Alternative – file the EIA Form 412 (and Attachment O, which utilizes the EIA Form 412) with MISO reconciling information contained in the EIA Form 412 to the municipal's audited financial statements as best as possible.
4. Resolution of cost assurance issues – CMMPA agreed to provide to MISO audited Form 1's.

iv. Others challenged costs discriminatorily and beyond reason

1. Others claimed that no amount of costs were too small for close review – MISO – no *de minimis*.
   (a) Much of CMMPA's closely scrutinized costs could have no possible effect on MISO rates.
   (b) *E.g.,* MISO challenged sales revenues and associated revenues of $8,458; transmission audit fees of $4,000; challenged CWIP reclassifications of $7,034 to expenses accounts; $5,158 of Brookings-related CapX meetings costs; and even challenged a

$250 CapX2020 Vision Team travel expense account classification.

(c) There is a Commission *de minimis* standard. Order No. 890 establishes a "rule of reason": [4] ("The Commission adopts the NOPR proposal to continue to require only those rules, standards, and practices that significantly affect transmission service be incorporated into a transmission provider's OATT. The Commission further affirms the use of a 'rule of reason' to determine what rules, standards, and practices significantly affect transmission service and, as a result, must be included in the transmission provider's OATT." Order No. 890, P 1649.) In *Midwest ISO*, 116 FERC ¶ 61,142 (2006), the Commission held that the Midwest ISO and MISO Transmission Owners did not need to file a "Funds Trust Agreement," as it would not have a significant effect on rates – "[t]he initial $49,000 fee and subsequent $44,000 fee [were] *de minimis* in relation to total costs being recovered under the formula rates established by Attachment O." *Id.* P 33. In other contexts, the Commission held that requiring Startrans to submit an amended filing to address a miscalculation of approximately $1,250 in its calculations "would be administratively burdensome and costly," ruling that the difference was "*de minimis* and favors ratepayers." *Startrans IO*, *L.L.C.*, 126 FERC ¶ 61,116, P 9 (2009). In *Otter Tail Power Co.*, 119 FERC ¶ 61,217 (2007), the Commission upheld excluding a factor from refunds under a *de minimis* standard even though doing so was against the ratepayers' interests. The Commission found that "[t]he effect of such exclusion, as calculated by Otter Tail Power, is only one one-thousandth of one percent of the Midwest ISO through and out rate." *Id.* P 17. It concluded that "the burden of calculating the adjustments for such a small amount of money does not justify" recalculation. *Id.* P 19. Several other cases allowed *de minimis* errors in calculations and similar small amounts that, had they been larger, might have warranted correction. These premises were not applied by MISO or FERC to a review of CMMPA costs.

2. Multiple rounds of exhaustive discovery requests.

[4] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

3. Others claimed that in filing an ATRR (MISO Attachment O), CMMPA could duplicate city costs even though CMMPA and not cities were investing in and seeking cost recovery for Brookings.
4. A potential claim was that city payments to finance CMMPA investments were payments and inclusions in rates of our transmission costs would “double-count” money that the cities had paid.
5. It was claimed that CMMPA is not entitled to its planning costs (even though such participation was required) because CMMPA was not responsible for the grid. See above. CMMPA/MMTG took the position that like other MISO Transmission Owners, CMMPA acts to plan for and supports the grid. CMMPA and CMMPA/MMTG members are charged O&M/A&G costs of other transmission owners through the Midwest ISO network rate. CMMPA may not reasonably be denied similar cost recovery for its similar O&M/A&G costs. FERC held: “[T]he cost of labor, materials and expenses incurred for developing transmission expansion plans under the USofA [Uniform System of Accounts] are properly includable in Account 561.5, Reliability, Planning and Standards Development.” Section 205 Order at P 24.

v. CMMPA/MMTG said that CMMPA’s costs that closely relate to Brookings Project development, as opposed to its more general transmission planning expenses, were more appropriately included in CWIP than in expense accounts. Section 205 Order at P 22.

1. FERC denied some costs as CWIP, but allowed them as expenses. (See below). Section 205 Order at PP 23-28.

vi. Operations & Maintenance

1. “[T]he cost of labor, materials and expenses incurred for developing transmission expansion plans under the USofA are properly includable in Account 561.5, Reliability, Planning and Standards Development …[T]he cost of assessing, developing and documenting transmission expansion plans is to be recorded in Account 561.5. Therefore, these types of costs are properly recordable in Account 561.5.” Section 205 Order at P 24. CMMPA’s ability to charge these costs were challenged because it was not a current Transmission Owner.
2. Others claimed that as a non-MISO Transmission Owner (not responsible for the grid or not owning transmission), CMMPA was not entitled to collect its general O&M or A&G and was only entitled to collect expenses that were directly related to Brookings.

vii. Administrative and general A&G costs are subject to a wage-salary allocator. *See* Section 205 Order at P 30. They are includable in the regulatory asset account. *See, e.g.*, *Green Power Express*, 127 FERC ¶ 61,031, P 55 (2009) (approving “administrative expenditures”); *Tallgrass Transmission*, *LLC*, 125 FERC ¶ 61,248, P 81 n.87 (2008) (approving "administrative expenditures" and "general expenditures related to the corporate structure, management of the business and overall planning."); *Primary Power, LLC,* 131 FERC ¶ 61,015, P 109 (2010) (approving “administrative expenditures” and “other expenses related to corporate structure”). CMMPA’s wage – salary allocator was challenged; percentages will change annually, but a start-up entity may show a relatively high allocator. Some power supply agencies have little or no distribution wages, and therefore will have relatively high wage/salary allocators. A small, relatively new agency having transmission planning and evaluation expenses may have an allocator numerator that is relatively high compared to its relatively low total wage amounts across all functions (generation, transmission, and distribution).

1. Wage and salary amounts come from its audited books under or reconciled to the Uniform System of Accounts.
2. CMMPA’s legal and consulting fees regarding its ability to issue debt including tax exempt bonds, and costs for our participation agreements were allowed as includable in Account 923, Outside Services Employed. “The instructions to Account 923 state that this account includes fees and expenses of professional consultants and others for general services, which are not applicable to a particular operating function or other accounts…[O]nce a company decides to issue a bond, the cost of drafting mortgages and trust deeds, fees and taxes for issuing or recording evidence of debt, and the cost of engraving and printing bonds and fees and other services is properly includable in Account 181, Unamortized Debt Expense, rather than Account 107.” Section 205 Order at P 26. Others had challenged CMMPA’s ability to charge costs for developing participation and member agreements and for getting advice on tax deductibility in support of our Brookings investments.
3. CMMPA’s legal and consulting costs for its incentive rate filings were considered operating expenses properly includable in Account 928. Regulatory Commission Expenses. Section 205 Order at 27.
4. Resolution: Orders and Settlement Agreement. Costs may be challenged at time of amortization of regulatory asset account. See above.

c. Claim: need to have a MISO Transmission Owner to include costs in MISO rates (but note Tariff Section 30.9 credits availability).

d. Some parties raise concerns about the zones to which municipal costs are allocated.

   i. Municipals often do not have their own pricing zones so their costs are included in pricing zones where other Transmission Owners’ costs are dominant.

      1. But dominant members of zones collect their costs from embedded cities through transmission rates.

2. Some investor-owned utilities want municipals to have their own pricing zones or bear their own costs as opposed to including them in others' pricing zones. (CMMPA/MMTG pay transmission rates that include others' costs that were challenged as to CMMPA's cost recovery.) Municipal ratepayers would bear all their investment costs and pay transmission rates including others' costs.
3. Brookings will be a Multi-Value Project, easing the zone allocation issue.

e. Confidentiality issues.

    i. Much of the CMMPA/MMTG issues were subject to FERC settlement processes.

    ii. MISO held confidential investor-owned utilities workpapers needed for comparison.

f. Starting date issue – CMMPA was allowed to include costs in the regulatory asset account incurred starting January 1, 2007, as CMMPA/MMTG had requested. Regulatory Asset Order at P 26 (Rejects MISO Transmission Owners' argument that CMMPA had to be a MISO Transmission Owner or be "integrated" in RTO before it could record costs for a period.) In Docket No. ER11-2700, leading up to the Section 205 Order, CMMPA/MMTG had requested a January 1, 2010 effective date to recover CMMPA's costs in MISO rates. This date correlated with other Brookings co-owners' recovery dates (*Xcel Energy Servs. Inc.*, 121 FERC ¶ 61,284 (2007); *Great River Energy*, 130 FERC ¶ 61,001 (2010); *Otter Tail Power Co.*, 129 FERC ¶ 61,287 (2009)) and CMMPA/MMTG's earlier requests. FERC denied CMMPA/MMTG's request and established a March 21, 2011 date, based upon CMMPA/MMTG's Section 205 filing date (made by MISO on their behalf). Section 205 Order at P 83. This date established the date when CMMPA could earn an equity return on its Brookings' assets, other than those in its regulatory asset account. The Commission held that CMMPA can establish a regulatory asset account and accrue carrying charges beginning January 16, 2012. Regulatory Asset Order at P 21. ("We also authorize the Applicants' request for CMMPA to accrue a carrying charge on the regulatory asset account beginning on January 16, 2012" (including amounts accrued beginning January 1, 2007 – see above), and "continuing until the regulatory asset is included in rate base.") *Accord, id.* P 22.

g. Claims of others on effective dates.

    i. Administrative burden to retroactivity.

    ii. Cannot collect in rates before making Section 205 filing.

    iii. Need to be a MISO Transmission Owner.

h. Regulatory asset amortization over five years. Regulatory Asset Order at P 22 (as CMMPA/MMTG requested) *Ne. Transmission Dev., LLC*, 135 FERC ¶ 61,244 (2011); *Cent. Transmission, LLC*, 135 FERC ¶ 61,145 (2011); *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009); *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009); *Tallgrass Transmission,* *LLC,* 125 FERC ¶ 61,248 (2008); *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 (2011); some cases provide for a ten year amortization. *Green Power Express LP*, 127 FERC ¶ 61,031, PP 107-109 (2009), cited in Section 205 Order at P 38 n.49.

i. Semi-annual compounding of regulatory asset account interest. Regulatory Asset Order at P 23.

j. Section 205 issues

   i. We are non-jurisdictional--Can non-jurisdictional entities file? CMMPA/MMTG took the position that they cannot because they are non-jurisdictional under Federal Power Act § 201(f), 16 U.S.C. § 824(f). *See Town of Edinburgh v. Ind. Mun. Power Agency*, 132 FERC ¶ 61,102, PP 22-23 (2010). Non-jurisdictional entities have filed. (*E.g., Great River Energy*, 130 FERC ¶ 61,001 (2010)).

      1. Technically, the MISO Section 205 filings for CMMPA/MMTG were MISO filings to change the MISO Tariff to include schedules for CMMPA rates.

      2. CMMPA/MMTG's petition for incentive rates implicated the filing and filing date.

      3. Implementation of CMMPA's rates; FERC refused request to make our rates subject to refund (although CMMPA/MMTG agreed to refunds). Section 205 Order at PP 71-72, citing Federal Power Act § 201(f); *City of Riverside,* 128 FERC ¶ 61,207, P 26, n.35 (2009) (citing *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 925 (9th Cir. 2005)). Our agreement to make refunds would be court enforceable. *See City of Redding v. FERC,* No. 09-72775 (9th Cir. filed June 22, 2012).

   ii. Commission can grant public power incentives requests. Incentive Rates Order at P 19 & n.23:

      19. We agree with Petitioners that we have authority to consider and grant their request for incentive rate treatment. In Order No. 679, the Commission stated that it would, "to the extent [its] jurisdiction allows, 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." 23/

      23/ Order No. 679, FERC [Stats. & Regs.] ¶ 31,222[,] P 354. We also noted that encouraging public power participation in such projects is consistent with the goals of section 219 of the FPA by encouraging a deep pool of participants.

k. Waivers--make sure to request, as necessary. Section 205 Order at P 86.

III. CMMPA/MMTG's efforts came out well.

a. Achieved incentives; equity rate of return; regulatory asset account – covering all requested category of costs for requested period; agreement on auditing CMMPA's costs.

b. CMMPA is a model.

c. CMMPA is well-positioned to get ultimate rate approval when we amortize costs.

   i. FERC has confirmed that the category of costs that it can include in its regulatory asset account, including its O&M/A&G that it could not collect currently under FERC's Section 205 Order. *See* Regulatory Asset Order at P 21 ("This will allow CMMPA to defer recovery of pre-commercial and transmission related expenses, as well as start-up and development costs, and, to the extent CMMPA has customers, to assess and recover those costs later"); Clarification Order at P 8 ("use of a regulatory asset is an option available to CMMPA in order to recover certain O&M and A&G costs that are otherwise unrecoverable with a transmission plant allocator of zero . . . .").

   ii. Annual review of CMMPA's costs will take place in the same manner as other owners. Settlement Agreement at § 3.16: "The Settling Parties acknowledge that MISO is obligated under its Tariff and pursuant to relevant FERC orders to review CMMPA's Attachment Os, Attachment MMs, FERC Form 1s, and related data in a comparable manner to how it reviews other MISO Transmission Owner's submissions and related data.") This allows CMMPA, when it seeks to amortize the regulatory asset account and include the amounts in MISO costs and rates, to request approval for MISO-reviewed costs based on audited statements and MISO Tariff Attachment Os.

IV. The following table illustrates examples of costs which have been approved for inclusion in regulatory asset accounts, and lists the Commission precedent for such approval. These costs can be incurred by either internal labor or external labor. Where the table lists a "Y," this shows that the applicant requested and the Commission approved the listed category of expenses in its regulatory asset account. Where the table lists a "N/A," this shows that the applicant did not request the category of relief. The cases referred to in the table and the expenses approved in those cases are discussed in detail in the Pardikes' testimony.[5] *See*

[5] Request for Approval of Revisions to Formula Rate and Tariff Changes to Provide for a Regulatory Asset Account Transmission Incentive on Behalf of the Central Minnesota Municipal Power Agency and the Midwest Municipal Transmission Group and Request for Waivers 9-10, 18-26, Nov. 16, 2011, Docket No. ER12-427-000, eLibrary No. 20111116-5129; Prepared Testimony of James Pardikes 27-47, Nov. 16, 2011, Docket No. ER12-427-000, eLibrary No. 20111116-5129.

	Tallgrass[6]	Green Power Express[7]	PATH[8]	Green Energy Express[9]	Primary Power[10]	Western Grid Development[11]	Atl. Grid Operation[12]
Entity formation costs	**Y**	**Y**	**Y***	**Y**	**Y**	**Y**	**Y***
Attorney and consultant fees	**Y**	**Y**	**N/A**	**Y**	**Y**	**Y**	**Y***
Taxes (other than income taxes)	**Y**	**Y**	**Y***	**Y**	**Y**	**Y**	**Y***
Travel costs	**Y**	**N/A**	**N/A**	**Y**	**Y**	**Y**	**Y***
General expenditures related to the corporate structure, management of the business, and overall planning	**Y**	**N/A**	**Y***	**Y**	**Y**	**Y**	**Y***
Administrative expenditures	**Y**	**Y**	**Y***	**Y**	**Y**	**Y**	**Y***
Efforts to establish formula rate and rate incentives	**N/A**	**Y**	**N/A**	**Y**	**Y**	**Y**	**N/A**
Approval and authorization from regulators and RTOs	**N/A**	**Y**	**N/A**	**Y**	**Y**	**Y**	**Y***
Costs related to outreach and education to stakeholders	**N/A**	**Y**	**N/A**	**Y**	**Y**	**Y**	**Y***
Engineering, routing, feasibility, environmental, and related studies and related professional services	**N/A**	**Y**	**Y***	**Y**	**Y**	**Y**	**N/A**
Designing of the line and other transmission facilities	**N/A**	**N/A**	**Y***	**N/A**	**N/A**	**N/A**	**N/A**

[6] *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, PP 81-82 & n.87 (2008).
[7] *Green Power Express LP*, 127 FERC ¶ 61,031, PP 53-56, 59-61 (2009).
[8] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, PP 49-52 (2008).
[9] *Green Energy Express LLC*, 129 FERC ¶ 61,165, PP 39-41 (2009).
[10] *Primary Power, LLC*, 131 FERC ¶ 61,015, PP 109, 115-17 (2010).
[11] *Western Grid Development, LLC*, 130 FERC ¶ 61,056, PP 99-100, 102-03 (2010).
[12] *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144, PP 15, 101-04 (2011).

Support of local and regional transmission planning activities	**N/A**	**Y**	**N/A**	**N/A**	**N/A**	**N/A**	**Y***
Third party internal labor and travel expenses including overhead loadings	**Y***	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Development service agreement payments from Investors to the project developer including hourly wages plus compensation payments based on the successful completion of each phase of the project	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**Y***
Items marked with an '*' were approved, but not discussed in the Commission's applicable order.							

Robert A. Jablon **202.879.4070** robert.jablon@spiegelmcd.com

Daniel H. Silverman **202.879.4045** daniel.silverman@spiegelmcd.com

www.spiegelmcd.com