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SUBMITTED VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***Xcel Energy Southwest Transmission Company, LLC***
Docket No. ER14-____-000

Dear Ms. Bose:

Pursuant to Federal Power Act ("FPA") Section 205 and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] Xcel Energy Southwest Transmission Company, LLC ("XEST")[2] submits this transmission formula rate filing for ultimate inclusion in the open access transmission tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). XEST is a transmission-only company established by Xcel Energy Inc. ("Xcel Energy") in May 2014. In this filing, XEST requests Commission approval of a formula transmission rate ("Formula Rate"). XEST's Formula Rate is composed of two parts: (i) a Formula Rate Template, which will calculate, on a project-by-project basis, an annual transmission revenue requirement ("ATRR") that will be recoverable through the SPP OATT; and (ii) Annual True-up, Information Exchange, and Challenge Procedures ("Protocols").

In addition, pursuant to FPA Section 219(c), XEST requests a 50 basis point adder to its Return on Equity ("ROE") for Regional Transmission Organization ("RTO") participation.[3] Other than this 50 basis point ROE adder, XEST is not seeking approval of any Order No. 679 incentives in this filing. Going forward, XEST reserves the right to seek additional Order No. 679 incentives through an appropriate filing with the Commission, and XEST will evaluate

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[1] 16 U.S.C. § 824d (2012); 18 C.F.R. pt. 35 (2014).

[2] Xcel Energy Services Inc. is the service company for the Xcel Energy Inc. holding company system and, *inter alia*, represents XEST in matters before the Commission.

[3] 16 U.S.C. § 824s (2012); *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86 (2007), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

whether to make such a filing on a case-by-case basis. However, consistent with other formula rates recently approved by the Commission, XEST's Formula Rate Template is designed with placeholders for Order No. 679 incentives. Thus, if in the future XEST requests and the Commission approves such incentives, the Formula Rate Template already will be capable of calculating them.

XEST requests an effective date of November 1, 2014, which is sixty-four (64) days after the date of this filing. This effective date is needed to promptly implement XEST's request for rate authorization for regulatory asset treatment of certain costs, which is discussed more fully below. In addition, prompt action will provide XEST with rate certainty in support of XEST's ability to participate fully in SPP's ongoing Order No. 1000[4] planning process and in SPP's first Order No. 1000 competitive solicitation process, which is expected to take place in 2015.

In accordance with the SPP OATT and SPP's other governing documents, XEST will ask SPP to file conforming changes to incorporate the XEST Formula Rate into the SPP OATT after the Formula Rate is accepted by the Commission.[5] Under the SPP OATT, costs will not flow through XEST's Formula Rate to SPP transmission service customers until XEST becomes a Transmission Owner as defined by the SPP OATT, which will occur either when (i) XEST's transmission facilities form part of the SPP transmission system, or (ii) XEST is issued a Notice to Construct by SPP.[6]

The elements of this filing are consistent with Commission policy and are fully supported by the testimony and associated exhibits included as part of this filing. In the event that the Commission finds that a hearing is necessary, XEST requests that the Commission suspend the Formula Rate only for a nominal period so that the XEST's request can go into effect on the requested effective date.

I. Contents of Filing

This filing consists of the following:

1. This transmittal letter.

2. The Formula Rate Template, included as Attachment A to this letter.

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[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *petitions for review denied sub nom. South Carolina Public Service Authority v. FERC*, No. 12-1232 (D.C. Cir. Aug. 15, 2014) (per curiam).

[5] For this reason, as discussed in Section VI below, XEST is requesting a partial waiver of the eTariff filing requirements, to the extent such a waiver is required.

[6] SPP OATT, § I(1)(T) (definition of "Transmission Owner").

3. The Protocols, included as Attachment B to this letter.

4. The Direct Testimony of Teresa M. Mogensen, Vice President – Transmission for Xcel Energy Services Inc. ("Xcel Energy Services"), Exhibit No. XES-100 ("Mogensen Direct Testimony"). Her testimony (i) provides an overview of XEST's Formula Rate filing; (ii) describes XEST and how it fits into the Xcel Energy corporate structure; and (iii) explains why Xcel Energy formed XEST.

5. The Direct Testimony of George E. Tyson, II, Vice President and Treasurer of Xcel Energy Services, Exhibit No. XES-200 ("Tyson Direct Testimony"). His testimony (i) explains the financial risks facing XEST as a newly formed entity focusing primarily on Order No. 1000 transmission projects; (ii) explains the sources of XEST's initial and ongoing funding, including XEST's targeted credit profile; and (iii) supports XEST's cost of debt, ROE, and capital structure included in the Formula Rate Template.

6. The Direct Testimony of Michael J. Rodriguez, Senior Director, Utility Accounting, for Xcel Energy Services, Exhibit No. XES-300 ("Rodriguez Direct Testimony"). His testimony describes the accounting treatment related to activities associated with XEST, including the basis for XEST's request for a Commission rate determination authorizing regulatory asset treatment of XEST's prudently incurred costs not capitalized, including pre-commercial and formation costs.

7. The Direct Testimony of Andrew H. Sawyer, Consultant, Capital Asset Accounting, for Xcel Energy Services, Exhibit No. XES-400 ("Sawyer Direct Testimony") and associated exhibits. His testimony discusses the proposed depreciation rates for XEST, which are reflected in the Formula Rate Template.

8. The Direct Testimony of Adrien M. McKenzie, Vice President, FINCAP, Inc., Exhibit No. XES-500 ("McKenzie Direct Testimony") and associated exhibits. His testimony provides an independent appraisal of XEST's cost of equity and recommends an ROE for XEST, which is included in the Formula Rate Template.

9. The Direct Testimony of Alan C. Heintz, Vice President, Brown, Williams, Moorhead & Quinn, Inc., Exhibit No. XES-600 ("Heintz Direct Testimony") and associated exhibits. His testimony supports the reasonableness of the proposed Formula Rate Template and the Protocols.

10. The attestation required by 18 C.F.R. § 35.13(d)(6) (2014).

II. Background

A. Xcel Energy Inc., the Xcel Energy Operating Companies, and Xcel Energy Services Inc.

Xcel Energy is a public utility holding company under the Public Utility Holding Company Act of 2005.[7] Xcel Energy owns, *inter alia*, four wholly owned, vertically integrated public utility operating company subsidiaries: (i) Southwestern Public Service Company ("SPS"); (ii) Northern States Power Company, a Minnesota corporation ("NSPM"); (iii) Northern States Power Company, a Wisconsin corporation ("NSPW"); and Public Service Company of Colorado ("PSCo") (collectively, the "Xcel Energy Operating Companies"). SPS owns and operates transmission facilities located in SPP and is a Transmission Owner in SPP. SPS has transferred operational control of its transmission facilities to SPP.[8] With limited exceptions for certain grandfathered transmission services, access to the transmission facilities owned by SPS is governed by the SPP OATT.

Xcel Energy Services is a wholly owned subsidiary of Xcel Energy. Xcel Energy Services provides services to Xcel Energy and to each of its subsidiaries, including the Xcel Energy Operating Companies and XEST. These services include, among others, executive management services, transmission management services, accounting services, supply chain services, wholesale market operations services, general counsel services, regulatory services, and financial services.[9]

B. Xcel Energy Transmission Holding Company, LLC

Xcel Energy Transmission Holding Company, LLC ("Xcel Energy Transmission Holdco") is a wholly owned first tier subsidiary of Xcel Energy. Xcel Energy Transmission Holdco was formed in April 2014 to facilitate transmission investment by Xcel Energy. Currently, Xcel Energy Transmission Holdco has two wholly owned subsidiaries: XEST and Xcel Energy Transmission Development Company, LLC ("XETD").[10]

C. Xcel Energy Southwest Transmission Company, LLC and Xcel Energy Transmission Development Company, LLC

XEST and XETD are wholly owned subsidiaries of Xcel Energy Transmission Holdco. XEST's primary focus is on participating in SPP's Order No. 1000 planning and competitive solicitation process, and XEST intends to develop and own transmission projects that emerge

[7] 42 U.S.C. §§ 16451-16463 (2012).

[8] *See* Mogensen Direct Testimony at 9.

[9] Rodriguez Direct Testimony at 6.

[10] Mogensen Direct Testimony at 1-2; Tyson Direct Testimony at 1-2.

from that process.[11] XEST was formed in May 2014. Currently, XEST does not own operational transmission facilities. To qualify for participation in SPP's Order No. 1000 competitive solicitation process, on June 30, 2014, XEST submitted to SPP an Application to become a Qualified RFP Participant.[12] XEST will become a Transmission Owner in SPP when XEST either (i) owns transmission facilities included in the SPP transmission system, or (ii) is issued a Notice to Construct by SPP.[13] XEST will transfer operational control of its transmission facilities to SPP when those facilities become operational. Although XEST's primary focus is on projects that emerge from SPP's Order No. 1000 process, XEST has not ruled out developing, owning, or acquiring transmission facilities outside of the SPP Order No. 1000 process, subject to all necessary state or federal approvals for such transactions or projects.

XETD's primary focus is on participating in the Midcontinent Independent System Operator, Inc.'s ("MISO") Order No. 1000 planning and competitive solicitation process, and XETD intends to develop and own transmission projects located in the MISO region that emerge from that process.[14] XETD was formed in April 2014. XETD has not ruled out developing, owning, or acquiring transmission facilities outside of the MISO Order No. 1000 process, subject to all necessary state or federal approvals for such transactions or projects.

III. The Proposed Formula Rate Is Just and Reasonable

The Commission has encouraged public utilities to file "transmission-related formula rates," observing that "formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs."[15] For this same reason, XEST requests approval of its Formula Rate, which is intended to remove a potential obstacle to XEST's ability to compete in SPP's Order No. 1000 process by providing XEST with certainty that it has the legal authorization necessary to recover the cost of transmission facilities that XEST seeks to develop and own pursuant to that process.

The Formula Rate Template and the Protocols, submitted as Attachments A and B to this filing, are just and reasonable. The Formula Rate Template is designed to calculate, on a project-by-project basis, an annual transmission revenue requirement that will be recoverable by XEST under the SPP OATT. The Formula Rate Template is a forward-looking formula under which costs are projected and then trued-up to actual costs once they are known.[16] The Formula Rate

[11] *See generally* SPP OATT, Attach. Y, § III(2).

[12] Mogensen Direct Testimony at 6.

[13] SPP OATT, § I(1)(T) (definition of "Transmission Owner").

[14] In a separate docket, XETD is filing a transmission formula rate for ultimate inclusion in the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").

[15] Order No. 679 at P 386.

[16] *See American Transmission Company*, 97 FERC ¶ 61,139 (2001); *see also Boston Edison Co.*, 91 FERC ¶ 61,198 (2000); *Northeast Utilities Service Co.*, 105 FERC ¶ 61,089 (2003), *reh'g denied*, 111 FERC ¶ 61,333

Template is similar to the formula rates approved by the Commission for other transmission-owning companies, including American Transmission Company, LLC and DATC Midwest Holdings, LLC.[17] The Formula Rate Template is consistent with Commission-approved ratemaking methodologies and contains sufficient specificity so that it can be applied without discretion on the part of XEST.

The Protocols for populating and updating the Formula Rate are consistent with recent Commission precedent addressing protocols for transmission owners with forward-looking formula rates.[18] The Protocols establish a transparent process governing an annual informational filing, information exchange between XEST and interested parties, as well as procedures for informal and formal challenges to XEST's implementation of the Formula Rate Template. The Protocols also make clear that the project-specific revenue requirements determined under the Formula Rate Template are "up to" rates, i.e., ceiling rates that permit XEST to discount its revenue requirements to the extent necessary to reflect the result of any cost commitments incurred in connection with competitive bidding on such projects. In recognition of the new challenges posed by the Order No. 1000 competitive solicitation process, other transmission-only companies have included this "up to" language in their respective protocols, and the Commission has accepted this language for filing.[19]

The Formula Rate provides XEST with both the rate certainty and the rate flexibility XEST needs to compete in SPP's Order No. 1000 process. Certainty is provided by the Formula Rate Template, which calculates, in a transparent way that SPP can evaluate during the competitive solicitation process, the ceiling revenue requirement XEST is authorized to charge if

(continued…)

(2005); *San Diego Gas & Electric Co.*, 103 FERC ¶ 61,115 (2003), *reh'g denied*, 104 FERC ¶ 61,149 (2003); *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008); *American Electric Power Service Corp.*, 124 FERC ¶ 61,306 (2008); *Tallgrass Transmission,* LLC, 132 FERC ¶ 61,114 (2010); *American Electric Power Transmission Co.*, 135 FERC ¶ 61,066 (2011); *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 (2011).

[17] Heintz Direct Testimony at 6; *see also American Transmission Co.*, 97 FERC ¶ 61,139 (2001); *DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224 (2012).

[18] *See Midwest Independent Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,149 (2013) (the "MISO Investigation Order"), *reh'g denied*, 146 FERC ¶ 61,209 (2014), and *Midcontinent Independent Transmission Sys. Operator, Inc.*, 146 FERC ¶ 61,212 (2014) (the "MISO Compliance Order"). As part of MISO's May 19, 2014 compliance filing in Docket No. ER13-2379, revised implementation protocols for NSPM and NSPW ("NSP Companies") were submitted to be applicable to Attachment O – NSP to the MISO Tariff. The XEST Protocols are similar to the NSP Companies' revised implementation protocols.

[19] *See, e.g., Transource Missouri, LLC*, 141 FERC ¶ 61,075 (2012) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated similar "up to" language) and *Transource Missouri, LLC*, 143 FERC ¶ 61,104 (2013) (approving a settlement establishing a formula rate that incorporated similar "up to" language); *see also MidAmerican Transco Cent. Cal. Transco, LLC*, 147 FERC ¶ 61,179 (2014) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated similar "up to" language).

selected to construct/own a new transmission facility based on XEST's actual costs.[20] Flexibility is provided by the Protocols, which recognize that XEST may need to charge a revenue requirement less than its ceiling revenue requirement where XEST decides a discount is necessary to strengthen a particular proposal.[21] In the Formula Rate Template, the effect of any such discount is taken into account when developing the revenue requirement charged to customers.[22] For these reasons, the Formula Rate is just and reasonable.

A. The Formula Rate Template

The Formula Rate Template tracks increases and decreases in cost and investment, and will allow XEST to forecast the net revenue requirement for each Rate Year (January to December), including any discount, and assess the resulting rate in the same Rate Year pursuant to the SPP OATT. To calculate its ATRR, XEST will forecast the values that will populate the Formula Rate Template each Rate Year.[23] These forecasted values are subject to a true-up mechanism, which ensures that customers are protected. Any difference between the actual ATRR and the forecasted ATRR is added to or subtracted from the revenue requirement calculated two years later, with interest.[24] For example, XEST would determine in 2017 if the actual ATRR for 2016 differed from the forecasted ATRR for 2016, and the difference, if any, will be reflected as an adjustment to the 2018 ATRR. In sum, the rates calculated under the Formula Rate Template and collected pursuant to the SPP OATT are subject to true-up with interest, protecting both customers and XEST from being harmed in circumstances where the forecasted ATRR differs from the actual ATRR.[25]

The Formula Rate Template uses 13-month average plant balances in determining the rate base upon which the return and the income tax components of the annual net revenue requirement are calculated.[26] XEST will forecast the average of the 13 monthly balances in rate base. If the forecasted balances are incorrect, the true-up mechanism will subsequently adjust the rate produced by the Formula Rate Template.

For service for each Rate Year, the average rate base balance and annual expenses are forecasted by October 1 preceding the Rate Year.[27] The rate in effect for the Rate Year is calculated pursuant to the formula using this forecast. On or before June 1 after the end of the

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[20] *See* Heintz Direct Testimony at 17-19.

[21] *See* Mogensen Direct Testimony at 8.

[22] *See* Heintz Direct Testimony at 17-19.

[23] *Id.* at 4-5.

[24] *Id.*

[25] *Id.*

[26] *Id.* at 5.

[27] *Id.*

Rate Year, the actual average rate base and annual expenses are then computed. The difference between the ATRR forecast and the actual ATRR, positive or negative, is computed, with interest as described below, and is used to adjust the rate for the subsequent Rate Year. As Mr. Heintz explains, the effect of any discount on XEST's ATRR is taken into account in determining the ATRR as part of the annual forecasting and true-up process, which ensures that customers receive the benefits of any discount.[28]

The Formula Rate Template is reasonable because XEST plans to invest substantial amounts in transmission facilities in SPP. The Formula Rate Template will allow XEST to collect a rate that is representative of the costs in the current period, provides for greater certainty for cost recovery of capital expenditures to improve transmission infrastructure, and ensures that customers pay no more than the cost to serve them over the lives of the projects.[29] The Formula Rate Template is derived from the Commission-approved, forward-looking formula rate filed by American Transmission Company, LLC.[30] The Commission has approved numerous other transmission formulas that employ similar true-up mechanisms.[31]

The Formula Rate Template's interest calculation is reasonable. Interest on any over-recovery is calculated pursuant to Section 35.19a of the Commission's regulations.[32] Interest on any under-recovery is calculated using the interest rate equal to XEST's actual short-term debt costs capped at the Commission interest rate determined pursuant to Section 35.19a. In either case, the interest payable is calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement exists.[33] The interest rate to be applied to the over-recovery or under-recovery amounts is determined using the average rate for the twenty one (21) months preceding October of the current year. This interest charge is then reflected in the rate for the subsequent year.[34] This approach is reasonable because the actual interest rates for the months following September will not be known prior to

[28] *Id.* at 18-19.

[29] *Id.* at 6.

[30] *American Transmission Co.*, 97 FERC ¶ 61,139 (2001).

[31] *See, e.g.*, *Boston Edison Co.*, 91 FERC ¶ 61,198 (2000); *Northeast Utilities Service Co.*, 105 FERC ¶ 61,089 (2003), *reh'g denied*, 111 FERC ¶ 61,333 (2005); *San Diego Gas & Electric Co.*, 103 FERC ¶ 61,115 (2003), *reh'g denied*, 104 FERC ¶ 61,149 (2003); *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008); *American Electric Power Service Corp.*, 124 FERC ¶ 61,306 (2008); *Tallgrass Transmission,* LLC, 132 FERC ¶ 61,114 (2010); *American Electric Power Transmission Co.*, 135 FERC ¶ 61,066 (2011); *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 (2011).

[32] 18 C.F.R. § 35.19a (2014).

[33] Heintz Direct Testimony at 7.

[34] *Id.*

the period during which the refund is calculated, and the monthly rate during that period may be constantly changing due to changes in interest rates.[35]

Although XEST is not requesting project-specific Order No. 679 incentives in this filing, the Formula Rate Template is developed to accommodate incentives that the Commission may grant at a later date.[36] The XEST revenue requirements per project are determined using the Project Revenue Requirement Worksheet. The Project Revenue Requirement Worksheet details the calculation of revenue requirements associated with all transmission facilities, including those for which Commission approval for incentives has been obtained.[37] If XEST seeks Commission approval for specific incentives in the future, these "placeholders" will enable the Formula Rate Template to calculate those incentives without the need for another filing by XEST to modify the Formula Rate Template.[38]

B. Formula Rate Protocols

The Protocols for populating and updating the Formula Rate Template are consistent with recent Commission orders addressing the MISO Tariff Attachment O protocols for forward-looking formula rates.[39] Based on the Commission's instruction to other entities with forward-looking formula rates,[40] XEST's Protocols satisfy the Commission's concerns with respect to (i) scope of participation in XEST's information exchange process, (ii) the transparency of the information exchange, and (iii) the ability of interested parties to challenge XEST's implementation of the Formula Rate as a result of the information exchange.[41] XEST's Protocols are consistent with MISO's compliance filing in Docket No. ER13-2379, which was filed in response to the Commission's order requiring modifications to the MISO Tariff

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[35] *Id.*

[36] *See, e.g.*, *Green Power Express LP*, 127 FERC ¶ 61,031 at P 104 (2009); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 at P 93 (2008).

[37] Heintz Direct Testimony at 15.

[38] *Id.*

[39] *See, e.g.*, *Midwest Independent Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,149 (2013) (the MISO Investigation Order), *reh'g denied*, 146 FERC ¶ 61,209 (2014), and *Midcontinent Independent Transmission Sys. Operator, Inc.*, 146 FERC ¶ 61,212 (2014) (the MISO Compliance Order).

[40] *See, e.g.*, *The Empire District Electric Co.*, 148 FERC ¶ 61,030 at P 6 (2014) (directing Empire to file revisions to its formula rate protocols "to conform to the requirements of the MISO Investigation Order and MISO Compliance Order or show cause why it should not be required to do so.")

[41] Two of the findings included in the MISO Investigation Order and the MISO Compliance Order do not apply to XEST. First, SPP's internet website and its OASIS link to one another in a way that renders inapplicable to SPP the requirement that certain information be posted on both the RTO's website and its OASIS site. Second, as a newly formed entity that has not yet become a member of SPP, XEST is not in a position to take the lead on establishing a joint meeting for multiple transmission owning members of SPP.

Attachment O protocols.[42] Because XEST's proposed Protocols satisfy the Commission's requirements for forward-looking formula rate protocols, XEST's proposed Protocols are just and reasonable.[43]

The Protocols make clear that the project-specific revenue requirements determined under the Formula Rate Template are "up to" rates, i.e., ceiling rates that permit XEST to discount its revenue requirements to the extent necessary to recognize any specific cost commitments XEST makes during the competitive bidding process in connection with a particular project. In recognition of the new challenges posed by the Order No. 1000 competitive solicitation process, other transmission-only companies have included similar "up to" language in their respective protocols, and the Commission has accepted this language.[44] The details of how SPP would implement a project developer's future cost commitment remains uncertain. If in the future XEST is selected by SPP to construct a transmission project on the basis of a cost commitment or other discount, then XEST will work with SPP to ensure that the terms of a discount accepted by SPP are filed appropriately with the Commission.

The Protocols reserve XEST's right to make limited FPA Section 205 filings to change the following values that are included as stated inputs to the Formula Rate Template: (i) depreciation rates or amortization periods; and (ii) Post-Employment Benefits Other Than Pensions charges. XEST may make a limited FPA Section 205 filing in which the sole issue will be whether the proposed change to one or more of these values is just and reasonable.

C. Rate of Return on Equity

1. Base ROE

Mr. McKenzie provides an independent appraisal of the cost of equity to XEST and recommends a rate of return on equity for XEST that is fair and allows XEST to attract capital on reasonable terms. Mr. McKenzie's evaluation considers the Commission's most recent guidance

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[42] *See* MISO's "Compliance Filing Revising Attachment O Formula Rate Protocols," Docket No. ER13-2379 (filed May 19, 2014). *See also* MISO Investigation Order and MISO Compliance Order.

[43] Heintz Direct Testimony at 16-17.

[44] *See, e.g., Transource Missouri, LLC*, 141 FERC ¶ 61,075 (2012) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated similar "up to" language) and *Transource Missouri, LLC*, 143 FERC ¶ 61,104 (2013) (approving a settlement establishing a formula rate that incorporated similar "up to" language); *see also MidAmerican Transco Cent. Cal. Transco, LLC*, 147 FERC ¶ 61,179 (2014) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated similar "up to" language).

and policy objectives, including the guidance provided in Opinion No. 531.[45] Mr. McKenzie concludes that a base ROE of 10.64% is reasonable for XEST.[46]

Mr. McKenzie estimates XEST's cost of equity by examining current capital market conditions and applying well-accepted quantitative analyses to estimate the current cost of equity for a reference group of other electric utilities with comparable investment risks under the methodology adopted in Opinion No. 531. In addition to relying on the results of the two-stage discounted cash flow ("DCF") model for electric utilities, Mr. McKenzie also evaluates the cost of equity for XEST using the risk premium approach, the Capital Asset Pricing Model ("CAPM"), and the expected earnings approach. The Commission relied on these three alternative benchmark methodologies in Opinion No. 531 in evaluating the placement of the base ROE from within the zone of reasonableness implied by the two-step DCF model. Based on the results of the two-stage DCF model recently endorsed by the Commission, Mr. McKenzie establishes a zone of reasonableness of 6.27% to 12.59%, with a median of 8.70%. Mr. McKenzie explains that the anomalous capital market conditions that prompted the Commission to approve an ROE at the middle of the top end of the DCF zone in Opinion No. 531 persist. Considering the need to meet established regulatory standards, continued anomalies in the capital markets, and the results of alternative methods, Mr. McKenzie recommends a base ROE for XEST of 10.64%, which falls halfway between the median and the top end of the zone of reasonableness established by the two-step DCF method.[47] Selecting a base ROE for XEST that falls at the middle of the top half of the zone of reasonableness is further supported by the company-specific risk XEST faces as a new transmission-only company established to focus primarily on projects that emerge from SPP's Order No. 1000 planning and competitive solicitation process.

In addition, Mr. McKenzie confirms the reasonableness of his recommended base ROE against the results of other ROE benchmarks developed by: (i) reference to allowed ROEs by state regulators and for Commission-regulated natural gas pipelines; (ii) an empirical form of the CAPM ("ECAPM"), applications of the risk premium, CAPM, and ECAPM approaches using projected bond yields; and (iii) applying the DCF model to a select group of low risk non-utility companies.[48]

Transmission facilities must compete with alternative uses of capital and the additional funding necessary to expand the grid will be allocated only if investors anticipate an opportunity

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[45] *Martha Coakley v. Bangor Hydro-Electric Company*, Opinion No. 531, 147 FERC ¶ 61,234 (2014) ("Opinion No. 531").

[46] McKenzie Direct Testimony at 10.

[47] *Id.* at 12-13. In Opinion No. 531, the Commission set the ROE at the point that is "halfway" between the midpoint and the top of the DCF zone of reasonableness. Opinion No. 531 at P 142 and P 152. In his testimony, Mr. McKenzie also refers to this point as being at "the middle of the top end" of the DCF zone of reasonableness. McKenzie Direct Testimony at 13.

[48] *Id.* at 14.

to earn a return that is sufficient to compensate for the associated risks. In evaluating a fair ROE for XEST, Mr. McKenzie also considers (i) the importance of setting an ROE that is sufficient to meet the Commission's policy goals of promoting participation in approved RTOs/ISOs and encouraging greater capital investment in transmission; (ii) the continued need for significant capital investment; and (iii) the implications of current allowed returns for state-jurisdictional utility operations. Coupled with the need to recognize flotation costs and expected trends in capital costs, these considerations confirm the reasonableness of the 10.64% base ROE for XEST.[49]

2. 50 Basis Point Adder

XEST requests a 50 basis point ROE adder for participation in the SPP RTO. Adding 50 basis points to XEST's base ROE of 10.64% results in an ROE of 11.14%. As explained by Mr. McKenzie, this 11.14% ROE falls well within the zone of reasonableness established by the two-step DCF method.[50]

For several years, the Commission has encouraged participation in RTOs by granting ROE enhancements to RTO participants. This incentive is distinct from incentives related to the construction of new transmission facilities.[51] In Order No. 679, the Commission stated that it will approve an ROE adder for RTO participation "for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization."[52] The Commission routinely has approved the ROE adder for RTO participation and should do so here.

The ROE adder for RTO participation continues to provide an important incentive for newly established transmission developers to participate in an RTO. Indeed, recognizing the continued benefits of RTO participation, the Commission has approved the ROE adder for entities that do not yet own operational transmission facilities where the applicant committed to become a member of an RTO and to turn over operational control of their transmission facilities to the RTO.[53] As described in Ms. Mogensen's testimony, XEST will become a transmission-owning member of SPP as soon as it constructs or acquires its first project that forms part of the SPP transmission system, or is granted a Notice to Construct by SPP, and XEST will turn over operational control of its transmission facilities to SPP at the time they become operational.[54]

[49] *See id.* at 13-16.

[50] *Id.* at 18.

[51] *See* FPA Section 219(c), 16 U.S.C. § 824s (2012); *see also* Order No. 679-A at P 87 & n. 143.

[52] Order No. 679 at P 326; Order No. 679-A at P 86.

[53] *See, e.g.*, *MidAmerican Transco Central California Transco, LLC*, 147 FERC ¶ 61,179 at P 45 (2014); *Transource Missouri, LLC*, 141 FERC ¶ 61,075 at P 75 (2012).

[54] *See* Mogensen Direct Testimony at 13; *see also* SPP OATT, § I(1)(T) (definition of "Transmission Owner").

The Commission therefore should grant XEST's request for the 50 basis point ROE adder for RTO participation.

D. Capital Structure

1. The Details of, and Basis for, XEST's Proposed Capital Structure

XEST's Formula Rate Template includes a fixed initial capital structure of 55% equity and 45% long-term debt.[55] Once XEST owns commercially operational transmission facilities, XEST will target an actual capital structure of approximately 55% equity and 45% long-term debt.[56] XEST's actual capital structure will be used in the Formula Rate Template, replacing the fixed capital structure, at the time XEST's first transmission facility becomes commercially operational.

The Commission previously has found that fixed or "hypothetical" capital structures "result in lower debt costs for the company" and assist companies in "receiving and maintaining an investment grade credit rating profile."[57] Moreover, a "hypothetical" capital structure presents "a pragmatic approach" to address a company's "fluctuating capital structure."[58] These same considerations apply here. As Mr. Tyson explains in his testimony, a capital structure of 55% equity and 45% debt should allow XEST to achieve reasonable costs of capital, which will benefit SPP transmission service customers who ultimately pay XEST's cost of service as part of SPP's transmission service rates.[59] XEST's target capital structure is similar to the target set by many other transmission-only entities. Allowing XEST to maintain an initial fixed capital structure at this level will place XEST on an equal footing with other transmission-only companies, so that XEST can compete for projects in SPP's Order No. 1000 process.

Although XEST intends to adhere as closely as possible to a debt-equity ratio of 55% equity and 45% debt, the challenge of raising capital (or receiving commitments from lenders to provide capital at a reasonable cost) to (i) compete effectively in SPP's Order No. 1000 process, and (ii) to finance construction of projects that emerge from that process, will sometimes cause XEST's actual capital structure to deviate from the target.[60] XEST intends to operate initially with equity infusions and borrowing from its parent, Xcel Energy Transmission Holdco. As more Requests for Proposals are issued under SPP's Order No. 1000 competitive solicitation

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[55] Heintz Direct Testimony at 15; Tyson Direct Testimony at 10.

[56] Tyson Direct Testimony at 10.

[57] *See Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 at P 55 (2008), *reh'g granted in part and denied in part*, 133 FERC ¶ 61,152 (2010); *Transource Missouri, LLC*, 143 FERC ¶ 61,104 at P 66 (2013).

[58] *See Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 at P 55 (2008).

[59] Tyson Direct Testimony at 10-11.

[60] *Id.*

process, XEST could need to secure additional loans and/or need to represent to lenders that XEST is a sufficiently creditworthy entity. [61] A capital structure that is fixed at a ratio of 55% equity and 45% debt until XEST's first transmission project goes into operation will help XEST achieve a strong credit profile and support an investment grade credit rating.[62]

2. XEST's Request for an Initial Fixed Capital Structure is Being Submitted Pursuant to FPA Section 205

XEST's request to use an initial fixed capital structure of 55% equity and 45% debt in its Formula Rate Template is being submitted pursuant to FPA Section 205. XEST is *not* requesting this approval as an "incentive" pursuant to FPA Section 219 and Order No. 679.

XEST is a new transmission-only company created to participate in SPP's Order No. 1000 process. XEST does not yet own transmission facilities and has not yet been selected to construct a specific transmission project. Under SPP's current Order No. 1000 process, the earliest that XEST could be selected by SPP for an Order No. 1000 project is late 2015. The first project may not be placed in service until several years later. In addition, during development and construction of its first Order No. 1000 project, XEST likely will be submitting proposals in response to Requests for Proposals issued by SPP in subsequent years.

Given XEST's focus on Order No. 1000 projects, a 55/45 fixed capital structure is just and reasonable for the time period up until XEST's first transmission project goes into operation. In contrast, the use of XEST's actual capital structure, which may be highly volatile in this early development stage, would be unreasonable and could undermine XEST's ability to secure credit and investment at a reasonable cost.[63] The potential volatility in XEST's actual capital structure at this stage in its development could, if used for rate purposes, undermine XEST's ability to access capital and negatively impact its credit rating.[64]

The fixed capital structure of 55% equity and 45% debt that XEST is requesting is just and reasonable. In recent incentives cases issued pursuant to FPA Section 219, the Commission has approved the use of such a fixed or "hypothetical" capital structure for other newly formed transmission companies.[65] As in those cases, a 55% equity/45% debt capital structure will contribute to XEST "receiving and maintaining an investment grade credit rating profile," which

[61] *See id.* at 5-9. To the extent required, XEST will separately seek Commission authorization for such financing arrangements pursuant to FPA Section 204.

[62] *Id.* at 11.

[63] *Id.* at 10-11.

[64] *See id.*

[65] *See DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224 at P 76 (2012); *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 at P 131 (2011); *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 at P 55 (2008).

is crucial for its success as a new entrant in the Order No. 1000 competitive solicitation process.[66] Moreover, the Commission recently has approved capital structures for entities in part because the requested capital structure was "within the range of actual capital structures for transmission-owning members" of the RTO.[67] The 55% equity and 45% debt capital structure proposed by XEST is comfortably within the range of capital structures for SPP members.[68] For these reasons, granting XEST the use of a fixed 55% equity/45% debt capital structure for its early development stage furthers the public policy goals of Order No. 1000 and is just and reasonable under FPA Section 205.

E. Depreciation Rates

XEST's proposed depreciation rates are set forth in Exhibit No. XES-401, included as an exhibit to the Direct Testimony of Andrew Sawyer. These depreciation rates are incorporated into the Formula Rate Template. XEST is a new transmission-only company that currently owns no transmission facilities. Other new transmission-only companies that did not yet own operational transmission facilities have filed formula rates that rely on depreciation rates identical to the depreciation rates previously approved by the Commission for a company other than the applicant. In those cases, as here, the applicant had no historical data to support a depreciation study such as the data needed to establish initial service life and net salvage estimates. The Commission accepted the applicants' proposed formula rates, including the depreciation rates.[69]

XEST has followed that same approach.[70] With three exceptions, the depreciation rates specified in Exhibit No. XES-401 are identical to the transmission depreciation rates accepted by the Commission for NSPM in Docket No. ER14-1325.[71] NSPM and NSPW are parties to a

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[66] *See DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224 at P 76 (2012); *see also Transource Missouri, LLC,* 141 FERC ¶ 61,075 at PP 66-67 (2012); *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 121 (2011).

[67] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 141 FERC ¶ 61,121 at P 51 (2012).

[68] Tyson Direct Testimony at 11-12.

[69] *RiteLine Illinois, LLC*, 137 FERC ¶ 61,039 (2011) (accepting in relevant part, a formula rate that incorporated depreciation rates identical to the depreciation rates approved for another company); *see also Transource Missouri, LLC*, 141 FERC ¶ 61,075 (2012) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated depreciation rates identical to the depreciation rates approved for another company) and *Transource Missouri, LLC*, 143 FERC ¶ 61,104 (2013) (approving a settlement establishing a formula rate that incorporated depreciation rates identical to the depreciation rates approved for another company); *DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224 (2012) (accepting, for purposes of filing and for purposes of settlement and hearing procedures, a formula rate that incorporated depreciation rates identical to the depreciation rates approved for another company) and *DATC Midwest Holdings, LLC*, 144 FERC ¶ 61,015 (2013) (approving a settlement establishing a formula rate that incorporated depreciation rates identical to the depreciation rates approved for another company).

[70] Sawyer Direct Testimony at 5-7.

[71] *Northern States Power Company, a Minnesota corporation*, Docket No. ER14-1325-000 (June 10, 2014) (unreported letter order). *See* Supplemental Filing of the NSP Companies, Docket No. ER13-954-001 (Apr. 8,

bilateral Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy (the "Interchange Agreement") that governs the allocation of NSP system generation and transmission costs between them. Under the Interchange Agreement, the NSP Companies submit a filing to the Commission each year to update the agreement's demand and energy allocation factors. The NSP Companies also update the depreciation rates that apply to NSPM and NSPW assets under the Interchange Agreement to reflect any changes in state-approved depreciation rates.[72]

The NSPM-based deprecation rates included in Exhibit No. 401 are taken directly from the NSPM depreciation rates for the same accounts as listed on revised Exhibit IX of the Interchange Agreement, which was submitted as part of the NSP Companies' February 14, 2014 filing in Docket No. ER14-1325. The Commission accepted these depreciation rates through a letter order issued on June 10, 2014. For the NSPM-based deprecation rate accounts listed on Exhibit No. 401, the depreciation rates accepted on June 10, 2014 were unchanged from the depreciation rates accepted by the Commission one year earlier through a June 6, 2013 letter order issued in Docket ER13-954.[73]

As the NSP Companies explained in their February 14, 2014 filing in Docket No. ER14-1325, these deprecation rates were supported by depreciation studies submitted to the three state regulatory agencies with jurisdiction over NSPM, which are located in the states of Minnesota, North Dakota, and South Dakota. The relevant depreciation studies were filed with the Commission in Docket No. ER13-954.[74]

Mr. Sawyer's testimony explains that the NSPM facilities that were the subject of these state-approved depreciation studies are a good proxy for the transmission facilities that XEST is likely to own in the future.[75] The employees of Xcel Energy Services who assist XEST also assist the Xcel Energy Operating Companies. These employees are familiar with the construction practices, operation and maintenance practices, and accounting practices of NSPM. XEST plans to rely on the expertise of these same service providers, and follow these same practices, when constructing, operating, and maintaining its own facilities in the future. Also, XEST's future transmission facilities could be located anywhere in the SPP region. Out of the four Xcel Energy Operating Companies, NSPM spans the largest number of states, covers the

(continued…)

2013); *see also* "Interchange Agreement -- Annual Update and E-Tariff Submission" of NSPM and NSPW at 5, Docket No. ER14-1325-000 (filed Feb. 14, 2014), as supplemented on April 8, 2014.

[72] Sawyer Direct Testimony at 8.

[73] *Id.* at 9.

[74] *See* Supplemental Filing of the NSP Companies, Docket No. ER13-954-001 (Apr. 8, 2013); *see also* "Interchange Agreement -- Annual Update and E-Tariff Submission" of NSPM and NSPW at 5, Docket No. ER14-1325-000 (Feb. 14, 2014), as supplemented on April 8, 2014.

[75] Sawyer Direct Testimony at 9.

largest geographical area, and has the most transmission facilities that operate at 345 kV or above. For these reasons, the NSPM depreciation rates provide a reasonable proxy for XEST's depreciation rates, including parameters, such as depreciable life and net salvage, associated with the facilities that XEST plans to own in the future.

As a new entity that does not yet know what projects it will own or where they will be located, XEST wants to have appropriate depreciation rates available for all of the 300 series of FERC accounts that it may use. XEST thus needs additional categories of depreciation rates that NSPM does not require. The additional depreciation rates are derived from other Xcel Energy Operating Companies' Commission-approved depreciation rates. As explained by Mr. Sawyer, these three depreciation rates are good proxies for XEST's depreciation rates for these asset categories.[76]

IV. Accounting

Mr. Rodriguez provides an overview of certain accounting matters related to XEST in support of XEST's Formula Rate, including support for XEST's request to create a regulatory asset for XEST's prudently incurred costs not capitalized, including pre-commercial and formation costs.[77] XEST uses the accrual method of accounting as required by Generally Accepted Accounting Principles ("GAAP") to record revenues and expenses. These revenues and expenses are and will be recorded in accounts prescribed by the Commission's Uniform System of Accounts. XEST will record the receipt of equity contributions from Xcel Energy Transmission Holdco as equity on its balance sheet. Xcel Energy Transmission Holdco will record contributions made to subsidiaries such as XEST as investments in subsidiaries on its balance sheet. XEST transactions will be recorded on the books of XEST. Consequently, the financial books and records of XEST will reflect the assets, liabilities, equity, and results of operations for XEST.[78]

XEST will be a pass-through entity for income tax purposes and therefore will not directly pay income taxes on its earnings. XEST will maintain its books of account based on the Commission's Uniform System of Accounts as if it were a taxable corporation, including the income tax accounting requirements. Therefore, XEST will record income taxes in its separate books of account even though these taxes will be paid by the appropriate taxpaying entity.[79]

As part of the Xcel Energy holding company system, XEST is able to secure various services, including accounting, financial reporting, information technology, legal, regulatory, and engineering services, from its affiliates. Mr. Rodriguez explains that services and transactions

[76] *Id.* at 10-11.

[77] Rodriguez Direct Testimony at 3.

[78] *Id.* at 4.

[79] *Id.*

between XEST and Xcel Energy Services will be priced at cost, as will services and transactions between XEST and any of the Xcel Energy Operating Companies.[80]

V. Request for Regulatory Asset Treatment

XEST requests a rate determination that it is authorized to recover through a regulatory asset all of its prudently incurred costs that are not capitalized, such as pre-commercial and formation costs. In light of the Commission's interpretation of the Order No. 679 nexus requirement, XEST is not submitting this request as an "incentive" under FPA Section 219.[81] XEST's request is being submitted pursuant to FPA Section 205.

A. Request for Commission Authorization to Establish a Regulatory Asset Account

XEST requests Commission authorization to defer as a regulatory asset its prudently incurred costs that are not capitalized, such as pre-commercial and formation costs. XEST was formed and began incurring costs in May 2014 in order to apply to be a Qualified RFP Participant under the SPP Order No. 1000 process. The Commission has recognized that regulatory asset treatment for pre-commercial and formation costs lowers a new transmission company's unrecovered costs and therefore lowers some of the risk to a new transmission company, thereby benefiting consumers. To ensure that XEST's Formula Rate generates a rate that is just and reasonable, the Commission should issue an order now confirming that XEST's prudently incurred costs that are not capitalized, such as pre-commercial and formation costs, may be deferred as a regulatory asset until charges are first assessed to customers under XEST's Formula Rate.[82]

XEST's pre-commercial and formation costs are being incurred in direct response to the Commission's policy directives in Order No. 1000. That order encourages new transmission-only companies to participate in the RTO regional planning process and to bid to construct transmission projects open to competition.[83] As compared to the process that pre-dated Order

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[80] *See Cross-Subsidization Restrictions on Affiliate Transactions*, Order No. 707, FERC Stats. & Regs. ¶ 31,264 (2008), *on reh'g*, Order No. 707-A, FERC Stats. & Regs. ¶ 31,272 (2008).

[81] *Northeast Transmission Development, LLC*, 135 FERC ¶ 61,244 at P 46 (2011) (stating the Commission will not pre-approve an incentive to encourage transmission investment and construction "for any future project without a specific showing justifying the incentive on a project-by-project basis[.]"), *clarified*, 137 FERC ¶ 61,138 (2011); *see also ITC Great Plains, LLC*, 126 FERC ¶ 61,223 at PP 24, 51 (2009) (denying applicant's request for incentives, including a regulatory asset incentive, for "Similar Future Projects").

[82] *See, e.g., RITELine Illinois, LLC*, 137 FERC ¶ 61,039 at P 95 (2011).

[83] Order No. 1000 at P 11 (articulating the Commission's policy goal of ensuring "an opportunity for more transmission projects to be considered in the transmission planning process on an equitable basis and increase the likelihood that those transmission facilities selected in a regional transmission plan for purposes of cost allocation are the more efficient or cost-effective solutions available").

No. 1000, participating in an RTO's Order No. 1000 process requires a company to be formed earlier and to incur costs well in advance of being selected to develop a transmission project. Such early formation and cost incurrence is a prerequisite if a company wishes to participate in all stages of the Order No. 1000 process for transmission projects that are identified, planned for, opened for bidding, subject to competing bids, selected through bid evaluation, and ultimately constructed.

For example, SPP is expected to issue its first set of Requests for Proposals no sooner than January 2015 under its Order No. 1000 process. To be eligible to submit such a bid, XEST had to submit an application to become a Qualified RFP Participant no later than June 30, 2014.[84] For this reason, XEST began to incur pre-commercial and formation costs in 2014 even though XEST's first project, if it emerges from SPP's Order No. 1000 process, cannot be identified until late 2015 at the earliest, with construction beginning after that date and completion of that facility a few years later.[85]

As a result of the timing requirements imposed by Order No. 1000, XEST has incurred pre-commercial and formation costs too early to qualify for project-specific incentive rate treatment pursuant to FPA Section 219. Just as the Commission issued rate-related orders confirming that RTO-formation costs would be eligible for recovery in rates to be collected after the RTO was formed,[86] XEST asks that these costs be found eligible for recovery in rates to be collected after XEST wins and develops transmission projects, and XEST's rate goes into effect. As Mr. Rodriguez explains, without a Commission order granting XEST the authority to defer these costs as a regulatory asset, it may be more difficult to recognize a regulatory asset for pre-commercial and formation costs for GAAP financial reporting purposes, which would impose a real financial burden on XEST during the first several years of operation.[87] Moreover, XEST's request for a rate determination that XEST is authorized to recover as a regulatory asset all of its prudently incurred pre-commercial and formation costs that are not capitalized simply preserves the opportunity for XEST to seek recovery in a future filing. XEST recognizes that, at the time XEST seeks to amortize and collect the regulatory asset account through rates, XEST will need to make another filing.[88]

Specifically, XEST asks that the Commission issue an order in this docket finding that the pre-commercial and formation costs that XEST has incurred and will continue to incur are

[84] SPP OATT, Attach. Y, § III(1) (requiring Qualified RFP Participant applications to be submitted by June 30 of the year prior to the year in which the entity intends to participate in the selection process); Mogensen Direct Testimony at 6.

[85] *See* Mogensen Direct Testimony at 14-15; Rodriguez Direct Testimony at 7-8.

[86] *See, e.g., Duke Energy Corp.*, 94 FERC ¶ 61,080 at 61,368-69 (2001), cited in *American Elec. Power Serv. Corp.,* 104 FERC ¶ 61,013 at P 27 (2003).

[87] Rodriguez Direct Testimony at 7-8.

[88] *Id.* at 9.

eligible for recovery in rates when XEST first begins charging a rate. This includes costs that ordinarily would be booked as expenses, including attorney fees; consultant fees; administrative expenses; entity formation costs; travel expenses; and costs to support regional activities that have been or will be undertaken with respect to XEST's participation in SPP's Order No. 1000 planning and solicitation processes. When the regulatory asset is recognized, XEST will accrue carrying costs at a rate equal to its Allowance for Funds Used During Construction ("AFUDC") on the unamortized cost balances, including the balance of deferred carrying costs, until a rate is first charged by XEST through the SPP OATT.[89] As part of this filing, XEST requests Commission approval to apply this carrying charge to any amounts tracked in this regulatory asset account.[90]

B. In the Alternative, the Commission Should Confirm that this Formula Rate Filing Does Not Preclude XEST from Seeking to Recognize a Regulatory Asset For These Pre-Commercial and Formation Costs in Connection with a Future Request for Rate Incentives.

To the extent the Commission denies XEST's regulatory asset authorization request under FPA Section 205, XEST alternatively requests that the Commission confirm, in its order on this filing, the following: if in the future XEST files a request for a regulatory asset rate incentive, nothing about the establishment of this Formula Rate in 2014 or the issuance of an order on this filing bars XEST from including, within the scope of that request for incentives, a request to recover all prudently incurred costs not capitalized, such as pre-commercial and formation costs, including costs dating back to 2014.[91]

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[89] *Id.* at 8-9. At the time XEST first begins charging a rate through the SPP OATT, XEST will stop calculating this carrying charge using the AFUDC rate, and will begin to calculate this carrying charge at its weighted costs of capital rate. When applying these rates, XEST will calculate the carrying charge semi-annually. *Id.*

[90] In light of the Commission's interpretation of its Order No. 679 "nexus" test, XEST is not seeking advance authorization for a specific mechanism by which to recover this regulatory asset (such as recovering the regulatory asset over a period of years). XEST recognizes that such a specific pre-approval of recovery would require one or more further filings by XEST pursuant to FPA Section 219 or, if appropriate, pursuant to FPA Section 205. *See, e.g.*, *Transource Missouri, LLC*, 141 FERC ¶ 61,075 at PP 53-54, 56-59 (2012); *see also Midwest Indep. Transmission Sys. Op., Inc.*, 138 FERC ¶ 61,021 at PP 8, 12-13, 21 (2012).

[91] "The creation and development of new business organizations to implement and carry out new business processes and methods of operation almost always require significant costs to be incurred prior to the date the organization is expected to provide any commercial benefits." *American Electric Power Service Corp.*, 104 FERC ¶ 61,013 at P 23 (2003), *reh'g denied*, 105 FERC ¶ 61,081 (2003). In those instances, "costs should be assigned to the periods in which the related benefits are expected to be realized." *Id.* at P 24; *see also PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,012 at P 50 (2004) ("[T]he development of new businesses allows the potential for commercial benefits. However, the initial development and determination of how the businesses will operate usually requires considerable costs that must be incurred before actual business operations commence."), *reh'g granted in part and denied in part*, 110 FERC ¶ 61,234 (2005), *petitions for review dismissed sub nom.*, *Va. State Corp. Comm'n v. FERC*, 468 F.3d 845 (D.C. Cir. 2006).

For example, if XEST is selected by SPP in late 2015 to build a project, XEST might then file a project-specific request for rate incentives in connection with that project in 2016. That request would include a regulatory asset incentive covering the identified prudently incurred costs not capitalized, including expenses incurred in 2014, 2015, and 2016. If that incentive request is approved, XEST would include the relevant expenses in the regulatory asset account for amortization, even if the costs had been accounted for as expenses in prior years.

In sum, XEST asks to be treated—eventually—like every other new transmission-only entity that requests the regulatory asset rate incentive for prudently incurred costs not capitalized. XEST seeks confirmation that the submission of its Formula Rate at this point in time will not bar XEST from including all such costs, even if expensed in prior years, (i) in a subsequent project-specific request for the regulatory asset incentive, and (ii) in the FPA Section 205 filing that is required before the party requesting such an incentive can begin recovering those costs in rates.

VI. Cost-of-Service Schedules, Posting, Service, and Requested Waivers

XEST requests that the Commission find that the Formula Rate, which tracks and is trued up using XEST's actual costs incurred during the applicable Rate Year, fully satisfies the requirement, found in 18 C.F.R. § 35.13, to file detailed cost-of-service schedules. Relying on the Formula Rate itself to satisfy these requirements is particularly appropriate here because XEST currently does not own transmission facilities and has not yet been selected to construct a specific project. Alternatively, consistent with its rulings on other transmission formula rate filings, XEST requests that the Commission waive the requirement to submit detailed cost-of-service schedules,[92] because XEST's rates are formulary and will be based on actual costs incurred during the relevant time period as reflected in FERC Form No. 1 filings.

To the extent necessary, XEST requests a limited partial waiver of the Commission's eTariff filing requirements under Order No. 714 and Sections 35.7 and 35.9 of the Commission's regulations.[93] Good cause exists for the Commission to grant the requested waiver, and the Commission previously has granted similar requests.[94] As discussed above, XEST does not yet qualify to be a Transmission Owner under the SPP OATT. When XEST becomes eligible to do so under the SPP OATT and SPP's other governing documents, XEST will ask SPP to file conforming changes to incorporate the XEST Formula Rate into the SPP OATT. It is in that subsequent docket, initiated by SPP, that an eTariff filing will be made that includes the Formula

[92] *DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224 at PP 97-98 (2012). *See also Commonwealth Edison Co.*, 119 FERC ¶ 61,238 at P 94 (2007), *order on reh'g*, 122 FERC ¶ 61,037, *order on reh'g*, 124 FERC ¶ 61,231 (2008); *Okla. Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 41 (2008); *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 at P 134 (2011).

[93] *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008); 18 C.F.R. §§ 35.7, 35.9 (2014).

[94] *See, e.g., ITC Holdings Corp.*, 143 FERC ¶ 61,257 at P 188 (2013).

Rate. Under the SPP OATT, costs will not flow through XEST's Formula Rate to SPP transmission service customers until XEST becomes a Transmission Owner as defined by the SPP OATT.

Pursuant to Sections 35.1(a) and 35.2(d) of the Commission's regulations,[95] a copy of this filing is being served electronically on SPP, all customers under the SPP OATT, all SPP members, as well as all state commissions within the SPP region. In addition, a copy of this filing will be posted at the Transmission page of the Xcel Energy website at http://www.xcelenergy.com/Safety_&_Operation/Transmission.

XEST respectfully requests that the Commission grant any necessary waivers needed so that the Formula Rate can be accepted as filed, given the benefits of the proposed formula rate approach and to support XEST's efforts to participate and compete in SPP's Order No. 1000 planning and competitive solicitation process.

VII. Correspondence and Communications

The following persons are authorized the receive notices and communications with respect to this filing:

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[95] 18 C.F.R. §§ 35.1(a), 35.2(d) (2014).

XEST requests that the individuals identified above with an asterisk be placed on the Commission's official service list in this proceeding. XEST respectfully requests waiver of Section 385.203(b)(3) of the Commission's regulations to permit the designation of more than two persons upon whom service is to made in this proceeding.[96]

VIII. Conclusion

For the reasons set forth above, XEST requests that the Commission:

- approve the Formula Rate Template and Protocols as just and reasonable and accept the Formula Rate no later than November 1, 2014, which is 64 days after the date of this filing (recognizing that XEST will not charge a rate to any customer until the effective date of a future SPP filing to incorporate the XEST Formula Rate into the SPP OATT, subject to the terms and conditions of the SPP OATT);
- grant XEST's request for a 50 basis point ROE adder for RTO participation and XEST's request for an initial fixed capital structure of 55% equity and 45% debt; and
- grant, with an effective date of November 1, 2014, XEST's request for a rate determination authorizing the establishment of a regulatory asset account that would include all of XEST's prudently incurred costs that are not capitalized, including pre-commercial and formation costs (or, if this request is denied, to grant XEST's alternative request as specified in Section V.B. above).

Respectfully submitted,

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[96] 18 C.F.R. § 385.203(b)(3) (2014).

Attachment A

Formula Rate Template

Formula Rate - Non-Levelized | Xcel Energy Southwest Transmission Company, LLC | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/____

Xcel Energy Southwest Transmission Company, LLC

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 47)				$ -
	REVENUE CREDITS	(Note O)	Total	Allocator		
2	Account No. 454	(page 4, line 29)	-	TP	-	-
3	Account No. 456.1	(page 4, line 33)	-	TP	-	-
4	Account No. 457.1 Scheduling	Attachment 5, line 39, col e	-	TP	-	-
5	Revenues from Grandfathered Interzonal Transactions	(Note N)	-	TP	-	-
6	Revenues from service provided by the ISO at a discount		-	TP	-	-
7	TOTAL REVENUE CREDITS	(Sum of Lines 2 through 6)	-			-
8	NET REVENUE REQUIREMENT	(line 1 minus line 7)				$ -
9	True-up Adjustment with Interest	Attachment 3	-	DA	1.00000	-
10	NET REVENUE REQUIREMENT	(line 8 plus line 9)				$ -

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Note U)					
1	Production	205.46.g for end of year, records for other months	-	NA		-
2	Transmission	Attachment 4, Line 14, Col. (b)	-	TP	-	-
3	Distribution	207.75.g for end of year, records for other months	-	NA		-
4	General & Intangible	Attachment 4, Line 14, Col. (c)	-	W/S	-	-
5	Common	356.1 for end of year, records for other months	-	CE	-	-
6	TOTAL GROSS PLANT	(Sum of Lines 1 through 5)	-	GP=	-	-
7	ACCUMULATED DEPRECIATION (Note U)					
8	Production	219.20-24.c for end of year, records for other months	-	NA		-
9	Transmission	Attachment 4, Line 14, Col. (h)	-	TP	-	-
10	Distribution	219.26.c for end of year, records for other months	-	NA		
11	General & Intangible	Attachment 4, Line 14, Col. (i)	-	W/S	-	-
12	Common	356.1 for end of year, records for other months	-	CE	-	-
13	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 8 through 12)	-			-
14	NET PLANT IN SERVICE					
15	Production	(line 1 - line 8)	-			
16	Transmission	(Line 2 minus Line 9)	-			-
17	Distribution	(line 3 - line 10)	-			
18	General & Intangible	(Line 4 minus Line 11)	-			-
19	Common	(line 5 - line 12)	-			-
20	TOTAL NET PLANT	(Sum of Lines 15 through 19)	-	NP=	-	-
21	ADJUSTMENTS TO RATE BASE					
22	Account No. 281 (enter negative)	Attachment 4, Line 28, Col. (d) (Note B)	-	NA	zero	-
23	Account No. 282 (enter negative)	Attachment 4, Line 28, Col. (e) (Note B)	-	NP	-	-
24	Account No. 283 (enter negative)	Attachment 4, Line 28, Col. (f) (Note B)	-	NP	-	-
25	Account No. 190	Attachment 4, Line 28, Col. (g) (Note B)	-	NP	-	-
26	Account No. 255 (enter negative)	Attachment 4, Line 28, Col. (h) (Note B)	-	NP	-	-
27	CWIP	Attachment 4, Line 14, Col. (d)	-	DA	1.00000	-
28	Unamortized Regulatory Asset	Attachment 4, Line 28, Col. (b) (Note T)	-	DA	1.00000	-
29	Unamortized Abandoned Plant	Attachment 4, Line 28, Col. (c) (Note S)	-	DA	1.00000	-
30	TOTAL ADJUSTMENTS	(Sum of Lines 22 through 29)	-			-
31	LAND HELD FOR FUTURE USE	Attachment 4, Line 14, Col. (e) (Note C)	-	TP	-	-
32	WORKING CAPITAL	(Note D)				
33	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	-			-
34	Materials & Supplies	Attachment 4, Line 14, Col. (f) (Note C)	-	TP	-	-
35	Prepayments (Account 165)	Attachment 4, Line 14, Col. (g)	-	GP	-	-
36	TOTAL WORKING CAPITAL	(Sum of Lines 32 through 35)	-			-
37	RATE BASE	(Sum of Lines 20, 30, 31 & 36)	-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b Attach. 5, Line 13, Col. (a)	-	TP	-	-
2	Less Account 566 (Misc Trans Expense)	321.97.b Attach. 5, Line 13, Col. (b)	-	TP	-	-
3	Less Account 565	321.96.b Attach. 5, Line 13, Col. (c)	-	TP	-	-
4	A&G	323.197.b Attach. 5, Line 13, Col. (d)	-	W/S	-	-
5	Less FERC Annual Fees	Attach. 5, Line 13, Col. (e)	-	W/S	-	-
6	Less EPRI & Reg. Comm. Exp. & Non-safety Ad.	(Note E) Attach. 5, Line 13, Col. (f)	-	W/S	-	-
6a	Less PBOP Expense in Year	Attachment 7, line 10	-	W/S	-	-
7	Plus Transmission Related Reg. Comm. Exp.	(Note E) Attach. 5, Line 13, Col. (g)	-	TP	-	-
7a	Plus PBOP Expense Allowed Amount	Attachment 7, line 8	-	W/S	-	-
8	Common	356.1	-	CE	-	-
9	Transmission Lease Payments	Attach. 5, Line 13, Col (h)	-	DA	1.0000	-
10	Account 566					
11	Amortization of Regulatory Asset	(Note T) Attach. 5, Line 13, Col. (i)	-	DA	1.0000	-
12	Miscellaneous Transmission Expense	Attach. 5, Line 13, Col .(j)	-	DA	1.0000	-
13	Total Account 566	(Line 11 plus Line 12) Ties to 321.97.b"	-			-
14	TOTAL O&M	(Sum of Lines 1, 4, 7, 7a, 8, 9, 13 less Lines 2, 3, 5, 6, 6a)	-			-
15	DEPRECIATION EXPENSE (Note U)					
16	Transmission	336.7.b&d Attach. 5, Line 13, Col. (k)	-	TP	-	-
17	General & Intangible	336.10.b&d, 336.1.b&d Attach. 5, Line 26, Col. (a)	-	W/S	-	-
18	Common	336.11.b&d	-	CE	-	-
19	Amortization of Abandoned Plant	(Note S) Attach. 5, Line 26, Col. (b)	-	DA	1.0000	-
20	TOTAL DEPRECIATION	(Sum of Lines 16 through 19)	-			-
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	263.i Attach. 5, Line 26, Col. (c)	-	W/S	-	-
24	Highway and vehicle	263.i Attach. 5, Line 26, Col. (d)	-	W/S	-	-
25	PLANT RELATED					
26	Property	263.i Attach. 5, Line 26, Co.l (e)	-	GP	-	-
27	Gross Receipts	263.i Attach. 5, Line 26, Col. (f)	-	NA	zero	-
28	Other	263.i Attach. 5, Line 26, Col. (g)	-	GP	-	-
29	Payments in lieu of taxes	Attach. 5, Line 26, Col. (h)	-	GP	-	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	-			-
31	INCOME TAXES	(Note G)				
32	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * (1-TEP)	WCLTD = Page 4, Line 20	-			
33	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 23	-			
34	FIT & SIT & P	(Note G)				
35						
36	1 / (1 - T) = (from line 32)	1 / (1 - T) = Line 32	-			
37	Amortized Investment Tax Credit	266.8f (enter negative) Attach. 5, Line 26, Col. (i)	-			
38	Excess Deferred Income Taxes	(enter negative) Attach. 5, Line 26, Col. (j)	-			
39	Tax Effect of Permanent Differences	Attach. 5, Line 26, Col. (k) (Note W)	-			
40	Income Tax Calculation	(Line 33 times Line 45)	-	NA		-
41	ITC adjustment	(Line 36 times Line 37)	-	NP	-	-
42	Excess Deferred Income Tax Adjustment	(Line 36 times Line 38)	-	NP	-	-
43	Permanent Differences Tax Adjustment	(Line 36 times Line 39)	-	NP	-	-
44	Total Income Taxes	(Sum of Lines 40 through 43)	-			-
45	RETURN					
46	Rate Base times Return	(Page 2, Line 37 times Page 4, Line 23)	-	NA		-
47	REV. REQUIREMENT	(Sum of Lines 14, 20, 30, 44 & 46)	-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)		(5)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total Transmission plant	(Page 2, Line 2, Column 3)					-		
2	Less Transmission plant excluded from ISO rates	(Note H)					-		
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-		
4	Transmission plant included in ISO rates	(Line 1 minus Lines 2 & 3)					-		
5	Percentage of Transmission plant included in ISO Rates	(Line 4 divided by Line 1)				TP=	-		
6	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
7	Production	354.20.b	-	-	-				
8	Transmission	354.21.b	-	-	-				
9	Distribution	354.23.b	-	-	-		W&S Allocator		
10	Other	354.24,25,26.b	-	-	-		($ / Allocation)		
11	Total	(Sum of Lines 7 through 10)	-		-	=	-	=	WS
12	COMMON PLANT ALLOCATOR (CE) (Note J)		**$**		% Electric		W&S Allocator		
13	Electric	200.3.c	-		(line 17 / line 20)		(line 16)		CE
14	Gas	200.3.d	-		-	*	-	=	-
15	Water	200.3.e	-						
16	Total	(Sum of Lines 13 through 15)	-						
17	RETURN (R)	(Note V)					$		
18					Cost				
19			$	%	(Notes K, Q, & R)		Weighted		
20	Long Term Debt	(Notes Q & R)	-	45.00%	0.0224		0.0101	=WCLTD	
21	Preferred Stock (112.3.c)	(Notes Q & R)	-	-	-		-		
22	Common Stock	(Notes K, Q & R)	-	55.00%	0.1114		0.0613		
23	Total	(Sum of Lines 20 through 22)	-				0.0714	=R	
24	REVENUE CREDITS								
25	ACCOUNT 447 (SALES FOR RESALE)	310 -311							
26	a. Bundled Non-RQ Sales for Resale	311.x.h					-		
27	b. Bundled Sales for Resale	Attach 5, line 39, col (a)					-		
28	Total of (a)-(b)						-		
29	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note M) Attach 5, line 39, col (b)					-		
30	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	330.x.n (Note P)							
31	a. Transmission charges for all transmission transactions	Attach 5, line 39, col (c)					-		
32	b. Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10.	Attach 5, line 39, col (d)					-		
33	Total of (a)-(b)						-		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data Xcel Energy Southwest Transmission Company, LLC | For the 12 months ended 12/31/____

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
B	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated. The maximum deferred tax offset to rate base is calculated in accordance with the proration formula prescribed by IRS regulation section 1.167(l)-1(h)(6).
C	Identified in Form 1 as being only transmission related.
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1.
E	Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes" and TEP = "the tax exempt ownership interest". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:			
	FIT =	-	
	SIT=	-	(State Income Tax Rate or Composite SIT)
	p =	-	(percent of federal income tax deductible for state purposes)
	TEP =	-	(percent of the tax exempt ownership)

H	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
I	Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
J	Enter dollar amounts
K	ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
L	Page 4, Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1.
M	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
N	Company will not have any grandfathered agreements. Therefore, this line shall remain zero.
O	The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes,-facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
P	Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, page 300.22.b.
Q	Prior to issuing any debt, a cost of debt of 2.4% will be used without true-up. After Issuing any debt, the cost of debt is determined using the internal rate of return methodology shown on Attachment 8 until a project is placed in service obtained subject to true-up pursuant to Attachment 9. The cost of debt is determined using the methodology in Attachment 5 once a project is placed in service. Attachment 8 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Appendix A
R	The capital structure will be 55% equity and 45% debt during the construction period, after the construction period, it will be based on the actual capital structure.
S	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
T	Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses related to projects. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rates becoming effective.
U	Excludes Asset Retirement Obligation balances
V	Company shall be allowed recovery of costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.
W	The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

Attachment 1
Project Revenue Requirement Worksheet
Xcel Energy Southwest Transmission Company, LLC

To be completed in conjunction with Attachment H.

Line No.	(1)	(2) **Attachment H Page, Line, Col.**	(3) **Transmission**	(4) **Allocator**
1	Gross Transmission Plant - Total	Attach H, p 2, line 2 col 5 plus line 27 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note A)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H, p 3, line 14 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	-	-
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach H, p 3, lines 17 & 18, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	-	-
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H, p 3, line 29 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	-	-
9	Less Revenue Credits	Attach H, p 1, line 7 col 5	-	
10	Annual Allocation Factor for Other Taxes	(line 9 divided by line 1 col 3)	-	-
11	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, 8, and 10**		**-**
	INCOME TAXES			
12	Total Income Taxes	Attach H, p 3, line 43 col 5	-	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2 col 3)	-	-
	RETURN			
14	Return on Rate Base	Attach H, p 3, line 45 col 5	-	
15	Annual Allocation Factor for Return on Rate Base	(line 1 divided by line 2 col 3)	-	-
16	**Annual Allocation Factor for Return**	**Sum of line 13 and 15**	-	**-**

Attachment 1
Project Revenue Requirement Worksheet
Xcel Energy Southwest Transmission Company, LLC

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(12a)	(13)	(14)	(15)	(16)
Line No.	Project Name (Note M)	ITEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation/Amortization Expense	Annual Revenue Requirement	Incentive Return in basis Points	Incentive Return	Ceiling Rate	Discount	Total Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 11)	(Col. 3 * Col. 4)	(Notes D & I)	(Page 1 line 16)	(Col. 6 * Col. 7)	(Notes E & I)	(Sum Col. 5, 8 & 9)	(Note K)	(Attachment 2, Line 28 Incentive Return * Col. 6)	(Sum Col. 10 & 12)	(Note J)	(Sum Col. 10 & 12 Less Col. 13)	(Note F)	Sum Col. 14 & 15 (Note G)
1a			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1c			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1b			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1d			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1e			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1f			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1g			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1h			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1i			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1j			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1k			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1l			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1m			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1n			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1o			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
																	-
2	Annual Totals		-			-				-		-	-	-	-	-	-
3	Rev. Req. Adj For Attachment H									-							

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment H
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment H and includes any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include Unamortized Abandoned Plant.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP, Unamortized Regulatory Assets, and Unamortized Abandoned Plant.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 12. Project Depreciation Expense includes the amortization of Abandoned Plant
F	True-Up Adjustment is calculated on the Project True-up Schedule
G	The Network Upgrade Charge is the value to be used in the SPP's rate calculation under the applicable Schedule under the SPP OATT for each project.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.
I	The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense.
J	The Discount is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process
K	Requires approval by FERC of incentive return applicable to the specified project(s)
M	All facilities other than those being recovered under Schedules 7, 8, 9 are to be included in Attachment 1.

Attachment 2
Incentive ROE
Xcel Energy Southwest Transmission Company, LLC

1	Rate Base	Attachment H, line 37, Col.5						-
2	100 Basis Point Incentive Return						$	
						Cost		
				$	%		Weighted	
3	Long Term Debt	(Notes DD and EE)		-	45.00%	0.0224	0.0101	
4	Preferred Stock	(Notes DD and EE)		-	-	-	-	
5	Common Stock	(Notes O, DD and EE)	Cost = Attachment H, Line 23, Cost plus .01	-	55.00%	0.1214	0.0668	
6	Total (sum lines 27-29)			-			0.0769	
7	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6)							-
8	INCOME TAXES							
9	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			-				
10	CIT=(T/1-T) * (1-(WCLTD/R)) =			-				
11	WCLTD = Line 3							
12	and FIT, SIT & p are as given in footnote K.							
13	1 / (1 - T) = (from line 9)			-				
14	Amortized Investment Tax Credit (266.8f) (enter negative)		Attachment H, Page 3, Line 7	-				
15	Excess Deferred Income Taxes (enter negative)		Attachment H, Page 3, Line 8	-				
16	Tax Effect of Permanent Differences (Note B)		Attachment H, Page 3, Line 9	-				
17	Income Tax Calculation = line 10 * line 7			-	NA		-	
18	ITC adjustment (line 13 * line 14)			-	NP	-	-	
19	Excess Deferred Income Tax Adjustment (line 13 * line 15)			-	NP	-	-	
20	Permanent Differences Tax Adjustment (line 13 * 16)			-	NP	-	-	
21	Total Income Taxes (sum lines 17 - 20)			-			-	-
22	Return and Income Taxes with 100 basis point increase in ROE							-
23	Return (Attach. H line 46 col 5)							-
24	Income Tax (Attach. H line 44 col 5)							-
25	Return and Income Taxes without 100 basis point increase in ROE							-
26	Incremental Return and Income Taxes for 100 basis point increase in ROE							-
27	Rate Base (line 1)							-
28	Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base							-

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual incentive is calculated on Attachment 1 and must be approved by the Commission. For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 137 on Attachment 1 column 16.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

Attachment 3
Project True-Up
Xcel Energy Southwest Transmission Company, LLC

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Actual	Actual	True-Up		Applicable	True-Up	
Line No.	Project Name	ITEP Project Number	Project Revenues Received [2] In the Rate Year	Net Revenue Requirement [1]	Adjustment Principal Under/(Over)	Prior Period Adjustment	Interest Rate on Under/(Over)	Adjustment Interest Under/(Over)	Total True-Up Adjustment
			as Reported in Form No 1	Actual Attachment 1 p 2 of 2, Col. 14	Col. (e) - Col. (d)	Attachment 11	Attachment 11	Col. [(f)+(g)] x Col. (g) x 24 months [2]	Col. (f) + Col. (i)
1a					-			-	-
1b				-	-			-	-
1c				-	-			-	-
1d				-	-			-	-
1e				-	-			-	-
…					-				
…					-				
2	Subtotal				-				
3	Under/(Over) Recovery				-				

[1] Amount excludes True-Up Adjustment and Discount, as reported in Attachment 1, columns 17 and 19
[2] Rounded to whole dollars.

Attachment 4
Rate Base Worksheet
Xcel Energy Southwest Transmission Company, LLC

Line No	Month	Gross Plant In Service		CWIP	LHFFU	Working Capital		Accumulated Depreciation	
		Transmission	General & Intangible	CWIP (Note C)	Held for Future Use	Materials & Supplies	Prepayments	Transmission	General & Intangible
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		207.58.g for end of year, records for other months	205.5.g & 207.90.g for end of year, records for other months	216.b for end of year, records for other months	214.x.c for end of year, records for other months	227.8.c & 227.16.c for end of year, records for other	111.57.c for end of year, records for other months	219.25.c for end of year, records for other months	219.28.c & 200.21.c for end of year, records for other months
1	December Prior Year	-	-	-	-	-	-	-	-
2	January	-	-	-	-	-	-	-	-
3	February	-	-	-	-	-	-	-	-
4	March	-	-	-	-	-	-	-	-
5	April	-	-	-	-	-	-	-	-
6	May	-	-	-	-	-	-	-	-
7	June	-	-	-	-	-	-	-	-
8	July	-	-	-	-	-	-	-	-
9	August	-	-	-	-	-	-	-	-
10	September	-	-	-	-	-	-	-	-
11	October	-	-	-	-	-	-	-	-
12	November	-	-	-	-	-	-	-	-
13	December	-	-	-	-	-	-	-	-
14	Average of the 13 Monthly Balances	-	-	-	-	-	-	-	-

Adjustments to Rate Base

Line No	Month	Unamortized Regulatory Asset	Unamortized Abandoned Plant	Account No. 281 Accumulated Deferred Income Taxes (Notes B & D)	Account No. 282 Accumulated Deferred Income Taxes (Notes B & D)	Account No. 283 Accumulated Deferred Income Taxes (Notes B & D)	Account No. 190 Accumulated Deferred Income Taxes (Notes B & D)	Account No. 255 Accumulated Deferred Investment Credit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Note S	Note S	273.8.k	275.2.k	277.9.k	234.8.c	267.8.h for end of year, records for other months
15	December Prior Year	-	-	-	-	-	-	-
16	January	-	-	[redacted]				-
17	February	-	-	[redacted]				-
18	March	-	-	[redacted]				-
19	April	-	-	[redacted]				-
20	May	-	-	[redacted]				-
21	June	-	-	[redacted]				-
22	July	-	-	[redacted]				-
23	August	-	-	[redacted]				-
24	September	-	-	[redacted]				-
25	October	-	-	[redacted]				-
26	November	-	-	[redacted]				-
27	December	-	-	-	-	-	-	-
28	Average of the 13 Monthly Balances	-	-	-	-	-	-	-

Notes:
A Information compiled from Company records.
B The maximum deferred tax offset to rate base is calculated in accordance with the proration formula prescribed by IRS regulation section 1.167(l)-1(h)(6).
C CWIP recovered under this formula is limited to the CWIP amounts authorized by FERC.
D ADIT is computed using the average of the beginning of the year and the end of the year.

Attachment 5
Attachment H, Page 3 Worksheet
Xcel Energy Southwest Transmission Company, LLC

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	A&G Expenses	FERC Annual Fees	EPRI & Reg. Comm. Exp. & Non-safety Ad.	Transmission Related Reg. Comm. Exp.	Transmission Lease Payments	Amortization of Regulatory Asset	Miscellaneous Transmission Expense	Depreciation Expense - Transmission
	Attachment H, Page 4, Line Number 8	1 (a)	2 (b)	3 (c)	4 (d)	5 (e)	6 (f)	7 (g)	9 (h)	11 (i)	12 (j)	16 (k)
1	January	-	-	-	-	-	-	-	-	-	-	-
2	February	-	-	-	-	-	-	-	-	-	-	-
3	March	-	-	-	-	-	-	-	-	-	-	-
4	April	-	-	-	-	-	-	-	-	-	-	-
5	May	-	-	-	-	-	-	-	-	-	-	-
6	June	-	-	-	-	-	-	-	-	-	-	-
7	July	-	-	-	-	-	-	-	-	-	-	-
8	August	-	-	-	-	-	-	-	-	-	-	-
9	September	-	-	-	-	-	-	-	-	-	-	-
10	October	-	-	-	-	-	-	-	-	-	-	-
11	November	-	-	-	-	-	-	-	-	-	-	-
12	December	-	-	-	-	-	-	-	-	-	-	-
13	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Month	Depreciation Expense - General & Intangible	Amortization of Abandoned Plant	Payroll Taxes	Highway & Vehicle Taxes	Property Taxes	Gross Receipts Taxes	Other Taxes	Payments in lieu of Taxes	Amortized Investment Tax Credit (266.8f)	Excess Deferred Income Taxes	Tax Effect of Permanent Differences
	Attachment H, Page 3, Line Number	17 (a)	19 (b)	23 (c)	24 (d)	26 (e)	27 (f)	28 (g)	29 (h)	37 (i)	42 (j)	43 (k)
14	January	-	-	-	-	-	-	-	-	-	-	-
15	February	-	-	-	-	-	-	-	-	-	-	-
16	March	-	-	-	-	-	-	-	-	-	-	-
17	April	-	-	-	-	-	-	-	-	-	-	-
18	May	-	-	-	-	-	-	-	-	-	-	-
19	June	-	-	-	-	-	-	-	-	-	-	-
20	July	-	-	-	-	-	-	-	-	-	-	-
21	August	-	-	-	-	-	-	-	-	-	-	-
22	September	-	-	-	-	-	-	-	-	-	-	-
23	October	-	-	-	-	-	-	-	-	-	-	-
24	November	-	-	-	-	-	-	-	-	-	-	-
25	December	-	-	-	-	-	-	-	-	-	-	-
26	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Attachment H, Page 3, Line Number	Bundled Sales for Resale included on page 4 of Attachment H 27 (a)	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) 29 (b)	Transmission charges for all transmission transactions 31 (c)	Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10. 32 (d)	Account No. 457.1 Scheduling Attach H, p 1 line 4 (e)
27	January	-	-	-	-	-
28	February	-	-	-	-	-
29	March	-	-	-	-	-
30	April	-	-	-	-	-
31	May	-	-	-	-	-
32	June	-	-	-	-	-
33	July	-	-	-	-	-
34	August	-	-	-	-	-
35	September	-	-	-	-	-
36	October	-	-	-	-	-
37	November	-	-	-	-	-
38	December	-	-	-	-	-
39	Total	$ -	$ -	$ -	$ -	$ -
40						
41	RETURN (R)					

		$
42	Long Term Interest (117, sum of 62.c through 67.c)	-
43	Preferred Dividends (118.29c) (positive number)	-
44	Proprietary Capital (112.16.c)	-
45	Less Preferred Stock (line 49)	-
46	Less Account 216.1 (112.12.c) (enter negative)	-
47	Common Stock (sum lines 44-46)	-

			$	%	Cost	Weighted	
48	Long Term Debt	112, sum of 18.c through 21.c	-	45.00%	0.0224	0.0101	=WCLTD
49	Preferred Stock (112.3.c)	112.3.c	-	-	-	-	
50	Common Stock	(Note K)	-	55.00%	0.1114	0.0613	
51	Total	(Sum of Lines 20 through 22)	-			0.0714	=R

Attachment 6
Short Term Debt
Xcel Energy Southwest Transmission Company, LLC

Description	**Debt Amount**	**Months O/S during year**	**Weighted Debt Amount**		**Eff. Rate**	**Weighted Rate**
Verified against debt amortization tables						
Weighted Avg. ST Debt -Jan	-	-	-	-	-	-
Weighted Avg. ST Debt -Feb	-	-	-	-	-	-
Weighted Avg. ST Debt -Mar	-	-	-	-	-	-
Weighted Avg. ST Debt - Apr	-	-	-	-	-	-
Weighted Avg. ST Debt - May	-	-	-	-	-	-
Weighted Avg. ST Debt - June	-	-	-	-	-	-
Weighted Avg. ST Debt - July	-	-	-	-	-	-
Weighted Avg. ST Debt - Aug	-	-	-	-	-	-
Weighted Avg. ST Debt - Sept	-	-	-	-	-	-
Weighted Avg. ST Debt - Oct	-	-	-	-	-	-
Weighted Avg. ST Debt - Nov	-	-	-	-	-	-
Weighted Avg. ST Debt - Dec	-	-	-	-	-	-
	-		-	0.00%		0.00%

Attachment 7
PBOPs
Xcel Energy Southwest Transmission Company, LLC

Calculation of PBOP Expenses

Attachment H, Page 4, Line Number 8

		NSPM (Note B)	NSPW	PSCo	SPS	XES	Total
1							
2	Total PBOP expenses (Note A)	4,673,000	1,007,000	(5,082,000)	(86,000)	2,194,000	
3	Labor dollars	307,898,359	51,513,634	227,316,400	101,418,582	301,757,205	
4	Cost per labor dollar	$0.015	$0.020	($0.022)	($0.001)	$0.007	
5	labor (labor not capitalized) current year	-	-	-	-	-	
6	PBOP Expense for current year	$0	$0	$0	$0	$0	-
7	Lines 2-6 cannot change absent approval or acceptance by FERC in a separate proceeding.						
8	PBOP amount included in Company's O&M and A&G expenses in Form No. 1						-

Note Letter	
A	Amounts reflect 2015 data from the May 7, 2014 actuarial report
B	Excludes former NMC

Attachment 8
Financing Costs for Long Term Debt using the Internal Rate of Return Methodology
Xcel Energy Southwest Transmission Company, LLC

Attachment H, Page 4, Line Number 8

Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below.
Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment.
The IRR calculation will use the Excel Worksheet Function XIRR.

Total Loan Amount	**$ 250,000,000**

Internal Rate of Return[1]	**6.38%**
Based on following Financial Formula[2]**:**	
NPV = 0 =	

Origination Fees	Rate	Amount
Underwriting Discount	-	-
Arrangement Fee	600,000	600,000
Upfront Fee	40.0-35.0	937,500
Rating Agency Fee	-	-
Legal Fees		165,000
Total Issuance Expense		1,702,500
Annual Rating Agency Fee	-	-
Annual Bank Agency Fee	35,000	35,000
Revolving Credit Commitment Fee	0.35%	

	2014	2015	2016	2017	2018	2019	2020
LIBOR Rate	0.24%	0.56%	1.45%	2.29%	2.76%	3.03%	3.21%
Spread	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Interest Rate	2.24%	2.56%	3.45%	4.29%	4.76%	5.03%	5.21%

(A) Year	(B) Quarter	(C) Capital Expenditures ($000's)	(D) Principle Drawn In Quarter	(E) Principle Drawn To Date ($000's)	(F) Interest & Principal ($000's)	(G) Origination Fees ($000's)	(H) Commitment, Utilization & Ratings Fees	(I) Net Cash Flows ($000's) (D-F-G-H)
1/1/2015		-						
3/31/2015	Q1	-	-	-	-			-
6/30/2015	Q2	-	-	-	-			-
9/30/2015	Q3	-	-	-	-			-
12/31/2015	Q4	-	-	-	-			-
3/31/2016	Q1	11,111	5,000	5,000	-	1,703	219	3,079
6/30/2016	Q2	11,111	5,000	10,000	43		249	4,708
9/30/2016	Q3	11,111	5,000	15,000	87		210	4,703
12/31/2016	Q4	11,111	5,000	20,000	131		206	4,664
3/31/2017	Q1	33,333	15,000	35,000	170		201	14,628
6/30/2017	Q2	33,333	15,000	50,000	375		223	14,402
9/30/2017	Q3	33,333	15,000	65,000	541		175	14,284
12/31/2017	Q4	33,333	15,000	80,000	703		162	14,135
3/31/2018	Q1	33,333	15,000	95,000	847		149	14,004
6/30/2018	Q2	33,333	15,000	110,000	1,127		171	13,702
9/30/2018	Q3	33,333	15,000	125,000	1,319		123	13,558
12/31/2018	Q4	33,333	15,000	140,000	1,499		109	13,391
3/31/2019	Q1	33,333	15,000	155,000	1,643		96	13,261
6/30/2019	Q2	33,333	15,000	170,000	1,943		118	12,939
9/30/2019	Q3	33,333	15,000	185,000	2,154		70	12,776
12/31/2019	Q4	33,333	15,000	200,000	2,344		57	12,599
1/1/2020	Q1	-	-	200,000	200,028		44	(200,071)

1 The IRR is the input to Debt Cost shown on Appendix A, Page 4, Line 20 during the construction period.

2 The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e. NPV function with goal seek in a spreadsheet program).

Attachment 9
Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

SUMMARY

YEAR		Estimated Effective cost of debt used in true up	Final Effective cost of debt for the construction loan:	Revenue Requirement: Based on Estimated Effective cost of debt	Revenue Requirement: Based on Actual Effective cost of debt	Over (Under) Recovery	Monthly Interest Rate applicable over the ATRR period	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2017 (Refund)/Owed
2015		7.18%	6.50%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2016		6.8%	6.50%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2017		7.2%	6.50%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2018		7.3%	6.50%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2019	*	7.1%	6.50%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2020	**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
								$ (553,329.99)

The Hypothetical Example:
**** Assumes that the construction loan is retired on Sept 1, 2020***
***** Assumes permanent debt structure is put in place on Sept 1, 2020 with effective rate of 6.5%***

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Calculation of Interest for 2015 True-Up Period							
					Monthly		
January	Year 2015	-	0.5500%	12.00	-		-
February	Year 2015	-	0.5500%	11.00	-		-
March	Year 2015	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2015	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2015	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2015	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2015	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2015	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2015	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2015	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2015	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2015	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		**(103,025)**
					Annual		
January through December	Year 2016	(103,025)	0.5600%	12.00	(6,923)		**(109,948)**
January through December	Year 2017	(109,948)	0.5400%	12.00	(7,125)		**(117,073)**
January through December	Year 2018	(117,073)	0.5800%	12.00	(8,148)		**(125,221)**
January through December	Year 2019	(125,221)	0.5700%	12.00	(8,565)		**(133,786)**
January through December	Year 2020	(133,786)	0.5700%	12.00	(9,151)		**(142,937)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**142,937**	0.5700%		(815)	(12,357)	(131,395)
February	Year 2021	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2021	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2021	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2021	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2021	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2021	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2021	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2021	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2021	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2021	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2021	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		
Total Amount of True-Up Adjustment for 2012 ATRR						$ (148,288)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (48,288)	

Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

Calculation of Interest for 2016 True-Up Period							
					Monthly		
January	Year 2016	(12,500)	0.5600%	12.00	840		13,340
February	Year 2016	(12,500)	0.5600%	11.00	770		13,270
March	Year 2016	(12,500)	0.5600%	10.00	700		13,200
April	Year 2016	(12,500)	0.5600%	9.00	630		13,130
May	Year 2016	(12,500)	0.5600%	8.00	560		13,060
June	Year 2016	(12,500)	0.5600%	7.00	490		12,990
July	Year 2016	(12,500)	0.5600%	6.00	420		12,920
August	Year 2016	(12,500)	0.5600%	5.00	350		12,850
September	Year 2016	(12,500)	0.5600%	4.00	280		12,780
October	Year 2016	(12,500)	0.5600%	3.00	210		12,710
November	Year 2016	(12,500)	0.5600%	2.00	140		12,640
December	Year 2016	(12,500)	0.5600%	1.00	70		12,570
					5,460		**155,460**
					Annual		
January through December	Year 2017	155,460	0.5400%	12.00	10,074		**165,534**
January through December	Year 2018	165,534	0.5800%	12.00	11,521		**177,055**
January through December	Year 2019	177,055	0.5700%	12.00	12,111		**189,166**
January through December	Year 2020	189,166	0.5700%	12.00	12,939		**202,104**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**(202,104)**	0.5700%		1,152	17,473	185,784
February	Year 2021	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2021	(169,370)	0.5700%		965	17,473	152,863
April	Year 2021	(152,863)	0.5700%		871	17,473	136,262
May	Year 2021	(136,262)	0.5700%		777	17,473	119,566
June	Year 2021	(119,566)	0.5700%		682	17,473	102,775
July	Year 2021	(102,775)	0.5700%		586	17,473	85,888
August	Year 2021	(85,888)	0.5700%		490	17,473	68,905
September	Year 2021	(68,905)	0.5700%		393	17,473	51,826
October	Year 2021	(51,826)	0.5700%		295	17,473	34,649
November	Year 2021	(34,649)	0.5700%		197	17,473	17,374
December	Year 2021	(17,374)	0.5700%		99	17,473	(0)
					7,566		
Total Amount of True-Up Adjustment for 2013 ATRR						$ 209,670	
Less Over (Under) Recovery						$ (150,000)	
Total Interest						$ 59,670	

Calculation of Interest for 2017 True-Up Period							
					Monthly		
January	Year 2017	8,333	0.5400%	12.00	(540)		(8,873)
February	Year 2017	8,333	0.5400%	11.00	(495)		(8,828)
March	Year 2017	8,333	0.5400%	10.00	(450)		(8,783)
April	Year 2017	8,333	0.5400%	9.00	(405)		(8,738)
May	Year 2017	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2017	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2017	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2017	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2017	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2017	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2017	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2017	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		**(103,510)**
					Annual		
January through December	Year 2018	(103,510)	0.5800%	12.00	(7,204)		**(110,714)**
January through December	Year 2019	(110,714)	0.5700%	12.00	(7,573)		**(118,287)**
January through December	Year 2020	(118,287)	0.5700%	12.00	(8,091)		**(126,378)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**126,378**	0.5700%		(720)	(10,926)	(116,173)
February	Year 2021	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2021	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2021	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2021	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2021	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2021	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2021	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2021	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2021	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2021	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2021	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2014 ATRR						$ (131,109)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (31,109)	

Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

Calculation of Interest for 2018 True-Up Period							
					Monthly		
January	Year 2018	25,000	0.5800%	12.00	(1,740)		(26,740)
February	Year 2018	25,000	0.5800%	11.00	(1,595)		(26,595)
March	Year 2018	25,000	0.5800%	10.00	(1,450)		(26,450)
April	Year 2018	25,000	0.5800%	9.00	(1,305)		(26,305)
May	Year 2018	25,000	0.5800%	8.00	(1,160)		(26,160)
June	Year 2018	25,000	0.5800%	7.00	(1,015)		(26,015)
July	Year 2018	25,000	0.5800%	6.00	(870)		(25,870)
August	Year 2018	25,000	0.5800%	5.00	(725)		(25,725)
September	Year 2018	25,000	0.5800%	4.00	(580)		(25,580)
October	Year 2018	25,000	0.5800%	3.00	(435)		(25,435)
November	Year 2018	25,000	0.5800%	2.00	(290)		(25,290)
December	Year 2018	25,000	0.5800%	1.00	(145)		(25,145)
					(11,310)		**(311,310)**
					Annual		
January through December	Year 2019	(311,310)	0.5700%	12.00	(21,294)		**(332,604)**
January through December	Year 2020	(332,604)	0.5700%	12.00	(22,750)		**(355,354)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**355,354**	0.5700%		(2,026)	(30,721)	(326,658)
February	Year 2021	326,658	0.5700%		(1,862)	(30,721)	(297,798)
March	Year 2021	297,798	0.5700%		(1,697)	(30,721)	(268,774)
April	Year 2021	268,774	0.5700%		(1,532)	(30,721)	(239,585)
May	Year 2021	239,585	0.5700%		(1,366)	(30,721)	(210,229)
June	Year 2021	210,229	0.5700%		(1,198)	(30,721)	(180,706)
July	Year 2021	180,706	0.5700%		(1,030)	(30,721)	(151,015)
August	Year 2021	151,015	0.5700%		(861)	(30,721)	(121,154)
September	Year 2021	121,154	0.5700%		(691)	(30,721)	(91,123)
October	Year 2021	91,123	0.5700%		(519)	(30,721)	(60,921)
November	Year 2021	60,921	0.5700%		(347)	(30,721)	(30,547)
December	Year 2021	30,547	0.5700%		(174)	(30,721)	0
					(13,303)		
Total Amount of True-Up Adjustment for 2015 ATRR					$	(368,657)	
Less Over (Under) Recovery					$	300,000	
Total Interest					$	(68,657)	

Calculation of Interest for 2019 True-Up Period							
					Monthly		
January	Year 2019	8,333	0.5700%	12.00	(570)		(8,903)
February	Year 2019	8,333	0.5700%	11.00	(523)		(8,856)
March	Year 2019	8,333	0.5700%	10.00	(475)		(8,808)
April	Year 2019	8,333	0.5700%	9.00	(428)		(8,761)
May	Year 2019	8,333	0.5700%	8.00	(380)		(8,713)
June	Year 2019	8,333	0.5700%	7.00	(333)		(8,666)
July	Year 2019	8,333	0.5700%	6.00	(285)		(8,618)
August	Year 2019	8,333	0.5700%	5.00	(238)		(8,571)
September	Year 2019	8,333	0.5700%	4.00	(190)		(8,523)
October	Year 2019	8,333	0.5700%	3.00	(143)		(8,476)
November	Year 2019	8,333	0.5700%	2.00	(95)		(8,428)
December	Year 2019	8,333	0.5700%	1.00	(48)		(8,381)
					(3,705)		**(103,705)**
					Annual		
January through December	Year 2020	(103,705)	0.5700%	12.00	(7,093)		**(110,798)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**110,798**	0.5700%		(632)	(9,579)	(101,851)
February	Year 2021	101,851	0.5700%		(581)	(9,579)	(92,853)
March	Year 2021	92,853	0.5700%		(529)	(9,579)	(83,803)
April	Year 2021	83,803	0.5700%		(478)	(9,579)	(74,702)
May	Year 2021	74,702	0.5700%		(426)	(9,579)	(65,549)
June	Year 2021	65,549	0.5700%		(374)	(9,579)	(56,344)
July	Year 2021	56,344	0.5700%		(321)	(9,579)	(47,086)
August	Year 2021	47,086	0.5700%		(268)	(9,579)	(37,776)
September	Year 2021	37,776	0.5700%		(215)	(9,579)	(28,412)
October	Year 2021	28,412	0.5700%		(162)	(9,579)	(18,995)
November	Year 2021	18,995	0.5700%		(108)	(9,579)	(9,525)
December	Year 2021	9,525	0.5700%		(54)	(9,579)	0
					(4,148)		
Total Amount of True-Up Adjustment for 2016 ATRR					$	(114,946)	
Less Over (Under) Recovery					$	100,000	
Total Interest					$	(14,946)	

Attachment 10
Depreciation Rates
Xcel Energy Southwest Transmission Company, LLC

FERC ACCOUNT	DESCRIPTION	RATE PERCENT	
TRANSMISSION			
E350	Land Rights	1.0300%	***
E352	Structures and Improvements	1.5397%	*
E353	Station Equipment	2.0285%	*
E354	Towers and Fixtures	1.8847%	*
E355	Poles and Fixtures	2.1496%	*
E356	Overhead Conductors & Devices	2.0973%	*
E357	Underground Conduit	1.3665%	*
E358	Underground Conductors & Devices	1.8416%	*
E359	Roads and Trails	1.4256%	**
GENERAL			
E302	Franchises and Consents	N/A	****
E303	Intangible Plant - 5 Year	20.0000%	*
E390	Structures and Improvements	2.1194%	*
E391	Office Furniture and Equipment	5.0671%	*
E391	Network Equipment	25.0000%	*
E392	Transportation Equipment - Auto	10.9667%	*
E392	Transportation Equipment - Light Truck	8.4139%	*
E392	Transportation Equipment - Trailers	6.9486%	*
E392	Transportation Equipment - Heavy Trucks	7.2364%	*
E393	Stores Equipment	5.0000%	*
E394	Tools, Shop and Garage Equipment	6.6672%	*
E395	Laboratory Equipment	10.0000%	*
E396	Power Operated Equipment	8.4139%	*
E397	Communication Equipment	11.1110%	*
E398	Miscellaneous Equipment	6.6672%	*

* NSPM approved rates per Docket No. ER14-1325-000.
** NSPW approved rate per Docket No. ER14-1325-000.
*** PSCo approved rate per Docket No. ER12-1589-000.
**** Electric Intangible Franchises are amortized over the life of the Franchise Agreement.

Attachment 11
True-Up Interest Calculation
Xcel Energy Southwest Transmission Company, LLC

	Monthly Interest Rate (Note A):				
1	1st Qtr	-	-		
2	2nd Qtr	-	-		
3	3rd Qtr	-	-		
4	4th Qtr	-	-		
5	1st Qtr	-	-		
6	2nd Qtr	-	-		
7	3rd Qtr	-	-		
8			-		
9	Avg. Monthly FERC Rate		-	-	
10	Average Short-term debt from Attachment 6				-

Prior Period Adjustments (See Note B)

		Adjustment	Amount	Interest	Total Adjustment
11	1	-	-	-	-
11a	2	-	-	-	-
11b	3	-	-	-	-
11c	4	-	-	-	-
…	…				-
..	…				-
12		Total			-

Notes:

A The Lower of the short-term debt on Attach 6 or the FERC Refund interest rate specified in CFR 35.19(a) for under recovery.
If there is no short-term debt, the rate specified in CFR 35.19(a) is used
The FERC Refund interest rate specified in CFR 35.19(a) for over recovery.

B Prior Period Adjustments are when an error is discovered relating to a prior true-up or refunds/surcharges ordered by FERC.

Attachment B

Formula Rate Protocols

Xcel Energy Southwest Transmission Company, LLC (XEST)

Attachment H – XEST

ANNUAL TRUE-UP, INFORMATION EXCHANGE,

AND CHALLENGE PROCEDURES

Section I. Applicability

The following procedures shall apply to XEST's calculation of its actual net revenue requirement, True-Up Adjustment, and projected net revenue requirement. The project-specific annual revenue requirements determined under the XEST formula are "up to" rates, i.e., ceiling rates, and permit XEST to discount the revenue requirement to the extent necessary to reflect the result of any cost commitment to SPP. In the Formula Rate Template, the effect of any such discount is removed from the projected revenue requirement and the actual revenue requirement, which ensures that customers receive the benefits of any discount.

Section II. Annual True-Up and Projected Net Revenue Requirement

A. Beginning on or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, XEST shall determine the Annual True-Up under this Attachment H - XEST and Section VII of these protocols, to derive a True-Up Adjustment to be included in XEST's projected net revenue requirement for the subsequent calendar year (the "Rate Year").

B. On or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, XEST shall provide the Annual True-Up, actual net revenue requirement, and True-Up Adjustment to SPP and cause such information to be posted on the SPP website. Within ten (10) days of such posting, XEST shall provide notice of such posting via the email exploder list. Interested Parties shall contact XEST at the following email address to be placed on the exploder list: XESTExploderList@xcelenergy.com.

C. On or before October 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent October 1, XEST shall provide the projected net revenue requirement to SPP and cause such information to be posted on the SPP website. Within ten (10) days of posting of the projected net revenue requirement, XEST shall provide notice of such posting to the email exploder list.

D. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

E. The Annual True-Up shall:

1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

2. Be based on XEST's FERC Form No. 1 reports for the prior calendar year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in the FERC Form No. 1 reports;[1]

4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the Annual True-Up results from the FERC Form No. 1 reports;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1 reports;

6. Identify all material adjustments made to the FERC Form No. 1 report data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 reports and any adjustments not shown in the FERC Form No. 1 reports;

7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the FERC Form No. 1 reports;

8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

    a. Identify any Accounting Changes, including:

        i. the initial implementation of an accounting standard or policy;

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1 It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from FERC Form No. 1 or reconcilable to FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The projected net revenue requirement shall:

1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement;

3. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the projected net revenue requirement;

4. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

    a. Identify any Accounting Changes, including:

        i. the initial implementation of an accounting standard or policy;

        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

        iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

        iv. the implementation of new estimation methods or policies that change prior estimates; and

        v. changes to income tax elections;

    b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

    c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement;

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

G. XEST shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") between the Publication Date and October 1. No less than seven (7) days prior to such Annual True-Up Meeting, XEST shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual True-Up Meeting and XEST shall provide notice of such meeting to the email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall (i) permit XEST to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from XEST about the Annual True-Up and True-Up Adjustment.

H. XEST shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") between the date that the projected net revenue requirement is posted to the SPP website (as described in Section II.C of these protocols) and October 31. No less than seven (7) days prior to such Annual Projected Rate Meeting, XEST shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual Projected Rate Meeting and XEST shall provide notice of such meeting to the email exploder list. The Annual Projected Rate Meeting shall (i) permit XEST to explain and clarify their projected net revenue requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from XEST about the projected net revenue requirement.

Section III. Information Exchange Procedures

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of XEST or by FERC order) to serve reasonable information and document requests on XEST ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) the extent or effect of an Accounting Change;

(2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the formula rate and procedures in these protocols;

(4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

(5) the prudence of actual costs and expenditures;

(6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or

(7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. XEST shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. XEST shall respond to all information and document requests by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by XEST or FERC.

C. XEST will cause to be posted on the SPP website all information requests from Interested Parties and XEST's response(s) to such requests; except, however, if responses to information and document requests include material deemed by XEST to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by XEST and the requesting party.

D. XEST shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing XEST's Annual True-Up or projected net revenue requirement.

Section IV. Challenge Procedures

A. Interested Parties shall have until January 31 following the Publication Date (unless such period is extended with the written consent of XEST or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify XEST in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until January 31 shall be referred to as the Review Period. If January 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.

B. A party submitting an Informal Challenge to XEST must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. XEST shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. XEST, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If XEST disagrees with such challenge, XEST will provide the Interested

Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31, and XEST must respond to all Informal Challenges by no later than February 28, unless the Review Period is extended by XEST or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

(b) Explain how the action or inaction violates the filed rate formula or protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the Annual True-Up projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(iii) the proper application of the formula rate and procedures in these protocols;

(iv) the accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form 1; or

(vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on XEST. Service to XEST must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on XEST's Informational Filing required under Section VI of these protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. XEST will cause to be posted on the SPP website all Informal Challenges from Interested Parties and XEST's response(s) to such Informal Challenges; except, however, if

Informal Challenges or responses to Informal Challenges include material deemed by XEST to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by XEST and the requesting party.

F. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by XEST will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by XEST on or before December 1 will be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to by XEST after December 1 will be reflected in the following year's Annual True-Up, as discussed in Section V of these protocols.

G. An Interested Party shall have until March 31 following the Review Period (unless such date is extended with the written consent of XEST to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on XEST on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as XEST's Informational Filing discussed in Section VI of these protocols. XEST shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, XEST shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in this Attachment H - XEST. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of XEST to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

J. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up or projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. XEST may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (i) amortization and depreciation rates, or (ii) Post-Employment Benefits Other Than Pensions rates. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

K. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with XEST in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to True-Up Adjustment or Projected Net Revenue Requirement

Except as provided in Section IV.F of these protocols, any changes to the data inputs, including but not limited to revisions to XEST's FERC Form No. 1 reports, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

Section VI. Informational Filings

A. By March 15 of each year, XEST shall submit to FERC an informational filing ("Informational Filing") of their projected net revenue requirement for the Rate Year, including their Annual True-Up and True-Up Adjustment. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that XEST has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, XEST shall provide notice of the Informational Filing via the email exploder list and shall cause SPP to post the docket number assigned to XEST's Informational Filing on the SPP website.

B. Any challenges to the implementation of the Attachment H - XEST formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-Up Adjustment

The True-Up Adjustment is developed on Attachment 3 and will be determined in the following manner:

(1) Actual transmission revenues for the previous year will be compared to Net Revenue Requirement not including any prior year True-Up Adjustment calculated in accordance with XEST's Attachment H of this Tariff for the previous year using XEST's FERC Form No. 1 for that same year to determine any over or under recovery ("True-Up Adjustment"). XEST shall cause the True-Up Adjustment and related calculations to be posted to the SPP website no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these protocols.

(2) Interest on any over recovery of the net revenue requirement, shall be determined on Attachment 11 of the formula rate. Interest on any under recovery of the net revenue requirement or any under recovery due to volume changes, shall be determined using the interest rate equal to XEST's actual short-term debt costs capped at the applicable FERC refund interest rate. In either case, the interest payable shall be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement or volume changes exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the twenty-one (21) months preceding October of the current year. The interest amount will be included in the projected costs made available on October 1 in accordance with Section II.C above.

(3) The Net Revenue Requirement for transmission services for the following Year shall be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment from the previous year, if any, including interest, as explained above.

(4) The XEST may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

Exhibit No. XES-100

Exhibit No. XES-100

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	**)** **)**	**Docket No. ER14-___-000**

DIRECT TESTIMONY
OF
TERESA M. MOGENSEN

ON BEHALF OF
XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF TERESA M. MOGENSEN

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DIRECT TESTIMONY OF
TERESA M. MOGENSEN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Teresa M. Mogensen. My business address is 250 Marquette Plaza, Suite 800, Minneapolis, Minnesota 55401.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Vice President – Transmission for Xcel Energy Services Inc. ("Xcel Energy Services"), a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a public utility holding company with, among other subsidiaries, four wholly owned, vertically integrated public utility operating company subsidiaries: Southwestern Public Service Company ("SPS"), Northern States Power Company, a Minnesota corporation ("NSPM"), Northern States Power Company, a Wisconsin corporation ("NSPW"), and Public Service Company of Colorado ("PSCo") (together, the "Xcel Energy Operating Companies"). Xcel Energy Services is the service company for the Xcel Energy holding company system and provides services to all subsidiaries of Xcel Energy.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Xcel Energy Southwest Transmission Company, LLC ("XEST"). Xcel Energy Transmission Holding Company ("Xcel Energy Transmission Holdco") is a wholly owned subsidiary of Xcel Energy. XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco. XEST is a Delaware limited liability company. XEST was formed in May 2014 to focus on development and ownership of transmission facilities located in the Southwest Power Pool, Inc. ("SPP") regional transmission organization ("RTO") region. A second wholly owned subsidiary of Xcel Energy Transmission Holdco, Xcel Energy Transmission Development Company, LLC ("XETD"), has been established to focus on development and ownership of transmission facilities located in the Midcontinent Independent System Operator, Inc. ("MISO") RTO region.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND BUSINESS EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering and a Masters Degree in Business Administration, both from Marquette University in Milwaukee, Wisconsin. I joined Xcel Energy Services in October 2007. In 2010, I became Vice President – Transmission. Prior to joining Xcel Energy Services, I was part of the leadership team that formed American Transmission Company, LLC ("ATC"), headquartered in Waukesha, Wisconsin, and held various leadership positions there, including Director of System Operations, Director of Engineering and Construction, and Director of Transmission Planning and Service. Prior to the formation of ATC, I held various engineering and managerial positions at Wisconsin Electric Power Company in Milwaukee, Wisconsin. I am a registered Professional Engineer in the state of Wisconsin and was previously a North American Electric Reliability Corporation ("NERC") certified System Operator. I also serve as Chair of the Board of Directors of the Midwest Reliability Organization ("MRO"), one of the eight Regional Entities responsible for development and enforcement of mandatory electric reliability standards adopted under Section 215 of the Federal Power Act.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. As Vice President – Transmission for Xcel Energy Services, I am responsible for overall leadership, direction, and management of the Xcel Energy transmission organization, which is an internal "business unit" which manages and operates the transmission systems owned by the four Xcel Energy Operating Companies. I am responsible for budgeting and financial analysis of the Xcel Energy transmission organization. On behalf of each of the Xcel Energy Operating Companies, I am responsible for the management of transmission line and transmission substation activities, including developing and executing transmission-related strategy and business plans for each Operating Company; transmission planning within the MISO and SPP RTOs, as well as in the WestConnect planning region in the Western Electricity Coordinating Council ("WECC"); development of the Xcel Energy Operating Companies' respective transmission facilities, including engineering, design, permitting, and siting; construction, maintenance, and operation of those facilities; interfacing with Xcel Energy's transmission project development partners, such as the entities in the NSPM/NSPW region participating in the CapX2020 transmission development initiative; and compliance with NERC standards and requirements applicable to the transmission assets and transmission operations of the Xcel Energy Operating Companies. As Vice President – Transmission, my responsibilities for XEST will be similar to my responsibilities for the Xcel Energy Operating Companies.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE A REGULATORY BODY?

A. Yes. In 2012, I submitted an affidavit in a complaint proceeding before the Commission in Docket No. EL12-28. I also have submitted testimony before the Colorado Public Utilities Commission regarding the PSCo resource plan submitted in response to the Colorado Clean Air Clean Jobs Act, and in various transmission-related proceedings before the Wisconsin Public Service Commission while employed at ATC.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to (1) provide an overview of this filing; (2) describe XEST and how it fits into the Xcel Energy Transmission Holdco and Xcel Energy corporate structure; and (3) explain why Xcel Energy formed XEST.

Q. OTHER THAN YOUR DIRECT TESTIMONY, ARE YOU SPONSORING ANY EXHIBITS?

A. No.

Q. WHAT OTHER WITNESSES ARE SUBMITTING TESTIMONY IN SUPPORT OF THIS APPLICATION?

A. In addition to my testimony, the following direct testimony is being submitted in support of this filing:

(1) The Direct Testimony of George E. Tyson, II, Vice President and Treasurer of Xcel Energy Services, Exhibit No. XES-200 ("Tyson Direct Testimony"). Mr. Tyson (i) explains the financial risks facing XEST as a newly formed entity focusing primarily on Order No. 1000 transmission projects; (ii) explains the sources of XEST's

initial and ongoing funding, including XEST's targeted credit profile; and (iii) supports XEST's cost of debt, return on common equity ("ROE"), and capital structure included in the Formula Rate Template.

(2) The Direct Testimony of Michael J. Rodriguez, Senior Director, Utility Accounting, for Xcel Energy Services, Exhibit No. XES-300 ("Rodriguez Direct Testimony"). Mr. Rodriguez describes the accounting matters related to activities associated with XEST, including the basis for XEST's request for a Commission rate determination authorizing regulatory asset treatment of XEST's prudently incurred costs not capitalized, including pre-commercial and formation costs.

(3) The Direct Testimony of Andrew H. Sawyer, Consultant, Capital Asset Accounting, for Xcel Energy Services, Exhibit No. XES-400 ("Sawyer Direct Testimony"). Mr. Sawyer supports XEST's proposed depreciation rates.

(4) The Direct Testimony of Adrien M. McKenzie, Vice President of FINCAP, Inc., Exhibit No. XES-500 ("McKenzie Direct Testimony"). Mr. McKenzie sponsors testimony regarding the appropriate ROE to be included in the XEST formula rate.

(5) The Direct Testimony of Alan C. Heintz, Vice President, Brown, Williams, Moorhead & Quinn, Inc., Exhibit No. XES-600 ("Heintz Direct Testimony"). Mr. Heintz supports the reasonableness of the proposed XEST transmission Formula Rate Template and Annual True-up, Information Exchange, and Challenge Procedures ("Protocols").

As such, my testimony provides an overview of XEST and the reasons for this filing, the Heintz Direct Testimony supports the Formula Rate and Protocols for which

XEST is requesting Commission approval, and the Tyson, Rodriguez, Sawyer, and McKenzie Direct Testimony all support components of or inputs to the proposed Formula Rate.

Q. PLEASE DESCRIBE XEST.

A. XEST was created to focus on development and ownership of transmission facilities in the SPP region, primarily through participation in the competitive solicitation process being implemented by SPP pursuant to the Commission's Order No. 1000. Under the SPP Open Access Transmission Tariff ("OATT"), SPP is expected to issue its first Request for Proposals ("RFP") to construct competitively bid transmission facilities in 2015, after the SPP Board of Directors approves the needed facilities in the 2015 SPP Transmission Expansion Plan ("STEP"). To be eligible to submit a proposal in response to an SPP RFP to be issued in 2015, XEST submitted to SPP on June 30, 2014 an application to be a Qualified RFP Participant. Although XEST's primary focus is on projects that emerge from SPP's Order No. 1000 process, XEST has not ruled out developing, owning, or acquiring transmission facilities outside of the SPP Order No. 1000 process, subject to all necessary state or federal approvals for such transactions or projects.

Q. WHAT IS THE PURPOSE OF THIS FILING?

A. In this proceeding, XEST is establishing a Formula Rate for ultimate inclusion in the SPP OATT. As described in the Heintz Direct Testimony, Exhibit No. XES-600, XEST's Formula Rate is composed of two parts: (1) an XEST Formula Rate Template, which will calculate, on a forward looking and project-by-project basis, an annual transmission revenue requirement ("ATRR") that will be included in Attachment H of the SPP OATT;

and (2) the Protocols, which establish the procedures for the annual forward looking rate update and the annual true-up to XEST's actual costs as reported in XEST's FERC Form 1, including information exchange and informal and formal challenge procedures available to interested parties, and an XEST informational filing to the Commission. In addition, the Protocols make clear that a project-specific revenue requirement determined under the Formula Rate Template is an "up to" rate, i.e., a ceiling rate that would permit XEST to discount its revenue requirement to the extent necessary to recognize any specific cost commitments XEST may make to SPP during the competitive solicitation process in connection with a particular project.

The Formula Rate provides XEST with the rate certainty and the rate flexibility XEST will need to compete in SPP's Order No. 1000 competitive solicitation and bid selection process. Rate certainty is provided by the Formula Rate Template, which calculates in a transparent way the ceiling revenue requirement XEST is authorized to charge if XEST is selected by SPP to construct and own a new transmission facility.

This regulatory certainty will be valuable to XEST as it interacts with SPP, with potential investors, and with potential transmission business partners. For example, when XEST submits a proposal in response to an RFP issued by SPP under Order No. 1000, one of the criteria by which SPP will judge XEST's proposal is a rate analysis. *See* SPP OATT, Attachment Y, Section III.2.f.4, which is currently pending before the Commission in Docket No. ER13-366. XEST is concerned that, if XEST does not have a Commission-accepted mechanism that calculates an ATRR, along with all necessary components of that ATRR, such as ROE and depreciation, then SPP and others will have reservations about the financial assumptions that are part of an XEST response to an SPP request for proposals. Acceptance of the XEST Formula Rate by the Commission would remove this potential obstacle to XEST's ability to compete in SPP's Order No. 1000 planning and competitive solicitation process.

Rate flexibility is provided by the Protocols, which state that the revenue requirements determined under the Formula Rate are "up to" rates, i.e., ceiling rates that permit XEST to discount its revenue requirements for projects to recognize any specific cost commitments XEST makes to SPP during the competitive solicitation process in connection with a particular project.

III. <u>THE TRANSMISSION FACILITIES OF THE XCEL ENERGY OPERATING COMPANIES</u>

Q. PLEASE DESCRIBE THE TRANSMISSION FACILITIES OWNED BY THE XCEL ENERGY OPERATING COMPANIES.

A. Between them, the four Xcel Energy Operating Companies own transmission assets in ten states and three Order No. 1000 planning regions. These transmission facilities are used to provide service to the retail distribution systems of each Operating Company and to wholesale loads, which includes service to the distribution systems of other utilities, electric cooperatives, and municipal utilities. The transmission facilities owned by the Xcel Energy Operating Companies are used to provide transmission service under the MISO Open Access Transmission Tariff, Energy and Operating Reserve Markets ("Tariff"), the SPP OATT, the Xcel Energy Operating Companies Joint OATT, and the WestConnect regional OATT. The Xcel Energy Operating Companies' current transmission investment stands at $4.49 billion (measured using year-end 2013 net plant in service numbers). These transmission facilities deliver energy to more than 1150 transmission substations spread over approximately 17,950 line miles of transmission facilities (69 kV and above). On behalf of the Xcel Energy Operating Companies, the Xcel Energy transmission organization is responsible for planning, operations, and overall management of the transmission systems owned by each of the Xcel Energy Operating Companies.

Q. DO ANY OF THE XCEL ENERGY OPERATING COMPANIES OWN TRANSMISSION FACILITIES LOCATED IN THE SPP REGION?

A. Yes. SPS owns transmission facilities in the SPP region.

Q. PLEASE DESCRIBE THE SPS TRANSMISSION SYSTEM.

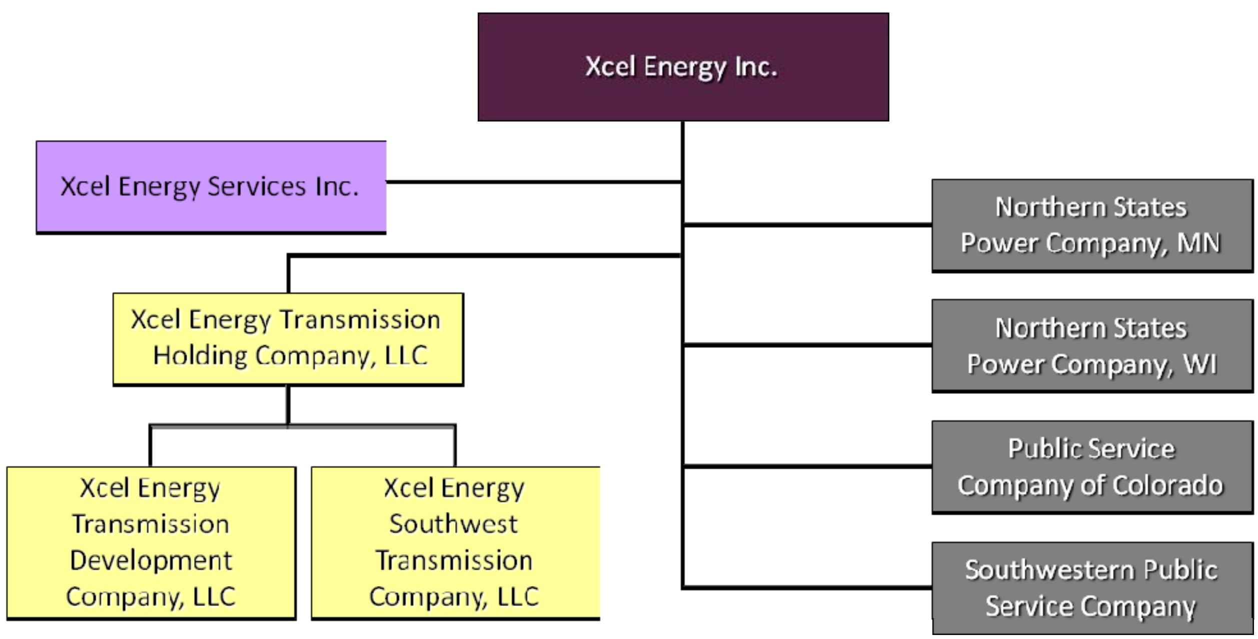
A. The SPS transmission system consists of facilities located in portions of four states: Texas, New Mexico, Oklahoma, and Kansas. The SPS transmission system serves approximately 376,000 wholesale and retail customers with an approximate peak demand of 6,000 MW. The SPS transmission system is comprised of approximately 5,300 miles of transmission circuits operating at or above 100 kV, including 600 miles of 345 kV transmission lines and 4,700 miles of 230 kV and 115 kV lines. Due to SPS's large geographic service region, SPS also has 1,600 miles of 69 kV transmission lines. SPS is located in the far southwestern corner of SPP and the Eastern Interconnection, and is connected to the Western Interconnection with three 200 MW high voltage back-to-back AC/DC/AC converters owned by El Paso Electric Company, Public Service Company of New Mexico, and PSCo, respectively. SPS is a transmission-owning member of SPP.

IV. <u>THE XCEL ENERGY CORPORATE STRUCTURE</u>

Q. PLEASE DESCRIBE THE CORPORATE STRUCTURE OF XEST WITHIN XCEL ENERGY.

A. Table 1, set forth below, shows the corporate structure of Xcel Energy's new transmission-only companies, and shows the corporate relationship between these transmission-only companies and the Xcel Energy Operating Companies.

TABLE 1: XCEL ENERGY CORPORATE STRUCTURE



As shown in Table 1, Xcel Energy Transmission Holdco is a first tier subsidiary of Xcel Energy, as is each of the Xcel Energy Operating Companies and Xcel Energy Services.

Q. WHY HAS XCEL ENERGY ESTABLISHED XEST?

A. Xcel Energy believes there will be a variety of circumstances where it will be advantageous to pursue Order No. 1000 competitive projects through a transmission-only company. Before Order No. 1000, the SPP OATT identified which of the existing SPP transmission owners would construct and own new, regionally planned transmission projects. However, under SPP's Order No. 1000 competitive solicitation process, companies now have the opportunity to bid on projects in response to specific transmission planning needs identified through the SPP regional transmission planning process. XEST was formed to be a transmission-only company whose primary focus is to compete in SPP's Order No. 1000 competitive solicitation process and to develop, construct, own, and operate new regionally cost allocated transmission facilities that emerge from that process.

Likewise, XETD was established to focus primarily on pursuing, developing, and owning transmission projects located in the MISO region. Xcel Energy may create additional subsidiaries of Xcel Energy Transmission Holdco in the future to focus on pursuing, developing, and owning transmission projects located in other regions.

Q. WHAT ARE THE BENEFITS OF ESTABLISHING XEST AS A TRANSMISSION-ONLY COMPANY FOCUSED ON PROJECTS IN SPP?

A. The separate ownership structure of XEST's transmission-only business allows XEST to compete for Order No. 1000 projects throughout the SPP region in a way that is separate and distinct from the business activities of SPS and the other Xcel Energy Operating Companies. This means that the business risks of XEST's focus on Order No. 1000 projects, including long-lead-time projects that could be located almost anywhere within the SPP region, will not be borne by SPS or its ratepayers. The costs of XETD facilities would be borne by SPS and its ratepayers only to the extent that XEST wins a project in the SPP region for which the SPP OATT allocates a portion of those costs to loads in the SPS pricing zone.

As discussed in the Tyson Direct Testimony, Exhibit No. XES-200, a separate XEST corporate entity permits Xcel Energy to finance transmission projects separately from projects financed by SPS or the other Xcel Energy Operating Companies. The financial flexibility and transparency of a separate transmission-only company should enhance Xcel Energy's ability to access capital markets, particularly in connection with large transmission projects. In addition, as a transmission-only company, XEST will be better able to participate in joint ventures or strategic partnership arrangements focused on regional transmission projects within SPP, including projects that may be located distant from the SPS transmission system.

Q. DOES XEST OWN OR OPERATE ANY TRANSMISSION FACILITIES TODAY?

A. No. XEST does not yet own any operational transmission facilities.

Q. WHAT KIND OF ASSETS WILL XCEL ENERGY TRANSMISSION HOLDCO OR XEST OWN?

A. It is not envisioned that Xcel Energy Transmission Holdco will own any transmission assets. Xcel Energy Transmission Holdco is a holding company for the transmission-only companies that will own transmission assets. As noted, XEST will pursue transmission projects approved in the SPP STEP and subject to SPP's Order No. 1000 competitive solicitation processes. In addition, XEST may pursue other projects whose costs would be recovered under the SPP OATT.

Q. WILL XEST HAVE ACCESS TO THE EXPERTISE AND MANAGEMENT PHILOSOPHY DEVELOPED BY THE XCEL ENERGY TRANSMISSION ORGANIZATION?

A. Yes. XEST does not currently have employees. XEST will rely on the expertise and the management philosophy developed by the Xcel Energy transmission organization. As explained above, the Xcel Energy transmission organization, which includes employees and contractors of Xcel Energy Services and the Xcel Energy Operating Companies, provides crucial planning, project development, operations, and management services and support functions to the Xcel Energy Operating Companies. XEST will secure these same services and support functions from the Xcel Energy transmission organization. This will enable XEST to apply the philosophy developed by Xcel Energy's transmission organization of advocating the best transmission plan and facilities to meet customers' needs, and to rely on the Xcel Energy transmission organization's proven approach to developing and constructing transmission projects.

V. RTO PARTICIPATION

Q. WILL XEST BECOME A MEMBER OF THE SPP RTO?

A. Yes. XEST will participate in SPP processes created to comply with Order No. 1000 by proposing, bidding on, developing, and owning new transmission projects. XEST will then transfer operational control of the transmission facilities it develops to SPP, and will become a transmission-owning member of SPP once it meets the requirements for being a transmission-owning member pursuant to the SPP Membership Agreement, SPP OATT and the SPP business practices. At the appropriate time, XEST will register with NERC and will become subject to the relevant NERC reliability standards.

Q. HOW WILL XEST PARTICIPATE IN THE SPP ORDER NO. 1000 COMPETITIVE SOLICITATION PROCESSES?

A. It is anticipated that SPP's first competitive solicitations will be issued in 2015 for certain regional transmission projects subject to competition under the SPP OATT and approved in the 2015 STEP. Xcel Energy Services personnel will represent XEST in the SPP planning and related study processes (just as they currently represent SPS in those processes). As part of the processes designed to comply with Order No. 1000, SPP will, among other things, evaluate the qualifications of potential developers and their proposed cost to develop, construct, operate, and maintain the transmission facilities defined within an RFP. XEST has submitted its application to be a Qualified RFP Participant. XEST plans to respond to the competitive solicitations issued by SPP with project-specific bids, and then develop and own the projects for which XEST is selected by SPP.

Q. PLEASE DESCRIBE THE RISKS TO XEST ASSOCIATED WITH ITS PARTICIPATION IN THE SPP ORDER NO. 1000 COMPETITIVE BIDDING PROCESSES.

A. XEST faces inherent risks due to its primary focus on pursuing transmission projects subject to the Order No. 1000 processes in the SPP region. The projects XEST will pursue are subject to competitive bidding by other entities that have chosen to register as Qualified RFP Participants in the SPP region. It is my understanding that, to date, more than 40 entities have applied to become Qualified RFP Participants, and therefore it is highly likely that multiple entities will submit proposals in response to each SPP competitive solicitation. XEST cannot expect to be the winning bidder on all of the projects on which it chooses to bid.

Because XEST will pursue projects within the SPP region, including projects that may be distant from the SPS transmission system, XEST also faces distinct risks associated with the development and completion of such projects. These include performing siting and land acquisition activities and pursuing regulatory approvals for projects in states or localities where the Xcel Energy Operating Companies, and thus the Xcel Energy transmission organization, do not presently do business.

In addition, the SPP region's Order No. 1000 processes are still evolving and subject to change, and therefore also contribute to considerable uncertainty for XEST. At the time of submission of this testimony, the Commission has not yet ruled on pertinent aspects of SPP's Order No. 1000 proposed compliance approach. For example, the provisions of SPP's OATT that define the information and supporting materials that must be submitted in response to an RFP are not yet final. These tariff requirements are found in Attachment Y of the SPP OATT, at Sections III.2.c, III.2.d, and III.2.e, which are currently pending before the Commission in Docket No. ER13-366. Also pending before the Commission are the SPP OATT provisions that define the criteria by which SPP's industry expert panel must evaluate such bids. *See* Sections III.2.b and III.2.f. of Attachment Y of the SPP OATT. Finally, litigation associated with the SPP competitive solicitation process is a possibility, which could result in an extended period of legal and regulatory uncertainty.

VI. <u>OTHER MATTERS</u>

Q. PLEASE EXPLAIN HOW XEST WILL RECOVER ITS COSTS IN RATES.

A. As discussed in the Heintz Direct Testimony, Exhibit No. XES-600, XEST requests Commission approval of the transmission Formula Rate proposed in this proceeding. For transmission projects XEST is selected to build and own, XEST will apply the approved Formula Rate, as ultimately included in the SPP OATT. XEST's revenue requirements will be included in the rates calculated according to the SPP OATT and billed to transmission customers taking transmission service under the SPP OATT. The specific proportions in which the cost of a project is allocated to various SPP transmission customers will depend on the project voltage and needs met by the project, as specified in the SPP OATT.

Q. WILL PROJECT DEVELOPMENT BY XEST IMPACT STATE REGULATORY AUTHORITY OVER CONSTRUCTION OF NEW TRANSMISSION FACILITIES?

A. No. The state commissions with jurisdiction over the determination of the need for a specific project and/or siting of new transmission facilities will have the same authority over XEST as they have over similar projects proposed by other transmission-only companies within those states. For example, to the extent state law and regulations apply similarly to both incumbent utilities and transmission only companies; XEST would follow the same processes for a new transmission project in Texas or New Mexico that SPS would follow for a project of similar size and voltage. XEST will apply the policies and methods of Xcel Energy's transmission organization, which has a strong track record of working with state commissions, regulatory staff, and interested stakeholders within the applicable processes in each state.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

TERESA M. MOGENSEN, being duly sworn, deposes and states: that the Direct Testimony of TERESA M. MOGENSEN was prepared by her or under her direct supervision, that the statements contained therein are true and correct to the best of her knowledge and belief, and that she adopts such prepared testimony as her direct testimony in this proceeding.

Teresa M. Mogensen

Subscribed and sworn before me this 25th day of August 2014.

Christopher C. Rogers
Notary Public
My commission expires: January 31, 2017

CHRISTOPHER C ROGERS
Notary Public
Minnesota
My Comm. Expires
Jan 31, 2017

WAI- 3190058v1

Exhibit No. XES-200

Exhibit No. XES-200

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	**)** **)**	**Docket No. ER14-___-000**

DIRECT TESTIMONY
OF
GEORGE E. TYSON, II

ON BEHALF OF
XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF GEORGE E. TYSON, II

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DIRECT TESTIMONY OF
GEORGE E. TYSON, II

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George E. Tyson, II. My business address is 414 Nicollet Mall, 4th Floor, Minneapolis, Minnesota.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Vice President and Treasurer for Xcel Energy Services Inc. ("Xcel Energy Services"), a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a public utility holding company with, among other subsidiaries, four wholly owned, vertically integrated public utility operating company subsidiaries: Southwestern Public Service Company ("SPS"), Northern States Power Company, a Minnesota corporation ("NSPM"), Northern States Power Company, a Wisconsin corporation ("NSPW"), and Public Service Company of Colorado ("PSCo") (together, the "Xcel Energy Operating Companies"). Xcel Energy Services is the service company for the Xcel Energy holding company system and provides services to all subsidiaries of Xcel Energy. I also am Vice President and Treasurer for Xcel Energy and each of the Xcel Energy Operating Companies.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Xcel Energy Southwest Transmission Company, LLC ("XEST"). Xcel Energy Transmission Holding Company ("Xcel Energy Transmission Holdco") is a wholly owned subsidiary of Xcel Energy. XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco. XEST is a Delaware limited liability company. XEST was formed in May 2014 to focus on development and ownership of transmission facilities located in the Southwest Power Pool, Inc. ("SPP") regional transmission organization ("RTO") region. A second wholly owned subsidiary of Xcel Energy Transmission Holdco, Xcel Energy Transmission Development Company, LLC ("XETD"), has been established to develop and own transmission facilities located primarily in the Midcontinent Independent System Operator, Inc. ("MISO") RTO region. I am Vice President and Treasurer of Xcel Energy Transmission Holdco, XEST and XETD.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND BUSINESS EXPERIENCE.

A. I received my Bachelor of Arts degree in Economics in 1988 from the University of Virginia and my Master of Business Administration degree with concentrations in Accounting and Finance in 1992 from the University of Chicago. Prior to joining Xcel Energy Services, I worked for Bankers Trust Company/Deutsche Bank Securities and Amoco Corporation. I have been employed by Xcel Energy Services since May 2002, first as Director of Origination in the Energy Markets function, then as Managing Director and Assistant Treasurer, and now in my current position as Vice President and Treasurer.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. As Vice President and Treasurer for Xcel Energy Services, I am responsible for recommending and implementing the financing required to achieve target capital structure objectives at Xcel Energy Inc. and at each of the Xcel Energy Operating Companies. For these same companies, I am responsible for corporate cash management, long-term financial forecasting, pension plan investment management, and hazard risk insurance. As Vice President and Treasurer of XEST, I am responsible for determining the appropriate capital structure for XEST and preparing and executing the financing required to achieve this targeted capital structure. This includes all equity and debt financings, such as inter-company loan agreements, bank credit facility agreements, construction loans, and long-term bond issuances.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified before the Federal Energy Regulatory Commission (the "Commission" or "FERC"), the Colorado Public Utilities Commission, the Minnesota Public Utilities Commission, the Public Service Commission of Wisconsin, the Public Utility Commission of Texas, and the New Mexico Public Regulation Commission.

II. <u>PURPOSE AND SUMMARY OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I first discuss the financial risks facing XEST as a newly formed transmission-only entity focusing primarily on FERC Order No. 1000 projects. Next, I discuss the sources of XEST's initial and ongoing funding, along with its targeted credit profile that should allow XEST to raise capital on a competitive basis. Finally, I recommend and provide support for XEST's cost of debt, return on equity, and target capital structure.

Q. IN ADDITION TO YOUR TESTIMONY, ARE YOU SPONSORING ANY OTHER EXHIBITS?

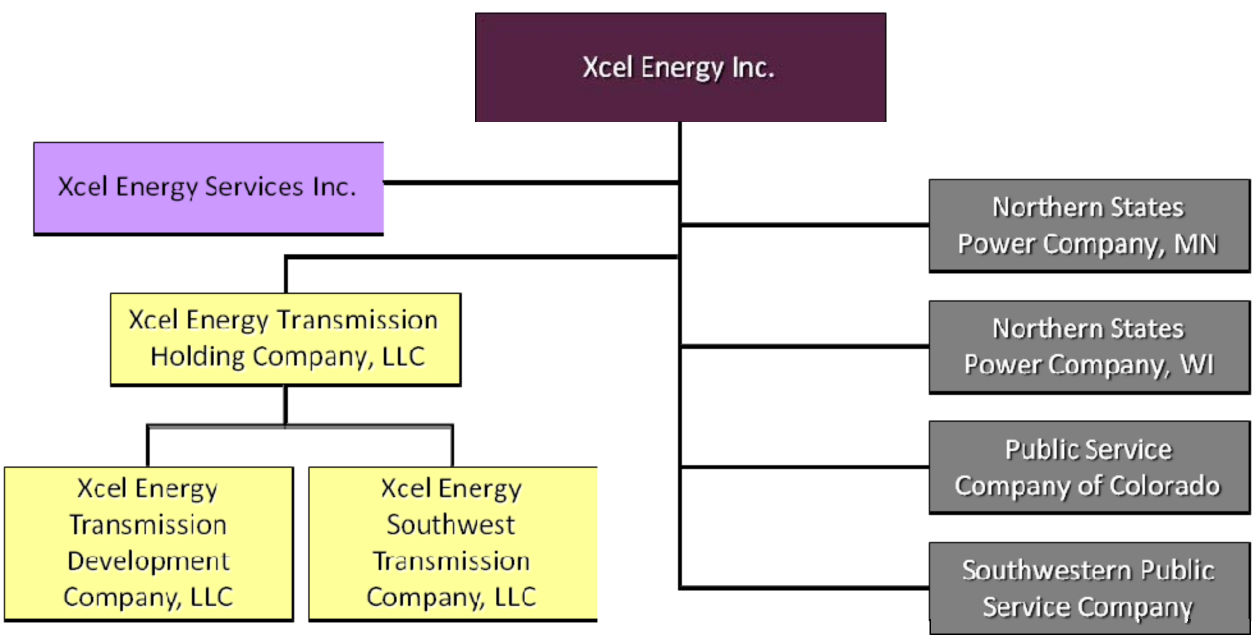
A. No.

III. FINANCIAL RISKS FACING XEST

Q. BRIEFLY DESCRIBE THE STRUCTURE OF XEST.

A. XEST is a limited liability company that was created for the sole purpose of developing, constructing, owning, and maintaining electric transmission assets, including new large scale projects. XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco, which is a wholly owned subsidiary of Xcel Energy. As discussed in the Mogensen Direct Testimony, Exhibit No. XES-100, XEST plans to develop transmission projects located in the SPP region. XETD, a second wholly owned subsidiary of Xcel Energy Transmission Holdco, was established for the purpose of developing transmission projects located in the MISO region. Table 1, set forth below, describes the current corporate structure of XEST and XETD, and shows the corporate relationship among these transmission development companies, the Xcel Energy Operating Companies, and Xcel Energy Services.

Table 1: Xcel Energy Corporate Structure



Q. WHEN WAS XEST FORMED?

A. XEST was formed in May 2014.

Q. AS A NEWLY FORMED ENTITY, DOES XEST FACE FINANCING RISKS?

A. Yes. Because it is a start-up transmission development company seeking to attract capital, XEST will face challenges in attracting capital unless it can demonstrate to potential investors that it can deliver the returns commensurate with its risk profile. XEST does not currently own any transmission assets and does not have any current or historic financials, credit history, or established credit ratings. XEST's business plan, capital structure, authorized Return on Equity ("ROE"), and cost-recovery mechanisms will therefore form the basis for investors to evaluate the company. The projected cash flows that investors will use to evaluate XEST will be significantly impacted by the Commission's acceptance of the proposed formula rate discussed in this proceeding ("Formula Rate"). Approval of the Formula Rate will help mitigate investor concerns about XEST being a newly formed entity with very limited financial history.

Q. DOES XEST FACE FINANCIAL RISKS DUE TO ITS FOCUS ON ORDER NO. 1000 PROJECTS?

A. Yes. The SPP Order No. 1000 planning and competitive solicitation process will affect XEST's ability to secure financing. As discussed in the Mogensen Direct Testimony, Exhibit No. XES-100, before Order No. 1000, the SPP Tariff identified which of the existing SPP transmission owners would construct and own new, regionally planned transmission projects. Under SPP's Order No. 1000 competitive solicitation process, however, a new company such as XEST now has the opportunity to bid on projects in response to specific transmission planning needs identified through the SPP regional transmission planning process. If the Commission's vision of the Order No. 1000 process is fulfilled, then multiple companies will submit rival proposals to build each identified project. XEST cannot expect to win all of the projects on which it chooses to bid. Under this new approach, there will be, for the first time, a bidding process and winners and losers in the business of building and owning new transmission facility projects.

As a company whose primary focus is on developing projects that are subject to the new Order No. 1000 competitive solicitation process in the SPP, XEST faces new risks that have not previously existed. To compete effectively, XEST will need to expend time and resources participating in the SPP's regional transmission planning process, evaluating projects for which XEST should bid, preparing and submitting bids, and taking any other steps needed to successfully win a project under SPP's Order No. 1000 process. Moreover, because XEST will pursue projects within the SPP region, including projects that may be distant from the SPS transmission system, XEST also faces certain new risks associated with the development and completion of such projects. These include performing siting and land acquisition activities, and pursuing regulatory approvals in states not presently served by the Xcel Energy Operating Companies. In addition, the SPP region's Order No. 1000 processes are still evolving and subject to change, and therefore also contribute to considerable uncertainty for XEST. These risks are discussed in the Mogensen Direct Testimony, Exhibit No. XES-100.

Q. DOES XEST FACE FINANCIAL RISKS DUE TO THE LARGE-SCALE PROJECTS THAT IT WILL BE PURSUING?

A. Yes. XEST faces additional financial risk given its focus on regionally planned and cost allocated projects. Many of the projects that emerge from the Order No. 1000 process are likely to be large-scale projects, where single projects could be located in multiple states or even multiple regions. These large-scale, regionally planned projects carry significant risk given the complexity, planning, acquisition of land rights, lengthy construction periods, and numerous legal and regulatory challenges that must be overcome. The long construction periods will pressure the credit profile of the company as capital is required to fund construction while revenue is limited, if it exists at all. The longer construction periods also increase the risk of project abandonment or cancellation due to unforeseen challenges or changed circumstances.

Q. HOW WILL XEST OBTAIN EQUITY FINANCING FOR ITS INITIAL START-UP AND FUTURE PROJECTS?

A. To fund its initial start-up operations, XEST plans to use paid-in-capital (equity investments) from its parent company, Xcel Energy Transmission Holdco. Once XEST is generating a revenue stream, it will use a combination of retained earnings and additional paid-in-capital from Xcel Energy Transmission Holdco to fund its ongoing investments and maintain the equity balance necessary to achieve its target equity ratio.

XEST does not plan to sell equity interests in the company at this time. However, if it chooses to do so, establishing XEST as a separate company should simplify the process of bringing additional equity investors into this transmission-only line of business. XEST's ownership structure also should simplify the process for pursuing partnerships and joint venture opportunities. With its focus on large regional projects, there may be opportunities for XEST to seek joint ownership arrangements in an effort to diversify financial risk and minimize potential state regulatory risk.

Q. HOW WILL XEST OBTAIN DEBT FINANCING FOR ITS INITIAL START-UP AND FUTURE PROJECTS?

A. Initially, XEST will secure its debt financing by borrowing short-term debt through an inter-company loan agreement with Xcel Energy Transmission Holdco. After XEST is selected to develop a specific project and construction expenditures can be projected, XEST plans to put in place either a revolving credit facility or a construction loan agreement to provide financing for short-term working capital requirements and project construction expenditures. As a project nears commercial operation and permanent financing can be utilized, XEST plans to access long-term debt financing through either public or private issuances of long-term debt securities.

Q. HOW DOES XEST EXPECT TO RAISE CAPITAL AT A REASONABLE COST?

A. In order for XEST to attract and secure financing at a reasonable cost, the company will need to maintain a strong credit profile that allows investors to be confident in the financial health and integrity of the company. To achieve that, XEST is targeting a corporate credit profile that is within the guidelines set forth by Standard & Poor's and Moody's for a BBB+/Baa1 investment grade credit rating. This investment grade rating is common among utility companies and XEST's target credit profile should provide the company with the opportunity to attract capital at competitive costs. Under the Xcel Energy corporate umbrella, XEST would be within one notch of Xcel Energy and the Xcel Energy Operating Companies, given that each of these entities currently has an A- corporate credit rating from Standard & Poor's.

Q. WHY IS IT IMPORTANT TO TARGET A CREDIT PROFILE THAT SUPPORTS AN INVESTMENT GRADE RATING?

A. A financially healthy utility with a strong credit profile is able to access capital at reasonable costs and has the flexibility to manage through difficult times, either when access to capital may be limited due to macroeconomic conditions that may affect capital markets or to manage through the unforeseen cash flow volatility related to building large, complex transmission projects. As a developer of projects that may span several years, it is imperative to maintain access to capital throughout all types of economic cycles. During credit-constrained periods such as the recent recession, companies with strong credit profiles are generally able to issue debt at reasonable rates while companies with weaker credit profiles may need to issue securities at a premium, if they are able to issue at all.

Q. HOW DOES XEST EXPECT TO ACHIEVE ITS TARGETED CREDIT PROFILE?

A. XEST's recommended capital structure is an essential prerequisite for ultimately establishing the cash flows necessary to maintain an investment grade credit profile. The combination of XEST's recommended capital structure, depreciation rates, ROE, and formula rate recovery should produce financial metrics that are within the current guidelines provided by the rating agencies for companies facing similar business risk (i.e., Commission-regulated electric transmission-only entities). Moreover, as discussed below, XEST is seeking a capital structure that is in alignment with other transmission entities that have credit profiles that are within the investment grade guidelines.

IV. SUPPORT FOR RECOMMENDED CAPITAL STRUCTURE, COST OF DEBT, AND COST OF EQUITY

Q. WHAT CAPITAL STRUCTURE IS XEST PROPOSING?

A. XEST is proposing a target fixed initial capital structure of 55% equity and 45% debt.

Q. DOES XEST PLAN TO UTILIZE DIFFERENT ACTUAL AND RATEMAKING CAPITAL STRUCTURES PRIOR TO XEST'S FIRST TRANSMISSION PROJECT GOING INTO SERVICE?

A. While XEST plans to use its actual capital structure for ratemaking purposes once it has a project in service, XEST is requesting approval of a fixed capital structure of 55% equity and 45% long-term debt through the construction period of its first transmission facility. XEST will use its actual capital structure (targeted at 55% equity and 45% long-term debt) once its first transmission project reaches commercial operation.

Q. WHY IS A FIXED CAPITAL STRUCTURE REASONABLE FOR XEST?

A. XEST's actual capital structure will likely fluctuate based on the amount, timing, and frequency of capital infusions (borrowings and equity infusions) that are needed to fund the construction cycle of a large transmission project. These fluctuations may drive significant volatility in the company's early-stage debt and equity ratios given that XEST will have no other assets to smooth out these changes. By adopting a fixed capital structure during the construction period, XEST's level of cash flow will become more predictable (if a construction work in progress ("CWIP") incentive, which XEST is not seeking at this time, is sought at a later date), thereby helping XEST raise capital at more reasonable costs, remain competitive with its cost of capital in the new bidding environment, and lower rates for customers taking service under the SPP Tariff.

Q. WHY IS AN INITIAL CAPITAL STRUCTURE OF 55% EQUITY AND 45% DEBT REASONABLE FOR XEST?

A. A 55% equity capital structure is one of the major components to achieving a strong credit profile and investment grade credit rating. As discussed above, it is critical that a utility maintain its credit quality in order to maintain access to capital and avoid the increased costs of financing that XEST would incur with a weaker credit profile. Given its risks as a start-up entity and the risks associated with pursuing large regional transmission projects open to competitive bidding, it will be important for XEST to have a capital structure that helps balance some of those risks. The capital structure being requested should help alleviate some of these risks since it is near the top end of the capital structure guideline for a Baa investment grade rating from Moody's Investor Service. Moreover, XEST's recommended capital structure is an essential prerequisite for XEST to demonstrate that it will have the future cash flows necessary to achieve its targeted credit profile and attract financing at a reasonable rate.

Q. HOW DOES THE PROPOSED CAPITAL STRUCTURE COMPARE TO THE CAPITAL STRUCTURE OF OTHER TRANSMISSION OWNING ENTITIES?

A. In comparison to the capital structure of other transmission owning entities, a 55% equity ratio is well within the range in the industry. Each year, MISO posts on its website Attachment O data showing the debt and equity levels of every MISO entity using an Attachment O formula rate. This data shows that the average actual capital structure for MISO transmission owners is roughly 55% equity and 45% long-term debt. Similarly, the SPP includes on its website the transmission formula rate true ups of each SPP member that must prepare such a true up. Excluding from consideration the cooperatives Midwest Energy, Inc. (39% equity) and Lincoln Electric System (25% equity) and the few public power entities that reported a debt service coverage ratio calculation instead of a traditional capital structure calculation, the SPP true-up information shows that the equity ratios of these SPP members generally range between 48% and 60% equity. XEST's proposed capital structure fits well within the range of actual capital structures of the SPP members. Lastly, the recommended 55% equity capital structure is in line with the capital structures of the Xcel Energy Operating Companies. Based on 2013 year-end 10-K information, the equity ratios for the Xcel Energy Operating Companies were between 53% and 56.5% (equity as a percentage of equity plus long-term debt). SPS, which is a member of SPP, currently has a 53.89% equity ratio in its SPP formula rate for 2014. XEST's recommended capital structure is reasonable given the current capital structures in the market and will provide XEST with a sound financial foundation to compete for projects in SPP's competitive solicitation processes.

Q. WHAT COST OF DEBT IS XEST REQUESTING IN ITS FORMULA RATES?

A. XEST's projected cost of long-term debt is 6.38% as shown on Attachment 8 to the Formula Rate Template, attached as Exhibit No. XES-602 to the Heintz Direct Testimony. This represents the estimated effective interest rate for a revolving credit facility using a hypothetical $250 million loan value, a hypothetical capital expenditure pattern, estimated credit facility origination fees, and estimated annual expenses. The interest expense on the drawn loan amount is based on the forward curve for the three-month London Interbank Offered Rate ("LIBOR") (as of August 15, 2014) plus a credit spread of 200 basis points. Under the current forward curve, the LIBOR is forecasted to increase from 0.2% in 2014 to 3.2% in 2020, which results in higher projected financing costs over the forecast period. The estimated credit spread of 200 basis points is based on the expectation that XEST would not have a credit rating when it secures its initial revolving credit facility or construction financing. The interest rate that XEST estimates that it will incur once debt is issued also is shown on Attachment 8 to the Formula Rate Template. At the time XEST is able to secure either a revolving credit facility or a construction loan, XEST will then include the actual costs for this type of credit agreement into its actual cost of debt (as set forth in that revolving credit facility or construction loan agreement) in the Formula Rate. At the time of commercial operation, XEST would expect to refinance the revolving credit facility or the construction loan with long-term debt financing, which would then factor into XEST's actual cost of debt in the Formula Rate.

Q. WHAT COST OF EQUITY IS XEST REQUESTING IN ITS FORMULA RATES?

A. As discussed in the McKenzie Direct Testimony, Exhibit No. XES-500, XEST is recommending a base ROE of 10.64 percent, plus the 50 basis point RTO membership adder given XEST's membership in SPP, for a total ROE of 11.14 percent.

Q. WHY IS IT IMPORTANT THAT XEST BE GRANTED THE REQUESTED ROE?

A. The requested ROE represents the return that is commensurate with the risk that XEST's equity investors bear. Without an adequate return, it will be challenging for XEST to attract the significant amount of equity capital that will be required to build large-scale regional transmission projects. This is particularly true in the early stages of XEST. While XEST is targeting a credit profile that will support a BBB+/Baa1 credit rating, it is a start-up entity that does not have a financial history nor does it currently have assets that are producing a revenue stream. As discussed earlier, XEST is preparing to participate in the first Order No. 1000 solicitation process in SPP in 2015. There is significant uncertainty and risk in the process given the investment in planning and bidding that will be required while the probability of securing projects is unknown.

Therefore, it is critical to provide XEST with an ROE that adequately addresses these risks and provides XEST with the ability to attract capital for its transmission investment plans.

Q. PLEASE DISCUSS THE IMPACT OF THE "UP-TO" RATE PROVISION ON INVESTMENTS IN XEST.

A. Through its calculation of a ceiling transmission revenue requirement, the Formula Rate meets XEST's need to offer the investment community an opportunity to earn a return commensurate with the investment risks. At the same time, the up-to rate provision provided for in the Formula Rate gives XEST the ability to discount below the ceiling revenue requirement when submitting a bid to SPP on a specific project, if XEST decides that it makes business sense to offer such a discount. This up-to rate may result in XEST collecting less than its ceiling revenue requirement for a specific project. At the time it develops and submits a response to an SPP request for proposals, XEST will need to evaluate what risks can be borne by XEST and its investors compared to the ceiling revenue requirement that otherwise would have been calculated and recovered through the Formula Rate.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

GEORGE E. TYSON, II, being duly sworn, deposes and states: that the Direct Testimony of GEORGE E. TYSON, II was prepared by him or under his direct supervision, that the statements contained therein are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

George E. Tyson, II

George E. Tyson II

Subscribed and sworn before me this 26th day of August 2014.

Sharon M. Quellhorst

Name: Sharon M. Quellhorst
Notary Public
My commission expires: 1/31/2015

SHARON M. QUELLHORST
Notary Public-Minnesota
My Commission Expires Jan 31, 2015

Exhibit No. XES-300

Exhibit No. XES-300

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

DIRECT TESTIMONY
OF
MICHAEL J. RODRIGUEZ

ON BEHALF OF
XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF MICHAEL J. RODRIGUEZ

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DIRECT TESTIMONY OF
MICHAEL J. RODRIGUEZ

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael J. Rodriguez. My business address is 1800 Larimer Street, 12th Floor, Denver, Colorado 80202.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Senior Director, Utility Accounting, for Xcel Energy Services Inc. ("Xcel Energy Services"), a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a public utility holding company with, among other subsidiaries, four wholly owned, vertically integrated public utility operating company subsidiaries: Southwestern Public Service Company ("SPS"), Northern States Power Company, a Minnesota corporation ("NSPM"), Northern States Power Company, a Wisconsin corporation ("NSPW"), and Public Service Company of Colorado ("PSCo") (together, the "Xcel Energy Operating Companies"). Xcel Energy Services is the service company for the Xcel Energy holding company system, and provides services to all subsidiaries of Xcel Energy.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Xcel Energy Southwest Transmission Company, LLC ("XEST"). Xcel Energy Transmission Holding Company, LLC ("Xcel Energy Transmission Holdco") is a wholly owned direct subsidiary of Xcel Energy. XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I obtained a Bachelor of Science degree in Business Administration with an emphasis in Finance from the University of Colorado, Boulder, in 1995, and a Master of Business Administration degree with an emphasis in Finance and Accounting from Regis University, Denver, in 2011.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed by Xcel Energy Services since August 2005 and have held the following positions: Team Lead, Energy Settlements; Manager, Energy Settlements; Sr. Manager, Transmission Accounting; Director, Utility Accounting; and my current position as Senior Director, Utility Accounting. Prior to working for Xcel Energy Services, I was a Senior Operations Manager for Transamerica, and prior to that an Accounting and Finance Officer for the United States Air Force.

Q. BRIEFLY OUTLINE YOUR RESPONSIBILITIES AS SENIOR DIRECTOR, UTILITY ACCOUNTING.

A. I am responsible for managing personnel performing certain accounting and financial functions for Xcel Energy Services. Utility Accounting supports commercial accounting, regulatory accounting, transmission accounting, retail revenue accounting, and market operations accounting.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified before the Federal Energy Regulatory Commission ("Commission") and the Public Utility Commission of Texas.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to (i) describe XEST's accounting methods in support of XEST's formula rate filing, and (ii) provide the basis for XEST's request that the Commission provide a rate determination that XEST is authorized to recover as a regulatory asset its prudently incurred pre-commercial and formation costs that are not capitalized.

Q. OTHER THAN YOUR TESTIMONY, ARE YOU SPONSORING ANY EXHIBITS?

A. No.

III. DESCRIPTION OF XEST'S ACCOUNTING

Q. PLEASE DESCRIBE HOW XEST ACCOUNTS AND WILL ACCOUNT FOR REVENUES AND EXPENSES THAT RESULT FROM ITS BUSINESS OPERATIONS?

A. XEST uses and will continue to use the accrual method of accounting as required by Generally Accepted Accounting Principles ("GAAP") to record revenues and expenses. Because XEST will be a transmission-only public utility regulated by the Commission, these revenues and expenses are recorded and will continue to be recorded in accounts prescribed by the Commission's Uniform System of Accounts.

Q. BRIEFLY DESCRIBE THE CORPORATE RELATIONSHIP BETWEEN XCEL ENERGY AND XEST.

A. As discussed in the Mogensen Direct Testimony, Exhibit No. XES-100, XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco, which is a wholly owned subsidiary of Xcel Energy. Xcel Energy Transmission Holdco has one other wholly owned subsidiary, Xcel Energy Transmission Development Company, LLC ("XETD").

Q. HOW WILL XEST RECORD EQUITY CONTRIBUTIONS?

A. XEST will record the receipt of contributions from Xcel Energy Transmission Holdco as equity on its balance sheet. Xcel Energy Transmission Holdco will record contributions made to subsidiaries such as XEST as investments in subsidiaries on its balance sheet.

Q. HOW WILL XEST RECORD TRANSACTIONS FOR ACCOUNTING PURPOSES?

A. Transactions will be recorded on the books of XEST. Consequently, the financial books and records of XEST will reflect the assets, liabilities, equity, and results of operations for XEST.

Q. WILL XEST RECORD INCOME TAXES?

A. XEST will be a pass-through entity for income tax purposes and therefore will not directly pay income taxes on its earnings. XEST will maintain its books of account based on the Commission's Uniform System of Accounts as if it were a taxable corporation. Therefore, XEST will record income taxes in its separate books of account, though these taxes will be paid by the appropriate taxpaying entity.

Q. PLEASE DESCRIBE THE TYPES OF EXPENSES XEST EXPECTS TO INCUR.

A. XEST will incur (i) native costs, and (ii) direct and allocated costs from its affiliates. At least initially, XEST is not expected to have any employees, so services will be provided by Xcel Energy Services and certain of the Xcel Energy Operating Companies.

XEST's native expenses are expected to consist primarily of billings from third parties pursuant to contracts entered into directly by XEST.

Charges from affiliates to XEST will include both direct charges and allocations. Xcel Energy Services operates under the principle that all costs that can be directly charged to a specific Xcel Energy subsidiary should be directly charged, and allocation factors used for those costs that cannot be directly charged. Direct charges are associated with services provided to XEST by employees or contractors of an affiliate, which are then charged only to XEST. For example, if an Xcel Energy Services accounting employee works on XEST activities, that employee will charge his or her time to an XEST work order, which directly charges the cost of that work to XEST. The charge for such a service is comprised of a direct labor charge and overhead costs related to that direct charge, which include, but are not limited to, salaries and wages, pension, lost time, incentive compensation, health care, workers compensation, payroll taxes, and facilities costs. Xcel Energy Services bills and will continue to bill these direct charges to XEST in the same way direct charges are billed to an Xcel Energy Operating Company for similar work.

As another example, if a contractor of Xcel Energy Services – such as a consulting firm or a contract transmission planning engineer retained by Xcel Energy Services – provides services specifically to XEST, Xcel Energy Services would charge XEST for the direct cost of that work as billed by the contract vendor, in the same way such charges are billed to an Xcel Energy Operating Company.

Similarly, if an employee of an Xcel Energy Operating Company, such as SPS, were to provide services to XEST for a specific project, that employee will charge his or her time to an XEST work order, which will directly charge the cost of that work to XEST. In that manner, XEST is charged for that employee’s time and labor-related overheads, rather than the employee’s operating company.

Allocated costs are comprised of XEST's allocated share of the centrally managed services of Xcel Energy Services that benefit all subsidiary companies. For example, Xcel Energy Services provides services that include, but are not limited to, executive management, accounting, financial reporting, finance, treasury, corporate communications, property services, human resources, information technology, environmental, legal, regulatory, customer services, engineering, transmission management, and support. Xcel Energy Services has established procedures in place for allocating these types of costs to companies within the Xcel Energy holding company system. All services provided to XEST by Xcel Energy Services will be priced at cost, as will all goods and services provided to XEST by the Xcel Energy Operating Companies.

Some costs will be incurred by Xcel Energy Transmission Holdco rather than by XEST or XETD. Any costs incurred by Xcel Energy Transmission Holdco that are directly related to XEST will be transferred to XEST. Initially, costs incurred on behalf of both XEST and XETD are being charged evenly between the two subsidiaries, at cost.

Q. ARE XEST'S ACCOUNTING METHODS CONSISTENT WITH GAAP AND THE COMMISSION'S UNIFORM SYSTEM OF ACCOUNTS?

A. Yes.

IV. <u>SUPPORT FOR RATE DETERMINATION FOR REGULATORY ASSET TREATMENT</u>

Q. HOW HAS XEST BEEN ACCOUNTING FOR COSTS INCURRED TO-DATE?

A. XEST has expensed costs to date as incurred.

Q. ARE THERE ANY CONTROLS IN PLACE TO MONITOR THE EXPENSES RELATED TO XEST?

A. Yes. Utility Accounting established a formal process for Xcel Energy Services or Operating Company employees to request approval to charge pre-commercial and formation costs to XEST. Additionally, reports are reviewed on a monthly basis to track expenses and to monitor individuals charging XEST.

Q. IS XEST SEEKING AUTHORITY FOR REGULATORY ASSET TREATMENT FOR ITS PRUDENTLY INCURRED COSTS THAT ARE NOT CAPITALIZED, SUCH AS PRE-COMMERCIAL AND FORMATION COSTS?

A. Yes. As discussed in the Mogensen Direct Testimony, XEST was formed to develop transmission projects through the Order No. 1000 planning and competitive solicitation process to be operated by Southwest Power Pool, Inc. ("SPP"). In comparison to the situation that existed prior to Order No. 1000, participating in an RTO's Order No. 1000 process requires a company to be formed long before a specific project will be developed, and requires the company to incur organization and administrative costs, including higher and new types of costs, to successfully develop and complete a transmission construction project. XEST is requesting authority to defer as a regulatory asset its prudently incurred costs that are not capitalized, such as pre-commercial and formation costs, for which it will be seeking future rate recovery. XEST proposes to defer as a regulatory asset in account 182.3, Other Regulatory Assets, pre-commercial and formation costs incurred prior to XEST first charging customers under its formula rate, which will be part of the SPP Open Access Transmission Tariff ("OATT"). Without a Commission order granting XEST the authority to defer these non-capitalized costs as a regulatory asset, it may be more difficult to recognize a regulatory asset for pre-commercial and formation costs for

GAAP financial reporting purposes, which would impose a real financial burden on XEST during the first several years of operation, as it seeks to propose and then construct specific projects.

Q. WHAT TYPES OF COSTS WILL XEST INCLUDE IN THE REGULATORY ASSET ACCOUNT, IF APPROVED?

A. XEST will include its prudently incurred pre-commercial and formation costs that are not capitalized, including costs associated with obtaining the necessary approvals from the Commission, SPP, and other relevant governmental and regulatory authorities, as well as organization and administrative costs. This includes costs that ordinarily would be recognized as expenses, including but not limited to attorney fees; consultant fees; administrative expenses; entity formation costs; travel expenses; and costs to support regional activities that have been or will be undertaken with respect to SPP's Order No. 1000 planning and solicitation processes.

Q. IS XEST SEEKING COMMISSION APPROVAL TO APPLY A CARRYING CHARGE TO BALANCES INCLUDED IN THIS REGULATORY ASSET ACCOUNT?

A. Yes. As part of this filing, XEST is requesting Commission approval to apply a carrying charge to any amounts eligible for deferral to this regulatory asset account. When the regulatory asset is established, XEST will accrue carrying costs at a rate equal to its allowance for funds used during construction ("AFUDC") on the unamortized cost balances, including the balance of deferred carrying costs, until a rate is first charged by XEST through the SPP OATT. At the time XEST first begins charging a rate through the SPP OATT, XEST will stop calculating this carrying charge using the AFUDC rate, and will begin to calculate this carrying charge at its weighted cost of capital rate. When applying these rates, XEST will calculate the carrying charge semi-annually. Any such carrying charges will be recorded by debiting Account 182.3 and crediting Account 421, Miscellaneous Non-operating Income.

Q. DOES COMMISSION APPROVAL OF REGULATORY ASSET TREATMENT IN THIS DOCKET ENSURE RECOVERY OF THE DEFERRED COSTS?

A. No. XEST is not seeking advance authorization for a specific mechanism by which to recover this regulatory asset (such as recovering the regulatory asset balance over a period of years). XEST recognizes that such a specific pre-approval of recovery would require one or more further filings by XEST, such as a project-specific rate incentive filing under Order No. 679. In addition, XEST recognizes that yet another filing with the Commission will be required at the time XEST seeks to include amortization of the regulatory asset account in rates. XEST's request for a rate determination that XEST is authorized to recover as a regulatory asset all of its prudently incurred pre-commercial and formation costs that are not capitalized simply preserves the opportunity for XEST to seek recovery in a future filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

MICHAEL J. RODRIGUEZ, being duly sworn, deposes and states: that the Direct Testimony of MICHAEL J. RODRIGUEZ was prepared by him or under his direct supervision, that the statements contained therein are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

Michael J. Rodriguez

Subscribed and sworn before me this 25th day of August 2014.

Mia L. Buffard
Notary Public
My commission expires: November 15, 2015

MIA L. BUFFARD
NOTARY
PUBLIC
STATE OF COLORADO
My Commission Expires 11/15/2015

WAI-3190060v1

Exhibit No. XES-400

Exhibit No. XES-400

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	**)** **)**	**Docket No. ER14-___-000**

DIRECT TESTIMONY AND EXHIBITS
OF
ANDREW H. SAWYER

ON BEHALF OF
XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF ANDREW H. SAWYER

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DIRECT TESTIMONY OF
ANDREW H. SAWYER

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Andrew H. Sawyer, 414 Nicollet Mall, Minneapolis, MN 55401-1993.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am Consultant, Capital Asset Accounting, for Xcel Energy Services Inc. ("Xcel Energy Services"), a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is a public utility holding company with, among other subsidiaries, four wholly-owned, vertically integrated public utility operating company subsidiaries: Southwestern Public Service Company ("SPS"), Northern States Power Company, a Minnesota corporation ("NSPM"), Northern States Power Company, a Wisconsin corporation ("NSPW"), and Public Service Company of Colorado ("PSCo") (together, the "Xcel Energy Operating Companies"). Xcel Energy Services is the service company for the Xcel Energy holding company system, and provides services to all subsidiaries of Xcel Energy.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Xcel Energy Southwest Transmission Company, LLC ("XEST"). Xcel Energy Transmission Holding Company, LLC ("Xcel Energy Transmission Holdco") is a direct wholly-owned subsidiary of Xcel Energy. XEST is a wholly owned subsidiary of Xcel Energy Transmission Holdco.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I obtained a Bachelor of Science degree in Accountancy from the University of Notre Dame in 2005, and a Master of Science in Accountancy from the University of Notre Dame in 2006. I have been employed by Xcel Energy Services since August 2009 and have held the following positions: Technical Accounting Analyst; External Reporting Analyst; Senior External Reporting Analyst; Senior Depreciation Analyst; and my current position is Capital Asset Accounting Consultant. Prior to working for Xcel Energy Services, I was an External Auditor for Ernst & Young, LLP.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

A. No. However, I have assisted with the preparation of written testimony for regulatory proceedings in the following state jurisdictions: Colorado, Minnesota, New Mexico, North Dakota, South Dakota, and Texas. The testimony with which I assisted has been included in dockets related to the establishment of general rates as well as accounting matters such as depreciation studies, theoretical reserve analyses, and remaining life determinations. I have also assisted in the preparation of filings submitted to the Federal Energy Regulatory Commission ("FERC" or "Commission") involving changes to the depreciation rates of NSPM and NSPW (the "NSP Companies") used in the Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (the "Interchange Agreement"), which is a wholesale formula rate agreement between NSPM and NSPW on file with the Commission that allocates the electric production (generation) and transmission costs of the integrated NSP System between the NSP Companies.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the proposed depreciation rates for transmission and general plant included in the proposed formula rate ("Formula Rate") filed by XEST. Company witness Mr. Alan Heintz discusses the formula rate.

Q. OTHER THAN YOUR TESTIMONY, ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

Exhibit No.	Description
XES-401	XEST proposed depreciation rate summary
XES-402	Exhibit IX to the Interchange Agreement depreciation rates
XES-403	PSCo Attachment O depreciation rate for Account 350

III. PROPOSED DEPRECIATION RATES

Q. WHAT IS THE PURPOSE OF DEPRECIATION?

A. Depreciation expense is an annual charge to reflect the declining remaining life of each asset over time. As described in the Rodriguez Direct Testimony, XEST will be a public utility and will conduct its accounting consistent with the Commission's Uniform System of Accounts. Each group of like-kind assets identified in the Commission's 300-series plant sub-account is assigned an expected total average service life reflecting the total expected operating life of the asset. Over time, depreciation expense accumulates in a reserve account such that at the end of its useful life all amounts have been recovered and the asset's rate base is zero. Once an asset's useful life has been exhausted, it is retired with the plant account credited and accumulated depreciation account debited.

Q. PLEASE DEFINE "DEPRECIATION."

A. The definition of depreciation as set forth in the Commission's Uniform System of Accounts is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.

A depreciation rate is calculated as follows:

(1 – Net Salvage Percentage) / Average Life

Depreciation expense is calculated as follows:

Average Plant Balance x Depreciation Rate

Q. WHAT IS NET SALVAGE PERCENTAGE AND WHY IS IT A COMPONENT OF DEPRECIATION EXPENSE?

A. Net salvage percentage represents the net removal costs expected to be incurred and salvage proceeds expected to be received at the end of an asset's useful life. The expected net salvage percentage is applied as a portion of depreciation expense such that over the life of the asset all expected costs to operate and remove the asset (net of salvage proceeds) are recovered from the customers who received the benefit of the asset's service. Once an asset is retired, removal costs accumulate in removal work in progress

("RWIP") until the asset is fully removed. At this point the RWIP balance is cleared against the related accumulated depreciation reserve.

Q. WHAT ARE THE DEPRECIATION RATES THAT XEST IS PROPOSING?

A. XEST's proposed depreciation rates are attached to my testimony as Exhibit No. XES-401.

Q. HOW WERE XEST'S PROPOSED DEPRECIATION RATES DEVELOPED?

A. To the maximum extent possible, XEST's proposed deprecation rates are taken from the depreciation rates currently in effect for NSPM, one of the Xcel Energy Operating Companies. However, there are several categories of transmission assets that XEST may own in the future where no depreciation rate has been established for NSPM. This is because, as a new transmission company that does not yet know what projects it will own or where those projects will be located, XEST wants to have appropriate depreciation rates available for all of the FERC 300-series plant sub-accounts it may use, including a few that NSPM does not presently use for depreciation. The basis of the XEST depreciation rates that apply to facility categories that NSPM does not use is addressed below.

Q. PLEASE IDENTIFY THE XEST DEPRECIATION RATES THAT ARE BASED ON THE DEPRECIATION RATES OF NSPM.

A. Table 1, set out below, identifies the XEST depreciation rates that are identical to NSPM's current depreciation rates:

Table 1

FERC ACCOUNT	DESCRIPTION	RATE PERCENT
TRANSMISSION		
E352	Structures and Improvements	1.5397%
E353	Station Equipment	2.0285%
E354	Towers and Fixtures	1.8847%
E355	Poles and Fixtures	2.1496%
E356	Overhead Conductors & Devices	2.0973%
E357	Underground Conduit	1.3665%
E358	Underground Conductors & Devices	1.8416%
GENERAL		
E303	Intangible Plant - 5 Year	20.0000%
E390	Structures and Improvements	2.1194%
E391	Office Furniture and Equipment	5.0671%
E391	Network Equipment	25.0000%
E392	Transportation Equipment -– Auto	10.9667%
E392	Transportation Equipment - Light Truck	8.4139%
E392	Transportation Equipment -– Trailers	6.9486%
E392	Transportation Equipment - Heavy Trucks	7.2364%
E393	Stores Equipment	5.0000%
E394	Tools, Shop and Garage Equipment	6.6672%
E395	Laboratory Equipment	10.0000%
E396	Power Operated Equipment	8.4139%
E397	Communication Equipment	11.1110%
E398	Miscellaneous Equipment	6.6672%

Q. WHY IS XEST USING DEPRECIATION RATES THAT ARE IDENTICAL TO THOSE OF NSPM?

A. XEST currently has no capital assets in service. Therefore, no direct historical data exists to perform a depreciation study estimating depreciation parameters such as average service lives, average remaining lives and net salvage percentages. Additionally, XEST does not have specific proposed projects at this time.

A key reason that XEST is relying on these current NSPM depreciation rates is that these NSPM depreciation rates have been recently accepted by the Commission, have been approved by the state commissions with retail jurisdiction over NSPM, and were supported by recent depreciation studies. The state regulatory proceedings approving these depreciation rates are:

- Minnesota Public Utilities Commission ("MPUC") Docket No. E,G002/D-12-858, Average Service Life and Vintage Group Depreciation Studies for 2012, order dated June 16, 2014; and Docket No. E002/GR-12-961, Application for Authority to Increase Electric Rates in Minnesota, order dated September 3, 2013;[1]
- North Dakota Public Service Commission Case No. PU-10-657, Application for Authority to Increase Rates for Electric Service in North Dakota, order dated February 29, 2012; and
- South Dakota Public Utilities Commission Docket No. EL-12-046, Application for Authority to Increase Electric Rates in South Dakota, order dated April 18, 2013.

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[1] Although the MPUC order in the NSPM retail electric rate case (Docket No. E002/GR-12-961) was issued before the order in the 2012 5 Year depreciation study (Docket No. E,G002/D-12-858), the rate case final order reflected the depreciation rates proposed in the 2012 5 year study.

Q. HAVE THE NSPM DEPRECIATION RATES BEEN FILED WITH THE COMMISSION?

A. Yes. The NSPM depreciation rates were most recently accepted by the Commission in Docket No. ER14-1325. As noted previously, the NSP Companies are parties to the bilateral Interchange Agreement that governs the allocation of NSP System generation and transmission costs between the two NSP Companies. Under the Interchange Agreement, the NSP Companies submit a filing to the Commission each year to update the demand and energy allocation factors. The NSP Companies also update the depreciation rates that apply to NSPM and NSPW assets under the Interchange Agreement to reflect any changes in state-approved depreciation rates.

The NSPM-based depreciation rates included in Exhibit No. XES-401 are taken directly from the NSPM depreciation rates for the same accounts as listed in Exhibit IX of the Interchange Agreement, which was most recently submitted as part of the NSP Companies' February 14, 2014 filing in Docket No. ER14-1325. See Exhibit No. XES-402 (Exhibit IX to the Interchange Agreement, as filed on February 14, 2014). The Commission accepted these depreciation rates through a letter order issued on June 10, 2014.

Exhibit No. XES-402 shows that each of the NSPM rates shown in Table 1 and in Exhibit No. XES-401 is taken from Exhibit IX included in the February 14, 2014 filing. The relevant rates on Exhibit No. XES-402 are marked with an asterisk. The depreciation rates shown on Exhibit No. XES-402 without an asterisk are the depreciation rates for production plant, and are not applicable to XEST because it is a transmission only entity.

For the NSPM-based depreciation rate accounts listed on Exhibit No. XES-401, the depreciation rates accepted on June 10, 2014 were unchanged from the depreciation rates accepted by the Commission one year earlier through a June 6, 2013 letter order issued in Docket No. ER13-954. As the NSP Companies explained in their February 14, 2014 filing in Docket No. ER14-1325, these NSPM depreciation rates were supported by the depreciation studies submitted to the three state regulatory agencies identified above.

Q. ARE THE NSPM DEPRECIATION RATES REASONABLE AND APPROPRIATE FOR XEST?

A. Yes. The NSPM facilities that were the subject of these state-approved depreciation studies are a good proxy for the transmission facilities that XEST is likely to own in the future. The employees of Xcel Energy Services who assist XEST also assist the Xcel Energy Operating Companies, including NSPM. These employees are familiar with the construction practices, operation and maintenance practices, and accounting practices of NSPM. As discussed in the Mogensen Direct Testimony, Exhibit No. XES-100, XEST plans to rely on the expertise of Xcel Energy Services, and follow the practices of the Xcel Energy transmission organization when constructing, operating, and maintaining XEST's facilities in the future. Also, XEST's future transmission facilities could be located almost anywhere in the Southwest Power Pool, Inc. ("SPP") region. Of the four Xcel Energy Operating Companies, NSPM spans the largest number of states, covers the largest geographical area, and has the most transmission facilities that operate at 345 kV and above. For these reasons, the NSPM composite rates provide a reasonable proxy for XEST's depreciation rates, including parameters such as depreciable life and net salvage parameter, associated with the facilities that XEST plans to own in the future.

Q. WHY DID XEST BASE SOME OF ITS DEPRECIATION RATES ON A SOURCE OTHER THAN NSPM'S CURRENTLY EFFECTIVE DEPRECIATION RATES?

A. Not every category of facility listed in the FERC 300 series of plant sub-accounts is used by each electric utility. Because XEST does not yet know what projects it will own or where those projects will be located, XEST wants to have appropriate depreciation rates available for all of the FERC 300-series plant sub-accounts it may use. Specifically, XEST has included three accounts that NSPM does not use: Account E350-Land Rights; Account E359-Roads and Trails; and Account E302-Franchises and Consents.

Q. WHAT IS THE BASIS FOR THE THREE DEPRECIATION RATES THAT NSPM DOES NOT USE?

A. XEST looked first to NSPW's depreciation rates. NSPW's depreciation rates were accepted along with NSPM's depreciation rates in Docket Nos. ER13-954 and ER14-1325. NSPW's approved depreciation rates included a rate for Account E359-Road and Trails, and XEST has adopted the NSPW depreciation rate of 1.4256%. This rate appears on Exhibit No. XES-402 and is marked with two asterisks.

For Account E350-Land Rights, XEST has used PSCo's currently effective depreciation rate of 1.03%. That rate was approved originally by the Commission in Docket No. ER08-224-000, and has been carried forward in each subsequent PSCo wholesale rate case. This depreciation rate is reflected in the currently effective PSCo transmission rate formula, and appears in Attachment O-PSCo to the Xcel Energy Operating Companies Open Access Transmission Tariff ("OATT"), and is shown in Exhibit No. XES-403 (which is a copy of the currently effective OATT page from the

Commission's eTariff system with the entry for this PSCo depreciation rate marked with three asterisks).

For Account E302-Franchises and Consents, XEST proposes to amortize any such costs over the life of the underlying Franchise Agreement rather than a fixed rate. This is consistent with the treatment allowed under the current PSCo transmission rate formula and ensures proper amortization in the event XEST incurs any capitalized franchise costs.

Q. DOES XEST ANTICIPATE THAT THE DEPRECIATION RATES PROPOSED HERE MAY BE UPDATED IN THE FUTURE?

A. Yes. After XEST has assets in operation, it may become clear that certain depreciation rates could or should be updated. As I understand it, the XEST depreciation rates that are stated in the formula (all such rates except the depreciation rate for Account E302-Franchises and Consents, as discussed above) can be changed only upon a filing submitted under Section 205 of the Federal Power Act. In that instance, XEST would file the depreciation rates with the Commission as a proposed modification to the Formula Rate template, with supporting documentation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit No. XES-401

Xcel Energy Southwest Transmission Company, LLC Exhibit No. XES-401
Proposed Depreciation Rates

FERC ACCOUNT	DESCRIPTION	RATE PERCENT	
TRANSMISSION			
E350	Land Rights	1.0300%	***
E352	Structures and Improvements	1.5397%	*
E353	Station Equipment	2.0285%	*
E354	Towers and Fixtures	1.8847%	*
E355	Poles and Fixtures	2.1496%	*
E356	Overhead Conductors & Devices	2.0973%	*
E357	Underground Conduit	1.3665%	*
E358	Underground Conductors & Devices	1.8416%	*
E359	Roads and Trails	1.4256%	**
GENERAL			
E302	Franchises and Consents	N/A	****
E303	Intangible Plant - 5 Year	20.0000%	*
E390	Structures and Improvements	2.1194%	*
E391	Office Furniture and Equipment	5.0671%	*
E391	Network Equipment	25.0000%	*
E392	Transportation Equipment - Auto	10.9667%	*
E392	Transportation Equipment - Light Truck	8.4139%	*
E392	Transportation Equipment - Trailers	6.9486%	*
E392	Transportation Equipment - Heavy Trucks	7.2364%	*
E393	Stores Equipment	5.0000%	*
E394	Tools, Shop and Garage Equipment	6.6672%	*
E395	Laboratory Equipment	10.0000%	*
E396	Power Operated Equipment	8.4139%	*
E397	Communication Equipment	11.1110%	*
E398	Miscellaneous Equipment	6.6672%	*

* NSPM approved rates per Docket No. ER14-1325-000.
** NSPW approved rate per Docket No. ER14-1325-000.
*** PSCo approved rate per Docket No. ER12-1589-000.
**** Electric Intangible Franchises are amortized over the life of the Franchise Agreement.

Exhibit No. XES-402

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2014 CONTRACT YEAR

The following annual composite depreciation rates are calculated based on the most recent actual depreciation expense accruals and plant balances. The actual depreciation expense is calculated based on the most recent remaining life depreciation studies certified by the respective State Commissions for NSP (Minn) and NSP (Wis). Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	4.75%
E312	STEAM	Boiler Plant Equipment	3.48%
E314	STEAM	Turbogenerator Units	3.53%
E315	STEAM	Accessory Electric Equipment	3.08%
E316	STEAM	Miscellaneous Power Plant Equipment	3.68%
E302	NUCLEAR	Franchises & Consents	4.49%
E321	NUCLEAR	Structures and Improvements	4.25%
E322	NUCLEAR	Reactor Plant Equipment	3.63%
E323	NUCLEAR	Turbogenerator Units	1.60%
E324	NUCLEAR	Accessory Electric Equipment	2.10%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	4.49%
E325	NUCLEAR	Decommissioning Minnesota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning South Dakota Jurisdiction	0.59%
E325	NUCLEAR	Decommissioning North Dakota Jurisdiction	0.00%
E325	NUCLEAR	Decommissioning Wisconsin Jurisdiction	0.72%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	3.95%
E332	HYDRO	Reservoirs, Dams and Waterways	3.95%
E333	HYDRO	Water Wheels, Turbines & Generators	3.95%
E334	HYDRO	Accessory Electric Equipment	3.95%
E335	HYDRO	Miscellaneous Power Plant Equipment	3.95%
E340.1	OTHER	Wind Rights	4.01%
E341	OTHER	Structures and Improvements	4.51%
E342	OTHER	Fuel Holders, Producers & Accessories	2.92%
E344	OTHER	Generators	3.39%
E345	OTHER	Accessory Electric Equipment	3.58%
E346	OTHER	Miscellaneous Power Plant Equipment	5.56%
E348	OTHER	Energy Storage Equipment – Production	0.00%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION			
E351	Energy Storage Equipment – Transmission	0.00%	
E352	Structures and Improvements	1.54%	*
*E352	Structures and Improvements-Prod.	1.54%	
E353	Station Equipment	2.03%	*
*E353	Station Equipment-Prod.	2.03%	
E354	Towers and Fixtures	1.88%	*
*E354	Towers and Fixtures-Prod.	1.92%	
E355	Poles and Fixtures	2.15%	*
*E355	Poles and Fixtures-Prod.	2.19%	
E356	Overhead Conductors & Devices	2.10%	*
*E356	Overhead Conductors & Devices-Prod.	2.14%	
E357	Underground Conduit	1.37%	*
E358	Underground Conductors & Devices	1.84%	*
DISTRIBUTION			
E361	Structures and Improvements	2.20%	
*E361	Structures and Improvements-Prod.	2.17%	
E362	Station Equipment	2.22%	
*E362	Station Equipment-Prod.	2.18%	
E363	Energy Storage Equipment – Distribution	0.00%	
E364	Poles, Towers and Fixtures	4.35%	
E365	Overhead Conductors and Devices	2.99%	
E366	Underground Conduit	2.05%	
E367	Underground Conductor and Devices	2.22%	
E368	Line Transformers	3.21%	
E368	Line Capacitors	4.29%	
E369	Overhead Services	3.95%	
E369	Underground Services	2.58%	
E370	Meters	6.59%	
E370.1	Meters-Old	0.00%	
E373	Street Lighting and Signal Systems	4.61%	

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

GENERAL - ELECTRIC

E303	Intangible Plant – 5 Year	20.00% *
E390	Structures and Improvements	2.12% *
E391	Office Furniture and Equipment	5.07% *
E391	Network Equipment	25.00% *
E392	Transportation Equipment – Auto	10.97% *
E392	Transportation Equipment – Light Truck	8.41% *
E392	Transportation Equipment – Trailers	6.95% *
E392	Transportation Equipment – Heavy Trucks	7.24% *
E393	Stores Equipment	5.00% *
E394	Tools, Shop and Garage Equipment	6.67% *
E394	Hand Held Meter Readers	0.00%
E395	Laboratory Equipment	10.00% *
E396	Power Operated Equipment	8.41% *
E397	Communication Equipment	11.11% *
E397	Communication Equipment-AMR	6.67%
E398	Miscellaneous Equipment	6.67% *

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2014 CONTRACT YEAR

NSP(Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE PERCENT
PRODUCTION			
E311	STEAM	Structures and Improvements	4.61%
E312	STEAM	Boiler Plant Equipment	3.65%
E314	STEAM	Turbogenerator Units	4.36%
E315	STEAM	Accessory Electric Equipment	4.21%
E316	STEAM	Miscellaneous Power Plant Equipment	2.23%
E302	HYDRO	Franchises & Consents	3.85%
E331	HYDRO	Structures and Improvements	3.40%
E332	HYDRO	Reservoirs, Dams and Waterways	3.43%
E333	HYDRO	Water Wheels, Turbines & Generators	2.54%
E334	HYDRO	Accessory Electric Equipment	3.44%
E335	HYDRO	Miscellaneous Power Plant Equipment	3.56%
E341	OTHER	Structures and Improvements	1.68%
E342	OTHER	Fuel Holders, Producers & Accessories	1.63%
E343	OTHER	Prime Movers	1.90%
E344	OTHER	Generators	1.54%
E345	OTHER	Accessory Electric Equipment	1.26%
E346	OTHER	Miscellaneous Power Plant Equipment	1.37%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.01%
*E352		Structures and Improvements-Prod.	1.98%
E353		Station Equipment	2.58%
*E353		Station Equipment-Prod.	2.33%
E354		Towers and Fixtures	1.73%
E355		Poles and Fixtures	2.99%
E356		Overhead Conductors & Devices	2.60%
E357		Underground Conduit	2.08%
E358		Underground Conductors & Devices	2.73%
E359		Roads and Trails	1.43% **

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

DISTRIBUTION		
E361	Structures and Improvements	2.13%
*E361	Structures and Improvements-Prod.	2.12%
E362	Station Equipment	2.44%
*E362	Station Equipment-Prod.	2.41%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	5.48%
E365	Overhead Conductors and Devices	4.28%
E366	Underground Conduit	1.80%
E367	Underground Conductor and Devices	2.73%
E368	Line Transformers	2.56%
E368	Line Transformers/Other	2.56%
E368	Line Capacitors	3.09%
E369	Overhead Services	4.02%
E369	Underground Services	2.78%
E370	Meters	3.99%
E370.1	Meters-Old	3.22%
E370.2	Meters-AMR	6.53%
E371	Customer Installations	5.01%
E373	Street Lighting and Signal Systems	6.63%
GENERAL - ELECTRIC		
E303	Intangible Plant – 5 year	20.00%
E390	Structures and Improvements	2.59%
E391	Office Furniture and Equipment	4.97%
E391	Network Equipment	24.25%
E392	Transportation Equipment – Auto	13.28%
E392	Transportation Equipment – Light Truck	13.51%
E392	Transportation Equipment – Heavy Truck	9.81%
E392	Transportation Equipment – Trailers	9.97%
E392	Transportation Equipment – M Veh Group 4	9.96%
E393	Stores Equipment	4.97%
E394	Tools, Shop and Garage Equipment	4.97%
E395	Laboratory Equipment	4.75%
E396	Power Operated Equipment	8.23%
E397	Communication Equipment	6.64%
E397	Communication Equipment-EMS	9.05%
E398	Miscellaneous Equipment	4.98%

Exhibit No. XES-403

Public Service Company of Colorado as of 8/22/2014
Electric TCS and MBR
Transmission Tariffs

Effective Date:	07/30/2010	Status:	Effective
FERC Docket:	ER10-02070-000 13		
FERC Order:	Delegated letter order	Order Date:	09/24/2010

O-PSCo, Rate Template, Appendix 3 - Depreciation Rates, 0.0.0 A

Appendix 3 to Attachment O

PSCo Depreciation Rates

Line No.	Acct No. (a)	Description (b)	Depreciation Rates Effective 1/1/07 (Percent) (c)
1	**Transmission Plant**		
2	350.2	Land Rights	1.030 ***
3	352.0	Structures & Improvements	1.440
4	353.0	Station Equipment	1.780
5	354.0	Towers & Fixtures	1.180
6	355.0	Poles & Fixtures	1.640
7	356.0	OH Conductors & Devices	1.790
8	357.0	UG Conduit	1.940
9	358.0	UG Conductors & Devices	1.880
10	359.0	Roads and Trails	0.970
11	**General Plant**		
12	390.0	Structures & Improvements	4.880
13	390.1	General Buildings	2.980
14	390.2	Partitions	7.690
15	391.0	Office Furniture & Equipment	4.750
16	391.1	Leased Partitions	5.000
17	391.2	Computers	20.000
18	392.0	Transportation Equipment	9.000
19	393.0	Stores Equipment	3.170
20	394.0	Tools, Shop & Garage Equipment	3.800
21	395.0	Laboratory Equipment	9.500
22	396.0	Power Operated Equipment	9.000
23	397.0	Communication Equipment	6.670
24	398.0	Miscellaneous Equipment	5.000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

ANDREW H. SAWYER, being duly sworn, deposes and states: that the Direct Testimony of ANDREW H. SAWYER was prepared by him or under his direct supervision, that the statements contained therein and the Exhibits attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

Andrew H. Sawyer

Subscribed and sworn before me this 25th day of August 2014.

Virginia J. Sailor
Virginia J. Sailor
Notary Public
My commission expires: January 31, 2016

VIRGINIA J SAILOR
NOTARY PUBLIC - MINNESOTA
MY COMMISSION EXPIRES 1/31/16

Exhibit No. XES-500

Exhibit No. XES-500

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-____-000**

DIRECT TESTIMONY AND EXHIBITS
OF
ADRIEN M. MCKENZIE

ON BEHALF OF

XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE

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EXHIBITS TO DIRECT TESTIMONY

Exhibit No.	Description
XES-501	Qualifications of Adrien M. McKenzie
XES-502	Summary of Results
XES-503	Risk Measures – National Group
XES-504	FERC Two-Stage DCF Model
XES-505	Electric Utility Risk Premium – FERC ROE
XES-506	Capital Asset Pricing Model
XES-507	Expected Earnings Approach
XES-508	Electric Utility Risk Premium – State ROE
XES-509	Empirical Capital Asset Pricing Model
XES-510	Risk Premium – Natural Gas Pipelines
XES-511	Allowed ROEs – National Group
XES-512	DCF Model – Non-Utility Group

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River Street, Austin, Texas, 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am a Vice President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q3. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A3. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Over the past year, I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in ten proceedings filed with the Federal Energy Regulatory Commission ("FERC" or "the Commission"), the Kansas State Corporation Commission, the Montana Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations.

In addition, over the course of my career I have worked with Dr. William Avera to prepare prefiled direct and rebuttal testimony in over 250 regulatory proceedings before the Commission (including Docket No. EL11-66-001, which established the Commission's current policies with respect to ROE for electric utilities, adopted in Opinion No. 531), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] In connection with these assignments, my responsibilities have included performing analyses to estimate investors' required rate of return, critically evaluating the results of alternative approaches, evaluating the positions of other parties, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I earned B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. A resume containing the details of my qualifications and experience is attached as Exhibit No. XES-501.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Commission my independent analysis of a fair ROE for Xcel Energy Southwest Transmission Company, LLC ("XEST" or "the Company").

Q5. HOW IS YOUR TESTIMONY ORGANIZED?

A5. After briefly summarizing the operations and finances of XEST, reflecting the testimony of Ms. Teresa M. Mogensen and Mr. George E. Tyson, II in this proceeding, I present my

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[1] This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc.

conclusions and recommendations regarding a fair ROE for the Company. Next I review current conditions in the capital markets and discuss their implications in evaluating a fair ROE for XEST under the standards adopted by the Commission in Opinion No. 531.[2] With this background, I applied the Commission's two-step discounted cash flow ("DCF") model to estimate the current cost of equity for a comparable-risk group of other electric utilities. I refer to these 31 utilities as the "National Group." Consistent with Opinion No. 531, my analyses also examined the cost of equity utilizing a risk premium approach based on Commission-authorized ROEs for electric utilities, the Capital Asset Pricing Model ("CAPM"), and the expected earnings approach. These three alternative benchmark methodologies were relied on by the Commission in Opinion No. 531 in evaluating the placement of the base ROE from within the zone of reasonableness implied by the two-step DCF model, and my recommended ROE relies on these same factors as well.[3] Finally, I evaluated my results by reference to additional benchmarks based on a risk premium approach based on ROEs authorized by state regulators, the empirical CAPM, which is a derivative of the traditional model, Commission-approved ROEs for natural gas pipelines, and a DCF analysis based on a select group of low risk non-utility firms.

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2 *Martha Coakley v. Bangor Hydro-Electric Company,* Opinion No. 531, 147 FERC ¶ 61,234 (2014) ("Opinion No. 531"), *reh'g granted for further consideration*, EL11-66-002 (Aug. 20, 2014).

3 *Id.* at P 146.

II. XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

Q6. BRIEFLY DESCRIBE XEST.

A6. As discussed in the testimony of Ms. Mogensen and Mr. Tyson, XEST is a wholly owned subsidiary of Xcel Energy Transmission Holding Company, LLC ("Xcel Energy Transmission Holdco"), whose parent company is Xcel Energy Inc. ("Xcel Energy"). XEST is a transmission-only public utility, and was created for the sole purpose of developing, constructing, owning, and maintaining transmission projects located in the Southwest Power Pool, Inc. ("SPP") region, which was approved as a regional transmission organization ("RTO") in 2004. As one of the elements necessary to comply with FERC's Order No. 1000,[4] SPP will use a competitive solicitation process for certain transmission projects 100 kV and above. XEST's primary focus will be to compete in SPP's Order No. 1000 competitive solicitation process for transmission projects approved in the SPP Transmission Expansion Plan ("STEP"). It is anticipated that SPP's first competitive solicitations will be issued in 2015. XEST will participate in the SPP regional transmission planning processes, and plans to respond to the competitive solicitations issued by SPP with project-specific bids, and then develop and own the projects for which XEST is selected by SPP.

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4 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *petitions for review denied sub nom. South Carolina Public Service Authority v. FERC*, No. 12-1232 (D.C. Cir. Aug. 15, 2014) (per curiam).

Q7. WILL XEST BECOME A MEMBER OF THE SPP RTO?

A7. Yes. As discussed by Ms. Mogensen, XEST will transfer operational control of the transmission facilities it develops to SPP, and will become a transmission owning member of the RTO once it meets SPP's Tariff and business practice requirements. XEST has submitted an application to SPP to become a Qualified RFP Participant ("QRP") under the SPP Order No. 1000 competitive solicitation process.

Q8. WHERE WILL XEST OBTAIN THE CAPITAL TO BE USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A8. As Mr. Tyson explains in his testimony, XEST will initially obtain equity capital from Xcel Energy Transmission Holdco. Once it is producing revenues it will likely use a combination of retained earnings and additional capital from its direct parent. XEST may also issue debt securities directly under its own name or enter into other credit arrangements to finance its operations.

Q9. WHAT ARE XEST'S ANTICIPATED CAPITAL REQUIREMENTS?

A9. XEST will be required to raise substantial amounts of capital to fund its projected capital expenditures. As Mr. Tyson explains, the transmission projects that are expected to emerge from the SPP Order No. 1000 process are likely to be large scale multi-state or even multi-region projects.

Q10. WHAT CREDIT RATINGS ARE ASSIGNED TO XEST?

A10. XEST does not have stand-alone published credit ratings; however, its ultimate parent company – Xcel Energy – is rated A- by Standard & Poor's Corporation ("S&P") and A3 by Moody's Investors Service ("Moody's"). As discussed in Mr. Tyson's testimony, XEST is targeting a credit profile that meets S&P's and Moody's guidelines for a BBB+/Baa1 investment grade credit rating.

Q11. HOW WILL XEST RECOVER THE COSTS, INCLUDING ITS ROE, ASSOCIATED WITH ITS TRANSMISSION INVESTMENTS?

A11. XEST intends to utilize a formula rate that will enable it to recover its costs of service. This formula is addressed in Mr. Heintz's testimony. ROE will be a fixed input in this formula rate.

III. RETURN ON EQUITY FOR XEST

Q12. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A12. This section of my testimony presents my conclusions regarding a fair ROE for XEST. In this regard I discuss the relationship between ROE and the preservation of a utility's ability to attract capital. Next, I summarize my analyses and my recommendation that the base ROE for XEST be set at 10.64%. I then address how an ROE at this level meets the Commission's policy goal of promoting investment in electric transmission infrastructure. Finally, I explain that including a 50 basis point incentive adder associated with XEST's membership in an RTO is consistent with Commission policy and precedent. According, I conclude that XEST's total ROE should be 11.14%

A. Importance of Regulatory Standards

Q13. WHAT IS THE ROLE OF ROE IN SETTING A UTILITY'S RATES?

A13. The ROE compensates shareholders for the use of their capital to finance the investment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in *Bluefield* [5] and *Hope,*[6] a utility's allowed return on common equity should be sufficient to: (1) fairly compensate capital invested in the utility; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial integrity.

Q14. WHAT ULTIMATELY GOVERNS THE SELECTION OF A FAIR ROE?

A14. The Commission has recognized that a reasonable point-estimate ROE should be determined based on the facts specific to each proceeding.[7] That point estimate must also meet the standards mandated by the Supreme Court.[8] As the Commission recently reaffirmed in Opinion No. 531: "The Commission's ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*."[9] This determination requires the Commission to consider all of the available evidence and identify an ROE that is just, reasonable, and sufficient to support XEST's need to attract capital and earn a competitive return and, at the same time, promote the Commission's goal of encouraging investment in utility electric transmission infrastructure.

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[5] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of the State of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

[6] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[7] *See, e.g., Midwest Independent Transmission System Operator, Inc.,* 106 FERC ¶ 61,302 at P 8 (2004).

[8] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at PP 13-14 (2004). The Commission observed that, "we are guided by the principle, enunciated by the Supreme Court, that an approved ROE should be 'reasonably sufficient to assure confidence in the financial soundness of the utility [or, in this case, utilities] and should be adequate under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.'" *Id.* at P 13 (*quoting Bluefield* at 693).

[9] Opinion No. 531 at P 144.

Q15. DOES IT MAKE SENSE TO RELY ON A SINGLE METHOD OR MECHANICAL FORMULA IN EVALUATING A FAIR ROE FOR XEST?

A15. No. While the Commission does look initially to the DCF methodology when evaluating a fair ROE, it has also made clear that it is the result reached, not the method used, that determines whether an ROE is just and reasonable.[10] A mechanical policy of referencing a single method or a rote application of a particular formula leaves the Commission with little flexibility when the result fails to reflect a fair and reasonable ROE. The Commission reached this exact conclusion in Opinion No. 531 when it determined that "a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*."[11]

Investors are also far more concerned with the end-result and the implications for the utility's finances than with adherence to specific rules or precedent. As S&P noted:

> As much as possible, regulators should, in our opinion, have the flexibility to react quickly and prudently to new situations as they develop. This is the sort of flexibility that we believe comes under principles-based regulation rather than rules-based regulation. In the latter, a regulator may attempt to set down every possible rule that can apply to a given situation that may arise in an industry. In the former, the regulator generally has the authority to achieve certain ends and some flexibility in how to achieve them.[12]

Any benefit of consistency is more than overwhelmed by the risks that an unresponsive, mechanical policy will lead to inadequate returns. Investors react swiftly and negatively

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[10] *See, e.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314 (1989).

[11] Opinion No. 531 at P 142.

[12] Standard & Poor's Corporation, "Executive Comment: What Characterizes Effective Regulation? Understanding, Manageability, And Consistency," *RatingsDirect* (May 5, 2010).

to evidence of waning regulatory support, and such an outcome would severely undermine investor confidence and the Commission's policy goals.

Q16. HAS THE COMMISSION RECOGNIZED THE IMPORTANCE OF CONSIDERING ALTERNATIVE APPROACHES AND EVIDENCE IN ESTABLISHING AN ROE THAT MEETS REGULATORY STANDARDS?

A16. Yes. Over time, the Commission has relied upon a variety of approaches to determine ROEs that are consistent with the standards prescribed by *Bluefield* and *Hope*. These evolving methods have each acknowledged that reasonableness and stability are essential elements of the Commission's regulatory policy. It is important to consider a broad array of evidence, including the ROE range of reasonableness, the results of alternative ROE benchmarks, and well-established policy considerations supporting an ROE that is sufficient to attract capital.[13]

The Commission endorsed the use of alternative benchmarks in Opinion No. 531, concluding that a mechanical application of the DCF model would result in an ROE that was insufficient to meet regulatory standards, and that "it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark

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[13] The Commission has long recognized the importance of preserving its flexibility to evaluate a fair ROE based on the case-specific evidence:

> The Commission has concluded that requiring the ROE to be set at one of only three possible positions in the range established by reference to the proxy companies does not give the Commission the necessary flexibility required to evaluate the specific circumstances of each case. Thus, the Commission has determined that the parties to a rate proceeding may present evidence they believe is warranted to support any ROE that is within the DCF-derived zone of reasonableness. . . .

Transcontinental Gas Pipe Line Corp., Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,427-3 (1998), *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

methodologies and state commission-approved ROEs," to determine a just and reasonable ROE.[14] In Opinion No. 531, the Commission found the risk premium, CAPM, and expected earnings methodologies to be informative and relied on these analyses to determine the just and reasonable point ROE within the DCF zone of reasonableness.

Q17. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

A17. Yes. Past challenges for the economy and capital markets highlight the benefits of a fair and balanced ROE, and changing course from the path of supporting utility financial strength would be extremely shortsighted. Uncertainty and volatility undermine investor confidence. As a result, regulatory signals are the primary driver of investors' risk assessments for utilities. Securities analysts study FERC and state commission orders and regulatory policy statements to gauge the financial impact of regulatory actions and to advise investors where to put their money. If regulatory actions instill confidence that the regulatory environment is supportive, investors will provide the capital necessary to support needed investment, such as the robust transmission grid envisioned by our national energy policy goals and the Commission. When investors are confident that a utility has supportive regulation, they will make funds available even in times of turmoil in the financial markets.

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[14] Opinion No. 531 at P 145.

B. Summary and Conclusions

Q18. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR XEST?

A18. Based on the results of my analyses, I recommend a base ROE for XEST of 10.64%. After including a 50 basis point adder to recognize XEST's membership in SPP, the total ROE would be 11.14%.

Q19. PLEASE SUMMARIZE THE RESULTS OF THE COMMISSION'S TWO-STEP DCF ANALYSIS.

A19. The results of my analyses are summarized in Exhibit No. XES-502. Page 1 of Exhibit No. XES-502 displays the results of the primary methods relied on by the Commission in Opinion No. 531. With respect to the DCF method, I conclude that:

- Application of the two-step DCF methodology results in an adjusted ROE zone of reasonableness of 6.27% to 12.59%;
- An ROE of 10.64% is halfway between the 8.70% median of the DCF estimates and the 12.59% value at the top of the zone.

Q20. DOES YOUR APPLICATION OF THIS METHOD CONSTITUTE AN ENDORSEMENT OF THE TWO-STEP APPROACH ADOPTED IN OPINION NO. 531 AND ITS RELATED ASSUMPTIONS?

A20. No. One of the principal elements of Opinion No. 531 was the change to the two-step DCF methodology, which incorporates long-term growth projections (based on projected GDP growth rates) in estimating a company's cost of equity. However, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for utility common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is at odds with the practical circumstances in which real-world investors operate. While I have applied this approach in deference to the Commission's recent decision in Opinion

No. 531, there is very clear evidence that this two-step DCF model results in cost of equity estimates that fall far below investors' expectations and violate regulatory standards of fairness.

The Commission confirmed this conclusion in Opinion No. 531 itself, noting that an ROE based on the measure of central tendency from the two-step DCF results would violate the *Hope* and *Bluefield* standards.[15] As the Commission observed:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[16]

The Commission's willingness to consider the results of alternative methods in evaluating where to place the just and reasonable ROE within the DCF-determined zone of reasonableness may ultimately result in a conclusion that satisfies the *Hope* and *Bluefield* standards, but this approach does not eliminate the fundamental flaws of the two-step DCF model.

Q21. IS THIS CONCLUSION REINFORCED BY YOUR EVALUATION OF ALTERNATIVE ROE METHODS?

A21. Yes. My applications of the risk premium, CAPM, and expected earnings methods demonstrate that the median value resulting from the Commission's two-step DCF

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15 Opinion No. 531 at P 142.

16 *Id.* at P 41. Application of the two-step DCF method without the "mid-point of the upper half of the range" adjustment would have resulted in an ROE for the ISO New England Transmission Owners of only 9.39%, a value the Commission found unreasonable. *Id* at P 142.

method is far below investors' required return. As a result, a fair ROE at or above the point that is halfway between the median and the top of the DCF zone of reasonableness is warranted.[17] As summarized on page 1 of Exhibit No. XES-502:

- The utility risk premium approach based on Commission-approved ROEs for electric utilities implies an ROE point estimate of 10.63%;
- The forward-looking CAPM estimates produce an ROE range of 8.49% to 13.91%, with a median of 11.06%;
- Earned returns for the electric utility industry are expected to average 10.56%, and fall in a range of 8.09% to 15.55% for the proxy group of comparable-risk electric utilities;
- The overall average of the median cost of equity estimates resulting from these alternative ROE benchmarks is 10.56%;
- Midpoint cost of equity estimates associated with these quantitative methods ranged from 10.56% to 11.82%, with the average of the individual midpoint estimates being 11.05%.

All of these results demonstrate that the median value resulting from the Commission's two-step DCF method is far too low to be considered reasonable. Taken together, these alternative benchmarks support my 10.64% ROE recommendation at the midpoint of the top end of the DCF range.

In Opinion No. 531, which was issued on June 19, 2014, the Commission recognized that the results of its two-step DCF model were impacted by unrepresentative financial inputs related to capital market condition that were anomalous when compared with the historical record.[18] As my testimony explains, the anomalous capital market

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[17] In Opinion No. 531, the Commission set the ROE at the point that is halfway between the midpoint and the top of the DCF zone of reasonableness. Opinion No. 531 at P 142. In my testimony, I also refer to this point as being at the middle of the top end of the DCF zone of reasonableness.

[18] Opinion No. 531 at P 145.

conditions that prompted the Commission to approve an ROE at the middle of the top end of the DCF zone in Opinion No. 531 have continued. Under these circumstances, and in order to ensure that the *Hope* and *Bluefield* standards are met, the Commission has recognized that it is appropriate and prudent to consider the results of other ROE models and benchmarks, which are widely employed in regulatory proceedings and utilized in the financial community. Apart from the results of these alternative methods, an ROE at the middle of the top half of the DCF zone of reasonableness is also justified by the fact that bond yields are uncharacteristically low and current cost of capital estimates are likely to understate investors' requirements.

Q22. IS A 10.64% BASE ROE FOR XEST SUPPORTED BY OTHER BENCHMARKS?

A22. Yes. Alternative ROE benchmarks consistently support an ROE at or above the middle of the top end of the DCF zone, and confirm the reasonableness of a 10.64% base ROE for XEST. In addition to the benchmarks utilized by the Commission in Opinion No. 531, I analyzed additional benchmarks that I believe are relevant to an analysis of a just and reasonable ROE. The results of these analyses are summarized below, and on page 2 of Exhibit No. XES-502:

- The utility risk premium approach based on state-approved ROEs for electric utilities implies an ROE point estimate of 10.19%;
- The ECAPM approach results in a zone of reasonableness of 9.36% to 14.13%, with a median of 11.60%;
- Reference to the ROEs approved by the Commission for natural gas pipelines implies a current base cost of equity for an electric utility of approximately 10.45%;
- After incorporating projected bond yields, the risk premium, CAPM, and ECAPM methods resulted in cost of equity estimates above 10.64%;
- DCF estimates for a low-risk group of non-utility firms suggest a cost of equity in the range of 9.29% to 12.19%, with a median of 10.74%;

- Taken together, the overall average of the median ROEs resulting from these alternative benchmarks equals 11.01%.

Q23. DO STATE APPROVED ROES ALSO SUPPORT AN ROE FOR XEST WELL ABOVE THE MEDIAN VALUE IMPLIED BY THE TWO-STEP DCF MODEL?

A23. Yes. As shown on Exhibit No. XES-511, the approved ROEs currently reported for the utilities in the National Group by *AUS Utility Reports* fell in a range of 9.38% to 11.48%, with a median of 10.38%. Meanwhile, as shown on page 1 of Exhibit No. XES-504, the median result of the Commission's two-step DCF model is 8.70%. This result falls 69 basis points below the 9.39% value recently rejected by the Commission as inadequate to meet regulatory standards for wholesale electric transmission operations.[19] Just as in Opinion No. 531, the significant discrepancy between state-approved ROEs for the proxy group and the 8.70% DCF median "serves as an indicator that an upward adjustment … is necessary to satisfy *Hope* and *Bluefield*."[20] This conclusion is reinforced by the Commission's determination that investors in electric transmission infrastructure face increased risks that distinguish these investments from state-regulated distribution.[21]

Q24. DO PRIOR COMMISSION DECISIONS SUPPORT ESTABLISHING AN ROE FOR XEST WITHIN THE TOP HALF OF THE ZONE OF REASONABLENESS?

A24. Yes. The Supreme Court has recognized the Commission's broad latitude in evaluating a reasonable ROE from within the DCF range:

> Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. *It allows a substantial spread between what is*

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[19] Opinion No. 531 at P 148.

[20] *Id.*

[21] *Id.* at P 149.

> *unreasonable because too low and what is unreasonable because too high.* To reduce the abstract concept of reasonableness to concrete expression in dollars and cents is the function of the Commission.[22]

In applying this standard, the Commission has recognized that the ROE need not be equal to the central tendency of the DCF zone to be considered reasonable. In prior cases the Commission has approved a base ROE at the middle of the top half of the zone.[23] This approach was recently employed in Opinion No. 531,[24] and is warranted in this proceeding based on the evidence presented in my testimony and the close parallels with the circumstances considered by the Commission in Opinion No. 531.

Taken together, these considerations support my recommendation to select a base ROE for XEST at the middle of the top end of the DCF zone of reasonableness, or 10.64%.

C. Consistency with Commission Policy Goals

Q25. IS A 10.64% BASE ROE FOR XEST CONSISTENT WITH ESTABLISHED COMMISSION POLICY TO SUPPORT INVESTMENT IN ELECTRIC TRANSMISSION INFRASTRUCTURE?

A25. Yes. The Commission's supportive regulatory actions have been successful in promoting much needed investment in the wholesale transmission grid. Unresponsive, mechanical decision-making that leads to inadequate returns will undermine the Commission's goal and the legislative mandate to promote capital investment in new transmission projects.

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22 *Montana-Dakota Utilities Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (emphasis added).

23 *Southern California Edison*, Opinion No. 445, 92 FERC ¶ 61,070 at 61,266 (2000); *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100 at 61,363-64 (1998).

24 Opinion No. 531 at P 152.

This potential adverse outcome was highlighted by the investment community with respect to the transmission segment of the power industry:

> The degree to which a utility revises its transmission capital plan will depend on expected returns. … Material reductions in the base ROE could lower the quality of and divert capital away from the transmission business, given its generally riskier profile than that of state-regulated utility businesses, such as distribution and generation. Moreover, investors could deploy capital to infrastructure projects with higher allowed returns, such as FERC-regulated natural gas pipelines, or to other industries generally.[25]

The Commission has recognized the need to support wholesale power markets by adjusting its methods and instituting reforms in response to changed circumstances, as exemplified by Order No. 1000. Considering the ongoing implications of anomalous capital market conditions and the results of well-accepted ROE benchmarks provides the Commission with the flexibility to ensure a reasonable end result that does not undermine its policy objectives.

Q26. WILL ROES THAT ARE BELOW THE LEVEL INDICATED BY APPROPRIATE BENCHMARKS UNDERMINE TRANSMISSION INVESTMENT?

A26. That risk is very real. As the investment community has recognized, setting the ROE for FERC-jurisdictional transmission operations below the level allowed by state commissions would undermine the ability of interstate operations to compete for capital. The global financial firm UBS observed that:

> We believe companies will redeploy capital elsewhere if transmission returns are materially reduced. In our view, the cost of capital could actually increase, because as returns are set lower, valuation multiples will also be reset much lower than current levels. Additionally, the second order

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25 *Wolfe Research*, "FERConomics: Risk to transmission base ROEs in focus," *Utilities & Power* (Jun. 11, 2013).

> effects on other state and Federal government policy objectives, i.e., renewables development, could be significant, in our view.

The 10.64% ROE from the point halfway between the median and the top of the DCF zone of reasonableness is appropriate in light of XEST's need to attract capital to interstate transmission infrastructure and the significant risks and challenges associated with these investments.

D. ROE Adder for RTO Membership

Q27. HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR PARTICIPATION IN A REGIONAL TRANSMISSION ORGANIZATION SUCH AS SPP IS APPROPRIATE?

A27. Yes. The Commission has repeatedly affirmed its policy of allowing an ROE adder to recognize the consumer benefits provided through membership in an RTO, and noted that a 50 basis point incentive was consistent with the level approved in other proceedings.[26] I support increasing the base ROE by a 50 basis-point incentive adder to recognize that XEST will be a member of SPP and any projects developed by XEST in SPP will be under the operational control of SPP. As discussed by Ms. Mogensen, XEST has applied to be a QRP pursuant to the procedures established by SPP.

Q28. WHAT ROE IS INDICATED FOR XEST AFTER INCORPORATING AN INCENTIVE FOR RTO MEMBERSHIP?

A28. I recommend increasing the base ROE by a 50 basis-point incentive adder to recognize that operational control of future XEST facilities will be relinquished to SPP. This results in an adjusted ROE of 11.14%, which falls well below the 12.59% upper bound of my

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26 *See, e.g., Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at PP 15-16 (2007).

ROE range of reasonableness. Accordingly, an adjusted ROE for XEST meets the requirements of established Commission policy and Opinion No. 531.[27]

IV. OUTLOOK FOR CAPITAL COSTS

Q29. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE BY SIMPLE APPLICATION OF THE TWO-STEP DCF METHOD?

A29. No. Current capital market conditions reflect the legacy of the Great Recession, and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment.

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[27] Opinion No. 531 at P 165.

Q30. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A30. Despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. Figure 1, below, compares the June 2014 yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

FIGURE 1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

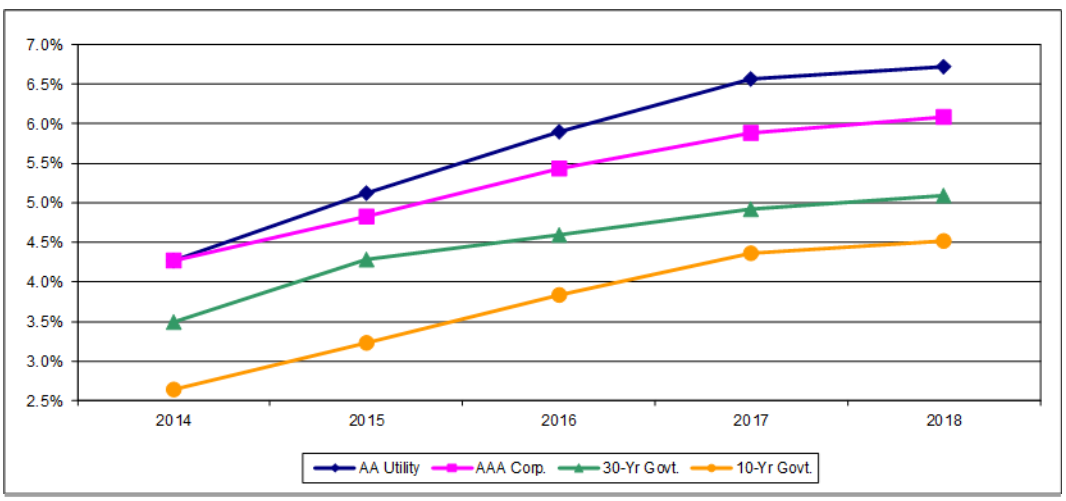
Q31. HAS THE COMMISSION ADDRESSED THE NATURE OF THESE HISTORICALLY LOW INTEREST RATES?

A31. Yes. In Opinion No. 531, the Commission determined that capital market conditions were anomalous and that the current atypically low interest rates impacted the results of the DCF analysis and led to results that were too low to be just and reasonable. Current capital market conditions are comparable to those addressed by the Commission in Opinion No. 531.

Q32. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

A32. No. Investors do not anticipate that these low interest rates will continue. It is widely anticipated that as the economy continues to stabilize and resumes a more robust pattern of growth, long-term capital costs will increase from present levels. Figure 2 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE 2
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014)
IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013)

These forecasting services are highly regarded and widely referenced, with the Commission incorporating forecasts from IHS Global Insight and the EIA in its two-step DCF model. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2015-2018 period than it is currently.

Q33. DO RECENT ACTIONS OF THE FEDERAL RESERVE SUPPORT THE CONTENTION THAT CURRENT LOW INTEREST RATES WILL CONTINUE INDEFINITELY?

A33. No. While the Federal Reserve continues to express support for maintaining a highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, it has also acted to steadily pare back its monthly bond-buying program. More recently, the Federal Reserve announced that it expects to continue steady reductions in bond-buying, and anticipates an end to new asset purchases after its October 2014 meeting.[28] Elimination of the Federal Reserve's bond buying program should exert upward pressure on long-term interest rates, with *The Wall Street Journal* observing that:

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[29]

While the Federal Reserve's tapering announcements have moderated uncertainties over just when, and to what degree, the stimulus program would be altered, investors continue to face ongoing uncertainties over future moves that could ultimately affect how quickly and how much interest rates are affected. The Federal Reserve's holdings of Treasuries and mortgage-backed securities amount to more than $4 trillion.[30] For now, the Federal Reserve is maintaining its policy of reinvesting principal payments

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28 *Minutes of the Federal Open Market Committee* (June 17-18, 2014).

29 Hilsenrath, Jon, "Fed Dials Back Bond Buying, Keeps a Wary Eye on Growth," *The Wall Street Journal* at A1 (Dec. 19, 2013).

30 Appelbaum, Binyamin, "Federal Reserve's Bond-Buying Fades, but Stimulus Doesn't End There," *The New York Times* (Jun. 19, 2014).

from these securities – about $16 billion a month – and rolling over maturing Treasuries at auction. As the Federal Reserve recently noted:

> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. The Committee's sizable and still-increasing holdings of longer-term securities should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative, which in turn should promote a stronger economic recovery and help to ensure that inflation, over time, is at the rate most consistent with the Committee's dual mandate.[31]

Of course, the corollary to these observations is that ending this policy of reinvestment could place significant upward pressure on bond yields, especially considering the enormous magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. Changes to this policy of reinvestment would further reduce stimulus measures and could place additional upward pressure on bond yields. The International Monetary Fund noted that, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "A smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[32] Similarly, *The Wall Street Journal* noted investors' "hypersensitivity to Fed interest rate

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[31] Federal Open Market Committee, *Press Release* (Jun. 18, 2014).

[32] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).

decisions," and expectations that higher interest rates "may come a bit sooner and be a touch more aggressive than expected."[33]

These developments highlight concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve curtailing the expansion of its enormous portfolio of Treasuries and mortgage bonds, ongoing concerns over political stalemate in Washington, continued economic weakness in the Eurozone, and political and economic unrest in Ukraine, the Middle East, and emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q34. DO THE CURRENT UNPRECEDENTED LOW INTEREST RATES AFFECT THE RESULTS OF THE COMMISSION'S DCF MODEL?

A34. Yes. The Commission's policy is to eliminate low-end DCF estimates that do not exceed average public utility bond yields by approximately 100 basis points or more.[34] As discussed above, current low interest rates are unprecedented and reflect the legacy of the recession and the Federal Reserve's stimulus policies. As illustrated in Figures 1 and 2, these low historical interest rates are anomalous and do not reflect expectations for the future, which is the only relevant consideration when evaluating investors' required return. As a result, adding a margin of approximately 100 basis points to average historical bond yields produces a threshold that is too low to reflect investors' required returns going forward. As I will discuss below, this conclusion is further supported by

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[33] Jon Hilsenrath and Victoria McGrane, "Yellen Debut Rattles Markets," Wall Street Journal (Mar. 19, 2014).

[34] *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

economic studies that show that risk premiums are higher when interest rates are at very low levels. Under these conditions, this static test of low-end outliers based on historical public utility bond yields retains low-end DCF estimates that are far below what investors require to accept the risks of an equity investment in electric utilities, including XEST.

To address the reality of current capital markets, it is imperative that the Commission consider current capital market anomalies and near-term forecasts for public utility bond yields when testing low-end DCF estimates and evaluating a fair ROE for XEST from within the zone of reasonableness.

V. CAPITAL MARKET ESTIMATES

Q35. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A35. This section presents capital market estimates of the cost of equity. I initially address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the results of the Commission's two-step DCF model applied to a benchmark group of comparable risk firms. I conclude this section with the results of my analyses utilizing the risk premium, CAPM, and expected rate of return methodologies, consistent with Opinion No. 531's reliance on these benchmarks.

While my recommended base ROE range and point estimate was based on the results of the two-step DCF model approved by the Commission in Opinion No. 531, the alternative benchmarks presented in my testimony provide critical guidance in determining whether an existing or proposed ROE is just and reasonable, and in evaluating a point estimate from within the zone of reasonableness. No single approach provides a fail-safe means to estimate investors' required ROE and it is important to consider the results of alternative methods.

A. Economic Standards

Q36. WHAT ROLE DOES ROE PLAY IN A UTILITY'S RATES?

A36. The ROE is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q37. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A37. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and

$RP_i =$ Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets; and (2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q38. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A38. Yes. The risk-return tradeoff can be documented readily in segments of the capital markets where required rates of return can be inferred directly from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of the various ratings categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q39. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A39. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be observed directly. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q40. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A40. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any that remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q41. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A41. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Development and Selection of a Proxy Group

Q42. HOW DID YOU IMPLEMENT THE DCF METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR XEST?

A42. Application of the DCF method, as well as the risk premium and CAPM approaches, to estimate the cost of equity requires observable capital market data, such as stock prices and beta values. Because XEST does not have publicly traded stock, its cost of common equity cannot be measured directly. Moreover, even for a firm with publicly traded stock, the cost of equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error.

As a result, the accepted approach to increase confidence in the results is to apply the DCF model to a proxy group of publicly traded companies that investors regard as risk comparable. The results of the analysis on the sample of companies are relied upon to establish a range of reasonableness for the cost of equity for the specific company at issue.

Q43. WHAT SPECIFIC PROXY GROUP DID YOU RELY ON FOR YOUR ANALYSIS?

A43. The National Group is composed of utilities that meet the following criteria:

1. Companies that are included in the Electric Utility Industry groups compiled by Value Line;
2. Electric utilities that paid common dividends over the last six months and have not announced a dividend cut since that time;
3. Electric utilities with no ongoing involvement in a major merger or acquisition that would distort quantitative results;
4. Electric utilities that have been assigned a corporate credit rating between BBB and A- by Standard & Poor's Corporation ("S&P"); and,
5. Electric utilities that have been assigned a long-term issuer rating between "Baa2" to "A3" by Moody's Investors Service ("Moody's").

As shown on Exhibit No. XES-503, the National Group is composed of 31 comparable-risk utilities.

Q44. WHAT WAS THE BASIS FOR THE RANGE OF CREDIT RATINGS USED TO IDENTIFY THE NATIONAL GROUP?

A44. In Opinion No. 531, the Commission determined that credit ratings from both major agencies – S&P and Moody's – should be considered independently as screening criteria when evaluating comparable risk.[35] In evaluating credit ratings to identify a proxy group of utilities with comparable risks, the Commission has adopted a "comparable risk band," interpreted as one "notch" higher or lower than the corporate credit ratings of the utility at issue and within the investment grade ratings scale.[36]

XEST has not issued debt in its own name and does not yet have an overall corporate or issuer credit rating. The criteria used to identify my risk-comparable proxy group assumes that XEST would qualify for ratings that are equivalent to the average BBB+ S&P corporate rating and Baa1 Moody's issuer rating maintained by the firms in Value Line's Electric Utility industry groups. These ratings benchmarks are consistent with the target credit profile for XEST discussed in Mr. Tyson's testimony and are one notch lower than the current ratings assigned to Xcel Energy. Consistent with the Commission's determination that a triple-B rating is a "minimum investment rating for an

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35 Opinion No. 531 at P 107.

36 *See, e.g., Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 53 (2010); *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008).

electric utility,"[37] other new entrant, stand-alone transmission companies have also adopted a similar approach based on industry credit metrics.[38]

The BBB to A- range of S&P credit ratings used to identify the National Group is consistent with the one notch higher or lower band under the Commission's guidelines. Applying the one notch higher or lower band to the average Moody's issuer rating for the electric utility industry results in a screening criterion based on Moody's long-term issuer ratings of Baa2 to A3.

Q45. WHAT OTHER RISK MEASURES DID YOU EXAMINE?

A45. Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Accordingly, my evaluation also included a comparison of three other objective measures of the investment risks associated with common stocks—Value Line's Safety Rank, Financial Strength Rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors.

The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total

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37 *Duquesne Power & Light Co.*, 118 FERC ¶ 61,087 at P 53 (2007).

38 *See, e.g., Northern Pass Transmission Co,* Docket No. ER11-2377 at Exh. NPT-600 (Dec. 15, 2010), and *Trans-Allegheny Interstate Line Co.,* Docket No. ER07-562 at Exh. TRC-100 (Feb. 21, 2007). Trans-Allegheny Interstate Line Co. currently is rated "BBB-" by S&P, which falls at the very bottom of the investment grade scale.

risk of a stock, and incorporates elements of stock price stability and financial strength.[39] The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is cited widely in academia and in the investment industry as a guide to investors' risk perceptions.

Q46. WHAT ARE THE AVERAGE RISK MEASURES ASSIGNED TO YOUR PROXY GROUP?

A46. Risk measures for the National Group are shown on Exhibit No. XES-503, and summarized in Table 1, below:

TABLE 1
COMPARATIVE RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
National Group	BBB+	Baa1	2	B++	0.75

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39 The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 at P 63 n.90 (2010).

Q47. ARE INVESTORS LIKELY TO VIEW THE FIRMS IN THE NATIONAL GROUP AS RISK-COMPARABLE TO XEST?

A47. No. In contrast to the utilities in the proxy group – which consists of relatively large, established companies in the electric utility sector with diversified activities and markets – XEST is a newly-formed transmission-only company that lacks any operating history and has no established capital base or cash flows. Large companies enjoy many advantages in accessing capital markets. Investors take comfort in their familiarity with such companies and their histories of meeting interest and principal payment obligations while declaring stable or gradually increasing dividends over the decades. Large, diversified companies can more easily weather unpleasant surprises in one or more markets because bad news in one business can be offset by good news elsewhere. In addition, XEST will be required to raise substantial amounts of capital to fund its projected capital expenditures. As a result, the investment risks associated with XEST exceed those of the utilities in the proxy group, which all have long track records and well-defined risk profiles.

As discussed above, the comparable risk band used to identify the National Group was based on credit ratings indicative of average risks in the electric utility industry. Given the absence of any debt repayment or earnings history, it almost certainly produces a proxy group with less risk than what investors would associate with XEST.

Q48. ARE THERE ADDITIONAL RISKS ASSOCIATED WITH XEST'S PRIMARY FOCUS ON COMPETING FOR TRANSMISSION PROJECTS IN THE SPP ORDER NO. 1000 COMPETITIVE BIDDING PROCESSES?

A48. Yes. As explained in the Direct Testimony of Ms. Mogensen, Exhibit No. XES-100, XEST faces inherent risks due to its primary focus on pursuing transmission projects subject to the Order No. 1000 competitive solicitation processes in the SPP region. The projects XEST primarily will pursue will be subject to competitive bidding by other entities that have chosen to register as QRPs in the SPP region. To date, it is my understanding that over 40 entities have registered to become QRPs, and therefore XEST cannot expect to win all of the projects on which it chooses to bid. Because XEST will pursue projects within the SPP region, including projects distant from the SPS transmission system, it also faces certain risks associated with the execution and delivery of such projects. These include performing siting and land acquisition activities, and pursuing regulatory approvals in states or regions with which Xcel Energy is less familiar.

In addition, as discussed by Ms. Mogensen, the SPP region's Order No. 1000 processes are still evolving and subject to change, and this contributes to considerable additional uncertainty for XEST. At the time of submission of this testimony, the Commission has not yet ruled on pertinent aspects of SPP's Order No. 1000 proposed compliance approach. For example, SPP's Tariff provisions that define the information and supporting materials that must be submitted in response to an RFP are not yet final; they are pending on compliance before the Commission. So too are the SPP Tariff provisions that define the criteria by which SPP's industry expert panel must evaluate such bids. Litigation associated with the SPP bidder selection process is also a possibility, which could result in an extended period of regulatory uncertainty.

Q49. WHAT ARE THE IMPLICATIONS OF THE COMPANY'S GREATER RISKS IN EVALUATING A FAIR ROE?

A49. The Commission has previously determined that "a new and independent entity … bears a significant risk at the permitting and initial project development stage and in the start-up investment," and concluded that such higher risks require enhanced rate treatment.[40] An ROE from the upper end of the zone of reasonableness is consistent with the need for financial support as XEST seeks to establish an investment grade credit standing while committing the capital investment necessary to undertake important enhancements to the transmission infrastructure within SPP.[41]

Similarly, the Commission has previously recognized that the ROE should be selected from the upper end of the zone of reasonableness when the utility's risks exceed those of the average firm in the proxy group. For example, in *Consumers Energy Co.*, the Commission concluded that, "In consideration of Trial Staff's testimony that Consumers is more risky than the average of the comparable group, we shall set the ROE at the midpoint of the upper-end of the range."[42] Similarly, the Commission concluded in *SoCal Edison* that:

> We will next consider where, within this zone of reasonable returns, SoCal Edison's ROE should be set. In making this determination, it is necessary to measure the business and financial risks faced by SoCal Edison relative

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40 *Trans Bay Cable LLC,* 112 FERC ¶ 61,095 at P 25 (2005).

41 These considerations also support XEST's requested capital structure.

42 *Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998).

> to the overall risks attributable to the appropriate proxy group of companies. … [B]ased on the higher bond ratings of the comparable companies, we find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group. Therefore, we will establish SoCal Edison's ROE at the midpoint of the upper half of the zone of reasonableness.[43]

Considering the higher risk associated with XEST's status as a new entrant transmission provider, the significant capital needs and long lead times associated with transmission projects, and the likelihood that a stand-alone credit rating for XEST would fall below that of the proxy group, the cost of equity estimates produced by my analyses provide a conservative basis on which to evaluate a fair ROE for XEST.

C. DCF Model

Q50. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A50. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. Thus, the cash flows that investors expect from a stock are estimated, and given its current

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43 *Southern California Edison Co.*, 92 FERC ¶ 61,070 at 61,266 (2000).

market price, we can back into the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q51. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A51. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price appreciation) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock.

Q52. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY?

A52. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[44]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;

D_1 = Expected dividend per share in the coming year;

k_e = Cost of equity;

g = Investors' long-term growth expectations.

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[44] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: (1) dividend yield (D_1/P_0); and (2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through stock price appreciation.

Q53. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A53. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q54. WHAT IS THE DISTINCTION BETWEEN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES AND THE CONSTANT GROWTH MODEL OUTLINED ABOVE?

A54. The two-step DCF method for electric utilities recently adopted by the Commission assumes that investors differentiate between near-term growth forecasts, such as the earnings growth rates published by securities analysts, and some notion of longer-term growth into the far distant future. Based on this assumption of disparate growth expectations, the two-step DCF method employs two separate growth rates for each firm, which are then weighted to arrive at a single value for the "g" component.

Q55. HOW WAS THE DIVIDEND YIELD FOR THE NATIONAL GROUP DETERMINED?

A55. Following the most recent statement of Commission policy in Opinion No. 531, an average dividend yield was calculated for each electric utility during the six months from January through June 2014.[45] As indicated on page 1 of Exhibit No. XES-504, these six-month average historical dividend yields were also increased by one-half of the IBES growth rates discussed subsequently ($1 + 0.5g$) to convert them to adjusted dividend yields.

Q56. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A56. The first growth rate, which is intended to represent expectations over the short-term, is the IBES consensus 5-year earnings growth forecast. The second growth rate is based on long-term forecasts of growth in nominal Gross Domestic Product ("GDP").

Q57. WHAT WAS THE SOURCE OF THE IBES GROWTH RATES USED IN YOUR APPLICATION OF THE COMMISSION'S TWO-STEP DCF METHOD?

A57. I obtained the IBES earnings growth rates from *Yahoo! Finance*, which has long been accepted and relied on by the Commission in applying the DCF approach. As noted in Opinion No. 531, "the Commission has consistently used IBES estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates."[46]

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[45] Opinion No. 531 at P 77.

[46] *Id.* at P 89.

Q58. HOW DID YOU ARRIVE AT YOUR PROJECTED GROWTH RATE IN NOMINAL GDP, REPRESENTING THE SECOND STAGE OF THE COMMISSION'S DCF MODEL?

A58. The Commission has a long history of relying on three independent sources for GDP growth projections in applying the two-step DCF approach.[47] More recently, the Commission has relied on the long-term projections of nominal GDP published by IHS Global Insight, EIA, and the Social Security Administration ("SSA"). The Commission affirmed the use of these sources in Opinion No. 531, while simultaneously reopening the evidentiary record to address the use of GDP forecasts in establishing a long-term growth rate.[48]

The calculation of the long-term growth rate in nominal GDP used in my application of the Commission's two-step DCF model is presented on page 2 of Exhibit No. XES-504. Consistent with the Commission's guidance, I relied on the most recent long-term projections published by IHS Global Insight and EIA, as well as the SSA forecast over the next 50 years. As shown there, this resulted in an average GDP growth rate of 4.39%.

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47 *See, e.g., Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034 at P 130 (2009).

48 Opinion No. 531 at P 43 & Appendix.

Q59. WHAT WEIGHTING DID YOU ASSIGN THESE RESPECTIVE GROWTH RATES TO ARRIVE AT THE SINGLE "*g*" COMPONENT OF THE TWO-STEP DCF MODEL?

A59. Following the Commission's long-standing practice, I weighted the individual IBES growth rates by two-thirds and the GDP growth projection by one-third to compute a single two-step growth rate for each utility in the proxy group.

Q60. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE NATIONAL GROUP USING THE TWO-STEP DCF MODEL?

A60. After combining the dividend yields and the weighted average of the IBES and GDP growth projections for each utility, the resulting cost of common equity estimates are shown on page 1 of Exhibit No. XES-504. As shown there, these individual DCF estimates ranged from 6.27% to 12.59%.

D. Evaluation of DCF Results

Q61. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE EXTREME OUTLIERS?

A61. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q62. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A62. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for the additional risk they assume. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range must be adjusted to eliminate cost of equity estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

The practice of eliminating low-end outliers has been affirmed in numerous proceedings,[49] and in Opinion No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[50] The Commission has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[51]

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49 *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).

50 Opinion No. 531 at P 122.

51 *Id.*

Q63. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A63. As indicated earlier, while utility bond yields have declined substantially as the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table 2 below, the most recent forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.65% over the period 2015-2018:

TABLE 2
IMPLIED UTILITY BOND YIELDS

	2015-18
Projected AA Utility Yield	
IHS Global Insight (a)	6.19%
EIA (b)	5.96%
Average	6.07%
Current BBB - AA Yield Spread (c)	0.58%
Implied Triple-B Utility Yield	**6.65%**

(a) IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Jan. 2014 - Jun. 2014

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb over 160 basis points through 2018.[52]

[52] *Blue Chip Financial Forecasts*, Vol. 32, No. 12 (Dec. 1, 2013).

Q64. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE NATIONAL GROUP?

A64. As indicated on page 1 of Exhibit No. XES-504, the low end of the DCF range was set by a cost of equity estimate of 6.27%. While I retained this low-end DCF estimate in deference to the methodology applied by the Commission in Opinion No. 531, this value falls below the implied 6.65% bond yield for the 2015-2018 period. In light of the risk-return tradeoff principle and the test of economic logic applied by the Commission, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, considering that current capital market conditions are not representative, and consistent with the upward trend expected for utility bond yields, the 6.27% estimate imparts a downward bias to the DCF results. Retaining this implausibly low estimate in the range makes my analysis conservative as a measure of the cost of equity for XEST. It also provides additional support for adopting an ROE for XEST from within the upper end of the zone of reasonableness that includes this low-end value.

Q65. DID YOU EXCLUDE DCF VALUES AT THE HIGH END OF THE RANGE?

A65. No. Under the Commission's two-step DCF model, long-term growth for all of the utilities in the proxy group is assumed to converge to that of the underlying economy. Because this assumption has the effect of significantly moderating the composite growth rate, the Commission noted that "it is unnecessary to screen the proxy group for unsustainable growth rates." As a result, the Commission concluded that the high-end outlier issue is now moot.

Moreover, the upper end of the DCF range for the National Group was set by a cost of equity estimate of 12.59%. This 12.59% high-end DCF estimate falls far below the 17.7% threshold formerly referenced by the Commission.[53] Similarly, the 11.21% growth rate underlying this cost of equity estimate is also well below the 13.3% growth rate benchmark that has been used by the Commission to evaluate values at the high end of the DCF range.[54] Accordingly, the 12.59% DCF cost of equity estimate provides a reasonable basis on which to evaluate investors' required rate of return for XEST, and is properly included.

E. Risk Premium Approach – FERC ROEs

Q66. BRIEFLY DESCRIBE THE RISK PREMIUM APPROACH.

A66. The risk premium approach extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

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53 *See, e.g., ISO New England*, 109 FERC ¶ 61,147 at P 205 (2004); *Southern Calif. Edison Co.*, 131 FERC ¶ 61,020 at P 57 (2010).

54 *Id.*

Q67. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A67. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for XEST.

Q68. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE MERITS OF THIS RISK PREMIUM APPROACH?

A68. Yes. The Commission's decision in Opinion No. 531 adopted my firm's application of the risk premium approach as an informative indicator of investors' required rate of return.[55] I am recommending exactly the same approach in this proceeding. Reliance on a risk premium methodology is also consistent with the Commission's prior practices. In a 1992 study, FERC Staff observed that a risk premium approach based on previously authorized ROEs "provides a powerful tool to the Financial Analysis Branch to help it formulate its recommendations on electric utilities' cost of common equity."[56] The Staff noted that:

> The results of our independent Risk Premium analysis are intended to complement the Discounted Cash Flow Model – the predominate model in use at the Commission.

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[55] Opinion No. 531 at P 146 (noting the risk premium analysis of Dr. William E. Avera).

[56] *Risk Premium Study*, Federal Energy Regulatory Commission, Office of Electric Power Regulation, Division of Electric Power Investigation, Financial Analysis Branch, at 1-2 (Aug. 4, 1992).

The Commission has previously considered evidence of alternative ROE benchmarks in evaluating a fair ROE, including the risk premium approach.[57]

Q69. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH?

A69. I based my estimates of equity risk premiums for utilities on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. The Commission has also recognized the importance of considering state authorized returns in evaluating a fair ROE for wholesale transmission operations.[58] Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q70. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR XEST?

A70. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk

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[57] *See, e.g., Distrigas of Mass. Corp.*, 41 FERC ¶ 61,205 at 61,550 (1987) ("The DCF methodology, which we endorse, is but one analytical tool. A risk premium analysis, . . . will also be considered. The weight to be given the results of each such methodology rests on the accuracy and sensibleness of the judgmental imputs [*sic*] and factors that the respective witnesses employed.")

[58] Opinion No. 531 at PP 145 & 150.

premiums consider objective market data (*e.g.*, stock prices dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q71. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A71. I applied the risk premium approach directly using ROEs approved by the Commission for electric utilities since 2006, after the Energy Policy Act of 2005 was enacted. This is exactly the same approach that my firm presented in Docket No. EL11-66-001, and which was relied on by the Commission in its evaluation of a fair ROE in that case.[59] On page 3 of Exhibit No. XES-505, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 2006 and 2013. As shown there, these equity risk premiums for electric utilities averaged 4.73%, and the yield on public utility bonds averaged 6.04%.

Q72. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A72. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[60] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication

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[59] Opinion No. 531 at PP 146-47.

[60] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Q73. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A73. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[61] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[62]

The Commission Staff noted in a study of risk premiums based on allowed ROEs that, "the lower the bond yield the higher the risk premium,"[63] and other regulators have also

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61 *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

62 Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. (2006) at 128.

63 *Risk Premium Study*, FERC, Office of Electric Power Regulation, Division of Electric Power Investigation, Financial Analysis Branch, at 6 (Aug. 4, 1992).

recognized that the cost of equity does not move in tandem with interest rates.[64] As the Commission has concluded, "The link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment."[65]

Q74. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A74. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q75. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING ROES AUTHORIZED BY THE COMMISSION?

A75. Based on the regression output between the interest rates and equity risk premiums displayed on page 6 of Exhibit No. XES-505, the equity risk premium for electric utilities increased approximately 88 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. XES-505, with an average six-month historical yield on triple-B public utility bonds at June 2014 of 4.90%,

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64 *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf.

65 Opinion No. 531 at P 147.

this implied a current equity risk premium of 5.73% for electric utilities. Adding this equity risk premium to the average six-month historical yield on triple-B utility bonds implies a current cost of equity of 10.63%.[66]

F. Capital Asset Pricing Model

Q76. PLEASE DESCRIBE THE CAPM.

A76. The CAPM approach generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect

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66 Because the S&P and Moody's ratings for AEP and FirstEnergy all fall in the triple-B category, my risk premium analysis was based on the average yield for triple-B utility bonds.

the expectations of actual investors in the market, not with backward-looking, historical data. In contrast to applications of the CAPM using historical, realized rates of return, which have been largely rejected by the Commission in the past, my CAPM analysis specifically incorporates forward-looking expectations that are consistent with the assumptions of this approach.

Q77. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A77. I used the exact same approach considered by the Commission in establishing a fair ROE in Opinion No. 531.[67] This application of the CAPM to the National Group, based on a forward-looking estimate for investors' required rate of return from common stocks, is presented on Exhibit No. XES-506. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 410 individual firms, current estimates imply an average growth rate over the next five years of 10.0%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.3%. Subtracting a 3.6% risk-free rate based on the

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[67] Opinion No. 531 at P 146.

six-month average yield on 30-year Treasury bonds at June 2014 produced a market equity risk premium of 8.7%.

Q78. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A78. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. While the Commission has expressed reservations in the past due to the fact that beta is measured based on historical stock prices, the long track record of published values supports the conclusion that Value Line's beta provides a good predictor of future stock price behavior relative to the market. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[68]

The fact that investors rely on Value Line betas in evaluating expected returns for utility common stocks provides strong support for this approach.

Q79. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A79. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On Average, small companies have higher returns than large ones. … The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[69]

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[68] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

[69] *Morningstar*, "2014 Ibbotson SBBI Classic Yearbook," at p. 99.

Because financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the cost of equity.[70] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 6.0% for a company in the first decile (market capitalization less than $339.5 million), to a reduction of 33 basis points for firms in the tenth decile (market capitalization greater than $21.8 billion). Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the National Group.

Q80. WHAT IS THE IMPLIED ROE FOR THE NATIONAL GROUP USING THE CAPM APPROACH?

A80. As shown on page 1 of Exhibit No. XES-506, a forward-looking application of the CAPM approach resulted in a median unadjusted ROE estimate of 10.13%, with average

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[70] *Morningstar,* "2014 Ibbotson SBBI Market Report," at Table 10.

and midpoint results of 10.07% and 10.13%, respectively. After adjusting for the impact of firm size, the CAPM approach implied a median cost of equity of 11.06% for the National Group, with the average and midpoint being 11.06% and 11.20%, respectively.

G. Expected Earnings Approach

Q81. WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE ROE FOR XEST?

A81. Consistent with Opinion No. 531, I also evaluated the ROE by reference to expected rates of return for electric utilities. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the Supreme Court in *Hope* and *Bluefield*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors. As the Commission recognized in Opinion No. 531:

> [T]he NETOs' expected earnings analysis, given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation.[71]

Q82. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A82. The simple but fundamental concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the

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[71] Opinion No. 531 at P 147.

utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital.

Q83. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A83. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. My application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Moreover, regulators do not set the returns that investors earn in the capital markets—they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q84. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A84. Yes. While this method predominated before the DCF model became fashionable with academic experts, it continues to be used around the country.[72] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[73] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[74] as well as sound regulatory economics. I have

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72 For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Another example is the Idaho Public Utilities Commission, which continues to confirm the relevance of return on book equity evidence.

73 Parcell, David C., "The Cost of Capital—a Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at 115-116 (2010).

74 *Id.* at 116.

routinely used the comparable earnings approach and it has been widely referenced in regulatory decision-making.[75]

Q85. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A85. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.56% over its 2017-2019 forecast horizon.[76] Meanwhile, for the firms in the National Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. XES-507. In *Southern California Edison*, the Commission correctly recognized that if the rate of return were based on end-of-year book values, such as those reported by Value Line, it would understate actual returns because of growth in common equity over the year.[77] Accordingly, consistent with the Commission's findings and the theory underlying this approach, I made an adjustment to compute an average rate of return.[78]

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[75] For example, a NARUC survey reported that 19 regulatory jurisdictions cited the comparable earnings test as a primary method favored in determining the allowed rate of return. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In my experience, while a few Commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

[76] The Value Line Investment Survey (May 2, May 23, Jun. 20, 2014).

[77] *Southern California Edison,* 92 FERC ¶ 61,070 at 61,263 and n.38 (2000).

[78] Use of an average return in developing the rate of return is well supported. *See*, *e.g.*, Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. (2006) at 305-306, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's prior findings.

As shown on Exhibit No. XES-507, Value Line's projections for the National Group resulted in an adjusted range of expected rates of return from 8.09% to 15.55%.[79]

VI. OTHER ROE BENCHMARKS

Q86. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A86. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances that apply to XEST. Specifically, I test my recommended ROE for XEST against a series of relevant benchmarks that measure the cost of equity based on: (a) a risk premium approach using ROEs approved by state regulators; (b) the empirical CAPM, (c) Commission-approved ROEs for natural gas pipelines; and (d) a DCF analysis based on a select group of low risk non-utility firms.[80] I also considered the potential role for flotation costs in evaluating a just and reasonable ROE. These other benchmarks provide additional guidance that is relevant in corroborating the end-result of the primary methods discussed previously.

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[79] The midpoint, median, and average values were 11.82%, 10.00%, and 10.48%, respectively.

[80] For the CAPM, ECAPM and risk premium analyses, I performed additional analyses utilizing projected bond yields.

Q87. THE COMMISSION DECLINED TO CONSIDER THE IMPLICATIONS OF ROE RESULTS FOR GAS PIPELINES OR NON-UTILITY FIRMS IN OPINION NO. 531. WHY HAVE YOU INCLUDED THEM IN YOUR EVALUATION IN THIS PROCEEDING?

A87. The Commission stated that it would not consider the risk premium analysis based on allowed ROEs for gas pipelines or the non-utility DCF analysis "because those methodologies are not based on electric utilities."[81] While this observation is true, in my opinion it does not provide a sufficient basis to ignore these findings. Given the Commission's observations regarding the evolution of the electric utility industry and its willingness to adopt the same two-step DCF approach used to establish ROEs for natural gas pipelines,[82] risk premiums for natural gas pipelines provide a very logical benchmark to evaluate corresponding DCF results for electric utilities. Moreover, my risk premium application does not assume that the gas pipeline and electric utility industries have equivalent risks or expected returns. Rather, I specifically consider and adjust for industry differences in arriving at an implied ROE using this method.

In addition, the fact that natural gas pipelines and non-utility firms do not operate in the same industry as electric utilities does not render them irrelevant. Investors have many opportunities for their capital and electric utilities must compete for funds with firms outside their own industry. The investment community has recognized the

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81 Opinion No. 531 at P 126 n.288.

82 *Id.* at P 32.

interrelationship between ROEs for pipelines and electric transmission companies in the allocation of capital. As Wolfe Research noted:

> Investors are concerned that a cut [in base ROEs for electric transmission] would cause an imbalance in the risk/reward trade-off of investing in transmission. In turn, the electric utility industry fears that investors could divert capital to other infrastructure investments with a more favorable risk/reward balance, such as natural gas pipelines, which are also regulated by FERC.[83]

For these same reasons, if electric transmission operations are unable to offer a return that is commensurate with what investors expect to earn from a non-regulated company of comparable risk, then capital will flow elsewhere.

A. Risk Premium – State ROEs

Q88. HOW ELSE DID YOU USE THE RISK PREMIUM APPROACH IN YOUR ANALYSIS?

A88. In addition to a risk premium analysis based on ROEs authorized for electric utilities by the Commission, I also applied the risk premium approach using ROEs authorized for electric utilities by regulatory commissions across the U.S., which are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. On page 3 of Exhibit No. XES-508, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2013.[84] As shown there, over this period these equity risk premiums for electric utilities averaged 3.53%, and the yield on public utility bonds averaged 8.69%.

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[83] Wolfe Research, "FERConomics: Risk to transmission base ROE in focus," *Utilities & Power* (Jun. 11, 2013).

[84] My analysis encompasses the entire period for which published data is available.

Q89. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM APPROACH BASED ON ROES APPROVED BY STATE REGULATORS?

A89. As shown on page 1 of Exhibit No. XES-508, adding an equity risk premium corresponding to current interest rate levels to the average yield on triple-B utility bonds for the six-months ending June 2014 of 4.90% implies a current cost of equity for electric utilities of 10.19%.

B. Empirical Capital Asset Pricing Model

Q90. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A90. The ECAPM is a variant of the traditional CAPM approach that is designed to correct for an observed bias in the CAPM results. Specifically, empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn somewhat less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping

with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[85]

As discussed in *New Regulatory Finance*, empirical evidence suggests that the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$Rj = Rf + 0.25(Rm - Rf) + 0.75[\beta j(Rm - Rf)]$$

This ECAPM equation, and the associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q91. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE ECAPM?

A91. My application of the ECAPM approach was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the traditional CAPM. As shown on page 1 of Exhibit No. XES-509, applying the forward-looking ECAPM approach to the firms in the National Group results in a theoretical cost of equity range of 9.69% to 11.65%, or 9.36% to 14.13% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[86]

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[85] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006). The Commission has recognized this as an authoritative source. *See, e.g.,* Opinion No. 531 at PP 145 n.287, 147 nn.289 & 294.

[86] The midpoint, median, and average ECAPM results based on historical bond yields were 10.67%, 10.67%, and 10.63%, respectively, or 11.74%, 11.60%, and 11.62%, respectively, after adjusting for firm size.

C. Gas Pipeline ROEs

Q92. HOW DOES YOUR RECOMMENDED ROE FOR XEST COMPARE WITH AN ROE BENCHMARK BASED ON NATURAL GAS PIPELINE RETURNS?

A92. While I recognize that in Opinion No. 531 the Commission elected not to compare electric utilities directly to natural gas pipelines when determining ROE, I believe the comparison is relevant. For example, in *Williston Basin*, FERC staff proposed expanding the proxy group used to estimate the cost of equity for gas pipelines to include utilities with electric utility operations, noting that investors "see a linkage between the risk profile of different types of utilities," and concluding that:

> [G]as pipelines and transmission facilities for electricity have characteristics in common in that both transmit a product with time end weather sensitive demand profiles over rights-of-way that are capital intensive and relatively inflexible. Expanding the gas pipeline proxy group to include publicly-owned companies engaged in other regulated lines of energy-related business will, in my opinion, increase the level of confidence in the reasonableness of the results of my DCF analysis...[87]

Staff's arguments were ultimately persuasive, as the Commission subsequently adopted a proxy group of natural gas pipeline companies that also included firms with substantial electric utility operations. This is consistent with the Commission's recent findings that distinctions between the gas pipeline and electric utility industries have moderated significantly due to changes to the electric utility industry.[88]

At the same time, the Commission previously has also rejected using DCF analyses for natural gas pipelines in establishing a fair ROE for electric utility operations

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[87] *Williston Basis Interstate Pipeline Company*, Docket No. RP00-107-000, *Prepared Direct and Answering Testimony of Commission Staff Witness George M Shriver, III,* P 17 (Jun. 7, 2000).

[88] Opinion No. 531 at P 8.

because of differences between the two industries. In *Southern California Edison*, the Commission stated that it was not appropriate to consider returns in the natural gas industry when evaluating electric utilities because "the electric industry is just beginning a significant new phase of its restructuring."[89] Thirteen years have passed since this statement was made, however, and as noted above, the Commission recognized in Opinion No. 531 that the electric industry and its restructuring have matured, which confirms my reference to gas company ROEs.

Q93. HOW DID YOU USE THE INFORMATION CONTAINED IN ROE DETERMINATIONS FOR NATURAL GAS PIPELINES TO DEVELOP AN ROE BENCHMARK FOR ELECTRIC UTILITIES?

A93. I first applied the risk premium approach discussed above to develop a current implied ROE for gas pipelines based on the Commission's historical allowed returns. My analysis then examined the historical ROE differential between the natural gas pipeline and electric utility industries, and then applied it to the current allowed ROE for natural gas pipelines to infer a corresponding ROE for electric utilities. As a result, this approach relies directly on the Commission's own determination as to the impact of relative industry risks and current returns.

Allowed ROEs approved by the Commission for natural gas pipelines for the years 2006 through 2013 are presented on pages 4 and 5 of Exhibit No. XES-510. The average annual ROE, the corresponding average bond yields, and implied risk premiums are summarized on page 3 of Exhibit No. XES-510. Consistent with state and

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89 *Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at 61,261 (2000).

Commission-approved ROEs for electric utilities, the implied equity risk premiums for gas pipelines increase as interest rates decline, and vice versa.

Q94. WHAT CURRENT COST OF EQUITY IS IMPLIED FOR AN ELECTRIC UTILITY BASED ON THESE ALLOWED GAS PIPELINE ROES?

A94. As shown on page 1 of Exhibit No. XES-510, adding an equity risk premium corresponding to current interest rate levels to the average yield triple-B utility bonds for the six-months ending June 2014 of 4.90% implies a current cost of equity for natural gas pipelines of 12.47%. As shown in the lower portion of page 3 of Exhibit No. XES-510, the average ROE for natural gas pipelines has exceeded the ROE approved by the Commission for electric utilities by 2.02% between 2006 and 2013. Subtracting this spread from the 12.47% current risk premium estimate for natural gas pipelines results in a current implied ROE for an electric utility of 10.45%, if one were to assume that the risk spread between utilities and pipelines should remain constant.

D. Projected Bond Yields

Q95. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE RISK PREMIUM, CAPM, AND ECAPM APPROACHES?

A95. Yes. As discussed earlier, there is widespread consensus that interest rates are currently anomalous, and will increase materially as the economy continues to strengthen. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective (and beyond). Accordingly, in addition to the use of current bond yields, I also applied the risk premium, CAPM, and ECAPM methods based on projections for utility bond yields published by IHS Global Insight and EIA.

Q96. WHAT RISK PREMIUM COST OF EQUITY ESTIMATES ARE PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A96. As shown on page 2 of Exhibit No. XES-505, incorporating a forecasted yield for 2015-2018 and adjusting for changes in interest rates since the study period implied an equity risk premium based on Commission-authorized ROEs of 4.19% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2015-2018 of 6.65% resulted in an implied cost of equity of 10.84%.

As shown on page 2 of Exhibit No. XES-508, applying the risk premium approach based on ROEs for electric utilities authorized by state regulators and incorporating average forecasted yields for 2015-2018 implied a cost of equity of approximately 11.19%.

Meanwhile, my risk premium analysis based on the Commission's findings for natural gas pipelines implied a cost of equity estimate of 10.93% based on forecasted yield for utility bonds (Exhibit No. XES-510, page 2).

Q97. DID YOU ALSO APPLY THE CAPM AND ECAPM USING FORECASTED BOND YIELDS?

A97. Yes. As shown on page 2 of Exhibit No. XES-506, applying the CAPM using a forecasted Treasury bond yield for 2015-2018 implied an ROE range of 9.26% to 11.54%

for the National Group, or 8.93% to 14.02% after adjusting for the impact of relative size.[90]

As shown on page 2 of Exhibit No. XES-509, incorporating a forecasted Treasury bond yield for 2015-2018 implied a ECAPM range of 10.02% to 11.73% for the National Group, or 9.69% to 14.21% after adjusting for the impact of relative size.[91]

E. Low-Risk Non-Utility DCF Model

Q98. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR XEST?

A98. Consistent with underlying economic and regulatory standards, I also applied the DCF model to a select group of low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group."

Q99. DO UTILITIES NEED TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A99. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there is a wide range of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry,

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[90] The midpoint of the unadjusted estimates was 10.40%, while the median was 10.40% and the average was 10.35%. The midpoint, median, and average values of the adjusted estimates were 11.48%, 11.33%, and 11.35%, respectively.

[91] The midpoint of the unadjusted CAPM results based on projected bond yields was 10.88%, with a median of 10.88% and an average of 10.84%. For the adjusted estimates, the midpoint was 11.95%, with a median of 11.81% and an average of 11.83%.

but with other investment opportunities of comparable risk.[92] Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q100. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A100. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings which are attended by corresponding risks and uncertainties[.]"[93] It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[94]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

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[92] Even for a single utility, capital will be allocated between competing uses in part based on opportunity costs. Where the utility has no regulatory obligation to undertake a particular project, an anemic return may foreclose investment altogether.

[93] *Bluefield* at 692.

[94] *Hope* at 603.

Q101. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A101. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities relative to estimates for firms in other industries. Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q102. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A102. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta less of 0.70 or less; and (5) have investment grade credit ratings from S&P.

Q103. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY PROXY GROUP COMPARE WITH THE NATIONAL GROUP?

A103. Table 3 compares the Non-Utility Group with the National Group across the same five indicators of investment risk discussed earlier:

TABLE 3
COMPARISON OF RISK INDICATORS

Proxy Group	S&P	Moody's	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Non-Utility	A	A2	1	A+	0.65
National Group	BBB+	Baa1	2	B++	0.75

As shown above, the average risk indicators for the Non-Utility Proxy Group suggest less risk than for the proxy group of electric utilities. A comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the National Group – and XEST – are greater than those of the firms in the Non-Utility Group.

The 16 companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, General Mills, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q104. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A104. As shown on Exhibit No. XES-512, I calculated the dividend yield component of the DCF model in exactly the same manner described earlier for the National Group. With respect to growth, my application of the DCF model to the Non-Utility Group relied on an average earnings growth rate based on projections from IBES and Value Line. As shown there, after excluding outliers, my DCF analysis for the Non-Utility Group resulted in an adjusted ROE range of 9.29% to 12.91%, with a midpoint of 11.10%, a median of 10.74%, and an average of 10.90%. As discussed above, considering expected returns for the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q105. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR PROXY GROUP OF UTILITIES?

A105. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms – as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the National Group. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for XEST. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector. In fact, considering the prominence of the 16 non-utility companies, the diversification afforded by considering multiple industries, and the scrutiny that analysts' afford to these paragons of American industry, the divergence between the DCF estimates for the group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result.

Q106. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A106. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. XES-502. The results of these alternative benchmarks confirm my conclusion that a base ROE of 10.64% for XEST is reasonable.

F. Flotation Costs

Q107. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A107. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q108. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A108. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q109. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A109. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[95]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[96]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 4.0% implies a flotation cost adjustment on the order of 14 to 40 basis points. While I did not make an explicit adjustment to the results of my alternative methods to include an adjustment for flotation costs, this is a legitimate consideration that supports the reasonableness of my recommended base ROE for XEST in this case.[97]

Q110. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A110. Yes.

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[95] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 323 (2006).

[96] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth at Exhibit GJE-11.1 (Jul. 2, 2004). Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[97] FERC Staff has previously recommended, and the Commission has approved, a flotation cost allowance in establishing the base ROE for an electric transmission utility. *See Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Co.*, 115 FERC ¶ 63,043 at PP 96, 104 (2006), *affirmed in relevant part*, Opinion No. 501, 123 FERC ¶ 61,047 at PP 57, 62-65 (2008), *on reh'g*, Opinion No. 501-A, 144 FERC ¶ 61,132 (2013), *reh'g granted for further consideration*, EL05-19-015 and ER05-168-014 (Oct. 10, 2013).

Exhibit No. XES-501

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, represent clients in settlement hearings and conferences, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE. Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power. Mr. McKenzie has represented clients at settlement negotiations and hearings.

Exhibit No. XES-502

SUMMARY OF RESULTS

PRIMARY METHODS

	Range	Median	Middle Top Half
Two-Stage DCF	6.27% -- 12.59%	8.70%	10.64%

Alternative Benchmark Methods

	Range	Midpoint	Median	Average
Risk Premium - FERC ROE (a)		10.63%	10.63%	10.63%
CAPM - Historical Bond Yield	8.49% -- 13.91%	11.20%	11.06%	11.06%
Expected Earnings				
Industry (a, b)		10.56%	10.56%	10.56%
Proxy Group	8.09% -- 15.55%	11.82%	10.00%	10.48%
Summary - Alternative Methods				
Average	**8.29% -- 14.73%**	**11.05%**	**10.56%**	**10.68%**
Median	**8.29% -- 14.73%**	**10.92%**	**10.60%**	**10.60%**

(a) Point estimate value.

(b) Average for Value Line Electric Utility industry group.

SUMMARY OF RESULTS

CHECKS OF REASONABLENESS

	Range	Midpoint	Median	Average
Risk Premium				
State ROE (a)		10.19%	10.19%	10.19%
FERC Gas Pipelines (a)		10.45%	10.45%	10.45%
Empirical CAPM	9.36% -- 14.13%	11.74%	11.60%	11.62%
Projected Bond Yields				
Risk Premium				
FERC ROE (a)		10.84%	10.84%	10.84%
State ROE (a)	10.84% -- 11.19%	11.19%	11.19%	11.19%
FERC Gas Pipelines (a)		10.93%	10.93%	10.93%
CAPM	8.93% -- 14.02%	11.48%	11.33%	11.35%
Empirical CAPM	9.69% -- 14.21%	11.95%	11.81%	11.83%
Non-Utility DCF	9.29% -- 12.91%	11.10%	10.74%	10.90%
Summary - All Methods				
Average		**11.10%**	**11.01%**	**11.03%**
Median		**11.10%**	**10.93%**	**10.93%**

(a) Point estimate value.

Exhibit No. XES-503

RISK MEASURES

			(a)	(b)	(c)			(d)
			S&P Corporate Rating	**Moody's Long-term Rating**	**Value Line**			
	Company	**SYM**			**Safety Rank**	**Financial Strength**	**Beta**	**Market Cap**
1	ALLETE	ALE	BBB+	A3	2	A	0.75	$2,050
2	Alliant Energy	LNT	A-	A3	2	A	0.75	$6,407
3	Ameren Corp.	AEE	BBB+	Baa2	2	B++	0.75	$9,440
4	American Elec Pwr	AEP	BBB	Baa1	3	B++	0.65	$25,765
5	Avista Corp.	AVA	BBB	Baa1	2	A	0.80	$1,934
6	Black Hills Corp.	BKH	BBB	Baa1	3	B+	0.90	$2,553
7	CenterPoint Energy	CNP	A-	Baa1	2	B++	0.75	$10,317
8	Cleco Corp.	CNL	BBB+	Baa2	1	A	0.75	$3,115
9	CMS Energy Corp.	CMS	BBB	Baa2	2	B++	0.75	$7,907
10	Consolidated Edison	ED	A-	A3	1	A+	0.60	$16,007
11	Dominion Resources	D	A-	Baa2	2	B++	0.70	$39,852
12	DTE Energy Co.	DTE	BBB+	A3	2	B++	0.75	$13,342
13	Duke Energy Corp.	DUK	BBB+	A3	2	A	0.60	$50,148
14	Edison International	EIX	BBB+	A3	2	A	0.80	$17,786
15	El Paso Electric	EE	BBB	Baa1	2	B++	0.70	$1,522
16	Empire District Elec	EDE	BBB	Baa1	2	B++	0.65	$1,032
17	Great Plains Energy	GXP	BBB+	Baa2	3	B+	0.85	$3,888
18	IDACORP, Inc.	IDA	BBB	Baa1	2	B++	0.80	$2,755
19	Integrys Energy Group	TEG	A-	Baa1	2	A	0.80	$4,555
20	ITC Holdings Corp.	ITC	A-	Baa2	2	B++	0.65	$5,739
21	NextEra Energy, Inc.	NEE	A-	Baa1	2	A	0.70	$42,107
22	Northeast Utilities	NU	A-	Baa1	2	B++	0.75	$14,221
23	OGE Energy Corp.	OGE	A-	A3	2	A	0.85	$7,282
24	Otter Tail Corp.	OTTR	BBB	Baa2	3	B+	0.90	$1,035
25	PG&E Corp.	PCG	BBB	Baa1	3	B+	0.60	$21,208
26	Pinnacle West Capital	PNW	A-	Baa1	1	A+	0.75	$6,054
27	Portland General Elec.	POR	BBB	A3	2	B++	0.80	$2,579
28	Pub Sv Enterprise Grp	PEG	BBB+	Baa2	1	A++	0.75	$19,476
29	Sempra Energy	SRE	BBB+	Baa1	2	A	0.80	$24,540
30	Westar Energy	WR	BBB+	Baa1	2	B++	0.75	$4,612
31	Xcel Energy Inc.	XEL	A-	A3	2	B++	0.65	$15,320
			BBB+	**Baa1**	**2**	**B++**	**0.74**	**$12,405**

(a) Corporate credit rating from www.standardandpoors.com (retrieved Jun. 8, 2014).
(b) Long-term rating from www.moodys.com (retrieved Jun. 8, 2014)
(c) The Value Line Investment Survey (May 2, May 23, & Jun. 20, 2014).
(d) www.valueline.com (retrieved Jun. 8, 2014).

Exhibit No. XES-504

DCF MODEL - NATIONAL GROUP

COST OF EQUITY ESTIMATES

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Dividend Yield			Growth Rate			
	Company	6-Mo. Average	Adjustment	Adjusted	IBES	GDP	Weighted	Cost of Equity
1	ALLETE	3.88%	1.0300	4.00%	6.00%	4.39%	5.46%	9.46%
2	Alliant Energy	3.64%	1.0245	3.73%	4.90%	4.39%	4.73%	8.46%
3	Ameren Corp.	4.07%	1.0100	4.11%	2.00%	4.39%	2.80%	6.91%
4	American Elec Pwr	3.95%	1.0240	4.04%	4.79%	4.39%	4.66%	8.70%
5	Avista Corp.	4.16%	1.0250	4.26%	5.00%	4.39%	4.80%	9.06%
6	Black Hills Corp.	2.74%	1.0350	2.83%	7.00%	4.39%	6.13%	8.96%
7	CenterPoint Energy	3.89%	1.0175	3.95%	3.50%	4.39%	3.80%	7.75%
8	Cleco Corp.	2.93%	1.0350	3.03%	7.00%	4.39%	6.13%	9.16%
9	CMS Energy Corp.	3.69%	1.0329	3.81%	6.58%	4.39%	5.85%	9.66%
10	Consolidated Edison	4.56%	1.0126	4.61%	2.52%	4.39%	3.14%	7.76%
11	Dominion Resources	3.43%	1.0301	3.54%	6.02%	4.39%	5.48%	9.01%
12	DTE Energy Co.	3.61%	1.0293	3.71%	5.85%	4.39%	5.36%	9.08%
13	Duke Energy Corp.	4.40%	1.0210	4.49%	4.19%	4.39%	4.26%	8.74%
14	Edison International	2.69%	1.0188	2.74%	3.75%	4.39%	3.96%	6.70%
15	El Paso Electric	2.94%	1.0350	3.05%	7.00%	4.39%	6.13%	9.18%
16	Empire District Elec	4.30%	1.0150	4.36%	3.00%	4.39%	3.46%	7.83%
17	Great Plains Energy	3.57%	1.0263	3.66%	5.25%	4.39%	4.96%	8.63%
18	IDACORP, Inc.	3.17%	1.0200	3.23%	4.00%	4.39%	4.13%	7.36%
19	Integrys Energy Group	4.67%	1.0175	4.75%	3.50%	4.39%	3.80%	8.55%
20	ITC Holdings Corp.	1.61%	1.0562	1.70%	11.23%	4.39%	8.95%	10.65%
21	NextEra Energy, Inc.	3.03%	1.0312	3.13%	6.23%	4.39%	5.62%	8.74%
22	Northeast Utilities	3.47%	1.0311	3.58%	6.21%	4.39%	5.60%	9.18%
23	OGE Energy Corp.	2.52%	1.0330	2.60%	6.60%	4.39%	5.86%	8.47%
24	Otter Tail Corp.	1.29%	1.0300	1.33%	6.00%	4.39%	5.46%	6.79%
25	PG&E Corp.	4.17%	1.0322	4.30%	6.44%	4.39%	5.76%	10.06%
26	Pinnacle West Capital	4.17%	1.0214	4.26%	4.28%	4.39%	4.32%	8.57%
27	Portland General Elec.	3.46%	1.0561	3.65%	11.21%	4.39%	8.94%	12.59%
28	Pub Sv Enterprise Grp	3.99%	1.0060	4.01%	1.20%	4.39%	2.26%	6.27%
29	Sempra Energy	2.71%	1.0348	2.80%	6.95%	4.39%	6.10%	8.90%
30	Westar Energy	4.00%	1.0145	4.06%	2.90%	4.39%	3.40%	7.45%
31	Xcel Energy Inc.	3.89%	1.0225	3.98%	4.49%	4.39%	4.46%	8.44%
	Range of Reasonableness							**6.27% -- 12.59%**
	Midpoint							**9.43%**
	Middle - Top Half of DCF Zone							**11.01%**
	Median							**8.70%**
	Middle - Top Half of DCF Zone							**10.64%**

(a) Six-month average dividend yield for Jan. - Jun. 2014.
(b) 1 + 0.5 x (d).
(c) (a) x (b).
(d) www.finance.yahoo.com (retrieved Jul. 8, 2014).
(e) See Exhibit XES-504, page 2.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).
(h) Excludes highlighted values.

GDP GROWTH RATE

	Source	Nominal GDP ($ Billions) 2019	2040	2044	2069	Compound Annual Growth Rate
(a)	**IHS Global Insight**	22,094.55		62,839.95		4.30%
(b)	**Energy Information Administration**					
	Real GDP	16,378	26,670			
	GDP Deflator	1.286	1.913			
		21,062	51,023			4.30%
(c)	**SSA Trustees Report**	22,667			211,559	4.57%
	Average GDP Growth Rate					**4.39%**

(a) IHS Global Insight, *The U.S. Economy, The 30-Year Focus* (First Quarter 2014)
(b) Energy Information Administration, *Annual Energy Outlook 2014* (May 7, 2014).
(c) Social Security Administration, *2013 OASDI Trustees Report,* http://www.ssa.gov/oact/tr/2013/lr6f6.html.

Exhibit No. XES-505

HISTORICAL BOND YIELDS

Current Equity Risk Premium		
(a)	Average Yield Over Study Period	6.04%
(b)	BBB Utility Bond Yield - Historical	4.90%
	Change in Bond Yield	-1.14%
(c)	Risk Premium/Interest Rate Relationship	-0.8816
	Adjustment to Average Risk Premium	1.01%
(a)	Average Risk Premium over Study Period	4.73%
	Adjusted Risk Premium	**5.73%**

Implied Cost of Equity		
(b)	BBB Utility Bond Yield - Historical	4.90%
	Adjusted Equity Risk Premium	5.73%
	Risk Premium Cost of Equity	**10.63%**

(a) See Exhibit XES-505, p. 3.
(b) Six-month average yield for Jan. 2014 - Jun. 2014 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit XES-505, p. 6.

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Average Yield Over Study Period	6.04%
(b)	BBB Utility Bond Yield 2015-2018	6.65%
	Change in Bond Yield	0.61%
(c)	Risk Premium/Interest Rate Relationship	-0.8816
	Adjustment to Average Risk Premium	-0.54%
(a)	Average Risk Premium over Study Period	4.73%
	Adjusted Risk Premium	**4.19%**

Implied Cost of Equity		
(b)	BBB Utility Bond Yield 2015-2018	6.65%
	Adjusted Equity Risk Premium	4.19%
	Risk Premium Cost of Equity	**10.84%**

(a) See Exhibit XES-505, p. 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) See Exhibit XES-505, p. 6.

IMPLIED RISK PREMIUM

Year	(a) Average Base ROE	(b) BBB Utility Bond Yield	Risk Premium
2006	11.01%	6.32%	4.69%
2007	10.96%	6.33%	4.63%
2008	10.82%	7.25%	3.57%
2009	10.84%	7.06%	3.78%
2010	10.64%	5.98%	4.67%
2011	10.67%	5.57%	5.11%
2012	10.96%	4.86%	6.11%
2013	10.24%	4.98%	5.26%
		6.04%	4.73%

(a) Exhibit XES-505, pp. 4-5.
(b) Moody's Investors Service, www.credittrends.com.

ALLOWED ROE

Date	**Docket No.**	**Utility**	**Base ROE**
Apr-06	ER05-515	Baltimore Gas & Elec.	10.80%
Apr-06	ER05-515	Baltimore Gas & Elec.	11.30%
Aug-06	ER05-925	Westar Energy Inc.	10.80%
Oct-06	ER04-157	Bangor Hydro-Elec. Co.	11.14%
Apr-07	ER07-284	San Diego Gas & Elec.	11.35%
Jul-07	ER06-787	Idaho Power Co.	10.70%
Jul-07	ER06-1320	Wisconsin Elec. Pwr. Co.	11.00%
Oct-07	ER07-583	Commonwealth Edison Co.	11.00%
Nov-07	EL06-109	Duquesne Light Co.	10.90%
Nov-07	ER08-10	Pepco Holdings, Inc.	10.80%
Feb-08	ER08-374	Atlantic Path 15	10.65%
Mar-08	ER08-396	Westar Energy Inc.	10.80%
Mar-08	ER08-413	Startrans IO, LLC	10.65%
Apr-08	ER07-549	NSTAR Elec. Co.	10.90%
Apr-08	EL05-19	Southwestern Public Service	9.33%
Apr-08	ER07-562	Trans-Allegheny	11.20%
Apr-08	ER08-92	Virginia Elec. & Power Co.	10.90%
Jul-08	ER07-1142	Arizona Public Service Co.	10.75%
Jul-08	ER08-375	So. Cal Edison (a)	9.54%
Aug-08	ER08-1207	Virginia Elec. & Power Co.	10.90%
Aug-08	ER08-686	Pepco Holdings, Inc.	11.30%
Aug-08	ER07-694	New England Pwr. Co.	11.14%
Sep-08	ER08-1233	Public Service Elec. & Gas	11.18%
Oct-08	ER08-1423	Pepco Holdings, Inc.	10.80%
Oct-08	EL08-74	Central Maine Power Co.	11.14%
Oct-08	ER08-1402	Duquesne Light Co.	10.90%
Nov-08	ER08-1548	Northeast Utils Service Co.	11.14%
Nov-08	EL08-77	Central Maine Power Co.	11.14%
Dec-08	ER09-14	NSTAR Elec. Co.	11.14%
Dec-08	ER09-35/36	Tallgrass / Prairie Wind	10.80%
Feb-09	ER08-1584	Black Hills Power Co.	10.80%
Mar-09	ER07-1069	AEP - SPP Zone	10.70%
Mar-09	ER09-75	Pioneer Transmission	10.54%
Mar-09	ER09-548	ITC Great Plains	10.66%
Mar-09	ER09-249	Public Service Elec. & Gas	11.18%
Apr-09	ER09-681	Green Power Express	10.78%
May-09	ER08-1457	PPL Elec. Utilities Corp.	11.10%
May-09	ER08-1457	PPL Elec. Utilities Corp.	11.14%
May-09	ER08-1457	PPL Elec. Utilities Corp.	11.18%
May-09	ER09-745	Baltimore Gas & Elec.	11.30%
May-09	ER08-552	Niagara Mohawk Pwr. Co.	11.00%

ALLOWED ROE

Date	Docket No.	Utility	Base ROE
May-09	ER08-281	Oklahoma Gas & Elec.	10.60%
Jun-09	ER08-1588	Kentucky Utilities Co.	11.00%
Aug-09	ER07-1344	Westar Energy Inc.	10.80%
Aug-09	ER09-187	So. Cal Edison (b)	10.04%
Oct-09	ER08-313	Xcel Energy	10.77%
Nov-09	ER09-628	National Grid Generation LLC	10.75%
Nov-09	ER09-1762	Westar Energy Inc.	10.80%
May-10	ER08-1329	AEP - PJM Zone	10.99%
Sep-10	ER10-160	So. Cal Edison (c)	10.33%
Oct-10	ER10-355	AEP Transco	10.99%
Oct-10	ER10-230	KCPL	10.60%
Dec-10	ER11-1952	So. Cal Edison	10.30%
Feb-11	ER11-2377	Northern Pass Transmission	10.40%
May-11	EL10-80	Ameren	12.38%
May-11	EL11-13	Atlantic Grid Operations	10.09%
Jun-11	ER10-1377	Xcel Energy	10.40%
Jun-11	ER11-3352	PJM & PSE&G	11.18%
Jun-11	ER10-516	South Carolina Elec. & Gas	10.55%
Oct-11	ER11-2895	Duke Energy Carolinas	10.20%
Oct-11	ER11-4069	RITELine	9.93%
Nov-11	ER08-386	PATH	10.40%
Dec-11	ER12-296	PJM & PSE&G	11.18%
May-12	ER11-2853	Public Service Colorado	10.10%
May-12	ER11-2853	Public Service Colorado	10.40%
Jun-12	ER12-1593	DATC Midwest Holdings	12.38%
Mar-13	ER12-91	Duke Energy Ohio	10.88%
May-13	ER12-778	Puget Sound Energy	9.80%
May-13	ER11-3643	PacifiCorp	9.80%
May-13	ER11-2560	Entergy Arkansas	10.20%
May-13	ER12-1593	Transource Missouri	9.80%
Jun-13	ER12-2681	ITC Holdings	12.38%
Aug-13	ER12-1650	Maine Public Service Co.	9.75%
Nov-13	ER11-3697	So. Cal Edison	9.30%

(a) Order issued April 15, 2010, with ROE applied for March 1, 2008 through December 31, 2008.
(b) Order issued April 19, 2012, with ROE applied for January 1, 2009 through May 31, 2010.
(c) Order issued April 19, 2012, with ROE applied for June 1, 2010 through December 31, 2010.

RISK PREMIUM - FERC ROE

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.958732302
R Square	0.919167627
Adjusted R Square	0.905695565
Standard Error	0.002479855
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000419579	0.000419579	68.22768596	0.000170306
Residual	6	3.68981E-05	6.14968E-06		
Total	7	0.000456477			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.100520221	0.006507571	15.44665738	4.65559E-06	0.084596757	0.116443686	0.084596757	0.116443686
X Variable 1	-0.881646652	0.106736816	-8.260005203	0.000170306	-1.142822421	-0.620470882	-1.142822421	-0.620470882

Exhibit No. XES-506

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Implied Cost of Equity
1	ALLETE	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$2,050	1.75%	11.88%
2	Alliant Energy	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$6,407	0.93%	11.06%
3	Ameren Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$9,440	0.80%	10.93%
4	American Elec Pwr	2.3%	10.0%	12.3%	3.6%	8.7%	0.65	9.26%	$25,765	-0.33%	8.93%
5	Avista Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$1,934	1.75%	12.31%
6	Black Hills Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.90	11.43%	$2,553	1.72%	13.15%
7	CenterPoint Energy	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$10,317	0.80%	10.93%
8	Cleco Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$3,115	1.72%	11.85%
9	CMS Energy Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$7,907	0.93%	11.06%
10	Consolidated Edison	2.3%	10.0%	12.3%	3.6%	8.7%	0.60	8.82%	$16,007	0.80%	9.62%
11	Dominion Resources	2.3%	10.0%	12.3%	3.6%	8.7%	0.70	9.69%	$39,852	-0.33%	9.36%
12	DTE Energy Co.	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$13,342	0.80%	10.93%
13	Duke Energy Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.60	8.82%	$50,148	-0.33%	8.49%
14	Edison International	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$17,786	0.80%	11.36%
15	El Paso Electric	2.3%	10.0%	12.3%	3.6%	8.7%	0.70	9.69%	$1,522	1.75%	11.44%
16	Empire District Elec	2.3%	10.0%	12.3%	3.6%	8.7%	0.65	9.26%	$1,032	2.48%	11.74%
17	Great Plains Energy	2.3%	10.0%	12.3%	3.6%	8.7%	0.85	11.00%	$3,888	1.19%	12.19%
18	IDACORP, Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$2,755	1.72%	12.28%
19	Integrys Energy Group	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$4,555	1.19%	11.75%
20	ITC Holdings Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.65	9.26%	$5,739	0.93%	10.19%
21	NextEra Energy, Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	0.70	9.69%	$42,107	-0.33%	9.36%
22	Northeast Utilities	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$14,221	0.80%	10.93%
23	OGE Energy Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.85	11.00%	$7,282	0.93%	11.93%
24	Otter Tail Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.90	11.43%	$1,035	2.48%	13.91%
25	PG&E Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	0.60	8.82%	$21,208	0.80%	9.62%
26	Pinnacle West Capital	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$6,054	0.93%	11.06%
27	Portland General Elec.	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$2,579	1.72%	12.28%
28	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$19,476	0.80%	10.93%
29	Sempra Energy	2.3%	10.0%	12.3%	3.6%	8.7%	0.80	10.56%	$24,540	-0.33%	10.23%
30	Westar Energy	2.3%	10.0%	12.3%	3.6%	8.7%	0.75	10.13%	$4,612	1.19%	11.32%
31	Xcel Energy Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	0.65	9.26%	$15,320	0.80%	10.06%
	Range of Reasonableness							**8.82% -- 11.43%**			**8.49% -- 13.91%**
	Midpoint							**10.13%**			**11.20%**
	Median							**10.13%**			**11.06%**
	Average							**10.07%**			**11.06%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) Six-month average yield on 30-year Treasury bonds for Jan. 2014 - Jun. 2014 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) See Exhibit XES-503.
(e) www.valueline.com (retrieved Jun. 8, 2014).
(f) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

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	Company	(a) Market Return (R_m) Div Yield	(b) Proj. Growth	Cost of Equity	(c) 2014-18 Risk-Free Rate	Risk Premium	(d) Beta	Unadjusted K_e	(e) Market Cap	(f) Size Adjustment	Implied Cost of Equity
1	ALLETE	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$2,050	1.75%	12.15%
2	Alliant Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$6,407	0.93%	11.33%
3	Ameren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$9,440	0.80%	11.20%
4	American Elec Pwr	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.64%	$25,765	-0.33%	9.31%
5	Avista Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$1,934	1.75%	12.53%
6	Black Hills Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.90	11.54%	$2,553	1.72%	13.26%
7	CenterPoint Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$10,317	0.80%	11.20%
8	Cleco Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$3,115	1.72%	12.12%
9	CMS Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$7,907	0.93%	11.33%
10	Consolidated Edison	2.3%	10.0%	12.3%	4.7%	7.6%	0.60	9.26%	$16,007	0.80%	10.06%
11	Dominion Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.02%	$39,852	-0.33%	9.69%
12	DTE Energy Co.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$13,342	0.80%	11.20%
13	Duke Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.60	9.26%	$50,148	-0.33%	8.93%
14	Edison International	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$17,786	0.80%	11.58%
15	El Paso Electric	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.02%	$1,522	1.75%	11.77%
16	Empire District Elec	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.64%	$1,032	2.48%	12.12%
17	Great Plains Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.85	11.16%	$3,888	1.19%	12.35%
18	IDACORP, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$2,755	1.72%	12.50%
19	Integrys Energy Group	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$4,555	1.19%	11.97%
20	ITC Holdings Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.64%	$5,739	0.93%	10.57%
21	NextEra Energy, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.02%	$42,107	-0.33%	9.69%
22	Northeast Utilities	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$14,221	0.80%	11.20%
23	OGE Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.85	11.16%	$7,282	0.93%	12.09%
24	Otter Tail Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.90	11.54%	$1,035	2.48%	14.02%
25	PG&E Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.60	9.26%	$21,208	0.80%	10.06%
26	Pinnacle West Capital	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$6,054	0.93%	11.33%
27	Portland General Elec.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$2,579	1.72%	12.50%
28	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$19,476	0.80%	11.20%
29	Sempra Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.78%	$24,540	-0.33%	10.45%
30	Westar Energy	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.40%	$4,612	1.19%	11.59%
31	Xcel Energy Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.65	9.64%	$15,320	0.80%	10.44%
	Range of Reasonableness							**9.26% -- 11.54%**			**8.93% -- 14.02%**
	Midpoint							**10.40%**			**11.48%**
	Median							**10.40%**			**11.33%**
	Average							**10.35%**			**11.35%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).

(c) Average yield on 30-year Treasury bonds for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).

(d) See Exhibit XES-503.

(e) The Value Line Investment Survey (May 2, May 23, & Jun. 20, 2014).

(f) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

Exhibit No. XES-507

EXPECTED EARNINGS APPROACH

NATIONAL GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity		
1	ALLETE	9.00%	1.0338	9.30%		
2	Alliant Energy	11.50%	1.0269	11.81%		
3	Ameren Corp.	9.50%	1.0217	9.71%		
4	American Elec Pwr	10.00%	1.0220	10.22%		
5	Avista Corp.	9.00%	1.0232	9.21%		
6	Black Hills Corp.	9.50%	1.0210	9.70%		
7	CenterPoint Energy	13.00%	1.0117	13.15%		
8	Cleco Corp.	10.50%	1.0221	10.73%		
9	CMS Energy Corp.	13.50%	1.0331	13.95%		
10	Consolidated Edison	8.50%	1.0142	8.62%		
11	Dominion Resources	15.00%	1.0366	15.55%		
12	DTE Energy Co.	10.00%	1.0278	10.28%		
13	Duke Energy Corp.	8.00%	1.0108	8.09%		
14	Edison International	11.00%	1.0298	11.33%		
15	El Paso Electric	10.00%	1.0209	10.21%		
16	Empire District Elec	8.50%	1.0237	8.70%		
17	Great Plains Energy	8.00%	1.0160	8.13%		
18	IDACORP, Inc.	8.00%	1.0211	8.17%		
19	Integrys Energy Group	9.50%	1.0198	9.69%		
20	ITC Holdings Corp.	17.50%	1.0540	18.45%		
21	NextEra Energy, Inc.	12.00%	1.0407	12.49%		
22	Northeast Utilities	9.50%	1.0193	9.68%		
23	OGE Energy Corp.	12.00%	1.0337	12.40%		
24	Otter Tail Corp.	12.50%	1.0306	12.88%		
25	PG&E Corp.	8.50%	1.0242	8.71%		
26	Pinnacle West Capital	9.50%	1.0232	9.72%		
27	Portland General Elec.	9.00%	1.0362	9.33%		
28	Pub Sv Enterprise Grp	10.50%	1.0241	10.75%		
29	Sempra Energy	11.50%	1.0245	11.78%		
30	Westar Energy	9.50%	1.0298	9.78%		
31	Xcel Energy Inc.	10.00%	1.0301	10.30%		
	Range of Reasonableness			**8.09%**	**--**	**18.45%**
	Adjusted Range of Reasonableness (d)			**8.09%**	**--**	**15.55%**
	Midpoint			**11.82%**		
	Median			**10.00%**		
	Average			**10.48%**		

(a) The Value Line Investment Survey (May 2, May 23, & Jun. 20, 2014).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Eliminates highlighted values.

Exhibit No. XES-508

RISK PREMIUM - STATE ROE

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield - Historical	4.55%
	Change in Bond Yield	-4.14%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.76%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**5.29%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield - Historical	4.90%
	Adjusted Equity Risk Premium	5.29%
	Risk Premium Cost of Equity	**10.19%**

(a) Exhibit XES-508, page 3.
(b) Six-month average yield for Jan. 2014 - Jun. 2014 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) Exhibit XES-508, page 4.

RISK PREMIUM - STATE ROE

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield 2015-2018	6.30%
	Change in Bond Yield	-2.39%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.01%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**4.54%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield 2015-2018	6.65%
	Adjusted Equity Risk Premium	4.54%
	Risk Premium Cost of Equity	**11.19%**

(a) Exhibit XES-508, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit XES-508, page 4.

IMPLIED RISK PREMIUM

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
Average	12.21%	8.69%	3.53%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

RISK PREMIUM - STATE ROE

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.918651654
R Square	0.843920861
Adjusted R Square	0.839813516
Standard Error	0.00513785
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005423795	0.005423795	205.4662334	6.57062E-17
Residual	38	0.001003105	2.63975E-05		
Total	39	0.0064269			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072131874	0.002698047	26.73484383	3.01556E-26	0.066669963	0.077593786	0.066669963	0.077593786
X Variable 1	-0.424559652	0.02961887	-14.33409339	6.57062E-17	-0.484519922	-0.364599382	-0.484519922	-0.364599382

Exhibit No. XES-509

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$2,050	1.75%	12.42%
2	Alliant Energy	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$6,407	0.93%	11.60%
3	Ameren Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$9,440	0.80%	11.47%
4	American Elec Pwr	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.65	75%	4.2%	6.4%	10.02%	$25,765	-0.33%	9.69%
5	Avista Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$1,934	1.75%	12.75%
6	Black Hills Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.90	75%	5.9%	8.0%	11.65%	$2,553	1.72%	13.37%
7	CenterPoint Energy	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$10,317	0.80%	11.47%
8	Cleco Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$3,115	1.72%	12.39%
9	CMS Energy Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$7,907	0.93%	11.60%
10	Consolidated Edison	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.60	75%	3.9%	6.1%	9.69%	$16,007	0.80%	10.49%
11	Dominion Resources	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.70	75%	4.6%	6.7%	10.34%	$39,852	-0.33%	10.01%
12	DTE Energy Co.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$13,342	0.80%	11.47%
13	Duke Energy Corp	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.60	75%	3.9%	6.1%	9.69%	$50,148	-0.33%	9.36%
14	Edison International	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$17,786	0.80%	11.80%
15	El Paso Electric	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.70	75%	4.6%	6.7%	10.34%	$1,522	1.75%	12.09%
16	Empire District Elec	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.65	75%	4.2%	6.4%	10.02%	$1,032	2.48%	12.50%
17	Great Plains Energy	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.85	75%	5.5%	7.7%	11.32%	$3,888	1.19%	12.51%
18	IDACORP, Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$2,755	1.72%	12.72%
19	Integrys Energy Group	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$4,555	1.19%	12.19%
20	ITC Holdings Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.65	75%	4.2%	6.4%	10.02%	$5,739	0.93%	10.95%
21	NextEra Energy, Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.70	75%	4.6%	6.7%	10.34%	$42,107	-0.33%	10.01%
22	Northeast Utilities	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$14,221	0.80%	11.47%
23	OGE Energy Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.85	75%	5.5%	7.7%	11.32%	$7,282	0.93%	12.25%
24	Otter Tail Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.90	75%	5.9%	8.0%	11.65%	$1,035	2.48%	14.13%
25	PG&E Corp.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.60	75%	3.9%	6.1%	9.69%	$21,208	0.80%	10.49%
26	Pinnacle West Capital	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$6,054	0.93%	11.60%
27	Portland General Elec.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$2,579	1.72%	12.72%
28	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$19,476	0.80%	11.47%
29	Sempra Energy	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.80	75%	5.2%	7.4%	11.00%	$24,540	-0.33%	10.67%
30	Westar Energy	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.75	75%	4.9%	7.1%	10.67%	$4,612	1.19%	11.86%
31	Xcel Energy Inc.	2.3%	10.0%	12.3%	3.6%	8.7%	25%	2.2%	0.65	75%	4.2%	6.4%	10.02%	$15,320	0.80%	10.82%
	Range of Reasonableness											**9.69%**	**--**	**11.65%**	**9.36%**	**-- 14.13%**
	Midpoint (h)												**10.67%**			**11.74%**
	Median												**10.67%**			**11.60%**
	Average												**10.63%**			**11.62%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 20

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).

(c) Six-month average yield on 30-year Treasury bonds for Jan. 2014 - Jun. 2014 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/ht

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) See Exhibit XES-503.

(f) www.valueline.com (retrieved Jun. 8, 2014)

(g) *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

(h) Average of low and high values

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)			2014-18	Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$2,050	1.75%	12.63%
2	Alliant Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$6,407	0.93%	11.81%
3	Ameren Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$9,440	0.80%	11.68%
4	American Elec Pwr	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.31%	$25,765	-0.33%	9.98%
5	Avista Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$1,934	1.75%	12.91%
6	Black Hills Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.90	75%	5.1%	7.0%	11.73%	$2,553	1.72%	13.45%
7	CenterPoint Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$10,317	0.80%	11.68%
8	Cleco Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$3,115	1.72%	12.60%
9	CMS Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$7,907	0.93%	11.81%
10	Consolidated Edison	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.60	75%	3.4%	5.3%	10.02%	$16,007	0.80%	10.82%
11	Dominion Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.59%	$39,852	-0.33%	10.26%
12	DTE Energy Co.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$13,342	0.80%	11.68%
13	Duke Energy Corp	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.60	75%	3.4%	5.3%	10.02%	$50,148	-0.33%	9.69%
14	Edison International	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$17,786	0.80%	11.96%
15	El Paso Electric	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.59%	$1,522	1.75%	12.34%
16	Empire District Elec	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.31%	$1,032	2.48%	12.79%
17	Great Plains Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.85	75%	4.8%	6.7%	11.45%	$3,888	1.19%	12.64%
18	IDACORP, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$2,755	1.72%	12.88%
19	Integrys Energy Group	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$4,555	1.19%	12.35%
20	ITC Holdings Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.31%	$5,739	0.93%	11.24%
21	NextEra Energy, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.59%	$42,107	-0.33%	10.26%
22	Northeast Utilities	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$14,221	0.80%	11.68%
23	OGE Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.85	75%	4.8%	6.7%	11.45%	$7,282	0.93%	12.38%
24	Otter Tail Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.90	75%	5.1%	7.0%	11.73%	$1,035	2.48%	14.21%
25	PG&E Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.60	75%	3.4%	5.3%	10.02%	$21,208	0.80%	10.82%
26	Pinnacle West Capital	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$6,054	0.93%	11.81%
27	Portland General Elec.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$2,579	1.72%	12.88%
28	Pub Sv Enterprise Grp	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$19,476	0.80%	11.68%
29	Sempra Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.6%	6.5%	11.16%	$24,540	-0.33%	10.83%
30	Westar Energy	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.88%	$4,612	1.19%	12.07%
31	Xcel Energy Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.65	75%	3.7%	5.6%	10.31%	$15,320	0.80%	11.11%
	Range of Reasonableness												**10.02% -- 11.73%**			**9.69% -- 14.21%**
	Midpoint (h)												**10.88%**			**11.95%**
	Median												**10.88%**			**11.81%**
	Average												**10.84%**			**11.83%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 20

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).

(c) Average yield on 30-year Treasury bonds for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Econom Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) See Exhibit XES-503.

(f) www.valueline.com (retrieved Jun. 8, 2014)

(g) *Morningstar* , "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

(h) Average of low and high values

Exhibit No. XES-510

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	6.04%
(b)	Average BBB Utility Bond Yield - Historical	4.90%
	Change in Bond Yield	-1.14%
(c)	Risk Premium/Interest Rate Relationship	-0.7244
	Adjustment to Average Risk Premium	0.83%
(a)	Average Risk Premium over Study Period	6.74%
	Adjusted Risk Premium	**7.57%**

Implied Cost of Equity - Gas Pipelines

(b)	Average BBB Utility Bond Yield - Historical	4.90%
	Adjusted Equity Risk Premium	7.57%
	Risk Premium Cost of Equity - Gas Pipeline	**12.47%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.02%**
	Implied Electric ROE	**10.45%**

(a) See Exhibit XES-510, p. 3.
(b) Six-month average yield for Jan. 2014 - Jun. 2014 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit XES-510, p. 6.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	6.04%
(b)	Average BBB Utility Bond Yield - Projected 2015-2018	6.65%
	Change in Bond Yield	0.61%
(c)	Risk Premium/Interest Rate Relationship	-0.7244
	Adjustment to Average Risk Premium	-0.44%
(a)	Average Risk Premium over Study Period	6.74%
	Adjusted Risk Premium	**6.30%**

Implied Cost of Equity

(b)	Average BBB Utility Bond Yield - Projected 2015-2018	6.65%
	Adjusted Equity Risk Premium	6.30%
	Risk Premium Cost of Equity - Gas Pipeline	**12.95%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.02%**
	Implied Electric ROE	**10.93%**

(a) See Exhibit XES-510, p. 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) See Exhibit XES-510, p. 6.

IMPLIED RISK PREMIUM

Year	(a) Average Pipeline ROE	(b) BBB Utility Bond Yield	Risk Premium
2006	12.86%	6.32%	6.54%
2007	13.07%	6.33%	6.74%
2008	12.79%	7.25%	5.55%
2009	13.18%	7.06%	6.12%
2010	12.61%	5.98%	6.63%
2011	13.31%	5.57%	7.74%
2012	12.65%	4.86%	7.79%
2013	11.79%	4.98%	6.81%
		6.04%	6.74%

Year	Average Pipeline ROE	(c) Average Electric Base ROE	Spread
2006	12.86%	11.01%	1.85%
2007	13.07%	10.96%	2.11%
2008	12.79%	10.82%	1.98%
2009	13.18%	10.84%	2.34%
2010	12.61%	10.64%	1.97%
2011	13.31%	10.67%	2.64%
2012	12.65%	10.96%	1.69%
2013	11.79%	10.24%	1.55%
			2.02%

(a) Exhibit XES-510, pp. 4-5.
(b) Moody's Investors Service, www.credittrends.com.
(c) Exhibit XES-505, p. 3.

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Feb-06	RP06-63	Guardian Pipeline LLC.	14.00%
Mar-06	CP05-372	Midwestern Gas Transmission Co.	13.00%
Mar-06	RP04-274	Kern River Gas Transmission Co.	9.34%
May-06	CP02-378	Cameron Interstate Pipeline, LLC	14.00%
Jun-06	CP04-411	Crown Landing LLC; Texas Eastern Transmission, LP	12.75%
Jun-06	CP05-83	Port Arthur Pipeline, L.P.	14.00%
Jun-06	CP05-130	Dominion Cove Point LNG	13.00%
Jun-06	CP05-360	Creole Trail LNG, L.P.	14.00%
Jul-06	CP06-71	Carolina Gas Transmission Corp.; SCG Pipeline, Inc.	12.70%
Jul-06	CP06-5	Empire State Pipeline	12.50%
Sep-06	CP06-354	Rockies Express Pipeline LLC	13.00%
Sep-06	CP06-167	Questar Overthrust Pipeline Co.	11.75%
Oct-06	RP04-274	Kern River Gas Transmission Co.	11.20%
Oct-06	CP06-61	North Baja Pipeline, LLC	14.00%
Dec-06	CP06-5	Empire Pipeline, Inc.	12.50%
Dec-06	CP98-150	Millennium Pipeline Co.	14.00%
Feb-07	CP06-403	Northern Natural Gas Co.	13.42%
Mar-07	CP06-448	Kinder Morgan Louisiana Pipeline LLC	14.00%
Apr-07	CP07-25	Questar Pipeline Company	11.75%
Apr-07	CP06-407	Missouri Interstate Gas	11.20%
Apr-07	CP06-89	WTG Hugoton, LP and Northern Natural Gas Co.	11.20%
Apr-07	CP06-471	Elba Express Co.	14.00%
May-07	CP07-44	Southeast Supply Header, LLC	13.50%
Jun-07	CP06-115	Texas Eastern Transmission LP	12.75%
Jun-07	CP00-6	Gulfstream Natural Gas Supply, L.L.C.	14.00%
Jun-07	CP07-14	Wyoming Interstate Co., Ltd.	12.50%
Jul-07	CP06-454	Kinder Morgan Illinois Pipeline LLC	13.00%
Jul-07	CP07-76	Sonora Pipeline, LLC	14.00%
Sep-07	CP07-32	Gulf South Pipeline LP	12.25%
Sep-07	CP05-91	Calhoun LNG/Point Comfort Pipeline, LP	14.00%
Oct-07	RP07-38	Eastern Shore Natural Gas Co.	13.60%
Dec-07	CP07-8	Guardian Pipeline, L.L.C.	14.00%
Apr-08	CP07-398	Gulf Crossing Pipeline LLC	13.50%
May-08	CP07-208	Rockies Express Pipeline LLC	13.00%
May-08	CP07-417	Texas Gas Transmission. LLC	11.50%

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Jul-08	CP08-65	Midcontinent Express Pipeline LLC	13.00%
Jul-08	CP08-17	Cimarron River Pipeline LLC	11.20%
Jul-08	CP08-5	Southern Natural Gas Co.	12.00%
Aug-08	CP08-65	Tennessee Gas Pipeline Co.	11.50%
Aug-08	CP08-398	White River Hub, LLC	13.00%
Sep-08	CP06-365	Bradwood Landing LLC/NorthernStar Energy LLC	14.00%
Sep-08	CP08-152	North Baja Pipeline LLC	14.00%
Nov-08	RP08-632	MarkWest Pioneer, L.L.C.	14.00%
Jan-09	CP07-62	AES Sparrows Point LNG/Mid-Atlantic Express L.L.C.	14.00%
Jan-09	RP08-350	Southern Star Central Pipeline, Inc.	11.25%
Jan-09	RP04-274	Kern River Gas Transmission Co.	11.55%
Feb-09	CP09-3	T.W. Phillips Pipeline Corp.	14.00%
Jun-09	CP08-429	Kern River Gas Transmission Co.	13.25%
Sep-09	CP09-54	Ruby Pipeline, L.L.C.	14.00%
Nov-09	CP09-17	Florida Gas Transmission Co.	13.00%
Nov-09	CP09-68	Texas Eastern Transmission, LP	12.75%
Dec-09	CP09-433	Fayetteville Express Pipeline LLC	14.00%
Dec-09	CP07-442	Pacific Connector Gas Pipeline, LP	14.00%
Apr-10	CP09-161	Bison Pipeline LLC	14.00%
Apr-10	CP09-460	ETC Tiger Pipeline	14.00%
May-10	CP09-444	Tennessee Gas Pipeline Co.	11.50%
Sep-10	CP10-14	Kern River Transmission Co.	11.55%
Nov-10	CP10-468	Northern Border Pipeline Co.	12.00%
Jan-11	CP10-194	Central New York Oil & Gas Co.	13.50%
Feb-11	RP08-306	Portland Natural Gas Transmission System	12.99%
Apr-11	CP11-19	Trunkline Gas Co., LLC	12.56%
Jul-11	CP09-54	Ruby Pipeline L.L.C.	14.00%
Nov-11	CP10-480	Central New York Oil & Gas Co.	13.50%
Jan-12	CP11-46	Kern River Gas Transmission Co.	11.55%
Feb-12	CP11-508	Texas Eastern Transmission, LP	12.75%
May-12	CP11-56	Texas Eastern Transmission, LP	12.75%
May-12	CP12-31	Southern LNG, L.L.C.	12.50%
Jun-12	CP12-4	Southern Natural Gas Co.-High Point Gas Trans.	12.99%
Jun-12	CP11-543	ANR Pipeline Co.-TC Offshore LLC	12.99%
Sep-12	CP13-21	Alliance Pipeline L.P.	12.99%
Mar-13	CP12-494	Gas Transmission Northwest	12.20%
Mar-13	RP10-729	Portland Natural Gas Transmission System	11.59%
May-13	CP12-490	Tennessee Gas Pipeline Co.	11.59%

RISK PREMIUM - GAS PIPELINE ROE

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.844037338
R Square	0.712399027
Adjusted R Square	0.664465532
Standard Error	0.004365541
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000283244	0.000283244	14.86223821	0.008409442
Residual	6	0.000114348	1.90579E-05		
Total	7	0.000397591			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.111176559	0.011455938	9.704710618	6.86983E-05	0.083144869	0.139208249	0.083144869	0.139208249
X Variable 1	-0.724382695	0.187899644	-3.855157352	0.008409442	-1.184156897	-0.264608492	-1.184156897	-0.264608492

Exhibit No. XES-511

ALLOWED ROE

NATIONAL GROUP

	Company	(c) Adjusted Return on Common Equity		
1	ALLETE		10.38%	
2	Alliant Energy		10.34%	
3	Ameren Corp.		9.49%	
4	American Elec Pwr		10.50%	
5	Avista Corp.		9.86%	
6	Black Hills Corp.		10.72%	
7	CenterPoint Energy		10.05%	
8	Cleco Corp.		10.70%	
9	CMS Energy Corp.		10.30%	
10	Consolidated Edison		9.93%	
11	Dominion Resources		10.52%	
12	DTE Energy Co.		10.75%	
13	Duke Energy Corp.		10.46%	
14	Edison International		10.50%	
15	El Paso Electric		11.25%	
16	Empire District Elec		NA	
17	Great Plains Energy		10.12%	
18	IDACORP, Inc.		10.18%	
19	Integrys Energy Group		10.03%	
20	ITC Holdings Corp.		NA	
21	NextEra Energy, Inc.		10.50%	
22	Northeast Utilities		9.38%	
23	OGE Energy Corp.		9.98%	
24	Otter Tail Corp.		10.75%	
25	PG&E Corp.		10.40%	
26	Pinnacle West Capital		11.00%	
27	Portland General Elec.		9.75%	
28	Pub Sv Enterprise Grp		10.30%	
29	Sempra Energy		11.48%	
30	Westar Energy		10.20%	
31	Xcel Energy Inc.		10.48%	
	Range of Reasonableness	**9.38%**	--	**11.48%**
	Midpoint		**10.43%**	
	Median		**10.38%**	
	Average		**10.36%**	

(a) AUS Monthly Utility Report (May 2014).

Exhibit No. XES-512

NON-UTILITY GROUP

			(a)	(b)	(c)	(d)	(e)	(f)	(g)		
			Dividend Yield			Growth Rate					
	Company		**6-Mo. Average**	**Adjustment**	**Adjusted**	**IBES**	**V-Line**	**Average**	**Cost of Equity**		
1	Church & Dwight	Household Products	1.81%	1.0488	1.90%	10.02%	9.50%	9.76%	11.66%		
2	Coca-Cola	Beverage	3.00%	1.0330	3.10%	6.70%	6.50%	6.60%	9.70%		
3	Colgate-Palmolive	Household Products	2.16%	1.0485	2.26%	8.90%	10.50%	9.70%	11.96%		
4	ConAgra Foods	Food Processing	3.24%	1.0412	3.38%	6.48%	10.00%	8.24%	11.62%		
5	Gen'l Mills	Food Processing	3.08%	1.0334	3.19%	6.86%	6.50%	6.68%	9.87%		
6	Hormel Foods	Food Processing	1.69%	1.0550	1.79%	11.00%	11.00%	11.00%	12.79%		
7	Johnson & Johnson	Medical Supply	2.80%	1.0338	2.89%	7.03%	6.50%	6.77%	9.66%		
8	Kellogg	Food Processing	2.93%	1.0314	3.02%	6.04%	6.50%	6.27%	9.29%		
9	Kimberly-Clark	Household Products	3.03%	1.0398	3.15%	6.90%	9.00%	7.95%	11.10%		
10	McCormick & Co.	Food Processing	2.15%	1.0378	2.23%	7.63%	7.50%	7.57%	9.80%		
11	McDonald's Corp.	Restaurant	3.31%	1.0366	3.43%	7.63%	7.00%	7.32%	10.74%		
12	PepsiCo, Inc.	Beverage	2.78%	1.0393	2.89%	7.20%	8.50%	7.85%	10.74%		
13	Procter & Gamble	Household Products	3.13%	1.0397	3.26%	8.38%	7.50%	7.94%	11.20%		
14	Smucker (J.M.)	Food Processing	2.35%	1.0371	2.44%	7.33%	7.50%	7.42%	9.85%		
15	Verizon Communic.	Telecommunications	4.43%	1.0415	4.62%	6.08%	10.50%	8.29%	12.91%		
16	Wal-Mart Stores	Retail Store	2.50%	1.0390	2.59%	8.11%	7.50%	7.81%	10.40%		
	Range of Reasonableness								**9.29%**	--	**12.91%**
	Adjusted Range of Reasonableness (h)								**9.29%**	--	**12.91%**
	Midpoint								**11.10%**		
	Median								**10.74%**		
	Average								**10.90%**		

(a) Six-month average dividend yield for January - June 2014.
(b) 1 + 0.5 x (f).
(c) (a) x (b).
(d) www.finance.yahoo.com (retreived Jul. 9, 2014).
(e) www.valueline.com (retrieved Jul. 9, 2014).
(f) Average of (d) and (e).
(g) (c) + (f).
(h) Excludes highlighted values.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

ADRIEN M. MCKENZIE, being duly sworn, deposes and states: that the Direct Testimony of ADRIEN M. MCKENZIE was prepared by him or under his direct supervision, that the statements contained therein and the Exhibits attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

Adrien M. McKenzie

Subscribed and sworn before me this 25th day of August 2014.

Notary Public
My commission expires: 1.7.17

ADAM TRULOVE
NOTARY PUBLIC
STATE OF TEXAS
EXPIRES
01-07-2017

Exhibit No. XES-600

Exhibit No. XES-600

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

DIRECT TESTIMONY AND EXHIBITS
OF
ALAN C. HEINTZ

ON BEHALF OF
XCEL ENERGY SOUTHWEST TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF ALAN C. HEINTZ

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ALAN C. HEINTZ

I. INTRODUCTION AND EXPERIENCE

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

A. My name is Alan C. Heintz. My business address is Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"), 1155 Fifteenth Street, NW, Suite 400, Washington, DC 20005. I am a Vice President of BWMQ.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy Southwest Transmission Company, LLC. ("XEST").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by the Federal Energy Regulatory Commission ("FERC" or "Commission") from November 1985 to February 1995. I served as a Public Utilities Specialist in the [Electric] Rate Filings Branch from November 1985 to October 1989. In November 1989, I was promoted to Section Chief in the Division of [Electric] Applications, and was responsible for supervising the review of the terms, conditions, and rates of electric rate applications for such services as interchange power, requirements power, and transmission. During my tenure with FERC, I prepared or supervised the preparation of memoranda recommending acceptance, rejection, deficiency, or investigation in hundreds of cases. These included cases that set important precedents on electric transmission pricing, such as the merger compliance transmission tariffs for Northeast Utilities; the first generation of open access transmission tariffs ("OATT") filed by utilities such as Entergy Services Inc., Louisville Gas and Electric Co., Florida Power & Light Co., Kansas City Power & Light Co., and American Electric

Power Service Corp.; as well as the Pennsylvania Electric Company case involving Penntech Papers, Inc. I also taught a one-year course to FERC Staff and gave several presentations to the Edison Electric Institute Interconnection and Interchange Arrangements Committee on the pricing of power and transmission services.

From February 1995 through October 2000, I was a Vice President of Stone & Webster Management Consultants, Inc. In this position, I provided consulting services to numerous electric utilities on matters involving requirements and off-system power rates, rate and implementation strategies for developing OATT filings, and issues concerning the organization of Independent System Operators ("ISO"), and Regional Transmission Organizations ("RTO"). I also assisted several utilities in preparing their retail delivery services filings. In November 2000, I joined R.J. Rudden Associates, Inc. as a Vice President, where I continued providing consulting services to the electric industry. I joined BWMQ in February 2004.

Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. I provide consulting services on matters relating to power sales, transmission, and ancillary service issues associated with FERC regulation of open access transmission service, including issues arising from FERC Order Nos. 888, 889, 890, 2000, 679, and 1000. I have been actively involved as a consultant to several ISOs and RTOs, participants in organized electric markets, and transmission-only entities. I have advised these clients on formula transmission rates, transmission and congestion pricing, and the treatment of pre-existing arrangements, losses, and ancillary services. In addition, I have provided advice on transmission pricing matters to several transmission-owning members of the PJM Interconnection, L.L.C. ("PJM"), Midcontinent Independent System

Operator, Inc. ("MISO"), California Independent System Operator Corporation, ISO New England Inc., New York Independent System Operator Inc., and Southwest Power Pool, Inc. ("SPP").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE FERC OR BEFORE OTHER REGULATORY AGENCIES AND COURTS ON UTILITY-RELATED MATTERS?

A. Yes. During my tenure at the FERC, I was assigned to the Commission's advisory staff and, therefore, was precluded from testifying before the FERC. However, while at the FERC, I presented cases publicly to the FERC Commissioners at their bi-weekly public meetings and was the technical contact to the Commissioners in numerous cases. Since leaving the FERC, I have filed testimony before the FERC in numerous proceedings. In addition to the FERC, I have testified before the British Columbia Utilities Commission in Canada, the Illinois Commerce Commission, the Maine Public Utilities Commission, the United States Court of Federal Claims, and the United States District Court in Florida. A summary of my prior testimony is contained in Exhibit No. XES-601.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received the degree of Bachelor of Science in Business, and the degree of Bachelor of Arts in Economics from the University of Colorado, Boulder, Colorado, in May 1982. I also received the degree of Master of Business Administration in Finance from the George Washington University in Washington, DC in December 1988.

II. PURPOSE OF TESTIMONY AND OVERVIEW OF THE FORMULA RATE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. XEST has requested that I develop a formula rate for XEST that will help facilitate competitive bids within the footprint of the SPP consistent with the upcoming SPP Order No. 1000 project selection process. In this testimony, I describe the proposed formula and explain and support the reasonableness of the proposed formula transmission rate. The proposed formula provides for the forecast of the net revenue requirement for the transmission facilities each rate year. A true-up between the forecasted and actual net revenue requirement will be calculated the following year (cost year plus one) and applied as an addition to or subtraction from the subsequent year's net revenue requirement and resultant rate (cost year plus two).

XEST will forecast its net revenue requirement for each calendar year, and SPP will include these revenue requirements in calculating the transmission rates to be effective each rate year beginning on January 1. The proposal includes a true-up mechanism to ensure customers are protected if the actual net revenue requirement is less than the billed net revenue requirement. The proposed true-up compares the actual net revenue requirement to the forecasted net revenue requirement collected during the cost year. Interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a ("FERC's Interest Rate") and interest on any surcharge shall be calculated using the lower of FERC's Interest Rate or XEST's short-term borrowing rate, if applicable. Therefore, the rates calculated and collected by SPP will be subject to true-up with interest.

The formula uses 13-month average plant balances in determining the rate base upon which the return and income tax components of the annual net revenue requirement are calculated. XEST will forecast the average of the 13 monthly balances in rate base. Should these estimates be incorrect, the true-up mechanism subsequently will adjust the rate produced by the formula.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE FORMULA FUNCTIONS.

A. For service from January to December ("the Rate Year"), the average rate base balance and annual expenses are forecasted by October 1 preceding the Rate Year. The revenue requirement in effect for the Rate Year is calculated pursuant to the formula using this forecast. On or before the June 1 following that Rate Year, the actual average rate base and annual expenses are computed. The difference between revenue requirement forecast and actual net revenue requirement, positive or negative, is computed with interest and used to adjust the rate for subsequent Rate Year. For example, XEST would estimate the revenue requirement for 2017 by October 1, 2016, and the true-up for 2017 would be calculated by June 1, 2018 and reflected (including interest) in the revenue requirement calculated for 2019.

Q. WHAT IS THE PROPOSED EFFECTIVE DATE?

A. XEST seeks an effective date of November 1, 2014. However, XEST will not collect charges from customers under the formula rate until after XEST has a project. In addition, SPP will need to make an additional filing to incorporate the XEST formula rate into its open access transmission tariff ("OATT"), and no costs will be charged to customers until after those SPP tariff sheets are accepted by the Commission.

Q. PLEASE EXPLAIN WHY THE PROPOSED FORMULA IS REASONABLE.

A. The proposed formula is very similar to the formula approved by the Commission in *American Transmission Company* ("*ATCLLC*"), 97 FERC ¶ 61,139 (2001), and numerous formula rate cases since *ATCLLC*. XEST plans to invest substantial amounts in the SPP footprint. The proposal allows XEST to collect a revenue requirement that is representative of the costs in the current period, provides for greater certainty for cost recovery of capital expenditures incurred to improve the transmission infrastructure, and ensures that SPP transmission service customers pay the cost to serve them over the lives of the projects. The Commission has approved numerous other transmission formulas that employ similar true-up mechanisms, in, for example *Boston Edison Company*, 91 FERC ¶ 61,198 (2000); *Northeast Utilities Service Company*, 105 FERC ¶ 61,089 (2003); *San Diego Gas & Electric Company*, 103 FERC ¶ 61,115 (2003); *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008); *American Electric Power Service Corp.*, 124 FERC ¶ 61,306 (2008); *American Electric Power Transmission Co.*, 135 FERC ¶ 61,066 (2011); *Tallgrass Transmission, LLC and Prairie Wind Transmission, LLC* 132 FERC ¶ 61,114 (2010); *American Electric Power Transmission Co.*, 135 FERC ¶ 61,066 (2011); and *RITELine Indiana, LLC and RITELine Illinois, LLC*, 137 FERC ¶ 61,039 (2011).

Q. PLEASE EXPLAIN THE PROPOSED INTEREST CALCULATION AND WHY IT IS REASONABLE.

A. As mentioned above, the interest on a true-up amount is calculated for both over or under recovery. Interest on any over recovery of the net revenue requirement, shall be determined based on the applicable FERC Interest Rate. Interest on any under recovery of the net revenue requirement, shall be determined using the interest rate equal to

XEST's actual short-term debt costs capped at the applicable FERC Interest Rate. In either case, the interest payable shall be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the twenty one (21) months preceding October of the current year. In the example above, the interest charge will be the average of interest rates for the period starting in January of the 2017 Rate Year through September of the following year (2018) and will then be reflected in the rate for the subsequent year (2019). This proposal is reasonable in that: (1) the actual interest rates for the months following September will not be known prior to this period during which the refund is returned or the surcharge is collected, and (2) the monthly rate during that period may be constantly changing due to changes in interest rates.

III. <u>FORMULA RATE</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROPOSED FORMULA RATE METHODOLOGY.

A. The formula rate has two components. The first is the formula itself with worksheets (Attachments 1-12) discussed later in my testimony, including a statement of the annual transmission revenue requirement ("ATRR"). The formula rate is attached to my testimony as Exhibit No. XES-602. The second component is the set of implementation protocols – the Annual True-up, Information Exchange and Challenge Procedures – which govern how the formula will be updated each year and how any changes to the annual rate restatement will be implemented. The protocols are attached to my testimony as Exhibit No. XES-603.

Q. PLEASE DESCRIBE IN DETAIL THE ACTUAL APPLICATION OF THE PROPOSED FORMULA RATE.

A. Page 1, lines 1-10 of Attachment H, summarizes the annual revenue requirement calculations for all of XEST's approved transmission projects in SPP. Line 1 is the gross revenue requirement carried forward from page 3, line 47. Line 7 is the amount of the revenue credits specified in lines 2 through 6. Line 8 is the net revenue requirement before true-up adjustment. Line 9 is the true-up adjustment with interest, calculated on Project True-Up Worksheet. Line 10 is net revenue requirement for the Rate Year, to be used by SPP to calculate the transmission rate.

Pages 2 through 3 of Attachment H calculate the traditional net plant revenue requirement for all SPP projects for XEST. The gross revenue requirement is the sum of operation and maintenance expense ("O&M"), depreciation expense, taxes other than income taxes, income taxes and return on rate base (page 3). The underlying cost data reflect XEST's costs (as estimated and trued-up the next year to data reported in Form 1 and other inputs to the formula).

Attachment H also includes, beginning on page 4, a listing of "Supporting Calculations and Notes" that are inputs to the basic formula on pages 1 through 3, specifically: (a) the Transmission Plant allocator ("TP") (page 4, lines 1-5); (b) the Wages & Salaries allocator ("W/S") (page 4, lines 6-11); and (c) the capital structure and overall Rate of Return ("R") (page 4, lines 17-23). These supporting calculations and notes are followed by explanatory notes on page 5.

Pages 1 through 4 generally have the same presentation of data: each line of the formula consists of five columns of information or data (in addition to the "Line No." column):

(1) a description of the cost item or formulaic result of the calculation on the line;

(2) the source of the input data (a FERC Form 1 page number or an attached worksheet), or an instruction describing a calculation (*e.g.*, "Sum lines 5 to 9");

(3) the actual Total Company data input (areas shaded) or sum of the data (unshaded);

(4) the allocator or functionalization factor applicable to the Total Company value; and

(5) the transmission-related amount obtained by applying the allocator or functionalization factor to the Total Company value.

Q. PLEASE DESCRIBE HOW RATE BASE IS CALCULATED PURSUANT TO THE FORMULA.

A. As set out on page 2, lines 1-6, Transmission Plant is allocated by the TP allocator discussed above, and General and Intangible Plant are functionalized to transmission by the W/S allocator. The Accumulated Depreciation associated with general and intangible plant is similarly functionalized (lines 7-13).

Net transmission plant, property and equipment balances are calculated at lines 14-20. All plant balances are calculated based on 13-month averages, the details of which are developed on Attachment 4.

Adjustments to Rate Base – Accumulated Deferred Income Tax ("ADIT"), Construction Work In Progress ("CWIP"), and unamortized balances for regulatory assets and abandoned plant are calculated on Attachment 4 and carried over to the formula at lines 21-30.

CWIP at line 27 reflects the 13 month average balances as shown on Attachment 4. Any amounts included in CWIP would be authorized by a specific FERC order.

The Unamortized Regulatory Asset, consisting of all prudently incurred costs that are not capitalized prior to the date the rate is charged to customers, is included at line 28. Once the XEST revenue requirement begins to be charged to SPP transmission customers under the SPP OATT, ongoing expenses will be recovered under the formula rather than being booked to the regulatory asset. The accounting for the regulatory asset is addressed in the Rodriguez Direct Testimony, Exhibit No. XES-300.

Unamortized Abandoned Plant is included in rate base at line 29. Any amounts included in Unamortized Abandoned Plant would be authorized by a specific FERC order.

Land Held for Future Use is specified on Attachment 4 and included at line 31.

Working Capital (lines 32-36) consists of three elements: (1) Cash Working Capital calculated as one-eighth of total O&M expenses; (2) Materials & Supplies; and (3) Prepayments.

Q. PLEASE DISCUSS HOW THE ADIT BALANCES ARE INCLUDED IN THE FORMULA.

A. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. The beginning and end of year balances reported in Form 1 and consistent with *ATCLLC*, the average of the beginning of year and end of year ADIT balances are allocated based on the Net Plant ratio.

Q. PLEASE DISCUSS THE DEVELOPMENT OF O&M EXPENSES.

A. Total transmission O&M expense shown at page 3, line 14, consists of Transmission expense (line 1) plus Administrative & General ("A&G") expense functionalized to transmission.

The formula (lines 2 and 3) excludes Accounts 566 (Miscellaneous Expenses), which is included on lines 11-12, as discussed below, and 565 (Transmission by Others, if any).

The TP allocator is applied to the total company amounts for Transmission O&M and Accounts 566 and 565.

Total company A&G expense (as adjusted for FERC Annual Fees, Regulatory Commission Expense, EPRI, and non-safety General Advertising Expense) is functionalized to Transmission by the W/S allocator.

Regulatory Commission Expenses related to transmission are included on line 7.

Common expenses (if any) and Transmission Lease Payments are included at lines 8 and 9.

As discussed in the Rodriguez Direct Testimony, Exhibit No. XES-300, XEST does not have its own employees; rather, employees of its affiliates (Xcel Energy Services Inc., and the Xcel Energy Operating Companies) will provide services to XEST on an at-cost basis through service agreements. Accordingly, the stated rate inputs for Post-employment Benefits Other than Pensions ("PBOP") in XEST's formula derive from the PBOP rates for other subsidiaries of Xcel Energy. As reflected on Attachment 12, the stated PBOP rates per dollar of labor expended on the project can be changed only pursuant to a separate Section 205 or 206 filing. This treatment is consistent with the treatment approved in *Trans-Allegheny Interstate Line Co*., 124 FERC ¶ 61,075 (2008).

Lines 11 and 12 provide a break out of Account 566 to show the amortization of the regulatory asset discussed above that will be amortized to Account 566 consistent with FERC precedent. Lines 11 and 12 will only be utilized after the Commission grants XEST authority to amortize the regulatory asset as discussed in more detail in the Rodriguez Direct Testimony, Exhibit No. XES-300.

Q. PLEASE DISCUSS HOW THE FORMULA DEVELOPS DEPRECIATION AND AMORTIZATION EXPENSE.

A. Total Transmission Depreciation and Amortization Expense is shown on page 3, line 20. It is the sum of transmission plant depreciation and amortization expense (line 16), plus general plant depreciation and intangible plant amortization (line 17), plus Common plant (line 18), plus amortization of abandoned plant (line 19), functionalized to transmission.

Consistent with the functionalization of general and intangible plant, G&I depreciation is functionalized to transmission by the W/S allocation factor. Common plant (line 18), if any, is functionalized to transmission by the CE allocation factor (developed on page 4 as the transmission plant percent of total plant times the transmission W/S allocator).

The formula also includes a provision (line 19) for including the amortization of any unrecovered abandoned plant costs (which would require Commission approval in a separate filing). Such amortization is directly assigned to the Transmission function.

Q. PLEASE DISCUSS HOW THE FORMULA DEVELOPS TAXES OTHER THAN INCOME TAXES.

A. Taxes other than income taxes ("Other Taxes") are functionalized to transmission and specified at lines 21-30 of page 3. Labor-related taxes are functionalized by the W/S allocator (lines 23-24). Real and personal property, miscellaneous other taxes and payments in lieu of taxes (if any) (lines 26, 28 and 29) are functionalized by the GP allocator. Gross receipts are excluded (line 27).

Q. PLEASE DISCUSS HOW THE FORMULA DEVELOPS INCOME TAXES ON PAGE 3 OF ATTACHMENT H.

A. Federal and state income taxes (line 44) are developed consistent with the return on rate base calculated at line 46.

The tax components are Federal Income Tax Rate ("FIT"), State Income Tax Rate (or Composite) ("SIT"), and the percent ("p"), if any, of federal income tax deductible in the calculation of state income tax, and the Tax Exempt Percent ("TEP") (lines 32-33). These components are specified in Note K. The composite federal/state income tax rate, ("T"), is calculated on line 32, where:

$$T = 1-\{[(1-SIT) * (1-FIT)] / (1-SIT * FIT * p)\} * (1-TEP)$$

The tax multiplier, 1/(1-T), is calculated on line 36.

The investment tax credit ("ITC") adjustment, the Excess Deferred Income Tax adjustment and the Permanent Differences Tax adjustment are shown at lines 37 through 39, respectively. The respective revenue effects of these adjustments are calculated by multiplying each of them (lines 41-43) by the tax multiplier at line 36, the products of which are functionalized to transmission by multiplying by the Net Plant ratio.

The income tax component is calculated at line 40 as the product of (T/1-T) times the portion of the investment return that is taxable (which is 1 minus the weighted debt cost rate divided by the overall rate of return) times the return on rate base (line 45). The weighted debt cost rate is calculated at page 4, line 20, and the overall rate of return is calculated at page 4, line 23.

Total income taxes (line 44) are the summation of the income tax component (line 40) and the three adjustments (lines 41-43).

Q. PLEASE DISCUSS HOW THE FORMULA DEVELOPS THE RETURN ON RATE BASE.

A. Return on Rate Base ("ROR") (line 46) is the product of rate base (page 2, line 37) times overall rate of return ("R") (page 4, line 23). R is the sum of the weighted cost rates for long-term debt ("LTD"), preferred stock, and common equity calculated at page 4, lines 20 through 23.

The LTD cost rate (page 4, line 20) prior to XEST's issuance of debt is set at the interest rate estimated to be incurred by the Company once debt is issued as shown on Attachment 8 without true up, which is estimated to be 2.24% for 2014. Once debt is issued, the LTD cost rate is developed on the Construction Loan Worksheet (Attachment 8) during the project financing phase and will be trued up. Once permanent financing is obtained, the LTD cost rate will be the actual cost incurred in the year as developed on line 20.

The preferred cost rate (if any) is calculated on page 4, line 21 consistent with standard FERC rate making.

The common equity of the capital structure is shown at line 22.

Total capitalization (page 4, line 23) is the sum of LTD, preferred stock and common equity. LTD (line 20), preferred stock (line 21) and common stock (line 22) divided by total capitalization gives the capitalization shares shown on those lines, respectively.

As discussed in the Tyson Direct Testimony, Exhibit No. XES-200, the capital structure will be 55% common equity, 45% long-term debt and 0% preferred equity until the facilities are placed into service. Having certainty associated with using the fixed 55-45 capital structure during project development and construction will improve the chances for favorable terms from the lenders. Once XEST's first facilities are commercially operational, XEST will target an actual capital structure of 55% equity and 45% long-term debt.

Q. WILL THERE BE INCENTIVE TREATMENT FOR XEST PROJECTS?

A. XEST is not requesting project-specific incentives at this time. XEST is seeking authorization for a 50 basis point adder to its ROE for RTO participation.

Although XEST is not requesting project-specific incentives in this filing, the formula is developed to accommodate incentives that the Commission may grant at a later date. The XEST revenue requirements per project are determined in the Project Revenue Requirement Worksheet. The Project Revenue Requirement Worksheet details the calculation of revenue requirements associated with all transmission facilities, including those for which Commission approval for incentives has been obtained. These "placeholders" would allow XEST to seek Commission approval for specific incentives without the need to modify the formula.

Q. PLEASE DISCUSS THE CONSTRUCTION LOAN AND CONSTRUCTION LOAN TRUE-UP WORKSHEETS

A. The Construction Loan Worksheet (Attachment 8) provides an example of the calculation of interest for the type of financing anticipated for the projects. The worksheet shows the method of calculating the effective cost of debt incurred while the projects are under construction.

The Construction Loan True-Up Worksheet calculates a true-up with interest for all years between the date the rate becomes effective and the date the actual annual average debt costs for the construction financing is known.

Q. DO THE PROTOCOLS CONFORM TO COMMISSION PRECEDENT, THE JULY 17, 2014 STAFF GUIDANCE, AND PROVIDE INTERESTED PARTIES AN OPPORTUNITIY TO REVIEW AND CHALLENGE THE ATRR PRODUCED BY THE FORMULA RATE TEMPLATE?

A. Yes. Consistent with similar protocols approved by the Commission, the XEST protocols provide the procedures for review and challenge and also conform to the July 17, 2014 Commission Staff guidance on Formula Rate Updates. The protocols include a requirement to post fully functional workable formulas in Microsoft Excel format with all formulas intact. The protocols provide for annual updates that are publically posted for interested parties and informational filings to the Commission that will contain sufficient support for all inputs so that interested parties can verify that each input is consistent with the requirements of the formula. The review procedures provide for transmission customers, state commissions, and other interested parties to review and submit a written preliminary challenge to specific items included in the template. These interested parties also may serve reasonable information requests on XEST. XEST will make a good faith effort to respond to these requests within 15 business days. If the parties have not been able to resolve any such challenge, the party bringing the challenge may file a formal challenge with the Commission. These procedures do not limit in any way XEST's right to file, pursuant to Section 205 of the FPA, changes to the Formula Rate or any of its inputs requiring a Section 205 filing under the protocols, or the right of any other party to file a complaint requesting such changes under FPA Section 206 at any time.

Q. IS XEST ASKING FOR THE RATES TO BE TREATED AS "UP TO" RATES?

A. Yes. XEST is requesting that the revenue requirements for each project be treated as an "up to" rate, i.e., ceiling rate, to allow XEST to discount the project-specific revenue requirement to reflect the result of any agreement between XEST and SPP. Such a discount may arise from the competitive solicitation process, and, as discussed below, is specifically identified in the formula rate template. The Commission has long recognized the reasonableness of "up to" rates. This aspect of the formula is reflected in both the protocols and the formula rate template.

Q. PLEASE PROVIDE AN EXAMPLE OF A SCENARIO WHERE SUCH A CEILING RATE CONCEPT MAY BE APPLIED.

A. The following is an example of a scenario where the ceiling rate concept might be applied. Assume that, in 2015, SPP requests proposals for a new 345 kV project with a planned in-service date in 2019 and with the project eligible for regional cost allocation under the SPP OATT. Assume further that, based on XEST's estimates of its development and operating costs, XEST estimates that the formula rate will calculate a ceiling revenue requirement in 2019 of $10 million for the project. XEST might provide a binding bid that caps its recoveries in 2019 at $10 million. If SPP then selects XEST's binding bid as the winning bid, XEST would develop the project and place it into service. If the project's costs are higher than XEST estimated, for example, resulting in a 2019 revenue requirement of $10.5 million, then only the $10 million would be included in SPP's regional transmission rates in 2019, thereby reducing by $500,000 the total ATRR charged to SPP customers for the project as compared to the ceiling revenue requirement calculated by the formula rate.

Q. DOES THE FORMULA RATE ALLOW FOR DISCOUNTS TO THE REVENUE REQUIREMENTS OF INDIVIDUAL PROJECTS THAT RESULT FROM A COMPETITIVE SOLICITATION PROCESS?

A. Yes. If XEST commits to a bid that results in a discount, the amount of such a discount is taken into account in the formula. Attachment 1, which develops the projected revenue requirement for each project, shows in Column (13), separately for each project, any discount to which XEST has agreed. The Discount in Column (13) is subtracted from the sum of the Annual Revenue Requirement in Column (10) and any Incentive Return calculated in Column (12) to calculate the Total Annual Revenue Requirement in Column (14). The Network Upgrade Charge in Column (16) is what will be charged to customers and is the sum of the Total Revenue Requirement in Column (14) and the True-Up Adjustment in column (15).

Attachment 3, which calculates the true-up, reflects the discount in both the actual net revenue requirement for each project in Column (e) and in the actual revenue received for each project in Column (d). The True-up Adjustment in Column (f) is the difference between the actual net revenue requirement (net of any discounts) and the amount actually collected by XEST from SPP.

Q. IN YOUR OPINION, DOES THE FORMULA RATE PROPOSED IN THIS PROCEEDING CONFORM TO COMMISSION PRECEDENT WITH RESPECT TO FORMULA RATES?

A. Yes. The classification, functionalization and allocation factors used for the cost items reflect standard Commission ratemaking. The estimate and true-up functions also reflect Commission precedent. Furthermore, the data used in the formula is taken directly out of the XEST Form 1 or, when more detailed data is required, the detailed data are provided in the worksheets attached to the Attachment H for XEST.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit No. XES-601

Summary of Testimony Experience
Alan C. Heintz

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
1	FERC	ER95-836-000	Maine Public Service Company	Maine Public Service Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
2	FERC	ER95-854-000	Kentucky Utilities Company	Kentucky Utilities Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
3	FERC	ER95-1686-000 ER96-496-000	Northeast Utilities Service Company	Northeast Utilities Service Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
4	FERC	ER96--58-000	Allegheny Power Services Corporation	Allegheny Power Services Corporation	1995 & 1996	Rates, Terms and Conditions for Open Access Transmission Services
5	FERC	OA96-138-000	Consolidated Edison Company of New York, Inc.	Consolidated Edison Company of New York, Inc.	1997	Rates, Terms and Conditions for Open Access Transmission Services
6	FERC	ER96-1208-000	Interstate Power Company	Interstate Power Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
7	British Columbia Utilities Commission		British Columbia Hydro and Power Authority	Bonneville Power Administration	1997	Rates, Terms and Conditions for Open Access Transmission Services

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
8	FERC	ER98-1438-000 EC98-24-000	Cincinnati Gas & Electric Company, et al. (Midwest Independent System Operator)	Midwest ISO Transmission Owners	1998 & 1999	Rates, Terms and Conditions for Midwest ISO Tariff
9	FERC	EC98-2770-000 ER98-2770-000 ER98-2786-000	American Electric Power Company, Inc. and Central & Southwest Corporation	Midwest Independent System Operator Transmission Owners	1999	Reasonableness of the conditions to be placed on the merging parties
10	Illinois Commerce Commission	99-0117	Commonwealth Edison Company	Commonwealth Edison Company	1998	Cost of service for Retail Distribution Services Tariff
11	FERC	ER99-3110-000	Nevada Power Company	Nevada Power Company	1998	Rates, Terms and Conditions for Open Access Transmission Services
12	FERC	ER99-4415-000	Illinois Power Company	Illinois Power Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
13	FERC	ER99-4470-000	Commonwealth Edison Company	Commonwealth Edison Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
14	U.S. District Court, FL	92-35-CIV-ORL-3A22	Florida Municipal Power Agency vs. Florida Power and Light Company	Florida Power and Light Company	1999	Rates, Terms and Conditions for Network Service in an anti-trust case
15	U.S. Court of Federal Claims, DC	97-268C	Carolina Power & Light Company vs. U.S. Department of Energy	Carolina Power & Light Company	1999	Cost recovery of Decontamination & Decommissioning Fund Assessments

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
16	FERC	ER98-496-006 ER98-2160-004	San Diego Gas & Electric	Dynegy	1999	Rates for Must Run units
17	FERC	ER00-980-000	Bangor Hydro Electric Company	Bangor Hydro Electric Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
18	Maine Public Utilities Commission	99-185	Bangor Hydro Electric Company	Bangor Hydro Electric Company	2000	Rates, Terms and Conditions for Open Access Transmission Services
19	FERC	EL00-98-000, et al.	Dynegy Power Marketing, Inc, et al.	Dynegy Power Marketing, Inc.	2000	Nexus between fuel and emissions costs and the market prices in California
20	Illinois Commerce Commission	No. 01-0423	Commonwealth Edison Company	Commonwealth Edison Company	2001	Direct, Rebuttal and Surrebuttal: Cost of service for Retail Distribution Services Tariff
21	FERC	ER01-2992	Commonwealth Edison Company	Commonwealth Edison Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
22	FERC	ER01-123.004	Midwest ISO Transmission Owners	Midwest ISO Transmission Owners	2001	Super Region Adjustment for the MISO/ARTO Super Region
23	FERC	ER01-2999	Illinois Power Company	Illinois Power Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
24	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Revised treatment of Network Upgrades

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
25	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Uncertainties that support a higher ROE
26	FERC	EL000-95-045, et.al	San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the CALISO…	Dynegy, Mirant, Reliant and Williams	2001 & 2002	Costing of emissions and start-up costs
27	FERC	EC02-23 & ER02-320	Trans-Elect, Inc., et. al	Trans-Elect, Inc.	2001 & 2002	Support of rates and ratemaking methodology for new transmission company
28	FERC		Sithe New Boston, LLC	Sithe New Boston, LLC	2001 & 2002	Cost of Service for Must Run Unit
29	FERC	RM01-12	FERC Technical Conference	SeTrans	2002	Allocation of FTRs/CRRs
30	FERC	EL02-111	Midwest ISO & PJM	Midwest ISO Transmission Owners	2002	Through and Out Rates
31	FERC	ER02-2595	Midwest ISO	Midwest ISO Transmission Owners	2002	Cost Allocation for FTR and Market Administration
32	FERC	ER03-37	Sierra Pacific Resources	Sierra Pacific and Nevada Power	2003	Ancillary Service Rates
33	FERC	ER03-626	Empire District Electric Co.	Empire District Electric Co.	2003	Cost of Service; Wholesale Requirements Customers
34	FERC	EL-02-25-001, et. al	Intermountain, Holy Cross, Yampa and Aquila	Public Service Co. of Colorado	2003	Fuel Adjustment Clause

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
35	FERC	ER03-959	Exelon Framingham LLC, et al.	Exelon Framingham LLC, et al.	2003	Production Cost of Service
36	FERC	ER03-1187	MidWest Generation, LLC	Commonwealth Edison	2003	Black Start Rates
37	FERC	ER03-1223	Montana Megawatts I, LLC, et al.	Montana Megawatt	2003	Production Formula Rates
38	FERC	ER03-1335	Commonwealth Edison	Commonwealth Edison	2003	Transmission Tariff Rates
39	FERC	ER03-1354	Black Hills Power Company, et al.	Black Hills Power Company, et al.	2003	Joint transmission Tariff Rates
40	FERC	ER03-1328	Sierra Pacific Resources	Nevada Power	2003	Transmission Tariff Rates
41	FERC	EL02-111, et. Al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Long-term Transmission Pricing Plan
42	FERC	ER05-14	Sierra Pacific Resources	Sierra Pacific	2004	Transmission Tariff Rates
43	FERC	ER05-26	Mirant Kendall, LLC	Mirant Kendall, LLC	2004	Reliability Must Run Agreement and Rates
44	Illinois Commerce Commission	No.04-0779	NICOR Gas Company	NICOR Gas Company	2004	Distribution Service Embedded Cost of Service Study
45	FERC	ER05-163	Milford Power Company LLC	Milford Power Company LLC	2004	Reliability Must Run Agreement and Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
46	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Seams Elimination
47	FERC	EL00-95, et. al	SDG&E V. Sellers, et al.	Portland General Electric Company	2005	California Refund Proceeding
48	FERC	ER05-447	Midwest ISO	Midwest ISO Transmission Owners	2005	Schedule 10 & 17 Recovery for Grandfathered Agreements
49	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
50	FERC	ER05-860	Whiting Clean Energy	Whiting Clean Energy	2005	Cost Based Power Rates
51	FERC	ER05-903	Con. Ed. Energy Mass., Inc.	Con. Ed. Energy Mass., Inc.	2005	Reliability Must Run Agreement and Rates
52	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
53	FERC	ER05-1050	AmerGen Energy Company, L.L.C.	AmerGen Energy Company, L.L.C.	2005	Reactive power charges
54	Illinois Commerce Commission	No.05-0597	Commonwealth Edison Co.	Commonwealth Edison Co.	2005	Distribution Service Embedded Cost of Service Study
55	FERC	ER05-1179	Berkshire Power Company, LLC	Berkshire Power Company, LLC	2005	Reliability Must Run Agreement and Rates

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
56	FERC	ER05-1243	Basin Electric Power Cooperative	Basin Electric Power Cooperative	2005	Revised Transmission Cost of Service
57	FERC	ER05-1304 & ER05-1305	Mystic I, LLC and Mystic Development, LLC	Mystic I, LLC and Mystic Development, LLC	2005	Reliability Must Run Agreement and Rates
58	FERC	ER05-273	Midwest ISO	Midwest ISO Transmission Owners	2005	Proper Pricing for Regional Non-firm Redirects
59	FERC	ER05-515	PHI and BGE	PHI and BGE	2005	Transmission Formula Rates
60	FERC	EL05-19	Southwestern Public Service Company	Southwestern Public Service Company	2005	Production rates and Fuel Adjustment Clause,
61	FERC	ER06-427	Mystic Development, LLC	Mystic Development, LLC	2006	Reliability Must Run Agreement and Rates
62	FERC	ER06-822	Fore River Development, LLC	Fore River Development, LLC	2006	Reliability Must Run Agreement and Rates
63	FERC	ER06-819	Consolidated Edison Energy Massachusetts, Inc	Consolidated Edison Energy Massachusetts, Inc	2006	Reliability Must Run Agreement and Rates
64	FERC	ER07-169	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2006	Ancillary service rates
65	FERC	ER06-1549	Duquesne Light Company	Duquesne Light Company	2006	Transmission Formula Rates
66	FERC	ER07-170	Ameren Energy, Inc.	Ameren Energy, Inc.	2006	Ancillary service rates
67	FERC	ER06-787	Idaho Power	Idaho Power	2006 & 2007	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
68	FERC	ER07-562	Trans-Allegheny Interstate Line Company	Trans-Allegheny Interstate Line Company	2007	Transmission Formula Rates
69	FERC	ER07-583	Commonwealth Edison	Commonwealth Edison	2007	Transmission Formula Rates
70	FERC	ER07-1171	Arizona Public Service Co.	Arizona Public Service Co.	2007	Transmission Formula Rates
71	Illinois Commerce Commission	No. 07-0566	Commonwealth Edison Co.	Commonwealth Edison Co.	2007	Distribution Service Embedded Cost of Service Study
72	FERC	ER07-1371	Sierra Pacific Resources	Sierra Pacific Resources	2007	Transmission Rates
73	FERC	ER08-281	Oklahoma Gas & Electric	Oklahoma Gas & Electric	2007	Transmission Formula Rates
74	FERC	ER08-313	Southwestern Public Service	Southwestern Public Service	2007	Transmission Formula Rates
75	FERC	ER08-386	Potomac-Appalachian Transmission Highline, LLC	Potomac-Appalachian Transmission Highline, LLC	2007	Transmission Formula Rates
76	FERC	ER08-374	Atlantic Path 15, LLC	Atlantic Path 15, LLC	2007	Transmission Rates
77	Illinois Commerce Commission	No. 08-0363	NICOR Gas Company	NICOR Gas Company	2008	Distribution Service Embedded Cost of Service Study
78	FERC	ER08-951	PSEG Energy Resources & Trade, LLC	PSEG Energy Resources & Trade, LLC	2008	Reactive Power Charges
79	FERC	ER08-1233	Public Service Gas & Electric Company	Public Service Gas & Electric Company	2008	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
80	FERC	ER08-1457	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2008	Transmission Formula Rates
81	FERC	ER08-1584	Black Hills Power	Black Hills Power	2008	Transmission Formula Rates
82	FERC	ER08-1600	Basin Electric Power Coop	Basin Electric Power Coop	2008	Transmission Rates
83	FERC	ER09-36	Prairie Wind Transmission, LLC	Prairie Wind Transmission, LLC	2008	Transmission Formula Rates
84	FERC	ER09-35	Tallgrass Transmission, LLC	Tallgrass Transmission, LLC	2008	Transmission Formula Rates
85	FERC	ER09-75	Pioneer Transmission, LLC	Pioneers Transmission, LLC	2008	Transmission Formula Rates
86	FERC	ER09-255	Nebraska Public Power District	Nebraska Public Power District	2008	Transmission Formula Rates
87	FERC	ER09-528	ITC Great Plains, LLC	ITC Great Plains, LLC	2009	Transmission Formula Rates
88	Illinois Commerce Commission	ER08-0532	Commonwealth Edison Co.	Commonwealth Edison Co.	2009	Distribution Service Embedded Cost of Service Study
89	FERC	ER08-370 & EL09-22	Missouri River Energy Services & MISO	Otter Tail Power Co.	2009	Formula Transmission Rate
90	FERC	ER10-152	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2009	Revised Depreciation Method
91	FERC	ER09-1727	ALLETE, INC	ALLETE. INC	2009	Formula Transmission Rate
92	FERC	ER10-230	KCP&L	KCP&L	2009	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
93	FERC	ER10-455	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2009	Reactive Power Rates
94	FERC	ER10-516	SCE&G	SCE&G	2010	Formula Transmission Rates
95	FERC	ER10-962	Union Electric Company	Union Electric Company	2010	Reactive Power Rates
96	FERC	ER10-1149	FP&L	FP&L	2010	Formula Transmission Rates
97	FERC	ER10-1418	Exelon Generation	Exelon Generation	2010	Reliability Must Run
98	FERC	ER10-1782	Tampa Electric Company	Tampa Electric Company	2010	Formula Transmission Rates
99	FERC	ER10-2061	Tampa Electric Company	Tampa Electric Company	2010	Formula Production Rates
100	FERC	ER11-1955	Dairyland Power Coop.	Dairyland Power Coop.	2011	Reactive Rates
101	FERC	ER05-6	Midwest ISO	MISO Transmission Owners	2010	Seams Elimination
102	FERC	ER11-2127	Terra Gen Dixie Valley	Terra Gen Dixie Valley	2010	Transmission Rates
103	FERC	ER09-1148	PPL Electric Utilities	PPL Electric Utilities	2011	Formula Transmission Rates
104	FERC	ER11-3643	PacifiCorp	PacifiCorp	2011	Formula Transmission Rates
105	FERC	ER11-3826	Black Hills	Black Hills	2011	Transmission Rates
106	FERC	ER11-3643	Puget Sound Energy	Puget Sound Energy	2012	Formula Transmission Rates
107	FERC	ER12-1378	CLECO	CLECO	2012	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
108	FERC	ER12-1593	DATC	DATC	2012	Formula Transmission Rates
109	FERC	ER12-2274	PSE&G	PSE&G	2012	Abandonment Costs
110	FERC	ER12-2554	Transource Missouri, LLC	Transource Missouri, LLC	2012	Formula Transmission Rate
111	FERC	ER13-1187	MidAmerican	MidAmerican	2013	Depreciation Rates under Formula
112	FERC	ER13-1207	PacifiCorp	PacifiCorp	2013	Regulation Service
113	FERC	EL13-48	PHI Companies	PHI Companies	2013	Complaint involving Formula Rates
114	FERC	ER13-1207	PacifiCorp	PacifiCorp	2013	Depreciation Rates under Formula
115	FERC	ER13-1605	NV Energy	NV Energy	2013	Transmission and Ancillary Service Rates
116	FERC	ER13-782	ITC	ITC	2013	Transmission Formula Rate
117	FERC	ER13-1962 & EL13-76	Midcontinent ISO & AERG	AERG/AEM	2013	Reliability Must Run
118	FERC	ER14-108	Entergy	Entergy	2013	Reactive Power Rates
119	FERC	ER14-1332	DATC Path 15, LLC	DATC Path 15, LLC	2014	Transmission Cost of Service
120	FERC	ER14-1382	Transource Missouri, LLC	Transource Missouri, LLC	2014	Transmission Formula
121	FERC	ER14-1425	Cheyenne L, F & P	Cheyenne L, F & P	2014	Transmission Rates

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
122	FERC	ER14-1661	MidAmerican Central California Transco, LLC	MidAmerican Central California Transco, LLC	2014	Transmission Formula
123	FERC	ER14-1956	Panther Creek Power Operating, LLC	Panther Creek Power Operating, LLC	2014	Reactive Power Rates
124	FERC	ER14-1969	Public Service Company of Colorado	Public Service Company of Colorado	2014	Ancillary Services for Intermittent Resources
125	FERC	ER14-2502	Entergy Power, LLC EAM Nelson Holding, LLC	Entergy Power, LLC EAM Nelson Holding, LLC	2014	Reactive Power Rates
126	FERC	ER14-2619	Illinois Power Marketing Company	Illinois Power Marketing Company	2014	Reliability Must Run

Exhibit No. XES-602

Formula Rate - Non-Levelized | Xcel Energy Southwest Transmission Company, LLC | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/____

Xcel Energy Southwest Transmission Company, LLC

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 47)				$ -
	REVENUE CREDITS	(Note O)	Total	Allocator		
2	Account No. 454	(page 4, line 29)	-	TP	-	-
3	Account No. 456.1	(page 4, line 33)	-	TP	-	-
4	Account No. 457.1 Scheduling	Attachment 5, line 39, col e	-	TP	-	-
5	Revenues from Grandfathered Interzonal Transactions	(Note N)	-	TP	-	-
6	Revenues from service provided by the ISO at a discount		-	TP	-	-
7	TOTAL REVENUE CREDITS	(Sum of Lines 2 through 6)	-			-
8	NET REVENUE REQUIREMENT	(line 1 minus line 7)				$ -
9	True-up Adjustment with Interest	Attachment 3	-	DA	1.00000	-
10	NET REVENUE REQUIREMENT	(line 8 plus line 9)				$ -

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Note U)					
1	Production	205.46.g for end of year, records for other months	-	NA		-
2	Transmission	Attachment 4, Line 14, Col. (b)	-	TP	-	-
3	Distribution	207.75.g for end of year, records for other months	-	NA		-
4	General & Intangible	Attachment 4, Line 14, Col. (c)	-	W/S	-	-
5	Common	356.1 for end of year, records for other months	-	CE	-	-
6	TOTAL GROSS PLANT	(Sum of Lines 1 through 5)	-	GP=	-	-
7	ACCUMULATED DEPRECIATION (Note U)					
8	Production	219.20-24.c for end of year, records for other months	-	NA		-
9	Transmission	Attachment 4, Line 14, Col. (h)	-	TP	-	-
10	Distribution	219.26.c for end of year, records for other months	-	NA		
11	General & Intangible	Attachment 4, Line 14, Col. (i)	-	W/S	-	-
12	Common	356.1 for end of year, records for other months	-	CE	-	-
13	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 8 through 12)	-			-
14	NET PLANT IN SERVICE					
15	Production	(line 1 - line 8)	-			
16	Transmission	(Line 2 minus Line 9)	-			-
17	Distribution	(line 3 - line 10)	-			
18	General & Intangible	(Line 4 minus Line 11)	-			-
19	Common	(line 5 - line 12)	-			-
20	TOTAL NET PLANT	(Sum of Lines 15 through 19)	-	NP=	-	-
21	ADJUSTMENTS TO RATE BASE					
22	Account No. 281 (enter negative)	Attachment 4, Line 28, Col. (d) (Note B)	-	NA	zero	-
23	Account No. 282 (enter negative)	Attachment 4, Line 28, Col. (e) (Note B)	-	NP	-	-
24	Account No. 283 (enter negative)	Attachment 4, Line 28, Col. (f) (Note B)	-	NP	-	-
25	Account No. 190	Attachment 4, Line 28, Col. (g) (Note B)	-	NP	-	-
26	Account No. 255 (enter negative)	Attachment 4, Line 28, Col. (h) (Note B)	-	NP	-	-
27	CWIP	Attachment 4, Line 14, Col. (d)	-	DA	1.00000	-
28	Unamortized Regulatory Asset	Attachment 4, Line 28, Col. (b) (Note T)	-	DA	1.00000	-
29	Unamortized Abandoned Plant	Attachment 4, Line 28, Col. (c) (Note S)	-	DA	1.00000	-
30	TOTAL ADJUSTMENTS	(Sum of Lines 22 through 29)	-			-
31	LAND HELD FOR FUTURE USE	Attachment 4, Line 14, Col. (e) (Note C)	-	TP	-	-
32	WORKING CAPITAL	(Note D)				
33	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	-			-
34	Materials & Supplies	Attachment 4, Line 14, Col. (f) (Note C)	-	TP	-	-
35	Prepayments (Account 165)	Attachment 4, Line 14, Col. (g)	-	GP	-	-
36	TOTAL WORKING CAPITAL	(Sum of Lines 32 through 35)	-			-
37	RATE BASE	(Sum of Lines 20, 30, 31 & 36)	-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b Attach. 5, Line 13, Col. (a)	-	TP	-	-
2	Less Account 566 (Misc Trans Expense)	321.97.b Attach. 5, Line 13, Col. (b)	-	TP	-	-
3	Less Account 565	321.96.b Attach. 5, Line 13, Col. (c)	-	TP	-	-
4	A&G	323.197.b Attach. 5, Line 13, Col. (d)	-	W/S	-	-
5	Less FERC Annual Fees	Attach. 5, Line 13, Col. (e)	-	W/S	-	-
6	Less EPRI & Reg. Comm. Exp. & Non-safety Ad.	(Note E) Attach. 5, Line 13, Col. (f)	-	W/S	-	-
6a	Less PBOP Expense in Year	Attachment 7, line 10	-	W/S	-	-
7	Plus Transmission Related Reg. Comm. Exp.	(Note E) Attach. 5, Line 13, Col. (g)	-	TP	-	-
7a	Plus PBOP Expense Allowed Amount	Attachment 7, line 8	-	W/S	-	-
8	Common	356.1	-	CE	-	-
9	Transmission Lease Payments	Attach. 5, Line 13, Col (h)	-	DA	1.0000	-
10	Account 566					
11	Amortization of Regulatory Asset	(Note T) Attach. 5, Line 13, Col. (i)	-	DA	1.0000	-
12	Miscellaneous Transmission Expense	Attach. 5, Line 13, Col .(j)	-	DA	1.0000	-
13	Total Account 566	(Line 11 plus Line 12) Ties to 321.97.b"	-			-
14	TOTAL O&M	(Sum of Lines 1, 4, 7, 7a, 8, 9, 13 less Lines 2, 3, 5, 6, 6a)	-			-
15	DEPRECIATION EXPENSE (Note U)					
16	Transmission	336.7.b&d Attach. 5, Line 13, Col. (k)	-	TP	-	-
17	General & Intangible	336.10.b&d, 336.1.b&d Attach. 5, Line 26, Col. (a)	-	W/S	-	-
18	Common	336.11.b&d	-	CE	-	-
19	Amortization of Abandoned Plant	(Note S) Attach. 5, Line 26, Col. (b)	-	DA	1.0000	-
20	TOTAL DEPRECIATION	(Sum of Lines 16 through 19)	-			-
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	263.i Attach. 5, Line 26, Col. (c)	-	W/S	-	-
24	Highway and vehicle	263.i Attach. 5, Line 26, Col. (d)	-	W/S	-	-
25	PLANT RELATED					
26	Property	263.i Attach. 5, Line 26, Co.l (e)	-	GP	-	-
27	Gross Receipts	263.i Attach. 5, Line 26, Col. (f)	-	NA	zero	-
28	Other	263.i Attach. 5, Line 26, Col. (g)	-	GP	-	-
29	Payments in lieu of taxes	Attach. 5, Line 26, Col. (h)	-	GP	-	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	-			-
31	INCOME TAXES	(Note G)				
32	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * (1-TEP)	WCLTD = Page 4, Line 20	-			
33	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 23	-			
34	FIT & SIT & P	(Note G)				
35						
36	1 / (1 - T) = (from line 32)	1 / (1 - T) = Line 32	-			
37	Amortized Investment Tax Credit	266.8f (enter negative) Attach. 5, Line 26, Col. (i)	-			
38	Excess Deferred Income Taxes	(enter negative) Attach. 5, Line 26, Col. (j)	-			
39	Tax Effect of Permanent Differences	Attach. 5, Line 26, Col. (k) (Note W)	-			
40	Income Tax Calculation	(Line 33 times Line 45)	-	NA		-
41	ITC adjustment	(Line 36 times Line 37)	-	NP	-	-
42	Excess Deferred Income Tax Adjustment	(Line 36 times Line 38)	-	NP	-	-
43	Permanent Differences Tax Adjustment	(Line 36 times Line 39)	-	NP	-	-
44	Total Income Taxes	(Sum of Lines 40 through 43)	-			-
45	RETURN					
46	Rate Base times Return	(Page 2, Line 37 times Page 4, Line 23)	-	NA		-
47	REV. REQUIREMENT	(Sum of Lines 14, 20, 30, 44 & 46)	-			-

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)		(5)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total Transmission plant	(Page 2, Line 2, Column 3)					-	
2	Less Transmission plant excluded from ISO rates	(Note H)					-	
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-	
4	Transmission plant included in ISO rates	(Line 1 minus Lines 2 & 3)					-	
5	Percentage of Transmission plant included in ISO Rates	(Line 4 divided by Line 1)				TP=	-	
6	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
7	Production	354.20.b	-	-	-			
8	Transmission	354.21.b	-	-	-			
9	Distribution	354.23.b	-	-	-		W&S Allocator	
10	Other	354.24,25,26.b	-	-	-		($ / Allocation)	
11	Total	(Sum of Lines 7 through 10)	-		-	=	-	= WS
12	COMMON PLANT ALLOCATOR (CE) (Note J)		**$**		% Electric		W&S Allocator	
13	Electric	200.3.c	-		(line 17 / line 20)		(line 16)	CE
14	Gas	200.3.d	-		-	*	-	= -
15	Water	200.3.e	-					
16	Total	(Sum of Lines 13 through 15)	-					
17	RETURN (R)	(Note V)					$	
18					Cost			
19			$	%	(Notes K, Q, & R)		Weighted	
20	Long Term Debt	(Notes Q & R)	-	45.00%	0.0224		0.0101	=WCLTD
21	Preferred Stock (112.3.c)	(Notes Q & R)	-	-	-		-	
22	Common Stock	(Notes K, Q & R)	-	55.00%	0.1114		0.0613	
23	Total	(Sum of Lines 20 through 22)	-				0.0714	=R
24	REVENUE CREDITS							
25	ACCOUNT 447 (SALES FOR RESALE)	310 -311						
26	a. Bundled Non-RQ Sales for Resale	311.x.h					-	
27	b. Bundled Sales for Resale	Attach 5, line 39, col (a)					-	
28	Total of (a)-(b)						-	
29	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note M) Attach 5, line 39, col (b)					-	
30	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	330.x.n (Note P)						
31	a. Transmission charges for all transmission transactions	Attach 5, line 39, col (c)					-	
32	b. Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10.	Attach 5, line 39, col (d)					-	
33	Total of (a)-(b)						-	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Xcel Energy Southwest Transmission Company, LLC

For the 12 months ended 12/31/____

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
B	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated. The maximum deferred tax offset to rate base is calculated in accordance with the proration formula prescribed by IRS regulation section 1.167(l)-1(h)(6).
C	Identified in Form 1 as being only transmission related.
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1.
E	Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes" and TEP = "the tax exempt ownership interest". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:			
	FIT =	-	
	SIT=	-	(State Income Tax Rate or Composite SIT)
	p =	-	(percent of federal income tax deductible for state purposes)
	TEP =	-	(percent of the tax exempt ownership)

H	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
I	Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
J	Enter dollar amounts
K	ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
L	Page 4, Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1.
M	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
N	Company will not have any grandfathered agreements. Therefore, this line shall remain zero.
O	The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes,-facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
P	Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, page 300.22.b.
Q	Prior to issuing any debt, a cost of debt of 2.4% will be used without true-up. After Issuing any debt, the cost of debt is determined using the internal rate of return methodology shown on Attachment 8 until a project is placed in service obtained subject to true-up pursuant to Attachment 9. The cost of debt is determined using the methodology in Attachment 5 once a project is placed in service. Attachment 8 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Appendix A
R	The capital structure will be 55% equity and 45% debt during the construction period, after the construction period, it will be based on the actual capital structure.
S	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
T	Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses related to projects. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rates becoming effective.
U	Excludes Asset Retirement Obligation balances
V	Company shall be allowed recovery of costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.
W	The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

Attachment 1
Project Revenue Requirement Worksheet
Xcel Energy Southwest Transmission Company, LLC

To be completed in conjunction with Attachment H.

Line No.	(1)	(2) Attachment H Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach H, p 2, line 2 col 5 plus line 27 col 5 (Note A)	-	
2	Net Transmission Plant - Total	Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note A)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H, p 3, line 14 col 5	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	-	-
	GENERAL AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G&C Depreciation Expense	Attach H, p 3, lines 17 & 18, col 5 (Note H)	-	
6	Annual Allocation Factor for G&C Depreciation Expense	(line 5 divided by line 1 col 3)	-	-
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H, p 3, line 29 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	-	-
9	Less Revenue Credits	Attach H, p 1, line 7 col 5	-	
10	Annual Allocation Factor for Other Taxes	(line 9 divided by line 1 col 3)	-	-
11	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, 8, and 10**		**-**
	INCOME TAXES			
12	Total Income Taxes	Attach H, p 3, line 43 col 5	-	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2 col 3)	-	-
	RETURN			
14	Return on Rate Base	Attach H, p 3, line 45 col 5	-	
15	Annual Allocation Factor for Return on Rate Base	(line 1 divided by line 2 col 3)	-	-
16	**Annual Allocation Factor for Return**	**Sum of line 13 and 15**	-	**-**

Attachment 1
Project Revenue Requirement Worksheet
Xcel Energy Southwest Transmission Company, LLC

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(12a)	(13)	(14)	(15)	(16)
Line No.	Project Name (Note M)	ITEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation/Amortization Expense	Annual Revenue Requirement	Incentive Return in basis Points	Incentive Return	Ceiling Rate	Discount	Total Annual Revenue Requirement	True-Up Adjustment	Network Upgrade Charge
			(Note C)	(Page 1 line 11)	(Col. 3 * Col. 4)	(Notes D & I)	(Page 1 line 16)	(Col. 6 * Col. 7)	(Notes E & I)	(Sum Col. 5, 8 & 9)	(Note K)	(Attachment 2, Line 28 Incentive Return * Col. 6)	(Sum Col. 10 & 12)	(Note J)	(Sum Col. 10 & 12 Less Col. 13)	(Note F)	Sum Col. 14 & 15 (Note G)
1a			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1c			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1b			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1d			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1e			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1f			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1g			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1h			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1i			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1j			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1k			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1l			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1m			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1n			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
1o			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
			$ -	-	-	$ -	-	-	$ -	-	-	-	-	-	-	$ -	-
																	-
2	Annual Totals		-			-				-		-	-	-	-	-	-
3	Rev. Req. Adj For Attachment H									-							

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment H
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment H and includes any CWIP included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include Unamortized Abandoned Plant.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP, Unamortized Regulatory Assets, and Unamortized Abandoned Plant.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 12. Project Depreciation Expense includes the amortization of Abandoned Plant
F	True-Up Adjustment is calculated on the Project True-up Schedule
G	The Network Upgrade Charge is the value to be used in the SPP's rate calculation under the applicable Schedule under the SPP OATT for each project.
H	The Total General and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.
I	The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense.
J	The Discount is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process
K	Requires approval by FERC of incentive return applicable to the specified project(s)
M	All facilities other than those being recovered under Schedules 7, 8, 9 are to be included in Attachment 1.

Attachment 2
Incentive ROE
Xcel Energy Southwest Transmission Company, LLC

Line	Description	Reference	Note	$	%	Cost	Weighted	
1	Rate Base	Attachment H, line 37, Col.5						-
2	100 Basis Point Incentive Return						$	
				$	%	Cost	Weighted	
3	Long Term Debt	(Notes DD and EE)		-	45.00%	0.0224	0.0101	
4	Preferred Stock	(Notes DD and EE)		-	-	-	-	
5	Common Stock	(Notes O, DD and EE)	Cost = Attachment H, Line 23, Cost plus .01	-	55.00%	0.1214	0.0668	
6	Total (sum lines 27-29)			-			0.0769	
7	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6)							-
8	INCOME TAXES							
9	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			-				
10	CIT=(T/1-T) * (1-(WCLTD/R)) =			-				
11	WCLTD = Line 3							
12	and FIT, SIT & p are as given in footnote K.							
13	1 / (1 - T) = (from line 9)			-				
14	Amortized Investment Tax Credit (266.8f) (enter negative)		Attachment H, Page 3, Line 7	-				
15	Excess Deferred Income Taxes (enter negative)		Attachment H, Page 3, Line 8	-				
16	Tax Effect of Permanent Differences (Note B)		Attachment H, Page 3, Line 9	-				
17	Income Tax Calculation = line 10 * line 7			-	NA		-	
18	ITC adjustment (line 13 * line 14)			-	NP	-	-	
19	Excess Deferred Income Tax Adjustment (line 13 * line 15)			-	NP	-	-	
20	Permanent Differences Tax Adjustment (line 13 * 16)			-	NP	-	-	
21	Total Income Taxes (sum lines 17 - 20)			-			-	-
22	Return and Income Taxes with 100 basis point increase in ROE							-
23	Return (Attach. H line 46 col 5)							-
24	Income Tax (Attach. H line 44 col 5)							-
25	Return and Income Taxes without 100 basis point increase in ROE							-
26	Incremental Return and Income Taxes for 100 basis point increase in ROE							-
27	Rate Base (line 1)							-
28	Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base							-

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual incentive is calculated on Attachment 1 and must be approved by the Commission. For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 137 on Attachment 1 column 16.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

Attachment 3
Project True-Up
Xcel Energy Southwest Transmission Company, LLC

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Project Name	ITEP Project Number	Actual Project Revenues Received [2] In the Rate Year	Actual Net Revenue Requirement [1]	True-Up Adjustment Principal Under/(Over)	Prior Period Adjustment	Applicable Interest Rate on Under/(Over)	True-Up Adjustment Interest Under/(Over)	Total True-Up Adjustment
			as Reported in Form No 1	Actual Attachment 1 p 2 of 2, Col. 14	Col. (e) - Col. (d)	Attachment 11	Attachment 11	Col. [(f)+(g)] x Col. (g) x 24 months [2]	Col. (f) + Col. (i)
1a					-			-	-
1b				-	-			-	-
1c				-	-			-	-
1d				-	-			-	-
1e				-	-			-	-
…					-				
…					-				
2	Subtotal				-				
3	Under/(Over) Recovery				-				

[1] Amount excludes True-Up Adjustment and Discount, as reported in Attachment 1, columns 17 and 19
[2] Rounded to whole dollars.

Attachment 4
Rate Base Worksheet
Xcel Energy Southwest Transmission Company, LLC

		Gross Plant In Service		**CWIP**	**LHFFU**	**Working Capital**		**Accumulated Depreciation**	
Line No	**Month**	**Transmission**	**General & Intangible**	**CWIP (Note C)**	**Held for Future Use**	**Materials & Supplies**	**Prepayments**	**Transmission**	**General & Intangible**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**
		207.58.g for end of year, records for other months	205.5.g & 207.90.g for end of year, records for other months	216.b for end of year, records for other months	214.x.c for end of year, records for other months	227.8.c & 227.16.c for end of year, records for other	111.57.c for end of year, records for other months	219.25.c for end of year, records for other months	219.28.c & 200.21.c for end of year, records for other months
1	December Prior Year	-	-	-	-	-	-	-	-
2	January	-	-	-	-	-	-	-	-
3	February	-	-	-	-	-	-	-	-
4	March	-	-	-	-	-	-	-	-
5	April	-	-	-	-	-	-	-	-
6	May	-	-	-	-	-	-	-	-
7	June	-	-	-	-	-	-	-	-
8	July	-	-	-	-	-	-	-	-
9	August	-	-	-	-	-	-	-	-
10	September	-	-	-	-	-	-	-	-
11	October	-	-	-	-	-	-	-	-
12	November	-	-	-	-	-	-	-	-
13	December	-	-	-	-	-	-	-	-
14	Average of the 13 Monthly Balances	-	-	-	-	-	-	-	-

Adjustments to Rate Base

Line No	**Month**	**Unamortized Regulatory Asset**	**Unamortized Abandoned Plant**	**Account No. 281 Accumulated Deferred Income Taxes (Notes B & D)**	**Account No. 282 Accumulated Deferred Income Taxes (Notes B & D)**	**Account No. 283 Accumulated Deferred Income Taxes (Notes B & D)**	**Account No. 190 Accumulated Deferred Income Taxes (Notes B & D)**	**Account No. 255 Accumulated Deferred Investment Credit**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**
		Note S	**Note S**	273.8.k	275.2.k	277.9.k	234.8.c	267.8.h for end of year, records for other months
15	December Prior Year	-	-	-	-	-	-	-
16	January	-	-	[redacted]				-
17	February	-	-					-
18	March	-	-					-
19	April	-	-					-
20	May	-	-					-
21	June	-	-					-
22	July	-	-					-
23	August	-	-					-
24	September	-	-					-
25	October	-	-					-
26	November	-	-					-
27	December	-	-	-	-	-	-	-
28	Average of the 13 Monthly Balances	-	-	-	-	-	-	-

Notes:
A Information compiled from Company records.
B The maximum deferred tax offset to rate base is calculated in accordance with the proration formula prescribed by IRS regulation section 1.167(l)-1(h)(6).
C CWIP recovered under this formula is limited to the CWIP amounts authorized by FERC.
D ADIT is computed using the average of the beginning of the year and the end of the year.

Attachment 5
Attachment H, Page 3 Worksheet
Xcel Energy Southwest Transmission Company, LLC

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	A&G Expenses	FERC Annual Fees	EPRI & Reg. Comm. Exp. & Non-safety Ad.	Transmission Related Reg. Comm. Exp.	Transmission Lease Payments	Amortization of Regulatory Asset	Miscellaneous Transmission Expense	Depreciation Expense - Transmission
	Attachment H, Page 4, Line Number 8	1	2	3	4	5	6	7	9	11	12	16
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	January	-	-	-	-	-	-	-	-	-	-	-
2	February	-	-	-	-	-	-	-	-	-	-	-
3	March	-	-	-	-	-	-	-	-	-	-	-
4	April	-	-	-	-	-	-	-	-	-	-	-
5	May	-	-	-	-	-	-	-	-	-	-	-
6	June	-	-	-	-	-	-	-	-	-	-	-
7	July	-	-	-	-	-	-	-	-	-	-	-
8	August	-	-	-	-	-	-	-	-	-	-	-
9	September	-	-	-	-	-	-	-	-	-	-	-
10	October	-	-	-	-	-	-	-	-	-	-	-
11	November	-	-	-	-	-	-	-	-	-	-	-
12	December	-	-	-	-	-	-	-	-	-	-	-
13	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Month	Depreciation Expense - General & Intangible	Amortization of Abandoned Plant	Payroll Taxes	Highway & Vehicle Taxes	Property Taxes	Gross Receipts Taxes	Other Taxes	Payments in lieu of Taxes	Amortized Investment Tax Credit (266.8f)	Excess Deferred Income Taxes	Tax Effect of Permanent Differences
	Attachment H, Page 3, Line Number	17	19	23	24	26	27	28	29	37	42	43
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
14	January	-	-	-	-	-	-	-	-	-	-	-
15	February	-	-	-	-	-	-	-	-	-	-	-
16	March	-	-	-	-	-	-	-	-	-	-	-
17	April	-	-	-	-	-	-	-	-	-	-	-
18	May	-	-	-	-	-	-	-	-	-	-	-
19	June	-	-	-	-	-	-	-	-	-	-	-
20	July	-	-	-	-	-	-	-	-	-	-	-
21	August	-	-	-	-	-	-	-	-	-	-	-
22	September	-	-	-	-	-	-	-	-	-	-	-
23	October	-	-	-	-	-	-	-	-	-	-	-
24	November	-	-	-	-	-	-	-	-	-	-	-
25	December	-	-	-	-	-	-	-	-	-	-	-
26	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Attachment H, Page 3, Line Number	Bundled Sales for Resale included on page 4 of Attachment H 27 (a)	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) 29 (b)	Transmission charges for all transmission transactions 31 (c)	Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10. 32 (d)	Account No. 457.1 Scheduling Attach H, p 1 line 4 (e)
27	January	-	-	-	-	-
28	February	-	-	-	-	-
29	March	-	-	-	-	-
30	April	-	-	-	-	-
31	May	-	-	-	-	-
32	June	-	-	-	-	-
33	July	-	-	-	-	-
34	August	-	-	-	-	-
35	September	-	-	-	-	-
36	October	-	-	-	-	-
37	November	-	-	-	-	-
38	December	-	-	-	-	-
39	Total	$ -	$ -	$ -	$ -	$ -
40						
41	RETURN (R)					

		$
42	Long Term Interest (117, sum of 62.c through 67.c)	-
43	Preferred Dividends (118.29c) (positive number)	-
44	Proprietary Capital (112.16.c)	-
45	Less Preferred Stock (line 49)	-
46	Less Account 216.1 (112.12.c) (enter negative)	-
47	Common Stock (sum lines 44-46)	-

			$	%	Cost	Weighted	
48	Long Term Debt	112, sum of 18.c through 21.c	-	45.00%	0.0224	0.0101	=WCLTD
49	Preferred Stock (112.3.c)	112.3.c	-	-	-	-	
50	Common Stock	(Note K)	-	55.00%	0.1114	0.0613	
51	Total	(Sum of Lines 20 through 22)	-			0.0714	=R

Attachment 6
Short Term Debt
Xcel Energy Southwest Transmission Company, LLC

Description	**Debt Amount**	**Months O/S during year**	**Weighted Debt Amount**		**Eff. Rate**	**Weighted Rate**
Verified against debt amortization tables						
Weighted Avg. ST Debt -Jan	-	-	-	-	-	-
Weighted Avg. ST Debt -Feb	-	-	-	-	-	-
Weighted Avg. ST Debt -Mar	-	-	-	-	-	-
Weighted Avg. ST Debt - Apr	-	-	-	-	-	-
Weighted Avg. ST Debt - May	-	-	-	-	-	-
Weighted Avg. ST Debt - June	-	-	-	-	-	-
Weighted Avg. ST Debt - July	-	-	-	-	-	-
Weighted Avg. ST Debt - Aug	-	-	-	-	-	-
Weighted Avg. ST Debt - Sept	-	-	-	-	-	-
Weighted Avg. ST Debt - Oct	-	-	-	-	-	-
Weighted Avg. ST Debt - Nov	-	-	-	-	-	-
Weighted Avg. ST Debt - Dec	-	-	-	-	-	-
	-		-	0.00%		0.00%

Attachment 7
PBOPs
Xcel Energy Southwest Transmission Company, LLC

Calculation of PBOP Expenses

Attachment H, Page 4, Line Number 8

		NSPM (Note B)	NSPW	PSCo	SPS	XES	Total
1							
2	Total PBOP expenses (Note A)	4,673,000	1,007,000	(5,082,000)	(86,000)	2,194,000	
3	Labor dollars	307,898,359	51,513,634	227,316,400	101,418,582	301,757,205	
4	Cost per labor dollar	$0.015	$0.020	($0.022)	($0.001)	$0.007	
5	labor (labor not capitalized) current year	-	-	-	-	-	
6	PBOP Expense for current year	$0	$0	$0	$0	$0	-
7	Lines 2-6 cannot change absent approval or acceptance by FERC in a separate proceeding.						
8	PBOP amount included in Company's O&M and A&G expenses in Form No. 1						-

Note Letter

A Amounts reflect 2015 data from the May 7, 2014 actuarial report
B Excludes former NMC

Attachment 8
Financing Costs for Long Term Debt using the Internal Rate of Return Methodology
Xcel Energy Southwest Transmission Company, LLC

Attachment H, Page 4, Line Number 8

Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below.
Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment.
The IRR calculation will use the Excel Worksheet Function XIRR.

Total Loan Amount	**$ 250,000,000**

Internal Rate of Return[1]	**6.38%**
Based on following Financial Formula[2]**:**	
NPV = 0 =	

Origination Fees	Rate	Amount
Underwriting Discount	-	-
Arrangement Fee	600,000	600,000
Upfront Fee	40.0-35.0	937,500
Rating Agency Fee	-	-
Legal Fees		165,000
Total Issuance Expense		1,702,500
Annual Rating Agency Fee	-	-
Annual Bank Agency Fee	35,000	35,000
Revolving Credit Commitment Fee	0.35%	

	2014	2015	2016	2017	2018	2019	2020
LIBOR Rate	0.24%	0.56%	1.45%	2.29%	2.76%	3.03%	3.21%
Spread	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Interest Rate	2.24%	2.56%	3.45%	4.29%	4.76%	5.03%	5.21%

(A) Year	(B) Quarter	(C) Capital Expenditures ($000's)	(D) Principle Drawn In Quarter	(E) Principle Drawn To Date ($000's)	(F) Interest & Principal ($000's)	(G) Origination Fees ($000's)	(H) Commitment, Utilization & Ratings Fees	(I) Net Cash Flows ($000's) (D-F-G-H)
1/1/2015		-						
3/31/2015	Q1	-	-	-	-			-
6/30/2015	Q2	-	-	-	-			-
9/30/2015	Q3	-	-	-	-			-
12/31/2015	Q4	-	-	-	-			-
3/31/2016	Q1	11,111	5,000	5,000	-	1,703	219	3,079
6/30/2016	Q2	11,111	5,000	10,000	43		249	4,708
9/30/2016	Q3	11,111	5,000	15,000	87		210	4,703
12/31/2016	Q4	11,111	5,000	20,000	131		206	4,664
3/31/2017	Q1	33,333	15,000	35,000	170		201	14,628
6/30/2017	Q2	33,333	15,000	50,000	375		223	14,402
9/30/2017	Q3	33,333	15,000	65,000	541		175	14,284
12/31/2017	Q4	33,333	15,000	80,000	703		162	14,135
3/31/2018	Q1	33,333	15,000	95,000	847		149	14,004
6/30/2018	Q2	33,333	15,000	110,000	1,127		171	13,702
9/30/2018	Q3	33,333	15,000	125,000	1,319		123	13,558
12/31/2018	Q4	33,333	15,000	140,000	1,499		109	13,391
3/31/2019	Q1	33,333	15,000	155,000	1,643		96	13,261
6/30/2019	Q2	33,333	15,000	170,000	1,943		118	12,939
9/30/2019	Q3	33,333	15,000	185,000	2,154		70	12,776
12/31/2019	Q4	33,333	15,000	200,000	2,344		57	12,599
1/1/2020	Q1	-	-	200,000	200,028		44	(200,071)

1 The IRR is the input to Debt Cost shown on Appendix A, Page 4, Line 20 during the construction period.

2 The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e. NPV function with goal seek in a spreadsheet program).

Attachment 9
Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

SUMMARY

YEAR		Estimated Effective cost of debt used in true up	Final Effective cost of debt for the construction loan:	Revenue Requirement: Based on Estimated Effective cost of debt	Revenue Requirement: Based on Actual Effective cost of debt	Over (Under) Recovery	Monthly Interest Rate applicable over the ATRR period	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2017 (Refund)/Owed
2015		7.18%	6.50%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2016		6.8%	6.50%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2017		7.2%	6.50%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2018		7.3%	6.50%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2019	*	7.1%	6.50%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2020	**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
								$ (553,329.99)

The Hypothetical Example:
**** Assumes that the construction loan is retired on Sept 1, 2020***
***** Assumes permanent debt structure is put in place on Sept 1, 2020 with effective rate of 6.5%***

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Calculation of Interest for 2015 True-Up Period							
					Monthly		
January	Year 2015	-	0.5500%	12.00	-		-
February	Year 2015	-	0.5500%	11.00	-		-
March	Year 2015	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2015	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2015	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2015	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2015	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2015	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2015	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2015	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2015	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2015	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		**(103,025)**
					Annual		
January through December	Year 2016	(103,025)	0.5600%	12.00	(6,923)		**(109,948)**
January through December	Year 2017	(109,948)	0.5400%	12.00	(7,125)		**(117,073)**
January through December	Year 2018	(117,073)	0.5800%	12.00	(8,148)		**(125,221)**
January through December	Year 2019	(125,221)	0.5700%	12.00	(8,565)		**(133,786)**
January through December	Year 2020	(133,786)	0.5700%	12.00	(9,151)		**(142,937)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**142,937**	0.5700%		(815)	(12,357)	(131,395)
February	Year 2021	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2021	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2021	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2021	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2021	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2021	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2021	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2021	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2021	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2021	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2021	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		
Total Amount of True-Up Adjustment for 2012 ATRR						$ (148,288)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (48,288)	

Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

Calculation of Interest for 2016 True-Up Period							
					Monthly		
January	Year 2016	(12,500)	0.5600%	12.00	840		13,340
February	Year 2016	(12,500)	0.5600%	11.00	770		13,270
March	Year 2016	(12,500)	0.5600%	10.00	700		13,200
April	Year 2016	(12,500)	0.5600%	9.00	630		13,130
May	Year 2016	(12,500)	0.5600%	8.00	560		13,060
June	Year 2016	(12,500)	0.5600%	7.00	490		12,990
July	Year 2016	(12,500)	0.5600%	6.00	420		12,920
August	Year 2016	(12,500)	0.5600%	5.00	350		12,850
September	Year 2016	(12,500)	0.5600%	4.00	280		12,780
October	Year 2016	(12,500)	0.5600%	3.00	210		12,710
November	Year 2016	(12,500)	0.5600%	2.00	140		12,640
December	Year 2016	(12,500)	0.5600%	1.00	70		12,570
					5,460		**155,460**
					Annual		
January through December	Year 2017	155,460	0.5400%	12.00	10,074		**165,534**
January through December	Year 2018	165,534	0.5800%	12.00	11,521		**177,055**
January through December	Year 2019	177,055	0.5700%	12.00	12,111		**189,166**
January through December	Year 2020	189,166	0.5700%	12.00	12,939		**202,104**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**(202,104)**	0.5700%		1,152	17,473	185,784
February	Year 2021	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2021	(169,370)	0.5700%		965	17,473	152,863
April	Year 2021	(152,863)	0.5700%		871	17,473	136,262
May	Year 2021	(136,262)	0.5700%		777	17,473	119,566
June	Year 2021	(119,566)	0.5700%		682	17,473	102,775
July	Year 2021	(102,775)	0.5700%		586	17,473	85,888
August	Year 2021	(85,888)	0.5700%		490	17,473	68,905
September	Year 2021	(68,905)	0.5700%		393	17,473	51,826
October	Year 2021	(51,826)	0.5700%		295	17,473	34,649
November	Year 2021	(34,649)	0.5700%		197	17,473	17,374
December	Year 2021	(17,374)	0.5700%		99	17,473	(0)
					7,566		
Total Amount of True-Up Adjustment for 2013 ATRR					$	209,670	
Less Over (Under) Recovery					$	(150,000)	
Total Interest					$	59,670	

Calculation of Interest for 2017 True-Up Period							
					Monthly		
January	Year 2017	8,333	0.5400%	12.00	(540)		(8,873)
February	Year 2017	8,333	0.5400%	11.00	(495)		(8,828)
March	Year 2017	8,333	0.5400%	10.00	(450)		(8,783)
April	Year 2017	8,333	0.5400%	9.00	(405)		(8,738)
May	Year 2017	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2017	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2017	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2017	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2017	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2017	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2017	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2017	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		**(103,510)**
					Annual		
January through December	Year 2018	(103,510)	0.5800%	12.00	(7,204)		**(110,714)**
January through December	Year 2019	(110,714)	0.5700%	12.00	(7,573)		**(118,287)**
January through December	Year 2020	(118,287)	0.5700%	12.00	(8,091)		**(126,378)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**126,378**	0.5700%		(720)	(10,926)	(116,173)
February	Year 2021	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2021	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2021	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2021	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2021	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2021	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2021	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2021	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2021	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2021	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2021	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2014 ATRR					$	(131,109)	
Less Over (Under) Recovery					$	100,000	
Total Interest					$	(31,109)	

Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
Xcel Energy Southwest Transmission Company, LLC

Calculation of Interest for 2018 True-Up Period							
					Monthly		
January	Year 2018	25,000	0.5800%	12.00	(1,740)		(26,740)
February	Year 2018	25,000	0.5800%	11.00	(1,595)		(26,595)
March	Year 2018	25,000	0.5800%	10.00	(1,450)		(26,450)
April	Year 2018	25,000	0.5800%	9.00	(1,305)		(26,305)
May	Year 2018	25,000	0.5800%	8.00	(1,160)		(26,160)
June	Year 2018	25,000	0.5800%	7.00	(1,015)		(26,015)
July	Year 2018	25,000	0.5800%	6.00	(870)		(25,870)
August	Year 2018	25,000	0.5800%	5.00	(725)		(25,725)
September	Year 2018	25,000	0.5800%	4.00	(580)		(25,580)
October	Year 2018	25,000	0.5800%	3.00	(435)		(25,435)
November	Year 2018	25,000	0.5800%	2.00	(290)		(25,290)
December	Year 2018	25,000	0.5800%	1.00	(145)		(25,145)
					(11,310)		**(311,310)**
					Annual		
January through December	Year 2019	(311,310)	0.5700%	12.00	(21,294)		**(332,604)**
January through December	Year 2020	(332,604)	0.5700%	12.00	(22,750)		**(355,354)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**355,354**	0.5700%		(2,026)	(30,721)	(326,658)
February	Year 2021	326,658	0.5700%		(1,862)	(30,721)	(297,798)
March	Year 2021	297,798	0.5700%		(1,697)	(30,721)	(268,774)
April	Year 2021	268,774	0.5700%		(1,532)	(30,721)	(239,585)
May	Year 2021	239,585	0.5700%		(1,366)	(30,721)	(210,229)
June	Year 2021	210,229	0.5700%		(1,198)	(30,721)	(180,706)
July	Year 2021	180,706	0.5700%		(1,030)	(30,721)	(151,015)
August	Year 2021	151,015	0.5700%		(861)	(30,721)	(121,154)
September	Year 2021	121,154	0.5700%		(691)	(30,721)	(91,123)
October	Year 2021	91,123	0.5700%		(519)	(30,721)	(60,921)
November	Year 2021	60,921	0.5700%		(347)	(30,721)	(30,547)
December	Year 2021	30,547	0.5700%		(174)	(30,721)	0
					(13,303)		
Total Amount of True-Up Adjustment for 2015 ATRR						$ (368,657)	
Less Over (Under) Recovery						$ 300,000	
Total Interest						$ (68,657)	

Calculation of Interest for 2019 True-Up Period							
					Monthly		
January	Year 2019	8,333	0.5700%	12.00	(570)		(8,903)
February	Year 2019	8,333	0.5700%	11.00	(523)		(8,856)
March	Year 2019	8,333	0.5700%	10.00	(475)		(8,808)
April	Year 2019	8,333	0.5700%	9.00	(428)		(8,761)
May	Year 2019	8,333	0.5700%	8.00	(380)		(8,713)
June	Year 2019	8,333	0.5700%	7.00	(333)		(8,666)
July	Year 2019	8,333	0.5700%	6.00	(285)		(8,618)
August	Year 2019	8,333	0.5700%	5.00	(238)		(8,571)
September	Year 2019	8,333	0.5700%	4.00	(190)		(8,523)
October	Year 2019	8,333	0.5700%	3.00	(143)		(8,476)
November	Year 2019	8,333	0.5700%	2.00	(95)		(8,428)
December	Year 2019	8,333	0.5700%	1.00	(48)		(8,381)
					(3,705)		**(103,705)**
					Annual		
January through December	Year 2020	(103,705)	0.5700%	12.00	(7,093)		**(110,798)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2021	**110,798**	0.5700%		(632)	(9,579)	(101,851)
February	Year 2021	101,851	0.5700%		(581)	(9,579)	(92,853)
March	Year 2021	92,853	0.5700%		(529)	(9,579)	(83,803)
April	Year 2021	83,803	0.5700%		(478)	(9,579)	(74,702)
May	Year 2021	74,702	0.5700%		(426)	(9,579)	(65,549)
June	Year 2021	65,549	0.5700%		(374)	(9,579)	(56,344)
July	Year 2021	56,344	0.5700%		(321)	(9,579)	(47,086)
August	Year 2021	47,086	0.5700%		(268)	(9,579)	(37,776)
September	Year 2021	37,776	0.5700%		(215)	(9,579)	(28,412)
October	Year 2021	28,412	0.5700%		(162)	(9,579)	(18,995)
November	Year 2021	18,995	0.5700%		(108)	(9,579)	(9,525)
December	Year 2021	9,525	0.5700%		(54)	(9,579)	0
					(4,148)		
Total Amount of True-Up Adjustment for 2016 ATRR						$ (114,946)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (14,946)	

Attachment 10
Depreciation Rates
Xcel Energy Southwest Transmission Company, LLC

FERC ACCOUNT	DESCRIPTION	RATE PERCENT	
TRANSMISSION			
E350	Land Rights	1.0300%	***
E352	Structures and Improvements	1.5397%	*
E353	Station Equipment	2.0285%	*
E354	Towers and Fixtures	1.8847%	*
E355	Poles and Fixtures	2.1496%	*
E356	Overhead Conductors & Devices	2.0973%	*
E357	Underground Conduit	1.3665%	*
E358	Underground Conductors & Devices	1.8416%	*
E359	Roads and Trails	1.4256%	**
GENERAL			
E302	Franchises and Consents	N/A	****
E303	Intangible Plant - 5 Year	20.0000%	*
E390	Structures and Improvements	2.1194%	*
E391	Office Furniture and Equipment	5.0671%	*
E391	Network Equipment	25.0000%	*
E392	Transportation Equipment - Auto	10.9667%	*
E392	Transportation Equipment - Light Truck	8.4139%	*
E392	Transportation Equipment - Trailers	6.9486%	*
E392	Transportation Equipment - Heavy Trucks	7.2364%	*
E393	Stores Equipment	5.0000%	*
E394	Tools, Shop and Garage Equipment	6.6672%	*
E395	Laboratory Equipment	10.0000%	*
E396	Power Operated Equipment	8.4139%	*
E397	Communication Equipment	11.1110%	*
E398	Miscellaneous Equipment	6.6672%	*

* NSPM approved rates per Docket No. ER14-1325-000.
** NSPW approved rate per Docket No. ER14-1325-000.
*** PSCo approved rate per Docket No. ER12-1589-000.
**** Electric Intangible Franchises are amortized over the life of the Franchise Agreement.

Attachment 11
True-Up Interest Calculation
Xcel Energy Southwest Transmission Company, LLC

	Monthly Interest Rate (Note A):					
1	1st Qtr	-	-			
2	2nd Qtr	-	-			
3	3rd Qtr	-	-			
4	4th Qtr	-	-			
5	1st Qtr	-	-			
6	2nd Qtr	-	-			
7	3rd Qtr	-	-			
8			-			
9	Avg. Monthly FERC Rate		-	-		
10	Average Short-term debt from Attachment 6					-

Prior Period Adjustments (See Note B)

		Adjustment	Amount	Interest	Total Adjustment
11	1	-	-	-	-
11a	2	-	-	-	-
11b	3	-	-	-	-
11c	4	-	-	-	-
…	…				-
..	…				-
12		Total			-

Notes:

A The Lower of the short-term debt on Attach 6 or the FERC Refund interest rate specified in CFR 35.19(a) for under recovery.
If there is no short-term debt, the rate specified in CFR 35.19(a) is used
The FERC Refund interest rate specified in CFR 35.19(a) for over recovery.

B Prior Period Adjustments are when an error is discovered relating to a prior true-up or refunds/surcharges ordered by FERC.

Exhibit No. XES-603

Xcel Energy Southwest Transmission Company, LLC (XEST)

Attachment H – XEST

ANNUAL TRUE-UP, INFORMATION EXCHANGE,

AND CHALLENGE PROCEDURES

Section I. Applicability

The following procedures shall apply to XEST's calculation of its actual net revenue requirement, True-Up Adjustment, and projected net revenue requirement. The project-specific annual revenue requirements determined under the XEST formula are "up to" rates, i.e., ceiling rates, and permit XEST to discount the revenue requirement to the extent necessary to reflect the result of any cost commitment to SPP. In the Formula Rate Template, the effect of any such discount is removed from the projected revenue requirement and the actual revenue requirement, which ensures that customers receive the benefits of any discount.

Section II. Annual True-Up and Projected Net Revenue Requirement

A. Beginning on or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, XEST shall determine the Annual True-Up under this Attachment H - XEST and Section VII of these protocols, to derive a True-Up Adjustment to be included in XEST's projected net revenue requirement for the subsequent calendar year (the "Rate Year").

B. On or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, XEST shall provide the Annual True-Up, actual net revenue requirement, and True-Up Adjustment to SPP and cause such information to be posted on the SPP website. Within ten (10) days of such posting, XEST shall provide notice of such posting via the email exploder list. Interested Parties shall contact XEST at the following email address to be placed on the exploder list: XESTExploderList@xcelenergy.com.

C. On or before October 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent October 1, XEST shall provide the projected net revenue requirement to SPP and cause such information to be posted on the SPP website. Within ten (10) days of posting of the projected net revenue requirement, XEST shall provide notice of such posting to the email exploder list.

D. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

E. The Annual True-Up shall:

1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

2. Be based on XEST's FERC Form No. 1 reports for the prior calendar year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in the FERC Form No. 1 reports;[1]

4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the Annual True-Up results from the FERC Form No. 1 reports;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1 reports;

6. Identify all material adjustments made to the FERC Form No. 1 report data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 reports and any adjustments not shown in the FERC Form No. 1 reports;

7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the FERC Form No. 1 reports;

8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

    a. Identify any Accounting Changes, including:

        i. the initial implementation of an accounting standard or policy;

[1] It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from FERC Form No. 1 or reconcilable to FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The projected net revenue requirement shall:

1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement;

3. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the projected net revenue requirement;

4. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

   a. Identify any Accounting Changes, including:

      i. the initial implementation of an accounting standard or policy;

      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

      iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

      iv. the implementation of new estimation methods or policies that change prior estimates; and

      v. changes to income tax elections;

   b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement;

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

G. XEST shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") between the Publication Date and October 1. No less than seven (7) days prior to such Annual True-Up Meeting, XEST shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual True-Up Meeting and XEST shall provide notice of such meeting to the email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall (i) permit XEST to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from XEST about the Annual True-Up and True-Up Adjustment.

H. XEST shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") between the date that the projected net revenue requirement is posted to the SPP website (as described in Section II.C of these protocols) and October 31. No less than seven (7) days prior to such Annual Projected Rate Meeting, XEST shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual Projected Rate Meeting and XEST shall provide notice of such meeting to the email exploder list. The Annual Projected Rate Meeting shall (i) permit XEST to explain and clarify their projected net revenue requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from XEST about the projected net revenue requirement.

Section III. Information Exchange Procedures

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of XEST or by FERC order) to serve reasonable information and document requests on XEST ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) the extent or effect of an Accounting Change;

(2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the formula rate and procedures in these protocols;

(4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

(5) the prudence of actual costs and expenditures;

(6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or

(7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. XEST shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. XEST shall respond to all information and document requests by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by XEST or FERC.

C. XEST will cause to be posted on the SPP website all information requests from Interested Parties and XEST's response(s) to such requests; except, however, if responses to information and document requests include material deemed by XEST to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by XEST and the requesting party.

D. XEST shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing XEST's Annual True-Up or projected net revenue requirement.

Section IV. Challenge Procedures

A. Interested Parties shall have until January 31 following the Publication Date (unless such period is extended with the written consent of XEST or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify XEST in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until January 31 shall be referred to as the Review Period. If January 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.

B. A party submitting an Informal Challenge to XEST must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. XEST shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. XEST, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If XEST disagrees with such challenge, XEST will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31, and XEST must respond to all Informal Challenges by no later than February 28, unless the Review Period is extended by XEST or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

(b) Explain how the action or inaction violates the filed rate formula or protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the Annual True-Up projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(iii) the proper application of the formula rate and procedures in these protocols;

(iv) the accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form 1; or

(vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on XEST. Service to XEST must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on XEST's Informational Filing required under Section VI of these protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. XEST will cause to be posted on the SPP website all Informal Challenges from Interested Parties and XEST's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by XEST to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by XEST and the requesting party.

F. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by XEST will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by XEST on or before December 1 will be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to by XEST after December 1 will be reflected in the following year's Annual True-Up, as discussed in Section V of these protocols.

G. An Interested Party shall have until March 31 following the Review Period (unless such date is extended with the written consent of XEST to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on

XEST on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as XEST's Informational Filing discussed in Section VI of these protocols. XEST shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, XEST shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in this Attachment H - XEST. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of XEST to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

J. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up or projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. XEST may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (i) amortization and depreciation rates, or (ii) Post-Employment Benefits Other Than Pensions rates. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

K. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with XEST in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to True-Up Adjustment or Projected Net Revenue Requirement

Except as provided in Section IV.F of these protocols, any changes to the data inputs, including but not limited to revisions to XEST's FERC Form No. 1 reports, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

Section VI. Informational Filings

A. By March 15 of each year, XEST shall submit to FERC an informational filing ("Informational Filing") of their projected net revenue requirement for the Rate Year, including their Annual True-Up and True-Up Adjustment. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that XEST has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, XEST shall provide notice of the Informational Filing via the email exploder list and shall cause SPP to post the docket number assigned to XEST's Informational Filing on the SPP website.

B. Any challenges to the implementation of the Attachment H - XEST formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-Up Adjustment

The True-Up Adjustment is developed on Attachment 3 and will be determined in the following manner:

(1) Actual transmission revenues for the previous year will be compared to Net Revenue Requirement not including any prior year True-Up Adjustment calculated in accordance with XEST's Attachment H of this Tariff for the previous year using XEST's FERC Form No. 1 for that same year to determine any over or under recovery ("True-Up Adjustment"). XEST shall cause the True-Up Adjustment and related calculations to be posted to the SPP website no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these protocols.

(2) Interest on any over recovery of the net revenue requirement, shall be determined on Attachment 11 of the formula rate. Interest on any under recovery of the net revenue requirement or any under recovery due to volume changes, shall be determined using the interest rate equal to XEST's actual short-term debt costs capped at the applicable FERC refund interest rate. In either case, the interest payable shall be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement or volume changes exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the twenty-one (21) months preceding October of the current year. The interest amount will be included in the projected costs made available on October 1 in accordance with Section II.C above.

(3) The Net Revenue Requirement for transmission services for the following Year shall be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment from the previous year, if any, including interest, as explained above.

(4) The XEST may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

AFFIDAVIT

ALAN C. HEINTZ, being duly sworn, deposes and states: that the Direct Testimony of ALAN C. HEINTZ was prepared by him or under his direct supervision, that the statements contained therein and the Exhibits attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

Alan C. Heintz

Subscribed and sworn before me this 25th day of August 2014.

[Name]
Notary Public
My commission expires: [date]

STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 30, 2019

STEPHANIE J. WILKERSON NOTARY PUBLIC MY COMMISSION EXPIRES 6/30/2019 DISTRICT OF COLUMBIA

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Xcel Energy Southwest Transmission Company, LLC	))	**Docket No. ER14-___-000**

ATTESTATION

I, George E. Tyson, II, Vice President and Treasurer, attest that to the best of my knowledge, information, and belief, the cost of service statements and supporting data submitted as part of this filing are true, accurate, and current representations of the utility's books, budgets, or other corporate documents.

George E. Tyson, II
George E. Tyson, II
Vice President and Treasurer
Xcel Energy Southwest Transmission Company, LLC

Subscribed and sworn before me this 20th day of August 2014.

Sharon M. Quellhorst
Name: Sharon M. Quellhorst
Notary Public
My commission expires: 1/31/2015

SHARON M. QUELLHORST
Notary Public-Minnesota
My Commission Expires Jan 31, 2015