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June 29, 2015

By Electronic Filing

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: *NorthWestern Corporation*, Docket No. ER15- -000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. pt. 35, NorthWestern Corporation d/b/a NorthWestern Energy, on behalf of its South Dakota operations ("NorthWestern"), hereby requests approval of a formula rate template and formula rate protocols to be included in the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff")[1] and an initial Annual Transmission Revenue Requirement ("ATRR") for NorthWestern to be collected by SPP as part of the transmission pricing Zone 19 under the SPP Tariff—the Upper Missouri Zone ("UMZ").[2]

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1 Southwest Power Pool, Inc., Open Access Transmission Tariff, Sixth Revised Volume No. 1.

2 In Docket Nos. ER14-2850-000 and ER14-2851-000, the Commission conditionally approved revisions to the SPP Tariff and SPP's governing documents to facilitate the decisions by Western Area Power Administration—Upper Great Plains Region ("WAPA"), Basin Electric Power Cooperative ("Basin Electric"), and Heartland Consumers Power District ("Heartland") (collectively, the "IS Parties") to join SPP and place their transmission facilities (the "Integrated System") under the SPP

NorthWestern is submitting for Commission approval *pro forma* versions of the formula rate template and protocols that will be incorporated into Attachment H of the SPP Tariff. Because NorthWestern is a "public utility" as defined by the FPA, NorthWestern is submitting its own filing to establish its own ATRR. SPP will, in a separate filing, submit revised tariff sheets to incorporate NorthWestern's Transmission Facilities and ATRR into the SPP Tariff. Due to the geographic location of its interconnections with the Integrated System, SPP intends to include NorthWestern's Transmission Facilities in Zone 19 for rate recovery under the SPP Tariff.

The Commission has long encouraged transmission owners to recover transmission costs through formula rates,[3] and most public utility transmission owners in SPP now use formula rates to recover their annual transmission revenue requirements. The formula rate template and protocols that NorthWestern is filing today are just and reasonable, and consistent with Commission precedent. NorthWestern respectfully requests that the Commission accept its formula rate template and protocols, and its initial ATRR, with an effective date of October 1, 2015—the date on which NorthWestern and the IS Parties plan to join SPP. Establishing an effective date of October 1, 2015 for this filing, and for SPP's subsequent rate filing, will allow these companies to integrate into SPP on October 1, 2015 as planned, thus fulfilling the Commission's goal of promoting the expansion of Regional Transmission Organizations ("RTOs").

I. Background

A. NorthWestern Energy and its South Dakota Operations

NorthWestern Energy is a public utility engaged in the generation, transmission and distribution of electricity and supply and transportation of natural gas. NorthWestern Energy owns and operates electric transmission facilities in both Montana and South Dakota. These transmission facilities are not physically connected and are not located in the same geographic regions. As a result, NorthWestern Energy maintains separate Open Access Transmission Tariffs ("OATTs") for its Montana and South Dakota operations. This filing involves only NorthWestern Energy's South Dakota operations (which are referred to as "NorthWestern" in this filing).

NorthWestern owns transmission facilities in eastern South Dakota that serve approximately 62,500 retail customers, with a 2014 peak demand of approximately 304 MW and an annual electric load of approximately 1.57 GWh. NorthWestern currently

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Tariff. Zone 19 constitutes the Integrated System. *See Southwest Power Pool, Inc.*, 149 FERC ¶ 61,113 (2014).

[3] *See, e.g.*, *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386 ("[W]e continue to encourage public utilities to explore the benefits of filing transmission-related formula rates . . . ."), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 61,326 (2006), *order on reh'g and clarif.*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

has eleven firm point-to-point transmission customers in South Dakota who use the transmission service to transmit power and energy obtained from WAPA. NorthWestern has no non-firm transmission customers or network customers.

NorthWestern owns approximately 339 miles of 115 kV transmission facilities that span from WAPA's Gavin Point substation near Yankton, South Dakota to Montana Dakota's Ellendale substation in North Dakota. NorthWestern also owns approximately 260 miles of 69 kV lines and 595 miles of 34.5 kV lines that serve as the main transmission in and around the load centers in the area. A map of NorthWestern's transmission system is attached as Exhibit MRC-1 to the testimony of Michael R. Cashell.

NorthWestern does not operate a control area for its South Dakota operations. WAPA's control area includes NorthWestern's 337 miles of 115 kV transmission facilities. These transmission facilities are included as part of the Integrated System and are administered under WAPA's OATT.[4] NorthWestern's 69 kV and 34.5 kV facilities are used primarily for local distribution and to provide wholesale distribution service to certain customers. NorthWestern relies on WAPA for a host of services needed to meet its local area load, including balancing authority services, ancillary services, and marketing services.

Mid-Continent Area Power Pool ("MAPP") serves as the regional transmission planning organization, the reliability planning coordinator, and the transmission services coordinator for NorthWestern. NorthWestern is the only public utility member of MAPP that is subject to the Commission's general jurisdiction under the FPA. All of MAPP's other members are municipalities or power cooperatives that are subject to the Commission's more limited jurisdiction under sections 210, 211 and 212 of the FPA. *See* 16 U.S.C. §§ 824i, 824j, 824k.

NorthWestern also owns a portion of three baseload generating plants located outside the WAPA balancing authority area. These plants are the Big Stone Plant near Big Stone City, South Dakota; George Neal Energy Center Unit 4 near Sioux City, Iowa; and Coyote Station near Beaulah, North Dakota. These plants are network resources for NorthWestern, and they are pseudo-tied into WAPA's balancing authority area.

Although NorthWestern has a Commission-approved OATT, the Commission has granted NorthWestern waiver of the obligation to comply with the Standards of Conduct and to operate an Open-Access Same Time Information System ("OASIS"). *See NorthWestern Corp.*, 117 FERC ¶ 61,199 (2006) (finding that NorthWestern meets the criteria for small public utility waivers provided in Order No. 676). NorthWestern relies on the MAPP OASIS to provide transmission scheduling in South Dakota.

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[4] The WAPA OATT is a reciprocity tariff that was originally accepted for filing by the Commission in Docket No. NJ98-1-000.

NorthWestern takes network transmission service on the Integrated System under a Network Integration Transmission Service Agreement ("NITSA") under the WAPA OATT. NorthWestern pays WAPA network transmission rates based on its load ratio share of the demand on the Integrated System. In turn, NorthWestern's transmission revenue requirement for its 115 kV facilities is treated as a "facility credit" by WAPA and credited to NorthWestern on a *pro rata* monthly basis on the monthly network transmission invoice.

B. The Integrated System and its Migration to SPP

The Integrated System is an electric transmission system located in the Upper Great Plains region of the United States. The Integrated System comprises approximately 10,000 miles of transmission lines rated 115 kV through 345 kV, and it stretches across seven states: North Dakota, South Dakota, Montana, Wyoming, Nebraska, Minnesota and Iowa. The Integrated System spans the Eastern and Western Interconnections of the United States electric grid.

The Integrated System includes the combined transmission facilities of WAPA, Basin Electric, and Heartland. WAPA is a federal power marketing agency that serves the Upper Great Plains region; Basin Electric is a large generation and transmission cooperative incorporated in North Dakota; Heartland is a public corporation and political subdivision of South Dakota. WAPA, Basin Electric and Heartland are not subject to this Commission's general jurisdiction under the FPA. The Integrated System also includes, through facility credits, transmission facilities owned by NorthWestern and Missouri River Energy Services. The Integrated System is a jointly-developed system that arose from the need to deliver federal hydropower owned by WAPA to preference power customers in the region. The Integrated System has been planned, expanded and operated to serve transmission customers in the region on an integrated, single-system basis under the WAPA OATT.

WAPA, Basin Electric, and Heartland have decided to become transmission-owning members of SPP and to transfer functional control of the Integrated System to SPP effective October 1, 2015. This will significantly expand SPP in an area of the United States grid that previously has not been subject to RTO functional control. As part of this migration to SPP, the WAPA OATT will be terminated, and open access transmission service over the Integrated System will instead be provided by SPP under the SPP Tariff. SPP intends to create a new joint pricing zone under the SPP Tariff (the UMZ or Zone 19) through which the owners of the Integrated System will recover their transmission costs.

C. NorthWestern's Decision to Join SPP

NorthWestern has decided to join SPP and transfer functional control of its transmission facilities to SPP along with the Integrated System on October 1, 2015. The migration of the Integrated System to SPP was a primary driver in NorthWestern's decision to join SPP. Of NorthWestern's fourteen interconnections with other transmission entities, ten of them are with the Integrated System. NorthWestern's reliability, access to markets, ancillary services and power delivery are, therefore, heavily tied to the Integrated System. In addition, joining SPP will enable NorthWestern to comply with its planning obligations under Order No. 1000.[5] The current planning and cost allocations with WAPA and MAPP do not satisfy the requirements of Order No. 1000, and, in any event, MAPP intends to dissolve on October 1, 2015, when the Integrated System migrates to SPP.[6]

When NorthWestern joins SPP with WAPA, Basin Electric and Heartland, on October 1, 2015, NorthWestern's NITSA with WAPA will terminate, and NorthWestern will instead take transmission service from SPP under the SPP Tariff. Services that NorthWestern currently receives from WAPA will be diminished considerably, and SPP will become the balancing authority for NorthWestern's area and will provide ancillary services in accordance with the SPP Tariff. NorthWestern will also terminate its agreement with MAPP, and all of the services provided by MAPP will instead be provided by SPP.

NorthWestern will become a transmission-owning member of SPP and will recover its transmission revenue requirements as part of the new UMZ (Zone 19) under the SPP Tariff. The rate in this new joint zone will be a blended rate based on the transmission revenue requirements for NorthWestern and the non-jurisdictional owners of the Integrated System (WAPA, Basin Electric and Heartland).

II. Description of this Filing

NorthWestern will join SPP as a transmission-owning member effective October 1, 2015, and its transmission facilities will become part of the new UMZ joint pricing zone. SPP will make a subsequent filing to incorporate the initial rates for that zone in the SPP Tariff.

In this filing, NorthWestern is seeking approval of a formula rate template and formula rate protocols under which NorthWestern's ATRR will be developed, as well as the ATRR that SPP will use in establishing rates for the new joint pricing zone. The formula rate template is attached as Attachment 1 to this letter and as Exhibit KGK-1 to the testimony of Kendall G. Kliewer. The formula rate protocols are attached as

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5 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) *aff'd sub nom. S. Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("Order No. 1000").

6 NorthWestern's decision to join SPP on October 1, 2015 is contingent on WAPA and the other owners of the Integrated System also joining SPP on that date.

Attachment 2 to this letter and as Exhibit MRC-3 to the testimony of Michael R. Cashell. The unpopulated formula rate and formula rate protocols will be incorporated into the SPP Tariff. SPP is responsible for filing the tariff sheets to revise the SPP Tariff to add these documents.

The Commission has long encouraged transmission owners to use formula rates for recovering transmission costs in order to remove disincentives and encourage transmission expansion programs. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386. All of the FERC-jurisdictional public utilities in SPP currently recover their transmission costs through formula rates under the SPP Tariff.

This section describes: (1) the formula rate template under which NorthWestern's ATRR will be developed; (2) the NorthWestern transmission facilities that will be transferred to SPP functional control and subject to cost recovery under the formula rate; (3) the fixed return on common equity ("ROE") component of the formula rate template; (4) NorthWestern's initial ATRR and the impact on transmission customers; and (5) the formula rate protocols that will accompany the formula rate template.

A. Formula Rate Template

NorthWestern's formula rate template is described in the testimony of Kendall G. Kliewer and is attached as Exhibit KGK-2 to his testimony. The template will be included in SPP's filing as part of the UMZ pricing zone in the SPP Tariff.

As explained by Mr. Kliewer, the formula rate template is a historical formula rate that uses actual, historic costs that will be updated annually. The inputs for the formula rate come primarily from the company's filed FERC Form No. 1 and will be supplemented with the prior year's accounting data as kept in the company's books and records. The formula rate develops the rate base by specific transmission assets at original cost, reduced by the accumulated depreciation, an allocated share of general and intangible assets, with adjustments for deferred taxes, prepayments, materials and supplies, and cash working capital. The expense portion of the cost of service includes operating and maintenance expenses of the specific transmission assets, an allocated portion of administrative and general expenses, test-year depreciation on the specific assets, and taxes other than income taxes. The cost of capital is calculated using the cost of debt and cost of equity based on the capital structure as shown on template Attachments 6 through 9.

B. NorthWestern Transmission Assets Under the Formula Rate

The NorthWestern transmission assets that will be turned over to SPP functional control and subject to cost recovery under the SPP Tariff are described in the testimony of Michael R. Cashell. As described by Mr. Cashell, NorthWestern will transfer functional control of most of its 115 kV transmission facilities (with the exception of two radial lines) and certain 69 kV facilities that satisfy the definition of "Transmission

Facilities" under Attachment AI of the SPP Tariff. In total, NorthWestern will transfer 333.64 miles of 115 kV transmission facilities and 180.10 miles of 69 kV facilities for a total of 513.74 miles of transmission facilities. A map showing these facilities and a list of the facilities are attached as Exhibits MRC-1 and MRC-2 to Mr. Cashell's testimony.

All of these facilities satisfy the definition of "Transmission Facilities" under Attachment AI of the SPP Tariff. Attachment AI, Section II(1), classifies the following as Transmission Facilities:

> All existing non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other. …

The transmission assets that NorthWestern will transfer functional control of to SPP—and receive cost recovery under the SPP Tariff—are Transmission Facilities under this provision. The 115 kV facilities qualify as "non-radial power lines, substations, and associated facilities, operated at 60 kV or above," and the 69 kV facilities qualify as "radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other." Before making this filing, NorthWestern reviewed these facilities with SPP staff, and they concurred that these facilities are appropriately included under the SPP Tariff.

C. ROE Component

The ROE component fixed in the formula rate template is based on the analysis and recommendations in the attached testimony of Adrien M. McKenzie, CFA, Vice President of FINCAP, Inc. Mr. McKenzie supports a base ROE of 10.47%, plus a 50 basis point ROE adder for RTO participation, for a total ROE of 10.97%.

Mr. McKenzie develops his recommendation for NorthWestern's base ROE using the two-step discounted cash flow ("DCF") model set forth in Opinion No. 531.[7] Mr. McKenzie's analysis under the two-step DCF model results in a zone of reasonableness of 7.13% to 12.26% based on EPS growth rates from IBES. Mr. McKenzie selects a base ROE of 10.47%, which represents the midpoint of the upper half of the zone of reasonableness. Consistent with Opinion No. 531, Mr. McKenzie's recommendation to place the ROE at the midpoint of the upper half of the zone of reasonableness is supported by an evaluation of three alternative benchmark analyses conducted by Mr. McKenzie: (1) a risk premium approach based on Commission-authorized ROEs for

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[7] *Martha Coakley, Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *reh'g denied*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *appeals docketed sub nom. Emera Me., f/k/a Bangor Hydro-Elec. Co. v. FERC*, Nos. 15-1118, *et al.* (D.C. Cir. filed April 30, 2015).

electric utilities; (2) the Capital Asset Pricing Model ("CAPM"); and (3) the expected earnings approach.

Mr. McKenzie's recommendation of a base ROE of 10.47% is also supported by reference to additional benchmarks based on a risk premium approach using ROEs authorized by state regulators, the empirical CAPM ("ECAPM") model, Commission-approved ROEs for natural gas pipelines, and a DCF analysis based on a select group of low risk non-utility firms. Mr. McKenzie also discusses the implications of flotation costs, which are properly considered in evaluating a fair ROE for NorthWestern. In addition, Mr. McKenzie concludes that the recommended base ROE is consistent with the Commission's policy goal of attracting investment in new transmission infrastructure.

Mr. McKenzie includes a 50 basis point adder to the base ROE for NorthWestern's participation in the SPP RTO. Including an ROE adder of up to 50 basis points for RTO participation is consistent with Commission precedent and the Commission's policy of encouraging utilities to join and remain in RTOs. *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,004 at PP 39-40 (2015); *AEP Appalachian Trans. Co.*, 130 FERC ¶ 61,075 at P 21 (2010). The Commission has typically allowed public utilities in SPP to include a 50 basis point adder to their base ROE, without setting the matter for hearing. *See, e.g., Xcel Energy Sw. Transmission Co.*, 149 FERC ¶ 61,182 at P 64 (2014); *The Empire Dist. Elec. Co.*, 140 FERC ¶ 61,087 at P 48 (2012). To NorthWestern's knowledge, the ROEs for all FERC-jurisdictional public utilities in SPP currently include an adder for RTO participation. The total ROE of 10.97%, including the 50 basis point adder, falls well below the 12.26% upper band of the zone of reasonableness and, therefore, meets the Commission's requirements governing incentive-based ROEs. *See, e.g.*, Order No. 679, 116 FERC ¶ 61,057 at P 93 (2006).

D. Initial ATRR and Impact on Customers

Mr. Kliewer's testimony calculates NorthWestern's initial ATRR to be used in SPP's development of transmission rates for the new UMZ joint pricing zone. Mr. Kliewer determines that the initial ATRR for NorthWestern is $8,162,218 based on 2014 FERC Form No. 1 data. Exhibit KGK-2 to Mr. Kliewer's testimony is a populated formula rate template that shows the details of his ATRR calculation.

Mr. Kliewer further explains that this ATRR represents an increase over the ATRR recovered by NorthWestern as facilities credits under the WAPA OATT. The primary reason for this increase is that the facilities credits under the WAPA OATT are based on 2012 cost information and do not reflect additional transmission upgrades to NorthWestern's system that are included in the 2014 data. Also, as explained above, NorthWestern's ATRR under the SPP Tariff includes certain 69 kV facilities that satisfy the definition of Transmission Facilities under Attachment AI, while only NorthWestern's 115 kV facilities are included under the WAPA OATT.

Mr. Kliewer also notes that NorthWestern's ATRR is only one factor in the rates to be paid by customers in the new UMZ joint pricing zone. Under the SPP Tariff, customers located in the new pricing zone pay a blended rate that is based on the revenue requirements for all transmission owners in the joint zone. Therefore, rates ultimately paid by these customers will be determined not only by the ATRR proposed in this filing, but also by the ATRRs proposed in SPP's subsequent filing to create the new joint zone.

E. Formula Rate Protocols

NorthWestern also seeks approval of the formula rate protocols that will accompany the formula rate template. Together, the formula rate template and the protocols comprise NorthWestern's filed rate. The formula rate protocols are described in the Cashell testimony and attached as Exhibit MRC-3 to the Cashell testimony. The protocols will be included in SPP's filing as an Addendum to Attachment H of the SPP Tariff.

As explained by Mr. Cashell, the protocols describe the procedures applicable to the annual update of the formula rate and the informational filing of the annual update with the Commission; describe how the annual update will be implemented; and provide a mechanism for parties to review and obtain information about the annual update, and present formal and informal challenges to the annual update. In developing the protocols, NorthWestern has considered the Commission's requirements relating to (1) scope of participation; (2) transparency of the information exchange; and (3) the ability of customers to present challenges, which the Commission addressed in its investigation of the formula rate protocols in the Midcontinent Independent System Operator, Inc. ("MISO") tariff. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,127 (2012), *order on investigation*, 143 FERC ¶ 61,149 (2013), *order on reh'g*, 146 FERC ¶ 61,209, *order on compliance filing*, 146 FERC ¶ 61,212 (2014) ("*MISO*"). NorthWestern's protocols are based on the protocols for historic formula rates under the MISO tariff that were developed in the *MISO* proceeding and on the protocols accompanying Empire's historic formula rate, which were filed by Empire in Docket No. ER14-2882-000. In developing these protocols, NorthWestern specifically has considered the guidance provided by the Commission in its March 19, 2015 order in *The Empire District Electric Co.*, 150 FERC ¶ 61,200 (2015).

As described by Mr. Cashell, NorthWestern's protocols establish a Rate Year of April 1 through March 31. Because NorthWestern is seeking an effective date of October 1, 2015 for its formula rate, the initial Rate Year will be from October 1, 2015 through March 31, 2016. The protocols require NorthWestern to develop and post on the SPP website its Annual Update on or before March 1 each year. The Annual Update will include a workable-data populated formula rate template and underlying workpapers, and will provide other information specified in Section II of the protocols.

The protocols require NorthWestern to hold an open meeting with Interested Parties to explain and clarify the Annual Update no later than June 1 of each year.

Interested Parties will then have until September 1 to obtain information about the Annual Update in accordance with the Informational Exchange Procedures in Section III of the protocols. Interested Parties will also have the opportunity to submit Informal and Formal Challenges to the Annual Update in accordance with Section IV. Section V provides that any change to the Annual Update—in response to Formal or Informal Challenges or to a complaint or to correct a Mistake in the Annual Update—will be incorporated into the Annual Update for the following Rate Year, with interest. Finally, consistent with the Commission's requirements, Section VI provides that NorthWestern will submit to the Commission an Informational Filing of its Annual Update by December 15 each year.

III. Proposed Effective Date and Request for Waivers

NorthWestern respectfully requests that the Commission accept the formula rate template and protocols, and initial ATRR, with an effective date of October 1, 2015—the date on which NorthWestern and the owners of the Integrated System will join SPP. This requested effective date will allow timely integration of the Integrated System into SPP in accordance with the parties' plans and, thereby, promote this Commission's goal of expanding the reach of RTOs.

NorthWestern respectfully asks the Commission not to impose a suspension of this filing that would prevent an effective date of October 1, 2015. Because NorthWestern's rates are based on actual, historic costs reflected in the FERC Form No. 1, the formula rate should not result in unjust and unreasonable and substantially excessive rates under the Commission's *West Texas* policy.[8] Moreover, suspending NorthWestern's filing beyond October 1, 2015 could create complications for SPP in developing rates for the new joint pricing zone which is planned to take effect on October 1, 2015. This could threaten the timely integration of the Integrated System into SPP.

NorthWestern requests waiver of section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13, to the extent applicable to this filing, and requests waiver of any other applicable requirement of 18 C.F.R. pt. 35 for which waiver is not specifically requested in order for the Commission to accept NorthWestern's formula rate template and protocols, and initial ATRR, for filing, with an effective date of October 1, 2015. NorthWestern specifically requests waiver of the requirement in section 35.13 to submit full Period I and Period II data. The Commission typically waives this requirement in rate filings for approval of formula rates that are based on FERC Form No. 1 data. *See, e.g.*, *Okla. Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 41 (2008) (granting waivers of sections 35.13(d)(1)-(2), 35.13(d)(5) and 35.13(h)); *Am. Elec. Power Serv. Corp.*, 120

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8 *West Tex. Utils. Co*., 18 FERC ¶ 61,189 at 61,375 (1982). *See, e.g.*, *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308 at P 51 (2005) (accepting a proposed transmission formula rate with only a nominal suspension because "the Commission has, in fact, urged transmission owners to move from stated rates to formula rates"), *reh'g denied*, 115 FERC ¶ 61,156 (2006).

FERC ¶ 61,205 at P 41 (2007) (granting waiver of requirement to provide full Period I and II data).

IV. Communications

Please place the following individuals on the official service list for this proceeding.

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V. Persons Served

NorthWestern has served a copy of this filing on SPP, the South Dakota Public Utilities Commission, the SPP service list, and all customers under NorthWestern's OATT for its South Dakota operations.

VI. Contents of Filing

The following documents are included in this filing:

This transmittal letter;

Attachment 1 Formula Rate Template;

Attachment 2 Formula Rate Protocols;

Attachment 3 Prepared Direct Testimony of Michael R. Cashell (including Exhibits);

Attachment 4 Prepared Direct Testimony of Kendall G. Kliewer (including Exhibits); and

Attachment 5 Prepared Direct Testimony of Adrien M. McKenzie (including Exhibits).

VII. Conclusion

For the reasons stated herein, NorthWestern respectfully requests that the Commission accept the formula rate template and protocols, and NorthWestern's initial ATRR to be included in the new joint pricing zone under the SPP Tariff, with an effective date of October 1, 2015.

Respectfully submitted,

/s/

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Enclosures

ATTACHMENT 1

FORMULA RATE TEMPLATE

ADDENDUM 27 TO ATTACHMENT H, Page 1 of 16

NorthWestern Corporation (South Dakota)

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(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Formula Rate Template Inputs
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Entered Directly From FERC Form No. 1 ("FF1"):

Line No	Account/Description/Classification	Inputs From 2014 FERC Form 1	FF1 Page Location	Template Sheet of the Link
1	Prepayments (165)		111.57c	ATT 5 - Cost Support, Ln. 37
2	Preferred Stock Issued (204) - End of Year		112.3c	ATT 8 - Pref Stock, Ln. 2, Col. A
3	Preferred Stock Issued (204) - Beg of Year		112.3d	ATT 8 - Pref Stock, Ln. 1, Col. A
4	Unappropriated Undistrib Subsid Earnings (216.1) - End of Yr		112.12c	ATT 7 - Com Stock, Ln. 2, Col. G
5	Unappropriated Undistrib Subsid Earnings (216.1) - Beg of Yr		112.12d	ATT 7 - Com Stock, Ln. 1, Col. G
6	Accum Other Comp Income (219) - End of Year		112.15c	ATT 7 - Com Stock, Ln. 2, Col. F
7	Accum Other Comp Income (219) - Beginning of Year		112.15d	ATT 7 - Com Stock, Ln. 1, Col. F
8	Total Proprietary Capital - End of Year (Total Company)		112.16c	ATT 7 - Com Stock, Ln. 2, Col. A
9	Total Proprietary Capital - Beginning of Year (Total Company)		112.16d	ATT 7 - Com Stock, Ln. 1, Col. A
10	Bonds (221) - End of Year (Total Company)		112.18c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. B
11	Bonds (221) - Beginning of Year (Total Company)		112.18d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. B
12	(Less) Reacquired Bonds (222) - End of Year		112.19c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. C
13	(Less) Reacquired Bonds (222) - Beginning of Year		112.19d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. C
14	Advances from Assoc Companies (223) - End of Year		112.20c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. A
15	Advances from Assoc Companies (223) - Beginning of Year		112.20d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. A
16	Other Long Term Debt (224) - End of Year		112.21c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. D
17	Other Long Term Debt (224) - Beginning of Year		112.21d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. D
18	Unamortized Premium on Long Term Debt - End of Year		112.22c	ATT 9 - LTD, Pg. 1, Ln. 5
19	Unamortized Premium on Long Term Debt - Beginning of Year		112.22d	ATT 9 - LTD, Pg. 1, Ln. 4
20	(Less) Unamortized Disc. on Long-Term Debt (Debit) - End of Yr		112.23c	ATT 9 - LTD, Pg. 1, Ln. 8
21	(Less) Unamortized Disc. on Long-Term Debt (Debit) - Beg of Yr		112.23d	ATT 9 - LTD, Pg. 1, Ln. 7
22	Accumulated Provision for Injuries and Damages (228.2)		112.28c	ATT 4 - Non-Escrowed Funds, Ln. 4
23	Elec - Taxes Other than Income Taxes (408.1)		115.14g	ATT 2 - Other Taxes, Ln. 22
24	Interest on LTD (427)		117.62c	ATT 9 - LTD, Pg. 2, Ln. 1
25	Amort of Debt Disc & Expenses (428)		117.63c	ATT 9 - LTD, Pg. 2, Ln. 2
26	Amort of Loss on Reacquired Debt (428.1)		117.64c	ATT 9 - LTD, Pg. 2, Ln. 3
27	(less) Amort of Premium on Debt-Credit (429)		117.65c	ATT 9 - LTD, Pg. 2, Ln. 4
28	(less) Amort of Gain on Reacquired Debt-Credit (429.1)		117.66c	ATT 9 - LTD, Pg. 2, Ln. 5
29	Total Dividends Declared Pref Stock (437)		118.29c	ATT 8 - Preferred Stock, Ln. 4, Col. F
30	Electric - Amortization of Other Utility Plant		200.21c	Appendix A - Ln. 8
31	Total Intangible Plant		205.5g	Appendix A - Ln. 22
32	Total Electric Plant in Service		207.104g	Appendix A - Ln. 6
33	Trn - Total Transmission Plant		207.58g	ATT 5 - Cost Support, Ln. 1a
34	Transmission Materials & Supplies		227.8.c	Appendix A - Ln. 41
35	Stores Expense Undistributed (Account 163)		227.16.c	Appendix A - Ln. 38
36	Total (Acct 190)		234.18c	ATT 1 - ADIT, Pg. 1, Ln. 9
37	Total (Acct 281)		273.17k	Line not used
38	Total (Acct 282)		275.9k	ATT 1 - ADIT, Pg. 1, Ln. 18
39	Total (Acct 283)		277.19k	ATT 1 - ADIT, Pg. 1, Ln. 28
40	Interest on Debt to Assoc. Companies		117.67c	ATT-9 - LTD, Pg. 2, Ln. 5a
41	Gen - Total General Plant		207.99g	Appendix A - Ln. 21
42	Transmission Accum. Depreciation		219.25c	Line not used
43	General Accum. Depreciation		219.28c	Appendix A - Ln. 29
44	Total Accum Depr Utility Plant		219.29.c	Appendix A - Ln. 7
45	Amortized Investment Tax Credit		266.8f	ATT 5 - Cost Support, Ln. 103
46	Trn Oper Transmission of Elec by Others		321.96b	ATT 5 - Cost Support, Ln. 50
47	Total Transmission Expenses		321.112b	ATT 5 - Cost Support, Ln. 49
48	A&G Oper Regulatory Commission Expenses		323.189b	Appendix A - Ln. 58 & ATT - 5, Ln. 63
49	A&G Oper General Advertising Expenses		323.191b	Appendix A - Ln. 59
50	Total Admin & General Expenses		323.197b	Appendix A - Ln. 54
51	Depreciation Exp (403) - Intangible Plant		336.1b	Appendix A - Ln.69
52	Depr Exp Asset Retire (403.1) - Intangible Plant		336.1c	Appendix A - Ln. 69
53	Amort Lim Term (404) - Intangible Plant		336.1d	Appendix A - Ln. 69
54	Amort of Other Intangible Electric Plant (405)		336.1e	Appendix A - Ln. 69
55	Depreciation Exp (403) - Transmission Plant		336.7b	Line not used
56	Depr Exp Asset Retire (403.1) - Transmission Plant		336.7c	Not used
57	Amort Lim Term (404) - Transmission Plant		336.7d	Not used
58	Depreciation Exp (403) - General Plant		336.10b	Appendix A - Ln. 68
59	Depr Exp Asset Retire (403.1) - General Plant		336.10c	Appendix A - Ln. 68
60	Amort Lim Term (404)- General Plant		336.10d	Appendix A - Ln. 68
61	Tot Elec O & M Transmission Direct Payroll		354.21b	Appendix A - Ln. 1
62	Tot Elec O & M Admin & General Direct Payroll		354.27b	Appendix A - Ln. 3
63	Total Elec O & M Direct Payroll		354.28b	Appendix A - Ln. 2
64	Transmission Towers and Fixtures		206.51.b	Appendix A - Ln. 16
65	Transmission Poles And Fixtures		206.52.b	Appendix A - Ln. 16
66	Distribution Poles, Towers, and Fixtures		206.64.b	Appendix A - Ln. 15
67	Rent from Electric Property		300.19.b	ATT 3 - Revenue Credits, Ln. 1
68	SD Property Taxes		263.23i	ATT 2 - Other Taxes, Ln. 1
69	ND Property Taxes		263.37i	ATT 2 - Other Taxes, Ln. 1
70	IA Property Taxes		263.1.12i	ATT 2 - Other Taxes, Ln. 1
71	Coal Conversion		263.1.18i	ATT 2 - Other Taxes, Ln. 16
72	Gross Revenue		263.1.24i	ATT 2 - Other Taxes, Ln. 17
73	Delaware Franchise		263.1.31i	ATT 2 - Other Taxes, Ln. 15
74	Vehicle Tax		263.5i	ATT 2 - Other Taxes, Ln. 3
75	Payroll Tax - FICA		263.7i	ATT 2 - Other Taxes, Ln. 8
76	Payroll Tax - Medicare		263.14i	ATT 2 - Other Taxes, Ln. 8
77	Payroll Tax - FUT		263.25i	ATT 2 - Other Taxes, Ln. 9
78	Payroll Tax - FUT-SD		263.32i	ATT 2 - Other Taxes, Ln. 10

Formula Rate Template Inputs
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Input from Company Records and/or Verification Required (Manual Input)

Line No	Account/Description/Classification	Inputs From End of Year	Source of Data	Template Sheet of the Link
1	Federal Income Tax Rate		From Tax Department	Appendix A - Ln. 98
2	State Income Tax Rate		From Tax Department	Appendix A - Ln. 99
3	Percent of Federal Tax Eligible for Deduction by South Dakota		From Tax Department	Appendix A - Ln. 100
4	State Income Tax Rate		From Tax Department	Line not used
5	State Income Tax Rate		From Tax Department	Line not used
6	State Income Tax Rate		From Tax Department	Line not used
7	Specific FERC 909 Ad costs		Company Records	ATT 5 - Cost Support, Ln. 64
8	EPRI Annual Membership Dues		Company Records	Line not used
9	Plant Held for Future Use (Account 105) - Total		FF1, 214.47.d	Appendix A - Ln. 26
10	Plant Held for Future Use (Account 105) - Non-Transmission		FF1, 214.47.d	Appendix A - Ln. 26
11	Transmission Related Regulatory Expenses		FF1, 350.41-44.d	ATT - 5, Ln. 63
12	Plant Held for Future Use (Non-Land) - Transmission Only		Company Records	Appendix A - Ln. 26
13	Transmission Gross Plant under SPP tariff		Company Records	Appendix A - Ln. 20
14	Transmission Accumulated Depreciation on assets under SPP tariff		Company Records	Appendix A - Ln. 28
15	Revenues from Directly Assigned Transmission Facilities (ATT 3, Note 2)		ATT 5 - Cost Support, Ln. 117	
16	Charges billed to Transmission Owner for system integration and transmission costs paid to others that benefit transmission customers and are recorded in Account 565.		Verify amount annually	
17	Line left intentionally blank.		Line left intentionally blank.	
18	Other Electric Revenues - Transmission for Others (Schedules 7 & 8)		From Acct 457. To: ATT-3, Line 4. Also see ATT 3, Notes 1 & 4	
19	Net revenues associated with Transmission Service Requests, Sponsored Upgrades, and Generation Interconnections for which the load is not included in the divisor.		Need to verify during each annual update if there are any such TSR revenues (including TSR revenue from SPP customers not in zone) for load that is NOT included in the UMZ divisor.	
20	Pre-OATT grandfathered Non-Firm Point to Point Service bundled demand revenues for which the load is not included in the divisor received by Transmission Owner and for which the revenues are divided between production and transmission functions.		This represents "Point-To-Point" demand revenue margins derived from any "grandfathered" agreements. The non-RQ "Demand Revenues" found in FF1, Pg. 311, Col. h (and page 311 extensions) for these customers should be reduced by the sum of the Demand Charges (costs) found in FF1, Pg. 327, col. j (and page 327 extensions) for these customers.	
21	Annual Depreciation Expense for Transmission Assets under SPP tariff		Company Records from Mgr of Property Acctg	Appendix A - Ln. 67
22	Transmission Pole/Structure Investment (Accts 354+355) under SPP tariff		Company Records from Mgr of Property Acctg	Appendix A - Ln. 17

The Worksheets listed below require Input of Data directly into the Worksheets themselves:

Line	Sheet	Description/Source
23	ATT 1 - ADIT	Accumulated Def Inc Taxes - Verify with Tax Department.
24	ATT 5 - Cost Support	From company records

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Shaded cells are input cells

Line	Description	Notes	FF1 Page # or Instruction	Amount
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b [From Inputs, Pg. 1, Ln. 61]	-
1a	Transmission under SPP Tariff Factor		[From ATT-5, Ln. 1a]	#DIV/0!
2	Total Wages Expense		p354.28.b [From Inputs, Pg. 1, Ln. 63]	0
3	Less A&G Wages Expense		p354.27.b [From Inputs, Pg. 1, Ln. 62]	0
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	0
5	**Wages & Salary Allocator**		(Line 1 * Line 1a) / Line 4	**#DIV/0!**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g [From Inputs, Pg. 1, Ln. 32]	0
7	Accumulated Depreciation (Total Electric Plant)		p219.29.c [From Inputs, Pg. 1, Ln. 44]	0
8	Accumulated Intangible Amortization (Other Utility Plant)	(Note A)	p200.21.c [From Inputs, Pg. 1, Ln. 30]	0
9	Total Accumulated Depreciation		(Line 7 + 8)	0
10	Net Plant		(Line 6 - Line 9)	0
11	Transmission Gross Plant under SPP tariff (excluding Land Held for Future Use)		(Line 27 - Line 26)	#DIV/0!
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**#DIV/0!**
13	Transmission Net Plant under SPP tariff (excluding Land Held for Future Use)		(Line 35 - Line 26)	#DIV/0!
14	**Net Plant Allocator**		(Line 13 / Line 10)	**#DIV/0!**
	T/D Pole Allocation Factor			
15	Gross Distribution Pole/Structure Investment (Acct 364)		p206.64.b [From Inputs, Pg. 1, Ln. 66]	-
16	Gross Transmission Pole/Structure Investment (Accts 354 + 355)		p206.51.b + p206.52.b [From Inputs, Pg. 1, Lns. 64 & 65]	-
17	Transmission Pole/Structure Investment (Accts 354 + 355) under SPP tariff		From Inputs, Pg. 2, Line 22	-
18	Total Pole/Tower Gross Plant		(Line 15 + Line 16)	-
19	**T/D Revenue Allocation Factor (For Pole Attachment Revenue)**		(Line 17 / Line 18)	**#DIV/0!**
	Plant Calculations			
	Plant In Service			
20	**Transmission Plant In Service under SPP tariff**		[From Inputs, Pg. 2, Ln. 13]	**0**
21	General		p207.99.g [From Inputs, Pg. 1, Ln. 41]	0
22	Intangible		p205.5.g [From Inputs, Pg. 1, Ln. 31]	0
23	Total General and Intangible Plant		(Line 21 + Line 22)	0
24	Wage & Salary Allocator		(Line 5)	#DIV/0!
25	**Total General and Intangible Functionalized to Transmission**		(Line 23 * Line 24)	**#DIV/0!**
26	**Land Held for Future Use**	(Note C)	[From Inputs, Pg. 2, Lns. 9, 10, & 12]	**0**
27	**Total Plant In Rate Base**		**(Line 20 + Line 25 + Line 26)**	**#DIV/0!**
	Accumulated Depreciation			
28	Transmission Accumulated Depreciation for assets under SPP tariff	(Note B)	[From Inputs, Pg. 2, Ln. 14]	**0**
29	General Plant Accumulated Depreciation		p219.28.c [From Inputs, Pg. 1, Ln. 43]	0
30	Accumulated Intangible Amortization (Other Utility Plant)		(Line 8)	0
31	Total Accumulated Depreciation		(Line 29 + 30)	0
32	Wage & Salary Allocator		(Line 5)	#DIV/0!
33	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 31 * Line 32)	#DIV/0!
34	**Total Accumulated Depreciation**		**(Sum Lines 28 + 33)**	**#DIV/0!**
35	**Total Net Property, Plant & Equipment**		**(Line 27 - Line 34)**	**#DIV/0!**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
36	**ADIT**		[From ATT 1, Pg. 1, Ln. 32]	**#DIV/0!**
	Prepayments			
37	Prepayments	(Note A)	[From ATT-5, Ln. 37]	**#DIV/0!**
	Materials and Supplies			
38	Undistributed Stores Expense	(Note A)	p227.16.c [From Inputs, Pg. 1, Ln. 35]	0
39	Wage & Salary Allocator		(Line 5)	#DIV/0!
40	Total Undistributed Stores Expense Allocated to Transmission		(Line 38 * Line 39)	#DIV/0!
41	Transmission Materials & Supplies		p227.8.c [From Inputs, Pg. 1, Ln. 34]	0
42	**Total Materials & Supplies Allocated to Transmission**		(Line 40 + Line 41)	**#DIV/0!**
	Cash Working Capital			
43	Operation & Maintenance Expense		(Line 66)	#DIV/0!
44	1/8th Rule		1/8	12.5%
45	**Total Cash Working Capital Allocated to Transmission**		(Line 43 * Line 44)	**#DIV/0!**
46	**Non-Escrowed Funds**		[From ATT-4, Line 3, Col. C]	**#DIV/0!**
47	**Total Adjustment to Rate Base**		(Lines 36 + 37 + 42 + 45 + 46)	**#DIV/0!**
48	**Rate Base**		(Line 35 + Line 47)	**#DIV/0!**

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Operations & Maintenance Expense				
	Transmission O&M				
49	Transmission O&M			[From ATT-5, Ln. 49]	#DIV/0!
50	Less Account 565			[From ATT-5, Ln. 50]	#DIV/0!
51	Line left intentionally blank				
52	Plus Charges billed to Transmission Owner and booked to Account 565			[From ATT-5, Ln. 52]	0
53	**Transmission O&M**			(Lines 49 - 50)	**#DIV/0!**
	Allocated Administrative & General Expenses				
54	Total A&G			323.197b [From Inputs, Pg. 1, Ln. 50]	0
55	Line left intentionally blank				
56	Line left intentionally blank				
57	Line left intentionally blank				
58	Less Regulatory Commission Exp Account 928		(Note D)	p323.189.b [From Inputs, Pg. 1, Ln. 48]	0
59	Less General Advertising Exp Account 930.1			p323.191.b [From Inputs, Pg. 1, Ln. 49]	0
60	Administrative & General Expenses			Sum (Lines 54 to 55) - Sum (Lines 56 to 59)	0
61	Wage & Salary Allocator			(Line 5)	#DIV/0!
62	**Administrative & General Expenses Allocated to Transmission**			(Line 60 * Line 61)	**#DIV/0!**
	Directly Assigned A&G				
63	Regulatory Commission Exp Account 928		(Note F)	[From ATT-5, Ln. 63]	0
64	Safety/Peak Alert Advertising Exp (Acct 909)		(Note E)	[From ATT-5, Ln. 64]	#DIV/0!
65	**Subtotal - Accounts 909 and 928 - Transmission Related**			(Line 63 + Line 64)	**#DIV/0!**
66	**Total Transmission O&M**			**(Lines 53 + 62 + 65)**	**#DIV/0!**
	Depreciation & Amortization Expense				
	Depreciation Expense				
67	Transmission Depreciation Expense for Assets under SPP tariff		(Note B)	p336.7.b&c&d [From Inputs, Pg. 2, Ln. 21]	**0**
68	General Depreciation Expense Including Amortization of Limited Term Plant			p336.10.b&c&d [From Inputs, Pg. 1, Lns. 58, 59, & 60]	0
69	Intangible Amortization		(Note A)	p336.1.b&c&d&e [From Inputs, Lns. 51, 52, 53, & 54]	0
70	Total			(Line 68 + Line 69)	0
71	Wage & Salary Allocator			(Line 5)	#DIV/0!
72	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 70 * Line 71)	**#DIV/0!**
73	**Total Transmission Depreciation & Amortization**			**(Lines 67 + 72)**	**#DIV/0!**
	Taxes Other than Income Taxes				
74	**Taxes Other than Income Taxes**			[From ATT-2, Pg. 1, Ln. 14]	**#DIV/0!**
75	**Total Taxes Other than Income Taxes**			**(Line 74)**	**#DIV/0!**
	Return \ Capitalization Calculations				
	Long Term Interest				
76	**Long Term Interest & Hedging Costs**			[From ATT-9, Pg. 2, Ln. 6]	**-**
77	**Preferred Dividends**			[From ATT-8, Pg. 1, Ln. 4]	**0**
	Common Stock				
78	Proprietary Capital			[From ATT-7, Pg. 1, Ln. 3, Col. A]	0
79	Less Accumulated Other Comprehensive Income Account 219			[From ATT-7, Pg. 1, Ln. 3, Col. F]	0
80	Less Preferred Stock			[From ATT-8, Pg. 1, Ln. 3, Col. F]	0
81	Less Account 216.1			[From ATT-7, Pg. 1, Ln. 3, Col. G]	0
82	**Common Stock**			(Line 78 - 79 - 80 - 81)	**0**
	Capitalization				
83	Total Long Term Debt (Average)			[From ATT-6, Pg. 1, Ln. 1, Col A]	0
84	Preferred Stock			[From ATT-6, Pg. 1, Ln. 2, Col A]	0
85	Common Stock			[From ATT-6, Pg. 1, Ln. 3, Col A]	0
86	**Total Capitalization**			(Sum Lines 83 to 85)	**0**
87	Debt %	Total Long Term Debt		[From ATT-6, Pg. 1, Ln. 1, Col B]	#DIV/0!
88	Preferred %	Preferred Stock		[From ATT-6, Pg. 1, Ln. 2, Col B]	#DIV/0!
89	Common %	Common Stock		[From ATT-6, Pg. 1, Ln. 3, Col B]	#DIV/0!
90	Debt Cost	Total Long Term Debt		[From ATT-6, Pg. 1, Ln. 1, Col C]	#DIV/0!
91	Preferred Cost	Preferred Stock		[From ATT-6, Pg. 1, Ln. 2, Col C]	0.00%
92	Common Cost	Common Stock		[From ATT-6, Pg. 1, Ln. 3, Col C]	0.00%
93	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 87 * Line 90)	#DIV/0!
94	Weighted Cost of Preferred	Preferred Stock		(Line 88 * Line 91)	#DIV/0!
95	Weighted Cost of Common	Common Stock		(Line 89 * Line 92)	#DIV/0!
96	**Rate of Return on Rate Base (ROR)**			(Sum Lines 93 to 95)	**#DIV/0!**
97	**Investment Return = Rate Base * Rate of Return**			**(Line 48 * Line 96)**	**#DIV/0!**

APPENDIX A
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Description	Formula	Note	Reference	Amount
	Composite Income Taxes				
	Income Tax Rates				
98	FIT=Federal Income Tax Rate		(Note G)	[From Inputs, Pg. 2, Ln. 1]	0.00%
99	SIT=State Income Tax Rate or Composite		(Note G)	[From Inputs, Pg. 2, Ln. 2]	0.00%
100	p	(% of fed inc tax deductible for state purposes)	(Note G)	[From Inputs, Pg. 2, Ln. 3]	0.00%
101	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.00%
102	T / (1-T)	Tax Gross-Up			0.00%
	ITC Adjustment				
103	Amortized Investment Tax Credit - Transmission Related			[From ATT-5, Ln. 103]	#DIV/0!
104	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)		(Line 103 * (1 / (1-Line 101))	**#DIV/0!**
105	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 102 * Line 97 * (1- (Line 93 / Line 96))]	**#DIV/0!**
106	**Total Income Taxes**			**(Line 105 - Line 104)**	**#DIV/0!**
	Revenue Requirement				
	Summary				
107	Net Property, Plant & Equipment			(Line 35)	#DIV/0!
108	Total Adjustment to Rate Base			(Line 47)	#DIV/0!
109	Rate Base			(Line 48)	#DIV/0!
110	Total Transmission O&M			(Line 66)	#DIV/0!
111	Total Transmission Depreciation & Amortization			(Line 73)	#DIV/0!
112	Taxes Other than Income			(Line 75)	#DIV/0!
113	Investment Return			(Line 97)	#DIV/0!
114	Income Taxes			(Line 106)	#DIV/0!
115	**Gross Revenue Requirement**			**(Sum Lines 110 to 114)**	**#DIV/0!**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
116	Transmission Plant In Service under SPP tariff			(Line 20)	0
117	Revenues from Direct Assigned Transmission F		(Note H)	[From ATT-5, Ln. 117]	0
118	Included Transmission Facilities			(Line 116 - Line 117)	0
119	Inclusion Ratio			(Line 118 / Line 116)	#DIV/0!
120	Gross Revenue Requirement			(Line 115)	#DIV/0!
121	**Adjusted Gross Revenue Requirement**			(Line 119 * Line 120)	**#DIV/0!**
	Revenue Credits & Adjustments				
122	Revenue Credits			[From ATT-3, Ln. 8]	#DIV/0!
122a	Refunds and Surcharges (Adjustments to Gross ATRR)				
122b	**Total Revenue Credits and Adjustments**			(Line 122 + Line 122a)	**#DIV/0!**
123	**Annual Total Net Revenue Requirement**			**(Line 121 - Line 122b)**	**#DIV/0!**

Notes:

A Electric portion only.

B Includes only transmission assets under the SPP tariff.

C Includes Transmission portion only.

D Includes all Regulatory Commission Expenses for all Electric jurisdictions.

E Includes safety-related and load/grid congestion management advertising expense included in Account 909 (Product codes ADAS, ADCS, ADPA).

F Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting; as itemized on ATT-5, Ln. 63.

G The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the South Dakota income tax rate, and p = the percentage of federal income tax deductible for South Dakota state income taxes.

H There are no direct assigned transmission facilities on our system as of 12/31/2014. Annual verification/updates will be documented on ATT 5.

ADDENDUM 27 TO ATTACHMENT H, Page 7 of 16
NorthWestern Corporation (South Dakota)

Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 190
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Account	Identification	*(A)* *YE Balance*	*(B)* *100% Non-Transmission Related*	*(C)* *100% Transmission Related*	*(D)* *Plant Related*	*(E)* *Labor Related*	*(F)* *Total Added to Ratebase*	*(G)* *Description*
1	190.0	Deferred FIT - Unbilled Revenue				-			
2	190.0	Deferred FIT - Officers & Directors Deferred Comp.					-		Deferred compensation, tax deductible when paid
3	190.0	Deferred FIT - Reserves & Accruals				-			
4	190.0	Deferred FIT - Post Retirement Benefits - Pension					-		Relates to pensions - tax funding vs book accrual
5	190.0	Environmental Liability		-					All natural gas related
6	190.0	Deferred FIT - Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
7									
8		**Total**	-	-	0	-	-		
9		**Conform - [FF1, pg. 234, ln. 18, col. c] (From Inputs Pg. 1, Line 36)**	-						
10		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
11		**Total Transmission**		0	0	#DIV/0!	#DIV/0!	#DIV/0!	
12									
13									
14	282.0	Accum Def FIT - Accel Depr & Amort.				-			Accelerated Depreciation & Amortization of non-flow thru items
15	282.0	Accum Def FIT - Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
16									
17		**Total**	-	-	0	-	0		
18		**Conform - [FF1, pg. 275, ln. 9, col. k] (Inputs Pg. 1, Line 38)**	-						
19		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
20		**Total Transmission**		-	0	#DIV/0!	#DIV/0!	#DIV/0!	
21									
22									
23	283.0	Regulatory Assets		-					MGP
24	283.0	FAS109 Flow through deferred taxes		-					tax gross up on FAS109 flow through deferred taxes
25	283.0	Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
26									
27		**Total**	-	-	0	0	0		
28		**Conform - [FF1, pg. 277, ln. 19, col. k] (Inputs Pg. 1, Line 39)**	-						
29		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
30		**Total Transmission**		0	0	#DIV/0!	#DIV/0!	#DIV/0!	
31									
32		**Total ADIT (Ln. 11 + Ln. 20 + Ln 30)**						#DIV/0!	To Appendix A, Line 36

Attachment 2 - Taxes Other Than Income

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Column A	Column B	Column C
	OTHER TAXES:	**Pg. 263 & 263.1 Col (i)**	**Allocator**	**Allocated Amount**
	Currently Included on Appendix A			
	Plant Related:		**Gross Plant Allocator**	
1	Real and Personal Property (State, Municipal or Local) -Current FF1 Year [FF1, Pg. 263, Lns. 23i & 37i; Pg. 263.1, Lns. 12i, 18i, 24i & 31i][From Inputs, Pg. 1, Lns. 68-70]	0		
2				
3	Vehicle Taxes [From Inputs, Pg. 1, Ln. 74]	0		
4				
5				
6				
7	**Total Plant Related [GP Allocator from Appendix A, Ln. 12]**	0	#DIV/0!	#DIV/0!
	Labor Related:		**Wages & Salary Allocator**	
8	Social Security (FICA/OAB) [FF1, Pg. 263, Ln.5i] [From Inputs, Pg. 1, Ln. 75-76]	0		
9	Federal Unemployment Comp. [FF1, Pg. 263, Ln. 7i] [From Inputs, Pg. 1, Ln. 77]	0		
10	State Unemployment Comp. [From Inputs, Pg. 1, Lines 78]	0		
11				
12				
13	**Total Labor Related [Wages & Sal. Alloc. from Appendix A, Ln.5]**	0	#DIV/0!	#DIV/0!
14	**Total Included (Column C, Lines 7 + 13)** [To Appendix A, Line 74]			#DIV/0!
	Currently Excluded from Appendix A			
15	Corporate Franchise-Retail [Current Year] [From Inputs, Pg. 1, Ln. 73] [FF1, Pg. 263, Col. i, Lns. 16, 21, & 35; Pg. 263.1, Col. i, Lns. 6, 14, 20, 26, & 33]	0		
16	Coal Conversion [From Inputs Pg. 1, Ln. 71]	0		
17	SD Gross Receipts Tax [From Inputs, Pg. 2, Ln. 72]	0		
18				
19				
20	**Subtotal of Excluded Taxes, [Ln. 15 + Ln. 16 + Ln.17]**	0		
21	**Total, Included and Excluded (Column A, Lines 7 + 13 + 20)**	0		
22	**Total Other Taxes [FF1, pg. 115.14.g] [From Inputs, Pg. 1, Ln. 23]**	-		
23	Difference (Line 21 - Line 22)	-		

Criteria for Allocation:

A Other Taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Gross Plant Allocator.

B Other Taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

NorthWestern Corporation (South Dakota)

Attachment 3 - Revenue Credits

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Account 454 - Rent from Electric Property	
1	Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 1, Ln. 67]	-
2	T/D Revenue Allocation Factor [From Appendix A, Ln. 19]	#DIV/0!
3	Rent from Electric Transmission Property [Line 1 x Line 2]	#DIV/0!
	Other Electric Revenues (Note 1)	
4	SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 3) [From Inputs, Pg. 2, Ln. 18]	0
5	Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 3) [From Inputs, Pg. 2, Ln. 20]	0
6	Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 2, Ln. 15]	0
7	Other Revenues Associated with Loads Outside of NorthWestern's Zone [From Inputs, Pg. 2, Ln. 19]	0
8	Gross Revenue Credits (sum Lines 3 thru 9) [To Appendix A, Line 122]	#DIV/0!

Note 1: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Accounts 457.137 (Firm Point-to-Point) and 457.138 (Non-Firm Point-to-Point). All NorthWestern point-to-point transmission customers are included in the UMZ Load Divisor.

Note 2: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

Note 3: The portion of Point-to-Point revenues collected by SPP and assigned to NorthWestern are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by NorthWestern for "grandfathered" bundled contracts will be included on ATT 3, Ln. 8. See note on "Inputs" worksheet, Pg. 2, Ln. 20 regarding remaining pre-OATT contracts.

ADDENDUM 27 TO ATTACHMENT H, Page 10 of 16
NorthWestern Corporation (South Dakota)
Attachment 4, NON-ESCROWED FUNDS
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

The purpose of this worksheet is to individually document the value(s) of the non-escrowed reserve funds that will be credited against working capital. All inputs are derived from the Company's Books and Records, as described.

Line	Description of Reserve:	FERC Reserve Acct	FERC Expense Acct [1]	Balance 12/31/20xx	Allocator NP	Working Capital Adjustment (Col. C = Col. A x Col. B)
				COL. A	COL. B	COL. C
1.	Accum Prov for Inj/Damgs	228.2	925	$ -	#DIV/0!	#DIV/0!
2.	Other adjustments				#DIV/0!	#DIV/0!
3.	**Total** (Ln. 1 + Ln. 2) [Appendix A, Pg. 1, Ln. 46]			$ -		#DIV/0!
4.	Conformation [FF1, Pg. 112, Ln. 28, Col. c] [From Inputs, Pg. 1, Ln. 22]			-		

[1] Account 925 is the FERC expense account which includes the cost of insurance, the cost of claims not covered by insurance, the re-imbursement from insurance companies, and amounts credited to account 228.2 as Accumulated Provision for Injuries and Damages.

Attachment 5 - Cost Support

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Prepayments		FF1 Amount	Gross Plant Allocator	Functionalized to Transmission	Details
37	Prepayments	FF1 Pg. 111.57.c [From Inputs, Pg. 1, Ln. 1]	0	#DIV/0!	#DIV/0!	

	Regulatory Expense Related to Transmission Cost Support:		FF1 Amount	Allocated to transmission	Functionalized to Transmission	Details
63	Regulatory Commission Exp Account 928	FF1 323.189.b [From Inputs, Pg. 1, Ln. 48] & 350.41.d thru 350.44.d [From Inputs, Pg. 2, Ln. 11]	0	0.00%	0	

	Advertisements:		FF1 Amount	T/D Allocator	Functionalized to Transmission	Details
64	Advertisements FERC 909	FF1 111.57.c [From Inputs, Pg. 2, Ln. 7]	0	#DIV/0!	#DIV/0!	

	ITC Adjustment:		FF1 Amount	GP Allocator	Functionalized to Transmission	Details
103	Amortized Investment Tax Credit	FF1 266.8.f [From Inputs, Pg.1, Ln. 45]	0	#DIV/0!	#DIV/0!	

	Adjustment to Remove Revenue Requirements Associated w/ Excluded Transmission Facilities		Revenues from Direct Assigned Transmission Facilities	General Description of the Direct Assigned Transmission Facilities
117	Revenues from Direct Assigned Transmission Facilities	[From Inputs, Pg. 2, Ln. 15]	0	Direct Assignment Facilities: Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval.

	Adjustments to Transmission O&M:		Total	Transmission under SPP Factor	Functionalized to Transmission	Details
49	Transmission O&M	FF1 321.112.b [From Inputs, Pg. 1, Ln. 47]	0	#DIV/0!	#DIV/0!	
50	Less Account 565	FF1 321.96.b [From Inputs, Pg. 1, Ln. 46]	0	#DIV/0!	#DIV/0!	
52	Plus Charges billed to Transmission Owner and booked to Account 565	[From Inputs, Pg. 2, Ln. 16]	0	#DIV/0!	#DIV/0!	

	Adjustments to Transmission Plant for only assets under SPP tariff:		Total Transmission	Transmission under SPP	Details
20	Transmission Assets	FF1 207.58g [From Inputs, Pg. 1, Ln. 33]	0	-	
1a	Transmission under SPP Factor	(Transmission under SS divided by Total Transimssion)	#DIV/0!		

ADDENDUM 27 TO ATTACHMENT H, Page 12 of 16
NorthWestern Corporation (South Dakota)
Attachment 6, WEIGHTED AVERAGE COST OF CAPITAL
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Type of Capital	Total Company Average Capitalization ($) Balance	Source	Weighted Cost Ratios (%) Col B = Col A/Col A Total	Cost of Capital (%)	Source	Weighted Cost of Capital (%) Col D = Col B x Col C
		Col A		Col B	Col C		Col D
1.	Long Term Debt	-	[Note (1)]	#DIV/0!	#DIV/0!	[Note (4)]	#DIV/0!
2.	Preferred Stock	0	[Note (2)]	#DIV/0!	0.00%	[Note (5)]	#DIV/0!
3.	Common Stock	-	[Note (3)]	#DIV/0!			#DIV/0!
4.	Totals	-		#DIV/0!			
5.	**Weighted Average Cost of Capital ("R")**						#DIV/0!

Note(1): From ATT 9, Pg. 1, Ln. 3.

Note (2): From ATT 8, Pg. 1, Ln. 3.

Note (3): From ATT 7, Pg. 1, Ln. 4.

Note(4): From ATT 9, Page 2, Ln. 8

Note (5): From ATT 8, Pg. 1, Ln. 5.

NorthWestern Corporation (South Dakota)

Attachment 7, COMMON STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Total Proprietary Capital*		Preferred Stock								Acc Other Comp Income		Unappropriated Undistributed Subsidiary Earnings		Common Equity Balance
				Outstanding Balance		Premium (Discount)		Gains/(Losses) on Reacq'd Preferred Stock		Other Paid-In Capital (Preferred Stock)						
		Balance	Source	Acct 204	Source	Acct 207, 213-Pfd	Source	Acct 210	Source	Accts 208 - 211	Source	Acct 219	Source	Acct 216.1	Source	
		Col A		Col B		Col C		Col D		Col E		Col F		Col G		Col H (H=A-B-C-D-E-F-G)
Line	Date															
1.	12/31/20xx	-	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0	[Note (11)]	0	[Note (13)]	-
2.	12/31/20xx	-	[Note (2)]	0	[Note(4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0	[Note (12)]	0	[Note (14)]	-
3.		-		0		0		0		0		0		0		
4.										**Common Equity Balance** [Average of Beg of Yr & End of Yr CE Balance]: [To ATT-6, Page 1, Line 3, Col A]						-

* Includes both Common and Preferred Stock accounts.

[Note (1)]: FF1, Pg. 112, Ln. 16, Col. d. [From Inputs, Pg. 1, Ln. 9]

[Note (2)]: FF1, Pg. 112, Ln. 16, Col. c. [From Inputs, Pg. 1, Ln. 8]

[Note (3)]: From ATT 8, Ln. 1, Col. A.

[Note (4)]: From ATT 8, Ln. 2, Col. A.

[Note (5)]: From ATT 8, Ln. 1; Col. B + Col. C.

[Note (6)]: From ATT 8, Ln. 2; Col. B + Col. C.

[Note (7)]: From ATT 8, Ln. 1, Col. D.

[Note (8)]: From ATT 8, Ln. 2, Col. D.

[Note (9)]: From ATT 8, Ln. 1, Col. E.

[Note (10)]: From ATT 8, Ln. 2, Col. E.

[Note (11)]: FF1, Pg. 112, Ln. 15, Col. d. [From Inputs, Pg. 1, Ln. 7]

[Note (12)]: FF1, Pg. 112, Ln. 15, Col. c. [From Inputs, Pg. 1, Ln. 6]

[Note (13)]: FF1, Pg. 112, Ln. 12, Col. D [From Inputs, Pg. 1, Ln. 5]

[Note (14)]: FF1, Pg. 112, Ln. 12, Col. C [From Inputs, Pg. 1, Ln. 4]

NorthWestern Corporation (South Dakota)

Attachment 8, PREFERRED STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Preferred Stock		Premium on Preferred Stock		Discount on Preferred Stock		Gain/(Loss) On Reaq'd Pref Stock		Other Paid-In Capital - Preferred		Total Outstanding
		Acct 204	Data Source	Acct 207	Data Source	Acct 213	Data Source	Acct 210	Data Source	Accts 208 - 211	Data Source	Col F = Cols A+B-C+D+E
Line	Date	Col A		Col B		Col C		Col D		Col E		COL F
1.	12/31/20xx	0	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0
2.	12/31/20xx	0	[Note (2)]	0	[Note (4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0
3.						**Avg of B of Yr and E of Yr Pref Stock** [To ATT 6, Pg. 1, Col. A, Ln. 2]:						0
4.						**Preferred Dividends** [Note 11]:						0
5.						**Average Cost Rate** [Ln 4 / Ln 3] [To ATT 6, Pg. 1, Col. C, Ln. 2]:						0.00%

Note (1): FF1, Pg. 112, Ln. 3, Col d. [From Inputs, Pg. 1, Ln. 3]

Note (2): FF1, Pg. 112, Ln. 3, Col c. [From Inputs, Pg. 1, Ln. 2]

Note (3): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. d that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (4): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. c that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (5): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. d that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (6): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. c that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (7): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (8): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (9): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. d that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (10): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. c that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (11): FF1, Pg. 118, Ln. 29, Col. c. (Enter as a positive number).

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

GROSS PROCEEDS - LTD OUTSTANDING

		Advances from Associated Company LTD		Bonds		Reacquired Bonds		Other Long Term Debt		Total Long Term Debt Outstanding
		Acct 223	Source	Acct 221	Source	Acct 222	Source	Acct 224	Source	Col E= Cols A+B+C+D
Line	Date	Col A		Col B		Col C		Col D		Col E
1.	12/31/20xx	0	[Note (1)]	-	[Note (3)]	0	[Note (5)]	-	[Note (7)]	-
2.	12/31/20xx	0	[Note (2)]	-	[Note (4)]	0	[Note (6)]	-	[Note (8)]	-
3.		**GROSS PROCEEDS** (Avg of Beg of Yr and End of Yr LTD Gross Outstanding Balances in Col E) [To ATT 6, Pg.1, Ln. 1, Col. A]:								-

Note (1):	FF1, Pg. 112, Line 20, Col d. [From Inputs, Pg. 1, Ln. 15]	Note (5):	FF1, Pg. 112, Ln 19, Col. d. [From Inputs, Pg. 1, Ln. 13]
Note (2):	FF1, Pg. 112, Line 20, Col c. [From Inputs, Pg. 1, Ln. 14]	Note (6):	FF1, Pg. 112, Ln 19, Col. c. [From Inputs, Pg. 1, Ln. 12]
Note (3):	FF1, Pg. 112, Ln 18, Col. D [From Inputs, Pg. 1, Ln. 11]	Note (7):	FF1, Pg. 112, Ln 21, Col. d. [From Inputs, Pg. 1, Ln. 17]
Note (4):	FF1, Pg. 112, Ln 18, Col. C [From Inputs, Pg.1, Ln. 10]	Note (8):	FF1, Pg. 112, Ln 21, Col. c. [From Inputs, Pg. 1, Ln. 16]

NET PROCEEDS

Line	Date		
4.	12/31/20xx	Unamortized balance Premiums (Beg of Yr) [Form 1, Pg. 112, Ln. 22, Col. d] [From Inputs, Pg. 1, Ln. 19]	0
5.	12/31/20xx	Unamortized balance Premiums (End of Yr) [Form 1, Pg. 112, Ln. 22, Col. c] [From Inputs, Pg. 1, Ln. 18]	0
6.		**Avg of Beg & End of Yr Premiums**	0
7.	12/31/20xx	Unamortized balance Discounts (Beg of Yr) [Form 1, Pg. 112, Ln. 23, Col. d] [From Inputs, Pg. 1, Ln. 21]	-
8.	12/31/20xx	Unamortized balance Discounts (End of Yr) [Form 1, Pg. 112, Ln. 23, Col. c] [From Inputs, Pg. 1, Ln. 20]	-
9.		**Avg of Beg & End of Yr Discounts**	-
10.		Gross Proceeds [From Line 3, above]	-
11.		Plus: Unamortized balance Premiums [From Line 6, above]	0
12.		Less: Unamortized balance Discounts [From Line 9, above]	-
13.		**NET PROCEEDS** (Avg of Beg of Yr and End of Yr LTD):	-

General Note: Net long-term average debt balance is used as the divisor to determine LTD debt cost rate. Gross long-term average debt balance is used in the capital structure.

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

LTD COSTS AND EXPENSES (Actual)

Line		
1.	LTD Interest Expense [FF1, Pg. 117, Ln. 62, Col. C] [From Inputs Pg.1, Ln. 24]	0
2.	Amortization Debt Discount and Expense (Acct 428) [FF1, Pg. 117, Ln. 63, Col. c] [From Inputs, Pg. 1, Ln. 25]	0
3.	Amortization of Loss on Reacquired Debt (Acct 428.1) [FF1, Pg. 117, Ln. 64, Col. c] [From Inputs, Pg. 1, Ln. 26]	0
4.	Less: Amort Premium on Debt Credit (Acct 429) [FF1, Pg. 117, Ln. 65, Col. c] [From Inputs, Pg.1, Ln. 27]	0
5.	Less: Amort Gain on Debt Credit (Acct 429.1) [FF1, Pg. 117, Ln. 66, Col. c] [From Inputs, Pg. 1, Ln. 28]	0
5a.	Plus: Interest on Debt to Associated Companies (Acct 430) [FF1, Pg. 117, Ln. 67, Col. c] [From Inputs, Pg. 1, Ln. 40]	0
6.	**TOTAL LTD Interest Amount**	-
7.	Total Long Term Debt Balance (Net Proceeds) [From Pg. 1, Ln. 13, above]	-
8.	**Embedded Cost of Long Term Debt [Line 6/Line 7]** [To ATT 6, Pg. 1, Ln. 1, Col. C]	**#DIV/0!**

ATTACHMENT 2

FORMULA RATE PROTOCOLS

NorthWestern Corporation (South Dakota)
Formula Rate Protocols

NorthWestern Corporation d/b/a NorthWestern Energy's Formula Rate Template and these Formula Rate Protocols together compose NorthWestern Energy's filed rate ("**Formula Rate**") for transmission service in the Upper Missouri Zone ("**UMZ**") of the Southwest Power Pool, Inc. ("**SPP**") footprint. NorthWestern Energy must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("**ATRR**").

The Formula Rate applies to service on and after April 1 of each calendar year through March 31 of the following calendar year ("**Rate Year**"). On or before March 1 of each year, NorthWestern Energy will recalculate the ATRR for the upcoming Rate Year in accordance with the Formula Rate ("**Annual Update**"). These Protocols outline the procedures for notice and review of, and challenges to, NorthWestern Energy's Annual Update.

If the deadline for any requirement in these Protocols falls on a Saturday, Sunday, or legal holiday, the requirement will be due the next business day.

I. Annual Update – Publication, Meetings, and Notice Requirements

A. Publication

1. On or before March 1, NorthWestern Energy will provide its Annual Update to SPP, and SPP will post the Annual Update on its website and on OASIS. The date on which such posting occurs is that year's "**Publication Date**."

2. Within 7 days of the Publication Date, NorthWestern Energy will provide notice of the posting to the e-mail distribution list discussed in Paragraph I.C.

3. Any delay in the Publication Date will result in an equivalent extension of time for subsequent deadlines.

B. Annual Meeting

1. Each year, NorthWestern Energy will host an open meeting no sooner than 30 days after the Publication Date and no later than June 1 ("**Annual Meeting**"). NorthWestern Energy will provide remote access to the Annual Meeting for Interested Parties (as defined in Paragraph I.C) who are unable to travel to the meeting location.

2. The Annual Meeting will permit NorthWestern Energy to explain and clarify its Annual Update and provide Interested Parties an opportunity to seek information and clarifications from NorthWestern Energy about the Annual Update.

3. At least 7 days before the Annual Meeting, NorthWestern Energy will provide notice of the time, date, location, and remote access instructions for the Annual Meeting through a posting on SPP's website and OASIS and via the e-mail distribution list.

C. NorthWestern Energy will maintain an e-mail distribution list for providing notice as required by these Protocols. Interested Parties may contact NorthWestern Energy to request to be added to the e-mail distribution list. "**Interested Parties**" include but are not limited to customers under the SPP tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

D. Joint Informational Meeting

1. NorthWestern Energy will endeavor to coordinate with other transmission owners using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

2. Notice of any Joint Informational Meeting will be provided at least 7 days before the meeting through a posting on SPP's website and OASIS and via the e-mail distribution list. The notice will include the time, date, location, and remote access instructions for the meeting.

3. Any Joint Informational Meetings will be held on or before August 1 of each year.

II. Annual Update - Contents

A. The Annual Update for the Rate Year will include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact.

B. To the extent specified in the Formula Rate, the Annual Update will be based upon NorthWestern Energy's FERC Form No. 1 for the most recent calendar year and, to the extent specified in the Formula Rate, upon the books and records of NorthWestern Energy consistent with FERC accounting regulations, policies, and practices.

C. The Annual Update will provide sufficiently detailed workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1.

D. The Annual Update will provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the FERC Form No. 1.

E. The Annual Update will identify any changes in the formula references (page and line numbers) to the FERC Form No. 1.

F. The Annual Update will identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1, and any adjustments not shown in the FERC Form No. 1.

G. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("**Accounting Change**"), the Annual Update will:

1. Identify any Accounting Changes, including:

    a. The initial implementation of an accounting standard or policy;

    b. The initial implementation of accounting practices for unusual or unconventional items where the Federal Energy Regulatory Commission ("FERC") has not provided specific accounting direction;

    c. Correction of errors and prior period adjustments that impact the revenue requirement;

    d. The implementation of new estimation methods or policies that change prior estimates; and

    e. Changes to income tax elections.

2. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

3. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction on inputs to the Formula Rate; and

4. For each Accounting Change identified pursuant to this section, provide a narrative explanation of the individual impact of such change on charges billed under the Formula Rate.

H. The Annual Update will not seek to modify the Formula Rate.

III. Information Exchange Procedures

Each Annual Update will be subject to the following Information Exchange Procedures.

A. Interested Parties will have until September 1 following the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to serve reasonable information and document requests on NorthWestern Energy ("**Information Exchange Period**"). The scope of such information and document requests is be limited to what is necessary to determine:

1. The extent, effect, or impact of an Accounting Change;

2. Whether the Annual Update 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 changes shown in the Annual Update;

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; 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 may not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. NorthWestern Energy must make a good-faith effort to respond to information and document requests pertaining to the Annual Update within 15 business days of receiving such requests. Information and document requests received after 4:00 P.M. Central Prevailing Time will be considered received the next business day. NorthWestern Energy will respond to all information and document requests by no later than October 1 following the Publication Date, unless the Information Exchange Period is extended by NorthWestern Energy or by FERC.

C. NorthWestern Energy will cause to be posted on SPP's website and OASIS all information and document requests from Interested Parties and NorthWestern Energy's response to such requests, unless the responses include material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made available to a requesting party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the requesting party.

D. NorthWestern Energy may 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 NorthWestern Energy's Annual Update.

IV. Challenge Procedures

A. A challenge must be limited to issues that may be necessary to determine (1) the extent, effect, or impact of an Accounting Change; (2) whether the Annual Update 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 changes shown in the Annual Update; (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; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

B. Informal Challenge

1. Interested Parties will have until October 31 after the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify NorthWestern Energy in writing, which notice may be made electronically, of any specific Informal Challenge. The period of time from the Publication Date until October 31 is the "**Review Period**."

2. Failure to pursue an issue through an Informal Challenge will not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update, as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update, but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

3. A party submitting an Informal Challenge to NorthWestern Energy must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects and must provide an appropriate explanation and documents to support its challenge.

4. NorthWestern Energy must make a good-faith effort to respond to any Informal Challenge within 20 business days of notice of such challenge. NorthWestern Energy will appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of

the challenge. If NorthWestern Energy disagrees with such challenge, NorthWestern Energy will provide the Interested Party with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Informal Challenge may be submitted after October 31, and NorthWestern Energy must respond to all Informal Challenges by no later than November 30, unless the Review Period is extended by NorthWestern Energy or by FERC.

6. Informal Challenges are subject to the resolution procedures and limitations in this Section IV.

7. NorthWestern Energy will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and NorthWestern Energy's response to such Informal Challenges, unless a challenge or the response includes material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made available to the challenging party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the challenging party.

8. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by NorthWestern Energy will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

C. Formal Challenge

1. A Formal Challenge must satisfy all of the following requirements:

   a. A Formal Challenge must clearly identify the action or inaction which is alleged to violate the Formula Rate.

   b. A Formal Challenge must explain how the action or inaction violates the Formula Rate.

   c. A Formal Challenge must set forth the business, commercial, economic, or other issues presented by the action or inaction as such relates to or affects the party filing the Formal Challenge, including:

      i. The extent or effect of an Accounting Change;

      ii. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

      iii. The proper application of the Formula Rate;

iv. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

v. The prudence of actual costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

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

d. A Formal Challenge must 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. A Formal Challenge must state whether the issues presented are pending in an existing FERC 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. A Formal Challenge must state the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.

g. A Formal Challenge must 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.

h. A Formal Challenge must 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. An Interested Party will have until January 15 following the Review Period (unless such date is extended with the written consent of NorthWestern Energy to continue efforts to resolve an Informal Challenge) to file a Formal Challenge with FERC. A Formal Challenge must be filed in the same docket as NorthWestern Energy's Informational Filing discussed in Section VI, below.

3. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on NorthWestern Energy. Service to NorthWestern Energy must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge must serve the

individual listed as the contact person on NorthWestern Energy's Informational Filing discussed in Section VI, below.

4. NorthWestern Energy must respond to the Formal Challenge by the deadline established by FERC, unless an extension is granted by FERC.

5. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

6. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or the FERC Form No. 1 must first raise the matter with NorthWestern Energy before pursuing a Formal Challenge.

7. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, NorthWestern Energy bears the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Except as specifically provided herein, nothing in these Protocols limits NorthWestern Energy's right to file unilaterally, pursuant to Federal Power Act Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, 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.

E. No party may seek to modify the Formula Rate under these Challenge Procedures, and the Annual Update is not 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.

V. Changes to Annual Update

A. If NorthWestern Energy files any corrections to correct a Mistake in its FERC Form No. 1 during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges will be reflected in the Annual Update for the next effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a ("**FERC's Interest Rate**"). For purposes of these Protocols, "**Mistake**" means errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or other inadvertent computational errors, erroneous Form No. 1 references, or the like. Mistakes do not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous FERC Form No. 1 references in the Formula Rate Template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or NorthWestern Energy to notify the other party of any mistake in any FERC Form No. 1 data or specific data applied in the Formula Rate Template.

B. Any changes to the data inputs, including but not limited to revisions to NorthWestern Energy's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, will be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism will apply in lieu of mid-Rate Year adjustments. Interest on any refund will be calculated in accordance with FERC's Interest Rate, and interest on any surcharge will be calculated using the lower of FERC's Interest Rate or NorthWestern Energy's short-term borrowing rate, if applicable.

VI. Informational Filing

A. By December 15 of each year, NorthWestern Energy will submit to FERC an informational filing of its Annual Update ("**Informational Filing**"), which will be filed in a new docket each year. This Informational Filing will 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 NorthWestern Energy has properly applied the Formula Rate; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of Accounting Changes that affect Formula Rate inputs. The Informational Filing will also describe any corrections or adjustments made during the Review Period, and will note any aspects of the Formula Rate or its inputs that are subject to an ongoing dispute under the Challenge Procedures.

B. Within 5 days of such Informational Filing, NorthWestern Energy will provide notice of the Informational Filing via the e-mail distribution list and by posting the docket number assigned to NorthWestern Energy's Informational Filing on SPP's website and OASIS.

C. Any challenges to the implementation of NorthWestern Energy's Formula Rate must be made through the Challenge Procedures described in Section IV, above, or in a separate complaint proceeding, and not in response to the Informational Filing.

ATTACHMENT 3

DIRECT TESTIMONY AND EXHIBITS OF MICHAEL R. CASHELL

Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation	**)**	**Docket No. ER15-___-000**

PREPARED DIRECT TESTIMONY
OF
MICHAEL R. CASHELL

ON BEHALF OF

NORTHWESTERN CORPORATION

June 29, 2015

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael R. Cashell. My business address is 40 East Broadway, Butte, Montana 59701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by NorthWestern Corporation ("NorthWestern"), and I am its Vice President - Transmission.

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

A. I am testifying on behalf of the South Dakota operations of NorthWestern, which is a FERC-jurisdictional public utility that intends to join the Southwest Power Pool, Inc. ("SPP") regional transmission organization.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the Montana Tech of the University of Montana in Butte, Montana, receiving a Bachelor of Science in Engineering Science in 1986. I also attended the University of Idaho's Utility Executive Course in 1997. I have been certified as a North American Electric Reliability Corporation ("NERC") System Operator. I have worked in the electric and natural gas utility industry for over 28 years, employed first by The Montana Power Company ("MPC") and now by NorthWestern. My experience is primarily in the areas of transmission operations and maintenance, substation operations and maintenance, balancing authority area operation, tariff and contract administration, bulk power supply and operations, hydroelectric and thermal electric generation plant optimization, and independent power production.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT – TRANSMISSION?

A. I am responsible for all aspects of NorthWestern's electric and natural gas transmission systems and substations in Montana and South Dakota, including the systems' safe, reliable, and efficient operation, transmission services, operations, planning, engineering, and maintenance. I am also responsible for the activities related to transmission and transportation contracts, interconnection agreements, and transmission service under NorthWestern's Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT") for our wholesale and retail customers. I am also responsible for transmission related compliance activities, including Western Electricity Coordinating Council ("WECC") criteria in Montana and Midwest Reliability Organization ("MRO") criteria in South Dakota.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes. I have testified before the Montana Public Service Commission ("MPSC"), the South Dakota Public Utilities Commission ("SDPUC"), and FERC.

II. PURPOSE AND EXHIBITS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to: (1) provide the background for the filing and an overview of NorthWestern's plans to join SPP; (2) provide an overview of NorthWestern's formula rate and initial Annual Transmission Revenue Requirement ("ATRR") filing in this proceeding; (3) describe NorthWestern's transmission facilities, the costs of which will be recovered through the formula rate under the SPP OATT; and (4) describe the formula rate protocols that will accompany the formula rate template and will be incorporated into the SPP OATT.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring three Exhibits. Exhibit MRC-1 is a map showing NorthWestern's South Dakota transmission system. Exhibit MRC-2 is a list of the NorthWestern transmission assets in South Dakota that SPP will functionally control under the SPP OATT. Exhibit MRC-3 is a copy of NorthWestern's formula rate protocols that will accompany its formula rate template and will be incorporated into the SPP OATT.

III. BACKGROUND

Q. PLEASE DESCRIBE NORTHWESTERN AND NORTHWESTERN'S TRANSMISSION SYSTEM IN SOUTH DAKOTA.

A. NorthWestern Energy is a public utility engaged in the generation, transmission, and distribution of electricity and the supply and transportation of natural gas. Its facilities are located primarily in Montana and South Dakota. NorthWestern Energy's Montana and South Dakota electric transmission facilities are not physically connected and are not in the same electric reliability region. As a result, NorthWestern Energy maintains separate OATTs, each approved by FERC, for transmission operations in each state. This filing concerns only NorthWestern Energy's South Dakota operations and OATT.

Q. PLEASE PROVIDE AN OVERVIEW OF THE SOUTH DAKOTA ELECTRIC TRANSMISSION OPERATIONS.

A. The South Dakota Electric Transmission System Map is shown as Exhibit MRC-1. The transmission system spans from north of the Aberdeen area at Ellendale, North Dakota, where the 115-kV system interconnects with Montana-Dakota Utilities ("MDU") and Otter Tail Power Company, south approximately 260 miles to Yankton, South Dakota, where the 115-kV system interconnects with Western Area Power Administration – Upper Great Plains Region ("WAPA") at Gavins Point Dam. In addition, there are approximately 76 miles of 115-kV lines that represent interties off the 115-kV mainline at the following locations: Aberdeen to Groton (interconnection with WAPA), Huron to Broadland (interconnection with WAPA), Mitchell to the McCook County Line (interconnection with Northern States Power Company (d/b/a Xcel Energy)), and Mitchell to Letcher Substation (interconnection with WAPA).

In addition, there are 69-kV and 34.5-kV facilities that serve as the main transmission in and around the major load centers. There is also a 34.5-kV facility that travels north-south from Aberdeen to Yankton and, in many places, in the same right-of-way as the 115-kV system.

Q. HOW IS NORTHWESTERN'S TRANSMISSION SYSTEM OPERATED?

A. NorthWestern has a Control Center in Huron from which NorthWestern operates, monitors, and controls the transmission system at 69 kV and below as well as some of the distribution system. WAPA operates, monitors, and controls the 115-kV facilities.

Q. HOW IS THE NORTHWESTERN TRANSMISSION SYSTEM DESIGNED?

A. In general, NorthWestern's transmission system has been developed over time to accomplish the following: (1) import generation from remote, jointly-owned coal-fired projects to the system; (2) connect major load centers in various operating areas—the Aberdeen Area, Huron Area, Mitchell Area, and Yankton Area; and (3) provide 69-kV and 34.5-kV "loops" through each of the operating areas. The system is designed to provide, where feasible, more than one transmission feed to each operating area in order to maintain high levels of reliability. In many cases, the transmission system has "emergency service" interconnections for areas that are served with radial feeds. These emergency services are not used for normal operations due primarily to the higher cost of energy from those sources. They do, however, provide access to other sources for reliability purposes under abnormal operating conditions.

Q. WHAT IS NORTHWESTERN'S OPERATIONAL RELATIONSHIP WITH WAPA?

A. The NorthWestern transmission system is located within WAPA's Balancing Authority Area. WAPA, through its Network Integration Transmission Service Agreement ("NITSA") with NorthWestern, provides important integration of NorthWestern's generation and transmission facilities as well as the provision of certain ancillary services required to provide reliable service to customers. NorthWestern has received notice from

WAPA to terminate the NITSA as part of WAPA's (and NorthWestern's) transition to SPP. The NITSA termination is expected to be effective October 1, 2015. After termination of the NITSA with WAPA, NorthWestern anticipates taking similar service from SPP.

Q. PLEASE DESCRIBE THE INTEGRATED SYSTEM ("IS") AND HOW NORTHWESTERN'S TRANSMISSION CUSTOMERS USE THE IS.

A. The IS is an electric transmission system located in the WAPA Upper Great Plains Region. The IS comprises about 10,000 miles of transmission lines owned by WAPA, Basin Electric Power Cooperative ("Basin"), and Heartland Consumers Power District ("Heartland"). NorthWestern pays WAPA network transmission fees on a monthly basis, based on NorthWestern's load ratio share of demand on the IS. In turn, the NorthWestern revenue requirement for its 115-kV facilities is treated as a "facility credit" by WAPA and credited to NorthWestern on a pro rata monthly basis on the monthly network transmission invoice. WAPA also provides various transmission services for NorthWestern, including transmission operation and maintenance ("O&M"), area balancing, ancillary services, and scheduling. The Mid-Continent Area Power Pool ("MAPP") serves as the regional transmission planning organization, the reliability planning coordinator, and the transmission services coordinator.

Q. WHY HAS NORTHWESTERN DECIDED TO JOIN SPP?

A. There are two primary reasons. First, the IS migration to SPP is a major factor in NorthWestern's decision to join SPP. NorthWestern's transmission system has fourteen interconnections with other transmission entities that provide delivery of capacity and energy, as well as system stability. Of the fourteen NorthWestern transmission interconnections, ten are within the IS. NorthWestern's reliability, access to markets, ancillary services, and power delivery are heavily tied to the IS.

Second, FERC Order No. 1000 also influenced NorthWestern's decision to join SPP. FERC Order No. 1000 reformed FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. The transmission planning component requires NorthWestern to join a regional planning group that satisfies certain identified criteria. It also requires that NorthWestern coordinate through this regional group with an even larger group of neighboring utilities at an inter-regional level. With respect to cost allocation, Order No. 1000 requires that the regional planning entity that NorthWestern participates in have a process for allocating the costs of new transmission facilities. The current arrangements for planning and cost allocation with WAPA and MAPP do not qualify as compliant with the requirements of FERC Order No. 1000. In addition, MAPP plans to dissolve once the IS migrates to SPP on October 1, 2015.

Q. HOW DOES JOINING SPP IMPACT NORTHWESTERN'S ARRANGEMENTS WITH MAPP AND WAPA?

A. When NorthWestern transfers control of its transmission system to SPP, its membership in MAPP will automatically terminate under the terms of the MAPP Agreement. All of the services currently provided by MAPP will be conducted by SPP. Services provided to NorthWestern by WAPA will be diminished considerably. NorthWestern will be subject to the SPP OATT including charges and revenue as part of the services offered. SPP will be the Balancing Authority for the area and provide ancillary services in accordance with its OATT. NorthWestern will still have transmission O&M agreements with WAPA; however, NorthWestern will be responsible for scheduling and settlement of its resources.

Q. PLEASE DESCRIBE NORTHWESTERN'S FUTURE RELATIONSHIP WITH SPP.

A. With WAPA, Basin, and Heartland joining SPP, the IS will become the Upper Missouri Zone ("UMZ") (Zone 19) in SPP. SPP will be the transmission provider for the UMZ and will invoice and collect the UMZ transmission rates. NorthWestern will continue to pay a load ratio share of the IS revenue requirement, but will pay these network transmission charges to SPP under Schedule 9 of the SPP OATT.

As a member of SPP, NorthWestern will become a transmission owner ("TO") in SPP. SPP will determine network transmission rates for the UMZ by combining the transmission revenue requirement for each of the TOs with facilities in the UMZ. Each UMZ TO (e.g., WAPA, Basin, Heartland, and NorthWestern) will develop its transmission revenue requirement individually under rates that will be included in Attachment H (Annual Transmission Revenue Requirement for Network Integration Transmission Service) to the SPP OATT. SPP will collect the revenue from network transmission services provided in the UMZ, and then distribute these revenues to the TOs based on each TO's share of the UMZ revenue requirement. SPP will also allocate through-and-out transmission service within the UMZ and other zones in SPP to SPP TOs according to the SPP OATT rules. Therefore, rather than receiving a facility credit deduction on its monthly network transmission service invoice as is done today, as part of SPP, NorthWestern will be invoiced the full monthly network transmission service and will receive a separate monthly distribution credit to recover the revenue requirement associated with the NorthWestern transmission facilities included under the SPP OATT.

Q. WHEN WILL NORTHWESTERN TRANSFER FUNCTIONAL CONTROL OF ITS TRANSMISSION FACILITIES TO SPP?

A. NorthWestern expects this to occur on October 1, 2015.

IV. <u>OVERVIEW OF THIS FILING</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THIS FILING.

A. In this filing, NorthWestern seeks FERC approval of the formula rate template and protocols that NorthWestern will use to develop its ATRR to be recovered under the SPP OATT. NorthWestern is also requesting approval of the initial ATRR for NorthWestern that SPP will use in developing rates for the new UMZ joint pricing zone (Zone 19). In addition to my testimony, NorthWestern is also submitting testimony from Kendall G. Kliewer and Adrien M. McKenzie. Mr. Kliewer testifies about the formula rate template, the calculation of the initial ATRR, and the impact on customers. Mr. McKenzie supports the fixed return-on-equity ("ROE") component in the formula rate template.

In addition, SPP will file for approval of a new joint pricing zone under the SPP OATT—the UMZ zone or Zone 19—that includes NorthWestern and the non-jurisdictional owners of the IS. SPP's filing will provide support for the initial ATRR of the non-jurisdictional entities in Zone 19 and will seek approval of the SPP OATT revisions necessary to create the new joint pricing zone. SPP's filing will include the SPP OATT revisions that incorporate NorthWestern's formula rate template and protocols into the SPP OATT.

V. TRANSMISSION ASSETS INCLUDED IN THE FORMULA RATE

Q. WHAT TRANSMISSION ASSETS WILL NORTHWESTERN TRANSFER FUNCTIONAL CONTROL OF TO SPP AND INCLUDE IN COST RECOVERY UNDER THE FORMULA RATE?

A. As noted in more detail below, NorthWestern will transfer to SPP functional control of most of NorthWestern's 115-kV transmission assets located in South Dakota and certain 69-kV transmission assets that satisfy the test for Transmission Facilities under Attachment AI of the SPP OATT.

Q. WHAT NORTHWESTERN FACILITIES WILL BE INCLUDED UNDER THE SPP OATT?

A. Most of the 115-kV facilities will be included, with the exception of a radial line in Aberdeen and a radial line in Yankton. All of NorthWestern's 69-kV facilities are radial; therefore, only 69-kV facilities that serve more than one transmission customer, including NorthWestern, will be included. Exhibit MRC-1 is a map showing these proposed facilities generally, and Exhibit MRC-2 is a table listing the transmission segments and voltage level of the transmission facilities to be included under the SPP OATT. As Exhibit MRC-2 shows, there are 333.64 miles of 115-kV and 180.10 miles of 69-kV facilities (for a total of 513.74 miles) that NorthWestern proposes to transfer to SPP.

Q. DO THESE ASSETS MEET THE CRITERIA FOR INCLUSION IN THE TRANSMISSION SYSTEM UNDER THE SPP OATT?

A. Yes. Under Attachment AI of the SPP OATT, a Transmission Facility is a facility that is included as part of the SPP Transmission System that meets any of the following criteria:

1. All existing non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other. Rate treatment for transmission upgrades completed after October 1, 2005, will be determined pursuant to Attachment J the SPP OATT. For the purpose of the application of this criterion, “open loops” are radial lines. Additionally, at such time an existing radial is incorporated into a looped transmission circuit, that existing radial would be eligible for inclusion in rates on the same basis as the remainder of the facilities in the loop.
2. Facilities that are utilized for interconnecting the various internal Zones to each other as well as those facilities that interconnect the SPP Transmission System with other surrounding entities.
3. Control equipment and facilities necessary to control and protect a facility qualifying as a Transmission Facility.
4. For a substation connected to the Transmission System, where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV, the facilities on the high voltage side of the transformer will be included with the exception of transformer isolation equipment.
5. The portion of the direct-current interconnections with areas outside of the SPP Region (DC ties) that are owned by a Transmission Owner in the SPP Region, including those portions of the DC tie that operate at a voltage lower than 60 kV.

6. All facilities operated below 60 kV that have been determined to be transmission pursuant to the seven (7) factor test set forth in FERC Order No. 888, 61 Fed. Reg. 21,540, 21,620 (1996), or any applicable successor test.

All of the facilities that NorthWestern will transfer to SPP qualify as Transmission Facilities under Section 1 of this definition. The 115-kV facilities qualify as “non-radial power lines, substations, and associated facilities, operated at 60 kV or above,” and the 69-kV facilities qualify as “all radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other.” Before making this filing, NorthWestern reviewed these facilities with SPP staff, and they concurred that these facilities are appropriately included under the SPP OATT.

Q. HOW DO FACILITIES INCLUDED UNDER THE SPP OATT DIFFER FROM THOSE INCLUDED IN THE IS AND ADMINISTERED UNDER THE WAPA OATT?

A. NorthWestern’s 115-kV facilities that will be included under the SPP OATT were also included in the IS and administered under the WAPA OATT. The IS did not include any of the 69kV facilities that will be transferred to SPP and that qualify as Transmission Facilities under Attachment AI of the SPP OATT.

VI. <u>FORMULA RATE PROTOCOLS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF NORTHWESTERN’S FORMULA RATE PROTOCOLS AND EXPLAIN HOW THEY WERE DEVELOPED.

A. The protocols describe the procedures applicable to the annual update of the formula rate and the informational filing of the annual update with the Commission; describe how the annual update will be implemented; and provide a mechanism for parties to review and obtain information about the annual update, and present formal and informal challenges to the annual update. In developing the protocols, NorthWestern has considered the Commission's requirements relating to: (1) scope of participation; (2) transparency of the information exchange; and (3) the ability of customers to present challenges, which the Commission addressed in its investigation of the formula rate protocols in the Midcontinent Independent System Operator, Inc. ("MISO") tariff. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,127 (2012), *order on investigation*, 143 FERC ¶ 61,149 (2013), *order on reh'g*, 146 FERC ¶ 61,209, *order on compliance filing*, 146 FERC ¶ 61,212 (2014) ("*MISO*"). NorthWestern's protocols are based on the protocols for the historic formula rate under the MISO tariff, which protocols were revised in the *MISO* proceeding, and on the protocols accompanying Empire District Electric Company's ("Empire") historic formula rate, which were filed by Empire in Docket No. ER14-2882-000. In developing these protocols, NorthWestern specifically has considered the guidance provided by the Commission in its March 19, 2015 order in *The Empire District Electric Co.*, 150 FERC ¶ 61,200 (2015). NorthWestern's protocols are attached as Exhibit MRC-3.

Q. PLEASE BRIEFLY DESCRIBE THE PROTOCOLS.

A. NorthWestern's protocols establish a Rate Year of April 1 through March 31. Because NorthWestern is seeking an effective date of October 1, 2015, for its formula rate, the initial Rate Year will be from October 1, 2015, through March 31, 2016. The protocols require NorthWestern to develop and post on the SPP website and OASIS its Annual Update by March 1 each year. The Annual Update will include a workable-data populated formula rate template and underlying workpapers, and will provide other information specified in Section II of the protocols.

The protocols require NorthWestern to hold an open meeting with Interested Parties to explain and clarify the Annual Update by June 1 of each year. Interested Parties will then have until September 1 to obtain information about the Annual Update in accordance with the Informational Exchange Procedures in Section III of the protocols. Interested Parties will also have the opportunity to submit Informal and Formal Challenges to the Annual Update in accordance with Section IV. Section V provides that any change to the Annual Update—in response to Formal or Informal Challenges or to a complaint or to correct a Mistake in the Annual Update—will be incorporated into the Annual Update for the following Rate Year, with interest. Finally, consistent with the Commission's requirements, Section VI provides that NorthWestern will submit to the Commission an Informational Filing of its Annual Update by December 15 each year.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation) **Docket No. ER15-___-000**

AFFIDAVIT

I, the undersigned, being duly sworn, depose and state, that the above and foregoing Prepared Testimony of Michael R. Cashell is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate and complete.

Michael R. Cashell

Michael R. Cashell

Subscribed and sworn to before me this
29th day of June, 2015, by Michael R. Cashell.

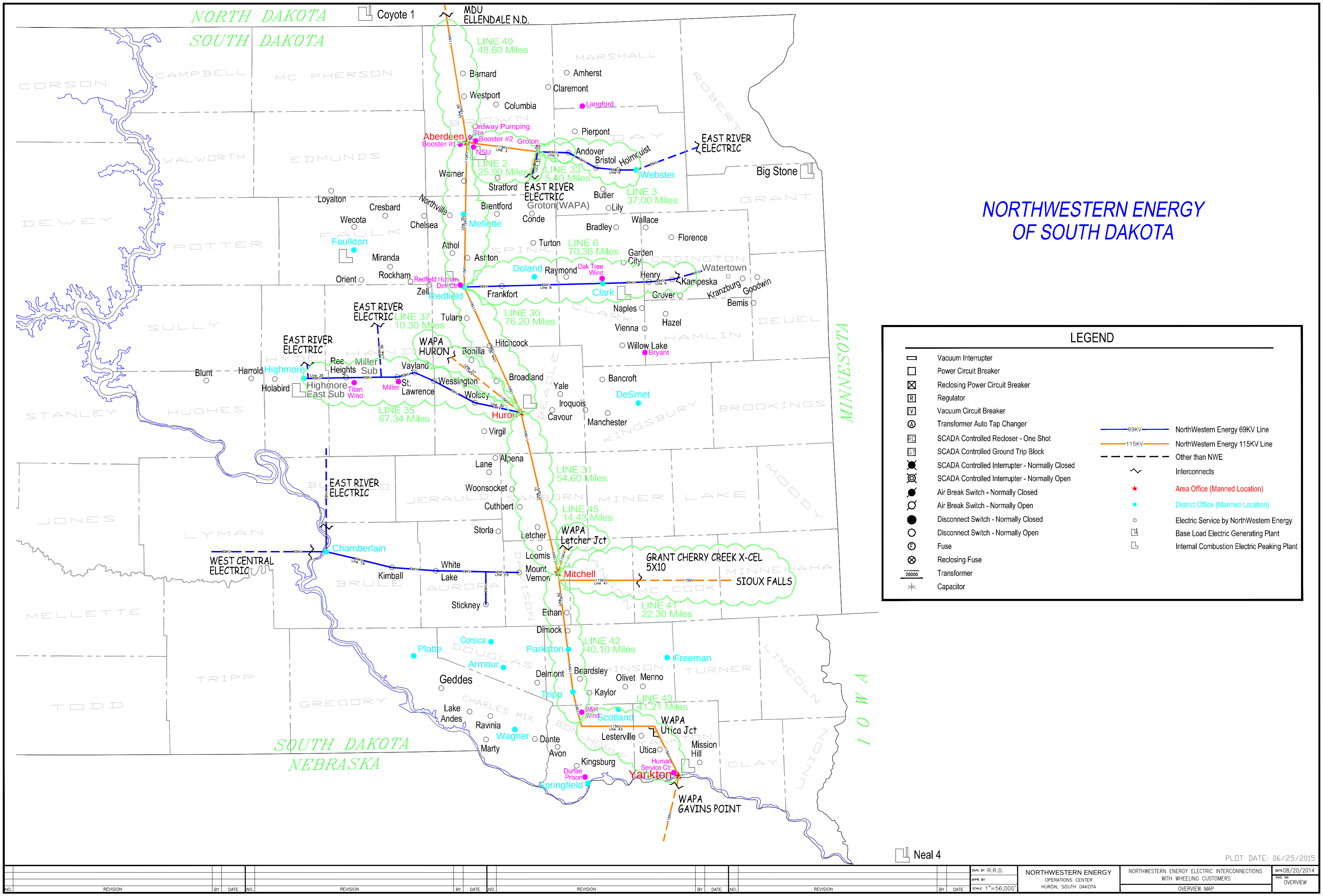
My Commission expires: August 16, 2016

Mary Kissell

Notary Public for the State of Montana
Residing at: Butte

MARY KISSELL
NOTARY PUBLIC for the
State of Montana
Residing at Butte, Montana
My Commission Expires
August 16, 2016

Exhibit No. MRC-1



NorthWestern Energy Transmission Assets
to be placed under the Southwest Power Pool OATT

Line No.	From	To	Voltage	Pole Miles	Miles in SPP
2	Aberdeen Siebrecht Sub 30C	Groton WAPA Sub 2A	115 kV	25.90	25.90
30	Aberdeen Siebrecht Sub 30C	Huron West Park Sub 30D	115 kV	76.20	76.20
31	Huron West Park Sub 30D	Mitchell Sub 31B	115 kV	54.60	54.60
37	Huron West Park Sub 30D	Broadland WAPA Sub 30B	115 kV	10.30	10.30
40	Aberdeen Siebrecht Sub 30C	Ellendale, ND Sub, Spur to Aberdeen City Sub 40B	115 kV	48.60	48.60
41	Mitchell Sub 31A	McCook County Line-NSP Tie	115 kV	22.30	22.30
42	Mitchell Sub 31A	Tripp Jct. Sub 42A	115 kV	40.10	40.10
43	Tripp Jct. Sub 42A	Yankton Jct. Sub 43A	115 kV	41.21	41.21
45	Mitchell Sub 31A	Letcher Jct. Sub (WAPA owned)	115 kV	14.43	14.43
	Total 115 kV				**333.64**
3	Groton Sub 3C	Webster Sub 3B	69 kV	37.00	37.00
6	Redfield Sub 30A	Kampeska Sub 6A	69 kV	70.36	70.36
33	Groton Sub 3C	Groton WAPA Sub 2A	69 kV	5.40	5.40
35	Huron West Park Sub 30D	Highmore Sub 35C	69 kV	67.34	67.34
	Total 69 kV				**180.10**
	Grand Total				**513.74**

NorthWestern Corporation (South Dakota)
Formula Rate Protocols

NorthWestern Corporation d/b/a NorthWestern Energy's Formula Rate Template and these Formula Rate Protocols together compose NorthWestern Energy's filed rate ("**Formula Rate**") for transmission service in the Upper Missouri Zone ("**UMZ**") of the Southwest Power Pool, Inc. ("**SPP**") footprint. NorthWestern Energy must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("**ATRR**").

The Formula Rate applies to service on and after April 1 of each calendar year through March 31 of the following calendar year ("**Rate Year**"). On or before March 1 of each year, NorthWestern Energy will recalculate the ATRR for the upcoming Rate Year in accordance with the Formula Rate ("**Annual Update**"). These Protocols outline the procedures for notice and review of, and challenges to, NorthWestern Energy's Annual Update.

If the deadline for any requirement in these Protocols falls on a Saturday, Sunday, or legal holiday, the requirement will be due the next business day.

I. Annual Update – Publication, Meetings, and Notice Requirements

A. Publication

1. On or before March 1, NorthWestern Energy will provide its Annual Update to SPP, and SPP will post the Annual Update on its website and on OASIS. The date on which such posting occurs is that year's "**Publication Date**."

2. Within 7 days of the Publication Date, NorthWestern Energy will provide notice of the posting to the e-mail distribution list discussed in Paragraph I.C.

3. Any delay in the Publication Date will result in an equivalent extension of time for subsequent deadlines.

B. Annual Meeting

1. Each year, NorthWestern Energy will host an open meeting no sooner than 30 days after the Publication Date and no later than June 1 ("**Annual Meeting**"). NorthWestern Energy will provide remote access to the Annual Meeting for Interested Parties (as defined in Paragraph I.C) who are unable to travel to the meeting location.

2. The Annual Meeting will permit NorthWestern Energy to explain and clarify its Annual Update and provide Interested Parties an opportunity to seek information and clarifications from NorthWestern Energy about the Annual Update.

3. At least 7 days before the Annual Meeting, NorthWestern Energy will provide notice of the time, date, location, and remote access instructions for the Annual Meeting through a posting on SPP's website and OASIS and via the e-mail distribution list.

C. NorthWestern Energy will maintain an e-mail distribution list for providing notice as required by these Protocols. Interested Parties may contact NorthWestern Energy to request to be added to the e-mail distribution list. "**Interested Parties**" include but are not limited to customers under the SPP tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

D. Joint Informational Meeting

1. NorthWestern Energy will endeavor to coordinate with other transmission owners using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

2. Notice of any Joint Informational Meeting will be provided at least 7 days before the meeting through a posting on SPP's website and OASIS and via the e-mail distribution list. The notice will include the time, date, location, and remote access instructions for the meeting.

3. Any Joint Informational Meetings will be held on or before August 1 of each year.

II. Annual Update - Contents

A. The Annual Update for the Rate Year will include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact.

B. To the extent specified in the Formula Rate, the Annual Update will be based upon NorthWestern Energy's FERC Form No. 1 for the most recent calendar year and, to the extent specified in the Formula Rate, upon the books and records of NorthWestern Energy consistent with FERC accounting regulations, policies, and practices.

C. The Annual Update will provide sufficiently detailed workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1.

D. The Annual Update will provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the FERC Form No. 1.

E. The Annual Update will identify any changes in the formula references (page and line numbers) to the FERC Form No. 1.

F. The Annual Update will identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1, and any adjustments not shown in the FERC Form No. 1.

G. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("**Accounting Change**"), the Annual Update will:

1. Identify any Accounting Changes, including:

   a. The initial implementation of an accounting standard or policy;

   b. The initial implementation of accounting practices for unusual or unconventional items where the Federal Energy Regulatory Commission ("FERC") has not provided specific accounting direction;

   c. Correction of errors and prior period adjustments that impact the revenue requirement;

   d. The implementation of new estimation methods or policies that change prior estimates; and

   e. Changes to income tax elections.

2. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

3. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction on inputs to the Formula Rate; and

4. For each Accounting Change identified pursuant to this section, provide a narrative explanation of the individual impact of such change on charges billed under the Formula Rate.

H. The Annual Update will not seek to modify the Formula Rate.

III. Information Exchange Procedures

Each Annual Update will be subject to the following Information Exchange Procedures.

A. Interested Parties will have until September 1 following the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to serve reasonable information and document requests on NorthWestern Energy ("**Information Exchange Period**"). The scope of such information and document requests is be limited to what is necessary to determine:

1. The extent, effect, or impact of an Accounting Change;

2. Whether the Annual Update 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 changes shown in the Annual Update;

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; 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 may not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. NorthWestern Energy must make a good-faith effort to respond to information and document requests pertaining to the Annual Update within 15 business days of receiving such requests. Information and document requests received after 4:00 P.M. Central Prevailing Time will be considered received the next business day. NorthWestern Energy will respond to all information and document requests by no later than October 1 following the Publication Date, unless the Information Exchange Period is extended by NorthWestern Energy or by FERC.

C. NorthWestern Energy will cause to be posted on SPP's website and OASIS all information and document requests from Interested Parties and NorthWestern Energy's response to such requests, unless the responses include material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made available to a requesting party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the requesting party.

D. NorthWestern Energy may 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 NorthWestern Energy's Annual Update.

IV. Challenge Procedures

A. A challenge must be limited to issues that may be necessary to determine (1) the extent, effect, or impact of an Accounting Change; (2) whether the Annual Update 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 changes shown in the Annual Update; (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; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

B. Informal Challenge

1. Interested Parties will have until October 31 after the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify NorthWestern Energy in writing, which notice may be made electronically, of any specific Informal Challenge. The period of time from the Publication Date until October 31 is the "**Review Period**."

2. Failure to pursue an issue through an Informal Challenge will not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update, as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update, but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

3. A party submitting an Informal Challenge to NorthWestern Energy must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects and must provide an appropriate explanation and documents to support its challenge.

4. NorthWestern Energy must make a good-faith effort to respond to any Informal Challenge within 20 business days of notice of such challenge. NorthWestern Energy will appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of

the challenge. If NorthWestern Energy disagrees with such challenge, NorthWestern Energy will provide the Interested Party with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Informal Challenge may be submitted after October 31, and NorthWestern Energy must respond to all Informal Challenges by no later than November 30, unless the Review Period is extended by NorthWestern Energy or by FERC.

6. Informal Challenges are subject to the resolution procedures and limitations in this Section IV.

7. NorthWestern Energy will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and NorthWestern Energy's response to such Informal Challenges, unless a challenge or the response includes material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made available to the challenging party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the challenging party.

8. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by NorthWestern Energy will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

C. Formal Challenge

1. A Formal Challenge must satisfy all of the following requirements:

    a. A Formal Challenge must clearly identify the action or inaction which is alleged to violate the Formula Rate.

    b. A Formal Challenge must explain how the action or inaction violates the Formula Rate.

    c. A Formal Challenge must set forth the business, commercial, economic, or other issues presented by the action or inaction as such relates to or affects the party filing the Formal Challenge, including:

        i. The extent or effect of an Accounting Change;

        ii. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

        iii. The proper application of the Formula Rate;

iv. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

v. The prudence of actual costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

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

d. A Formal Challenge must 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. A Formal Challenge must state whether the issues presented are pending in an existing FERC 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. A Formal Challenge must state the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.

g. A Formal Challenge must 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.

h. A Formal Challenge must 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. An Interested Party will have until January 15 following the Review Period (unless such date is extended with the written consent of NorthWestern Energy to continue efforts to resolve an Informal Challenge) to file a Formal Challenge with FERC. A Formal Challenge must be filed in the same docket as NorthWestern Energy's Informational Filing discussed in Section VI, below.

3. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on NorthWestern Energy. Service to NorthWestern Energy must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge must serve the

individual listed as the contact person on NorthWestern Energy's Informational Filing discussed in Section VI, below.

4. NorthWestern Energy must respond to the Formal Challenge by the deadline established by FERC, unless an extension is granted by FERC.

5. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

6. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or the FERC Form No. 1 must first raise the matter with NorthWestern Energy before pursuing a Formal Challenge.

7. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, NorthWestern Energy bears the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Except as specifically provided herein, nothing in these Protocols limits NorthWestern Energy's right to file unilaterally, pursuant to Federal Power Act Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, 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.

E. No party may seek to modify the Formula Rate under these Challenge Procedures, and the Annual Update is not 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.

V. Changes to Annual Update

A. If NorthWestern Energy files any corrections to correct a Mistake in its FERC Form No. 1 during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges will be reflected in the Annual Update for the next effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a ("**FERC's Interest Rate**"). For purposes of these Protocols, "**Mistake**" means errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or other inadvertent computational errors, erroneous Form No. 1 references, or the like. Mistakes do not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous FERC Form No. 1 references in the Formula Rate Template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or NorthWestern Energy to notify the other party of any mistake in any FERC Form No. 1 data or specific data applied in the Formula Rate Template.

B. Any changes to the data inputs, including but not limited to revisions to NorthWestern Energy's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, will be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism will apply in lieu of mid-Rate Year adjustments. Interest on any refund will be calculated in accordance with FERC's Interest Rate, and interest on any surcharge will be calculated using the lower of FERC's Interest Rate or NorthWestern Energy's short-term borrowing rate, if applicable.

VI. Informational Filing

A. By December 15 of each year, NorthWestern Energy will submit to FERC an informational filing of its Annual Update ("**Informational Filing**"), which will be filed in a new docket each year. This Informational Filing will 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 NorthWestern Energy has properly applied the Formula Rate; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of Accounting Changes that affect Formula Rate inputs. The Informational Filing will also describe any corrections or adjustments made during the Review Period, and will note any aspects of the Formula Rate or its inputs that are subject to an ongoing dispute under the Challenge Procedures.

B. Within 5 days of such Informational Filing, NorthWestern Energy will provide notice of the Informational Filing via the e-mail distribution list and by posting the docket number assigned to NorthWestern Energy's Informational Filing on SPP's website and OASIS.

C. Any challenges to the implementation of NorthWestern Energy's Formula Rate must be made through the Challenge Procedures described in Section IV, above, or in a separate complaint proceeding, and not in response to the Informational Filing.

ATTACHMENT 3

DIRECT TESTIMONY AND EXHIBITS OF KENDALL G. KLIEWER

Attachment 4

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation	**)**	**Docket No. ER15-___-000**

PREPARED DIRECT TESTIMONY OF KENDALL G. KLIEWER

ON BEHALF OF

NORTHWESTERN CORPORATION

June 29, 2015

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kendall G. Kliewer. My business address is 3010 W. 69th Street, Sioux Falls, South Dakota, 57108.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Vice President and Controller of NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "the Company").

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

A. I am testifying on behalf of the South Dakota operations of NorthWestern Corporation, which is a FERC-jurisdictional public utility that intends to join the Southwest Power Pool Regional Transmission Organization ("SPP").

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have been with NorthWestern since November 2002. My primary responsibilities include, among other duties, overseeing compliance with financial reporting requirements established by the Securities and Exchange Commission ("SEC") and other regulatory agencies, technical research with regard thereto, reviewing NorthWestern's financial statements, and implementing and overseeing accounting policies and procedures. Previously, I was a Senior Manager at KPMG, LLP in Lincoln, Nebraska. During my tenure at KPMG, I coordinated financial statement audits, consulted with clients on appropriate accounting practices and SEC reporting requirements, assisted clients with the preparation and review of various SEC filings, and planned and supervised audits. I have a Bachelor of Science degree in Business Administration from the University of Nebraska and am a Certified Public Accountant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes, I provided testimony before the South Dakota Public Utilities Commission and the Montana Public Service Commission.

II. PURPOSE AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the transmission formula rate template ("TFR") that NorthWestern will use to determine its annual transmission revenue requirement ("ATRR") once NorthWestern joins SPP, which is expected to be October 1, 2015. My testimony also calculates NorthWestern's initial ATRR that SPP will use to develop rates for joint Zone 19 under the SPP Open Access Transmission Tariff ("OATT"). In addition, my testimony describes the increase in NorthWestern's ATRR proposed in this filing and the impact on NorthWestern's transmission customers. In addition to my testimony, NorthWestern is also submitting testimony from Michael R. Cashell and Adrien M. McKenzie. Mr. Cashell testifies about NorthWestern's transmission facilities, the costs of which will be recovered through this formula rate under the SPP OATT, and describes the formula rate protocols that will accompany the formula rate template and be incorporated into the SPP OATT. Mr. McKenzie supports the fixed return on equity ("ROE") component in the formula rate template.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring two exhibits. Exhibit KGK-1 is an unpopulated version formula rate template under which NorthWestern will recover its transmission revenue requirement under the SPP OATT. This exhibit is the same formula rate template that SPP is filing today as part of the revisions to the SPP OATT to create the new joint pricing zone. Exhibit KGK-2 is a populated version of NorthWestern's formula rate template that includes inputs based on NorthWestern's most recent Form 1 data for the year-end 2014.

III. <u>FORMULA RATE TEMPLATE</u>

Q. PLEASE DESCRIBE NORTHWESTERN'S TFR.

A. The proposed Formula Rate Template and the Protocols together comprise NorthWestern's filed rate. The rate template uses actual, historical numbers which will be updated annually. The data comes primarily from the company's filed FERC Form 1 and will be supplemented with the prior year's accounting data as kept in the company's books and records. The formula rate develops rate base by including specific transmission assets at original cost, reduced by the accumulated depreciation, an allocated share of general and intangible assets, with adjustments for deferred taxes, prepayments, materials and supplies, and cash working capital. The expense portion of the cost of service includes operating and maintenance expenses of the specific transmission assets, an allocated portion of administrative and general expenses, test year depreciation on the specific assets, and taxes other than income taxes. The cost of capital is calculated using the cost of debt and cost of equity weighted based on the capital structure as shown on Attachments 6-9. The debt component of the capital structure is the average long-term debt of the company using the beginning and the ending balances as taken from the FERC Form 1. The equity component of the capital structure is based on the average book proprietary capital using the beginning and the ending balances also taken from the FERC Form 1. The cost of debt is calculated by dividing the total long-term debt interest expense, as reported in FERC Form 1, by the average long-term debt outstanding. The proposed cost of equity of 10.97% is determined by the company's ROE Witness, Adrien M. McKenzie. As he describes in his prefiled testimony, this rate is in the middle of the top half of the range of reasonable returns, and includes an adder in recognition of NorthWestern's participation in a Regional Transmission Organization ("RTO").

Q. PLEASE DESCRIBE THE INPUTS WORKSHEET.

A. The first page of the inputs worksheet includes numbers taken directly from the FERC Form 1. The second page includes numbers from the company's records and also a summary of the worksheets that require direct input. The numbers in the inputs worksheet are used throughout the formula rate template.

Q. PLEASE DESCRIBE THE APPENDIX A SPREADSHEET.

A. Appendix A is the cost of service associated with this formula rate. Its numbers come from various worksheets in the template. Lines 1-19 show the calculation to derive the various allocation factors used. Line 123 shows the net revenue requirement.

Q. PLEASE DESCRIBE ATTACHMENT 1 OF THE TFR.

A. This attachment includes the Deferred Income Tax calculation, which is used in Appendix A as an Adjustment to Rate Base (Line 36). Deferred taxes are differences between the book and tax treatment for certain transactions. Accelerated tax depreciation generally exceeds book depreciation during the early years of an asset's service life, creating an accumulated deferred income tax liability.

Q. WHY DO DEFERRED INCOME TAXES REDUCE RATE BASE?

A. Since deferred income taxes are typically liabilities for taxes due in future periods, they represent a source of funds. Accordingly, the average accumulated deferred income tax liability balance is deducted from rate base to recognize such funds are available for NorthWestern to use between the time they are collected in rates from customers and the time they are eventually remitted to the government.

Q. PLEASE DESCRIBE ATTACHMENT 2 OF THE TFR.

A. This attachment shows the taxes other than income taxes. Plant and labor related taxes are included in the cost of service, whereas franchise taxes, gross receipts tax, and coal conversion taxes are excluded. The property taxes are allocated to transmission using the gross plant factor whereas the labor related taxes are allocated using the wages factor.

Q. PLEASE DESCRIBE ATTACHMENT 3 OF THE TFR.

A. This attachment shows revenue received by NorthWestern that is associated with the transmission system and must be credited against the gross revenue requirement. It primarily consists of an allocation of pole rental revenue. It could also include revenue from direct assignment facilities; however, NorthWestern currently has no such customers.

Q. PLEASE DESCRIBE ATTACHMENT 4 OF THE TFR.

A. This attachment shows NorthWestern's provision for general liability, workman's compensation, and auto claims. This provision is allocated to transmission based on net plant and is a reduction to rate base in Appendix A.

Q. PLEASE DESCRIBE ATTACHMENT 5 OF THE TFR.

A. This attachment provides the details for several adjustments in Appendix A. The line numbers in the left column of this spreadsheet correspond to the line numbers in Appendix A where the data is incorporated into the cost of service.

Q. PLEASE DISCUSS ATTACHMENTS 6-9 OF THE TFR.

A. Attachment 6 is the summation of Attachments 7, 8, and 9 and reflects the ROE of 10.97%, which is comprised of the 10.47% as recommended in the prefiled testimony of Adrien M. McKenzie, plus an ROE adder for participating in an RTO.

Attachment 7 shows the calculation of the equity component of the capital structure, which is the average of the beginning and ending propriety capital balances for the total company.

Attachment 8 shows the calculation of Preferred Stock, of which the company has none for the test period.

Attachment 9 shows the calculation of the debt component of the capital structure, which is the average of the beginning and ending long-term debt outstanding for the total company. Also shown is cost of debt which is calculated by dividing the total long-term debt costs and expenses by the average long-term debt outstanding for the total company. Total long-term debt costs and expenses include not only interest expenses, but also the amortization of debt issuance costs, gains or losses on reacquired debt, and debt premiums or discounts.

Q. WHAT OTHER SUPPLEMENTAL DATA IS REQUIRED FOR INPUT INTO THE TFR?

A. Only certain NorthWestern transmission assets qualify for inclusion in the SPP tariff. A review of newly added assets must be performed annually to determine inclusion into SPP. Attachment 5 shows the includable assets as a percentage of total transmission assets and that percentage is applied to transmission plant for purposes of this filing. Michael R. Cashell provides Exhibit MRC-2 describing NorthWestern's transmission assets that qualify for inclusion in SPP.

IV. INITIAL ATRR AND IMPACT ON CUSTOMERS

Q. WHAT IS THE INITIAL ATRR THAT WILL BE RECOVERED UNDER THE FORMULA RATE?

A. The revenue requirement is $8,162,218. Exhibit KGK-2 shows the details of the computation. The TFR uses a historic formula template that includes actual calendar year cost data. It does not use projected transmission costs and, as such, does not include a true-up mechanism.

Q. DOES THIS REPRESENT AN INCREASE IN THE ATRR CURRENTLY RECOVERED BY NORTHWESTERN AS FACILITIES CREDITS UNDER THE WESTERN AREA POWER ADMINISTRATION ("WAPA") OATT?

A. Yes. The initial ATRR represents an increase over the ATRR recovered by NorthWestern as facilities credits under the WAPA OATT. The primary reason for the increase is that the facilities credits under the WAPA OATT are based on 2012 FERC Form 1 information and do not reflect additional transmission upgrades to NorthWestern's system that are included in the 2014 data. Also, as explained in the testimony of Michael R. Cashell, NorthWestern's ATRR under the SPP OATT includes certain 69 kV facilities that satisfy the definition of Transmission Facilities under Attachment AI, while only NorthWestern's 115 kV facilities were included under the WAPA OATT.

Q. DOES THIS INCREASE IN ATRR REFLECT THE RATES THAT NORTHWESTERN'S TRANSMISSION CUSTOMERS WILL PAY UNDER THE SPP OATT?

A. No. NorthWestern's transmission assets will be included within a new joint transmission pricing zone under the SPP OATT. Under the SPP OATT, customers located in a joint pricing zone pay a blended rate based on the revenue requirements for all transmission owners in the joint zone. SPP will make filings to support the ATRRs for the non-jurisdictional entities in the new joint zone. The rates ultimately paid by NorthWestern customers will be based not only on the ATRR proposed in this filing, but also on the ATRRs proposed in the filings for the other transmission owners in the joint zone.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation) **Docket No. ER15-___-000**

AFFIDAVIT

I, the undersigned, being duly sworn, depose and state, that the above and foregoing Prepared Testimony of Kendall G. Kliewer is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate and complete.

____
Kendall G. Kliewer

Subscribed and sworn to before me this
26 day of June, 2015

My Commission expires: 3/20/18

Nancy Thompson
Notary Public, South Dakota

NANCY THOMPSON
SEAL NOTARY PUBLIC SOUTH DAKOTA SEAL

ADDENDUM 27 TO ATTACHMENT H, Page 1 of 16
NorthWestern Corporation (South Dakota)
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(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

NorthWestern Corporation (South Dakota)

Formula Rate Template Inputs
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Entered Directly From FERC Form No. 1 ("FF1"):

Line No	Account/Description/Classification	Inputs From 2014 FERC Form 1	FF1 Page Location	Template Sheet of the Link
1	Prepayments (165)		111.57c	ATT 5 - Cost Support, Ln. 37
2	Preferred Stock Issued (204) - End of Year		112.3c	ATT 8 - Pref Stock, Ln. 2, Col. A
3	Preferred Stock Issued (204) - Beg of Year		112.3d	ATT 8 - Pref Stock, Ln. 1, Col. A
4	Unappropriated Undistrib Subsid Earnings (216.1) - End of Yr		112.12c	ATT 7 - Com Stock, Ln. 2, Col. G
5	Unappropriated Undistrib Subsid Earnings (216.1) - Beg of Yr		112.12d	ATT 7 - Com Stock, Ln. 1, Col. G
6	Accum Other Comp Income (219) - End of Year		112.15c	ATT 7 - Com Stock, Ln. 2, Col. F
7	Accum Other Comp Income (219) - Beginning of Year		112.15d	ATT 7 - Com Stock, Ln. 1, Col. F
8	Total Proprietary Capital - End of Year (Total Company)		112.16c	ATT 7 - Com Stock, Ln. 2, Col. A
9	Total Proprietary Capital - Beginning of Year (Total Company)		112.16d	ATT 7 - Com Stock, Ln. 1, Col. A
10	Bonds (221) - End of Year (Total Company)		112.18c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. B
11	Bonds (221) - Beginning of Year (Total Company)		112.18d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. B
12	(Less) Reacquired Bonds (222) - End of Year		112.19c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. C
13	(Less) Reacquired Bonds (222) - Beginning of Year		112.19d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. C
14	Advances from Assoc Companies (223) - End of Year		112.20c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. A
15	Advances from Assoc Companies (223) - Beginning of Year		112.20d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. A
16	Other Long Term Debt (224) - End of Year		112.21c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. D
17	Other Long Term Debt (224) - Beginning of Year		112.21d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. D
18	Unamortized Premium on Long Term Debt - End of Year		112.22c	ATT 9 - LTD, Pg. 1, Ln. 5
19	Unamortized Premium on Long Term Debt - Beginning of Year		112.22d	ATT 9 - LTD, Pg. 1, Ln. 4
20	(Less) Unamortized Disc. on Long-Term Debt (Debit) - End of Yr		112.23c	ATT 9 - LTD, Pg. 1, Ln. 8
21	(Less) Unamortized Disc. on Long-Term Debt (Debit) - Beg of Yr		112.23d	ATT 9 - LTD, Pg. 1, Ln. 7
22	Accumulated Provision for Injuries and Damages (228.2)		112.28c	ATT 4 - Non-Escrowed Funds, Ln. 4
23	Elec - Taxes Other than Income Taxes (408.1)		115.14g	ATT 2 - Other Taxes, Ln. 22
24	Interest on LTD (427)		117.62c	ATT 9 - LTD, Pg. 2, Ln. 1
25	Amort of Debt Disc & Expenses (428)		117.63c	ATT 9 - LTD, Pg. 2, Ln. 2
26	Amort of Loss on Reacquired Debt (428.1)		117.64c	ATT 9 - LTD, Pg. 2, Ln. 3
27	(less) Amort of Premium on Debt-Credit (429)		117.65c	ATT 9 - LTD, Pg. 2, Ln. 4
28	(less) Amort of Gain on Reacquired Debt-Credit (429.1)		117.66c	ATT 9 - LTD, Pg. 2, Ln. 5
29	Total Dividends Declared Pref Stock (437)		118.29c	ATT 8 - Preferred Stock, Ln. 4, Col. F
30	Electric - Amortization of Other Utility Plant		200.21c	Appendix A - Ln. 8
31	Total Intangible Plant		205.5g	Appendix A - Ln. 22
32	Total Electric Plant in Service		207.104g	Appendix A - Ln. 6
33	Trn - Total Transmission Plant		207.58g	ATT 5 - Cost Support, Ln. 1a
34	Transmission Materials & Supplies		227.8.c	Appendix A - Ln. 41
35	Stores Expense Undistributed (Account 163)		227.16.c	Appendix A - Ln. 38
36	Total (Acct 190)		234.18c	ATT 1 - ADIT, Pg. 1, Ln. 9
37	Total (Acct 281)		273.17k	Line not used
38	Total (Acct 282)		275.9k	ATT 1 - ADIT, Pg. 1, Ln. 18
39	Total (Acct 283)		277.19k	ATT 1 - ADIT, Pg. 1, Ln. 28
40	Interest on Debt to Assoc. Companies		117.67c	ATT-9 - LTD, Pg. 2, Ln. 5a
41	Gen - Total General Plant		207.99g	Appendix A - Ln. 21
42	Transmission Accum. Depreciation		219.25c	Line not used
43	General Accum. Depreciation		219.28c	Appendix A - Ln. 29
44	Total Accum Depr Utility Plant		219.29.c	Appendix A - Ln. 7
45	Amortized Investment Tax Credit		266.8f	ATT 5 - Cost Support, Ln. 103
46	Trn Oper Transmission of Elec by Others		321.96b	ATT 5 - Cost Support, Ln. 50
47	Total Transmission Expenses		321.112b	ATT 5 - Cost Support, Ln. 49
48	A&G Oper Regulatory Commission Expenses		323.189b	Appendix A - Ln. 58 & ATT - 5, Ln. 63
49	A&G Oper General Advertising Expenses		323.191b	Appendix A - Ln. 59
50	Total Admin & General Expenses		323.197b	Appendix A - Ln. 54
51	Depreciation Exp (403) - Intangible Plant		336.1b	Appendix A - Ln.69
52	Depr Exp Asset Retire (403.1) - Intangible Plant		336.1c	Appendix A - Ln. 69
53	Amort Lim Term (404) - Intangible Plant		336.1d	Appendix A - Ln. 69
54	Amort of Other Intangible Electric Plant (405)		336.1e	Appendix A - Ln. 69
55	Depreciation Exp (403) - Transmission Plant		336.7b	Line not used
56	Depr Exp Asset Retire (403.1) - Transmission Plant		336.7c	Not used
57	Amort Lim Term (404) - Transmission Plant		336.7d	Not used
58	Depreciation Exp (403) - General Plant		336.10b	Appendix A - Ln. 68
59	Depr Exp Asset Retire (403.1) - General Plant		336.10c	Appendix A - Ln. 68
60	Amort Lim Term (404)- General Plant		336.10d	Appendix A - Ln. 68
61	Tot Elec O & M Transmission Direct Payroll		354.21b	Appendix A - Ln. 1
62	Tot Elec O & M Admin & General Direct Payroll		354.27b	Appendix A - Ln. 3
63	Total Elec O & M Direct Payroll		354.28b	Appendix A - Ln. 2
64	Transmission Towers and Fixtures		206.51.b	Appendix A - Ln. 16
65	Transmission Poles And Fixtures		206.52.b	Appendix A - Ln. 16
66	Distribution Poles, Towers, and Fixtures		206.64.b	Appendix A - Ln. 15
67	Rent from Electric Property		300.19.b	ATT 3 - Revenue Credits, Ln. 1
68	SD Property Taxes		263.23i	ATT 2 - Other Taxes, Ln. 1
69	ND Property Taxes		263.37i	ATT 2 - Other Taxes, Ln. 1
70	IA Property Taxes		263.1.12i	ATT 2 - Other Taxes, Ln. 1
71	Coal Conversion		263.1.18i	ATT 2 - Other Taxes, Ln. 16
72	Gross Revenue		263.1.24i	ATT 2 - Other Taxes, Ln. 17
73	Delaware Franchise		263.1.31i	ATT 2 - Other Taxes, Ln. 15
74	Vehicle Tax		263.5i	ATT 2 - Other Taxes, Ln. 3
75	Payroll Tax - FICA		263.7i	ATT 2 - Other Taxes, Ln. 8
76	Payroll Tax - Medicare		263.14i	ATT 2 - Other Taxes, Ln. 8
77	Payroll Tax - FUT		263.25i	ATT 2 - Other Taxes, Ln. 9
78	Payroll Tax - FUT-SD		263.32i	ATT 2 - Other Taxes, Ln. 10

Formula Rate Template Inputs
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Input from Company Records and/or Verification Required (Manual Input)

Line No	Account/Description/Classification	Inputs From End of Year	Source of Data	Template Sheet of the Link
1	Federal Income Tax Rate		From Tax Department	Appendix A - Ln. 98
2	State Income Tax Rate		From Tax Department	Appendix A - Ln. 99
3	Percent of Federal Tax Eligible for Deduction by South Dakota		From Tax Department	Appendix A - Ln. 100
4	State Income Tax Rate		From Tax Department	Line not used
5	State Income Tax Rate		From Tax Department	Line not used
6	State Income Tax Rate		From Tax Department	Line not used
7	Specific FERC 909 Ad costs		Company Records	ATT 5 - Cost Support, Ln. 64
8	EPRI Annual Membership Dues		Company Records	Line not used
9	Plant Held for Future Use (Account 105) - Total		FF1, 214.47.d	Appendix A - Ln. 26
10	Plant Held for Future Use (Account 105) - Non-Transmission		FF1, 214.47.d	Appendix A - Ln. 26
11	Transmission Related Regulatory Expenses		FF1, 350.41-44.d	ATT - 5, Ln. 63
12	Plant Held for Future Use (Non-Land) - Transmission Only		Company Records	Appendix A - Ln. 26
13	Transmission Gross Plant under SPP tariff		Company Records	Appendix A - Ln. 20
14	Transmission Accumulated Depreciation on assets under SPP tariff		Company Records	Appendix A - Ln. 28
15	Revenues from Directly Assigned Transmission Facilities (ATT 3, Note 2)		ATT 5 - Cost Support, Ln. 117	
16	Charges billed to Transmission Owner for system integration and transmission costs paid to others that benefit transmission customers and are recorded in Account 565.		Verify amount annually	
17	Line left intentionally blank.		Line left intentionally blank.	
18	Other Electric Revenues - Transmission for Others (Schedules 7 & 8)		From Acct 457. To: ATT-3, Line 4. Also see ATT 3, Notes 1 & 4	
19	Net revenues associated with Transmission Service Requests, Sponsored Upgrades, and Generation Interconnections for which the load is not included in the divisor.		Need to verify during each annual update if there are any such TSR revenues (including TSR revenue from SPP customers not in zone) for load that is NOT included in the UMZ divisor.	
20	Pre-OATT grandfathered Non-Firm Point to Point Service bundled demand revenues for which the load is not included in the divisor received by Transmission Owner and for which the revenues are divided between production and transmission functions.		This represents "Point-To-Point" demand revenue margins derived from any "grandfathered" agreements. The non-RQ "Demand Revenues" found in FF1, Pg. 311, Col. h (and page 311 extensions) for these customers should be reduced by the sum of the Demand Charges (costs) found in FF1, Pg. 327, col. j (and page 327 extensions) for these customers.	
21	Annual Depreciation Expense for Transmission Assets under SPP tariff		Company Records from Mgr of Property Acctg	Appendix A - Ln. 67
22	Transmission Pole/Structure Investment (Accts 354+355) under SPP tariff		Company Records from Mgr of Property Acctg	Appendix A - Ln. 17

The Worksheets listed below require Input of Data directly into the Worksheets themselves:

Line	Sheet	Description/Source
23	ATT 1 - ADIT	Accumulated Def Inc Taxes - Verify with Tax Department.
24	ATT 5 - Cost Support	From company records

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Shaded cells are input cells

Line	Description	Notes	FF1 Page # or Instruction	Amount
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b [From Inputs, Pg. 1, Ln. 61]	-
1a	Transmission under SPP Tariff Factor		[From ATT-5, Ln. 1a]	#DIV/0!
2	Total Wages Expense		p354.28.b [From Inputs, Pg. 1, Ln. 63]	0
3	Less A&G Wages Expense		p354.27.b [From Inputs, Pg. 1, Ln. 62]	0
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	0
5	**Wages & Salary Allocator**		(Line 1 * Line 1a) / Line 4	**#DIV/0!**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g [From Inputs, Pg. 1, Ln. 32]	0
7	Accumulated Depreciation (Total Electric Plant)		p219.29.c [From Inputs, Pg. 1, Ln. 44]	0
8	Accumulated Intangible Amortization (Other Utility Plant)	(Note A)	p200.21.c [From Inputs, Pg. 1, Ln. 30]	0
9	Total Accumulated Depreciation		(Line 7 + 8)	0
10	Net Plant		(Line 6 - Line 9)	0
11	Transmission Gross Plant under SPP tariff (excluding Land Held for Future Use)		(Line 27 - Line 26)	#DIV/0!
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**#DIV/0!**
13	Transmission Net Plant under SPP tariff (excluding Land Held for Future Use)		(Line 35 - Line 26)	#DIV/0!
14	**Net Plant Allocator**		(Line 13 / Line 10)	**#DIV/0!**
	T/D Pole Allocation Factor			
15	Gross Distribution Pole/Structure Investment (Acct 364)		p206.64.b [From Inputs, Pg. 1, Ln. 66]	-
16	Gross Transmission Pole/Structure Investment (Accts 354 + 355)		p206.51.b + p206.52.b [From Inputs, Pg. 1, Lns. 64 & 65]	-
17	Transmission Pole/Structure Investment (Accts 354 + 355) under SPP tariff		From Inputs, Pg. 2, Line 22	-
18	Total Pole/Tower Gross Plant		(Line 15 + Line 16)	-
19	**T/D Revenue Allocation Factor (For Pole Attachment Revenue)**		(Line 17 / Line 18)	**#DIV/0!**
	Plant Calculations			
	Plant In Service			
20	**Transmission Plant In Service under SPP tariff**		[From Inputs, Pg. 2, Ln. 13]	**0**
21	General		p207.99.g [From Inputs, Pg. 1, Ln. 41]	0
22	Intangible		p205.5.g [From Inputs, Pg. 1, Ln. 31]	0
23	Total General and Intangible Plant		(Line 21 + Line 22)	0
24	Wage & Salary Allocator		(Line 5)	#DIV/0!
25	**Total General and Intangible Functionalized to Transmission**		(Line 23 * Line 24)	**#DIV/0!**
26	**Land Held for Future Use**	(Note C)	[From Inputs, Pg. 2, Lns. 9, 10, & 12]	**0**
27	**Total Plant In Rate Base**		**(Line 20 + Line 25 + Line 26)**	**#DIV/0!**
	Accumulated Depreciation			
28	Transmission Accumulated Depreciation for assets under SPP tariff	(Note B)	[From Inputs, Pg. 2, Ln. 14]	**0**
29	General Plant Accumulated Depreciation		p219.28.c [From Inputs, Pg. 1, Ln. 43]	0
30	Accumulated Intangible Amortization (Other Utility Plant)		(Line 8)	0
31	Total Accumulated Depreciation		(Line 29 + 30)	0
32	Wage & Salary Allocator		(Line 5)	#DIV/0!
33	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 31 * Line 32)	#DIV/0!
34	**Total Accumulated Depreciation**		**(Sum Lines 28 + 33)**	**#DIV/0!**
35	**Total Net Property, Plant & Equipment**		**(Line 27 - Line 34)**	**#DIV/0!**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
36	**ADIT**		[From ATT 1, Pg. 1, Ln. 32]	**#DIV/0!**
	Prepayments			
37	Prepayments	(Note A)	[From ATT-5, Ln. 37]	**#DIV/0!**
	Materials and Supplies			
38	Undistributed Stores Expense	(Note A)	p227.16.c [From Inputs, Pg. 1, Ln. 35]	0
39	Wage & Salary Allocator		(Line 5)	#DIV/0!
40	Total Undistributed Stores Expense Allocated to Transmission		(Line 38 * Line 39)	#DIV/0!
41	Transmission Materials & Supplies		p227.8.c [From Inputs, Pg. 1, Ln. 34]	0
42	**Total Materials & Supplies Allocated to Transmission**		(Line 40 + Line 41)	**#DIV/0!**
	Cash Working Capital			
43	Operation & Maintenance Expense		(Line 66)	#DIV/0!
44	1/8th Rule		1/8	12.5%
45	**Total Cash Working Capital Allocated to Transmission**		(Line 43 * Line 44)	**#DIV/0!**
46	**Non-Escrowed Funds**		[From ATT-4, Line 3, Col. C]	**#DIV/0!**
47	**Total Adjustment to Rate Base**		(Lines 36 + 37 + 42 + 45 + 46)	**#DIV/0!**
48	**Rate Base**		(Line 35 + Line 47)	**#DIV/0!**

APPENDIX A
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Operations & Maintenance Expense			
	Transmission O&M			
49	Transmission O&M		[From ATT-5, Ln. 49]	#DIV/0!
50	Less Account 565		[From ATT-5, Ln. 50]	#DIV/0!
51	Line left intentionally blank			
52	Plus Charges billed to Transmission Owner and booked to Account 565		[From ATT-5, Ln. 52]	0
53	**Transmission O&M**		(Lines 49 - 50)	**#DIV/0!**
	Allocated Administrative & General Expenses			
54	Total A&G		323.197b [From Inputs, Pg. 1, Ln. 50]	0
55	Line left intentionally blank			
56	Line left intentionally blank			
57	Line left intentionally blank			
58	Less Regulatory Commission Exp Account 928	(Note D)	p323.189.b [From Inputs, Pg. 1, Ln. 48]	0
59	Less General Advertising Exp Account 930.1		p323.191.b [From Inputs, Pg. 1, Ln. 49]	0
60	Administrative & General Expenses		Sum (Lines 54 to 55) - Sum (Lines 56 to 59)	0
61	Wage & Salary Allocator		(Line 5)	#DIV/0!
62	**Administrative & General Expenses Allocated to Transmission**		(Line 60 * Line 61)	**#DIV/0!**
	Directly Assigned A&G			
63	Regulatory Commission Exp Account 928	(Note F)	[From ATT-5, Ln. 63]	0
64	Safety/Peak Alert Advertising Exp (Acct 909)	(Note E)	[From ATT-5, Ln. 64]	#DIV/0!
65	**Subtotal - Accounts 909 and 928 - Transmission Related**		(Line 63 + Line 64)	**#DIV/0!**
66	**Total Transmission O&M**		**(Lines 53 + 62 + 65)**	**#DIV/0!**
	Depreciation & Amortization Expense			
	Depreciation Expense			
67	Transmission Depreciation Expense for Assets under SPP tariff	(Note B)	p336.7.b&c&d [From Inputs, Pg. 2, Ln. 21]	**0**
68	General Depreciation Expense Including Amortization of Limited Term Plant		p336.10.b&c&d [From Inputs, Pg. 1, Lns. 58, 59, & 60]	0
69	Intangible Amortization	(Note A)	p336.1.b&c&d&e [From Inputs, Lns. 51, 52, 53, & 54]	0
70	Total		(Line 68 + Line 69)	0
71	Wage & Salary Allocator		(Line 5)	#DIV/0!
72	**General Depreciation & Intangible Amortization Allocated to Transmission**		(Line 70 * Line 71)	**#DIV/0!**
73	**Total Transmission Depreciation & Amortization**		**(Lines 67 + 72)**	**#DIV/0!**
	Taxes Other than Income Taxes			
74	**Taxes Other than Income Taxes**		[From ATT-2, Pg. 1, Ln. 14]	**#DIV/0!**
75	**Total Taxes Other than Income Taxes**		**(Line 74)**	**#DIV/0!**
	Return \ Capitalization Calculations			
	Long Term Interest			
76	**Long Term Interest & Hedging Costs**		[From ATT-9, Pg. 2, Ln. 6]	**-**
77	**Preferred Dividends**		[From ATT-8, Pg. 1, Ln. 4]	**0**
	Common Stock			
78	Proprietary Capital		[From ATT-7, Pg. 1, Ln. 3, Col. A]	0
79	Less Accumulated Other Comprehensive Income Account 219		[From ATT-7, Pg. 1, Ln. 3, Col. F]	0
80	Less Preferred Stock		[From ATT-8, Pg. 1, Ln. 3, Col. F]	0
81	Less Account 216.1		[From ATT-7, Pg. 1, Ln. 3, Col. G]	0
82	**Common Stock**		(Line 78 - 79 - 80 - 81)	**0**
	Capitalization			
83	Total Long Term Debt (Average)		[From ATT-6, Pg. 1, Ln. 1, Col A]	0
84	Preferred Stock		[From ATT-6, Pg. 1, Ln. 2, Col A]	0
85	Common Stock		[From ATT-6, Pg. 1, Ln. 3, Col A]	0
86	**Total Capitalization**		(Sum Lines 83 to 85)	**0**
87	Debt %	Total Long Term Debt	[From ATT-6, Pg. 1, Ln. 1, Col B]	#DIV/0!
88	Preferred %	Preferred Stock	[From ATT-6, Pg. 1, Ln. 2, Col B]	#DIV/0!
89	Common %	Common Stock	[From ATT-6, Pg. 1, Ln. 3, Col B]	#DIV/0!
90	Debt Cost	Total Long Term Debt	[From ATT-6, Pg. 1, Ln. 1, Col C]	#DIV/0!
91	Preferred Cost	Preferred Stock	[From ATT-6, Pg. 1, Ln. 2, Col C]	0.00%
92	Common Cost	Common Stock	[From ATT-6, Pg. 1, Ln. 3, Col C]	0.00%
93	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 87 * Line 90)	#DIV/0!
94	Weighted Cost of Preferred	Preferred Stock	(Line 88 * Line 91)	#DIV/0!
95	Weighted Cost of Common	Common Stock	(Line 89 * Line 92)	#DIV/0!
96	**Rate of Return on Rate Base (ROR)**		(Sum Lines 93 to 95)	**#DIV/0!**
97	**Investment Return = Rate Base * Rate of Return**		**(Line 48 * Line 96)**	**#DIV/0!**

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Composite Income Taxes				
	Income Tax Rates				
98	FIT=Federal Income Tax Rate		(Note G)	[From Inputs, Pg. 2, Ln. 1]	0.00%
99	SIT=State Income Tax Rate or Composite		(Note G)	[From Inputs, Pg. 2, Ln. 2]	0.00%
100	p	(% of fed inc tax deductible for state purposes)	(Note G)	[From Inputs, Pg. 2, Ln. 3]	0.00%
101	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.00%
102	T / (1-T)	Tax Gross-Up			0.00%
	ITC Adjustment				
103	Amortized Investment Tax Credit - Transmission Related			[From ATT-5, Ln. 103]	#DIV/0!
104	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)		(Line 103 * (1 / (1-Line 101))	**#DIV/0!**
105	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 102 * Line 97 * (1- (Line 93 / Line 96))]	**#DIV/0!**
106	**Total Income Taxes**			**(Line 105 - Line 104)**	**#DIV/0!**
	Revenue Requirement				
	Summary				
107	Net Property, Plant & Equipment			(Line 35)	#DIV/0!
108	Total Adjustment to Rate Base			(Line 47)	#DIV/0!
109	Rate Base			(Line 48)	#DIV/0!
110	Total Transmission O&M			(Line 66)	#DIV/0!
111	Total Transmission Depreciation & Amortization			(Line 73)	#DIV/0!
112	Taxes Other than Income			(Line 75)	#DIV/0!
113	Investment Return			(Line 97)	#DIV/0!
114	Income Taxes			(Line 106)	#DIV/0!
115	**Gross Revenue Requirement**			**(Sum Lines 110 to 114)**	**#DIV/0!**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
116	Transmission Plant In Service under SPP tariff			(Line 20)	0
117	Revenues from Direct Assigned Transmission F		(Note H)	[From ATT-5, Ln. 117]	0
118	Included Transmission Facilities			(Line 116 - Line 117)	0
119	Inclusion Ratio			(Line 118 / Line 116)	#DIV/0!
120	Gross Revenue Requirement			(Line 115)	#DIV/0!
121	**Adjusted Gross Revenue Requirement**			(Line 119 * Line 120)	**#DIV/0!**
	Revenue Credits & Adjustments				
122	Revenue Credits			[From ATT-3, Ln. 8]	#DIV/0!
122a	Refunds and Surcharges (Adjustments to Gross ATRR)				
122b	**Total Revenue Credits and Adjustments**			(Line 122 + Line 122a)	**#DIV/0!**
123	**Annual Total Net Revenue Requirement**			**(Line 121 - Line 122b)**	**#DIV/0!**

Notes:

A Electric portion only.

B Includes only transmission assets under the SPP tariff.

C Includes Transmission portion only.

D Includes all Regulatory Commission Expenses for all Electric jurisdictions.

E Includes safety-related and load/grid congestion management advertising expense included in Account 909 (Product codes ADAS, ADCS, ADPA).

F Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting; as itemized on ATT-5, Ln. 63.

G The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the South Dakota income tax rate, and p = the percentage of federal income tax deductible for South Dakota state income taxes.

H There are no direct assigned transmission facilities on our system as of 12/31/2014. Annual verification/updates will be documented on ATT 5.

NorthWestern Corporation (South Dakota)

Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 190

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Account	Identification	*(A)* *YE Balance*	*(B)* *100% Non-Transmission Related*	*(C)* *100% Transmission Related*	*(D)* *Plant Related*	*(E)* *Labor Related*	*(F)* *Total Added to Ratebase*	*(G)* *Description*
1	190.0	Deferred FIT - Unbilled Revenue				-			
2	190.0	Deferred FIT - Officers & Directors Deferred Comp.					-		Deferred compensation, tax deductible when paid
3	190.0	Deferred FIT - Reserves & Accruals				-			
4	190.0	Deferred FIT - Post Retirement Benefits - Pension					-		Relates to pensions - tax funding vs book accrual
5	190.0	Environmental Liability		-					All natural gas related
6	190.0	Deferred FIT - Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
7									
8		**Total**	-	-	0	-	-		
9		**Conform - [FF1, pg. 234, ln. 18, col. c] (From Inputs Pg. 1, Line 36)**	-						
10		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
11		**Total Transmission**		0	0	#DIV/0!	#DIV/0!	#DIV/0!	
12									
13									
14	282.0	Accum Def FIT - Accel Depr & Amort.				-			Accelerated Depreciation & Amortization of non-flow thru items
15	282.0	Accum Def FIT - Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
16									
17		**Total**	-	-	0	-	0		
18		**Conform - [FF1, pg. 275, ln. 9, col. k] (Inputs Pg. 1, Line 38)**	-						
19		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
20		**Total Transmission**		-	0	#DIV/0!	#DIV/0!	#DIV/0!	
21									
22									
23	283.0	Regulatory Assets		-					MGP
24	283.0	FAS109 Flow through deferred taxes		-					tax gross up on FAS109 flow through deferred taxes
25	283.0	Non-jurisdictional (SD Gas, NE Gas)		-					Not South Dakota Electric related
26									
27		**Total**	-	-	0	0	0		
28		**Conform - [FF1, pg. 277, ln. 19, col. k] (Inputs Pg. 1, Line 39)**	-						
29		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	#DIV/0!	#DIV/0!		
30		**Total Transmission**		0	0	#DIV/0!	#DIV/0!	#DIV/0!	
31									
32		**Total ADIT (Ln. 11 + Ln. 20 + Ln 30)**						#DIV/0!	To Appendix A, Line 36

Attachment 2 - Taxes Other Than Income

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Description	Column A Pg. 263 & 263.1 Col (i)	Column B Allocator	Column C Allocated Amount
	OTHER TAXES:			
	Currently Included on Appendix A			
	Plant Related:		**Gross Plant Allocator**	
1	Real and Personal Property (State, Municipal or Local) -Current FF1 Year [FF1, Pg. 263, Lns. 23i & 37i; Pg. 263.1, Lns. 12i, 18i, 24i & 31i][From Inputs, Pg. 1, Lns. 68-70]	0		
2				
3	Vehicle Taxes [From Inputs, Pg. 1, Ln. 74]	0		
4				
5				
6				
7	**Total Plant Related [GP Allocator from Appendix A, Ln. 12]**	0	#DIV/0!	#DIV/0!
	Labor Related:		**Wages & Salary Allocator**	
8	Social Security (FICA/OAB) [FF1, Pg. 263, Ln.5i] [From Inputs, Pg. 1, Ln. 75-76]	0		
9	Federal Unemployment Comp. [FF1, Pg. 263, Ln. 7i] [From Inputs, Pg. 1, Ln. 77]	0		
10	State Unemployment Comp. [From Inputs, Pg. 1, Lines 78]	0		
11				
12				
13	**Total Labor Related [Wages & Sal. Alloc. from Appendix A, Ln.5]**	0	#DIV/0!	#DIV/0!
14	**Total Included (Column C, Lines 7 + 13)** [To Appendix A, Line 74]			#DIV/0!
	Currently Excluded from Appendix A			
15	Corporate Franchise-Retail [Current Year] [From Inputs, Pg. 1, Ln. 73] [FF1, Pg. 263, Col. i, Lns. 16, 21, & 35; Pg. 263.1, Col. i, Lns. 6, 14, 20, 26, & 33]	0		
16	Coal Conversion [From Inputs Pg. 1, Ln. 71]	0		
17	SD Gross Receipts Tax [From Inputs, Pg. 2, Ln. 72]	0		
18				
19				
20	**Subtotal of Excluded Taxes, [Ln. 15 + Ln. 16 + Ln.17]**	0		
21	**Total, Included and Excluded (Column A, Lines 7 + 13 + 20)**	0		
22	**Total Other Taxes [FF1, pg. 115.14.g] [From Inputs, Pg. 1, Ln. 23]**	-		
23	Difference (Line 21 - Line 22)	-		

Criteria for Allocation:

A Other Taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Gross Plant Allocator.

B Other Taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

NorthWestern Corporation (South Dakota)

Attachment 3 - Revenue Credits

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Account 454 - Rent from Electric Property	
1	Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 1, Ln. 67]	-
2	T/D Revenue Allocation Factor [From Appendix A, Ln. 19]	#DIV/0!
3	Rent from Electric Transmission Property [Line 1 x Line 2]	#DIV/0!
	Other Electric Revenues (Note 1)	
4	SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 3) [From Inputs, Pg. 2, Ln. 18]	0
5	Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 3) [From Inputs, Pg. 2, Ln. 20]	0
6	Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 2, Ln. 15]	0
7	Other Revenues Associated with Loads Outside of NorthWestern's Zone [From Inputs, Pg. 2, Ln. 19]	0
8	Gross Revenue Credits (sum Lines 3 thru 9) [To Appendix A, Line 122]	#DIV/0!

Note 1: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Accounts 457.137 (Firm Point-to-Point) and 457.138 (Non-Firm Point-to-Point). All NorthWestern point-to-point transmission customers are included in the UMZ Load Divisor.

Note 2: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

Note 3: The portion of Point-to-Point revenues collected by SPP and assigned to NorthWestern are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by NorthWestern for "grandfathered" bundled contracts will be included on ATT 3, Ln. 8. See note on "Inputs" worksheet, Pg. 2, Ln. 20 regarding remaining pre-OATT contracts.

ADDENDUM 27 TO ATTACHMENT H, Page 10 of 16

NorthWestern Corporation (South Dakota)

Attachment 4, NON-ESCROWED FUNDS

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

The purpose of this worksheet is to individually document the value(s) of the non-escrowed reserve funds that will be credited against working capital. All inputs are derived from the Company's Books and Records, as described.

Line	Description of Reserve:	FERC Reserve Acct	FERC Expense Acct [1]	Balance 12/31/20xx	Allocator NP	Working Capital Adjustment (Col. C = Col. A x Col. B)
				COL. A	COL. B	COL. C
1.	Accum Prov for Inj/Damgs	228.2	925	$ -	#DIV/0!	#DIV/0!
2.	Other adjustments				#DIV/0!	#DIV/0!
3.	**Total** (Ln. 1 + Ln. 2) [Appendix A, Pg. 1, Ln. 46]			$ -		#DIV/0!
4.	Conformation [FF1, Pg. 112, Ln. 28, Col. c] [From Inputs, Pg. 1, Ln. 22]			-		

[1] Account 925 is the FERC expense account which includes the cost of insurance, the cost of claims not covered by insurance, the re-imbursement from insurance companies, and amounts credited to account 228.2 as Accumulated Provision for Injuries and Damages.

Attachment 5 - Cost Support

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Prepayments		FF1 Amount	Gross Plant Allocator	Functionalized to Transmission	Details
37	Prepayments	FF1 Pg. 111.57.c [From Inputs, Pg. 1, Ln. 1]	0	#DIV/0!	#DIV/0!	

	Regulatory Expense Related to Transmission Cost Support:		FF1 Amount	Allocated to transmission	Functionalized to Transmission	Details
63	Regulatory Commission Exp Account 928	FF1 323.189.b [From Inputs, Pg. 1, Ln. 48] & 350.41.d thru 350.44.d [From Inputs, Pg. 2, Ln. 11]	0	0.00%	0	

	Advertisements:		FF1 Amount	T/D Allocator	Functionalized to Transmission	Details
64	Advertisements FERC 909	FF1 111.57.c [From Inputs, Pg. 2, Ln. 7]	0	#DIV/0!	#DIV/0!	

	ITC Adjustment:		FF1 Amount	GP Allocator	Functionalized to Transmission	Details
103	Amortized Investment Tax Credit	FF1 266.8.f [From Inputs, Pg.1, Ln. 45]	0	#DIV/0!	#DIV/0!	

	Adjustment to Remove Revenue Requirements Associated w/ Excluded Transmission Facilities		Revenues from Direct Assigned Transmission Facilities	General Description of the Direct Assigned Transmission Facilities
117	Revenues from Direct Assigned Transmission Facilities	[From Inputs, Pg. 2, Ln. 15]	0	Direct Assignment Facilities: Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval.

	Adjustments to Transmission O&M:		Total	Transmission under SPP Factor	Functionalized to Transmission	Details
49	Transmission O&M	FF1 321.112.b [From Inputs, Pg. 1, Ln. 47]	0	#DIV/0!	#DIV/0!	
50	Less Account 565	FF1 321.96.b [From Inputs, Pg. 1, Ln. 46]	0	#DIV/0!	#DIV/0!	
52	Plus Charges billed to Transmission Owner and booked to Account 565	[From Inputs, Pg. 2, Ln. 16]	0	#DIV/0!	#DIV/0!	

	Adjustments to Transmission Plant for only assets under SPP tariff:		Total Transmission	Transmission under SPP	Details
20	Transmission Assets	FF1 207.58g [From Inputs, Pg. 1, Ln. 33]	0	-	
1a	Transmission under SPP Factor	(Transmission under SS divided by Total Transimssion)	#DIV/0!		

ADDENDUM 27 TO ATTACHMENT H, Page 12 of 16
NorthWestern Corporation (South Dakota)
Attachment 6, WEIGHTED AVERAGE COST OF CAPITAL
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Type of Capital	Total Company Average Capitalization ($)		Weighted Cost Ratios	Cost of Capital		Weighted Cost of Capital
		Balance	Source	(%)	(%)	Source	(%)
				Col B = Col A/Col A Total			Col D = Col B x Col C
Line		Col A		Col B	Col C		Col D
1.	Long Term Debt	-	[Note (1)]	#DIV/0!	#DIV/0!	[Note (4)]	#DIV/0!
2.	Preferred Stock	0	[Note (2)]	#DIV/0!	0.00%	[Note (5)]	#DIV/0!
3.	Common Stock	-	[Note (3)]	#DIV/0!			#DIV/0!
4.	Totals	-		#DIV/0!			
5.	**Weighted Average Cost of Capital ("R")**						#DIV/0!

Note(1): From ATT 9, Pg. 1, Ln. 3.

Note (2): From ATT 8, Pg. 1, Ln. 3.

Note (3): From ATT 7, Pg. 1, Ln. 4.

Note(4): From ATT 9, Page 2, Ln. 8

Note (5): From ATT 8, Pg. 1, Ln. 5.

NorthWestern Corporation (South Dakota)

Attachment 7, COMMON STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Total Proprietary Capital*		Preferred Stock								Acc Other Comp Income		Unappropriated Undistributed Subsidiary Earnings		Common Equity Balance
				Outstanding Balance		Premium (Discount)		Gains/(Losses) on Reacq'd Preferred Stock		Other Paid-In Capital (Preferred Stock)						
		Balance	Source	Acct 204	Source	Acct 207, 213-Pfd	Source	Acct 210	Source	Accts 208 - 211	Source	Acct 219	Source	Acct 216.1	Source	
		Col A		Col B		Col C		Col D		Col E		Col F		Col G		Col H (H=A-B-C-D-E-F-G)
Line	Date															
1.	12/31/20xx	-	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0	[Note (11)]	0	[Note (13)]	-
2.	12/31/20xx	-	[Note (2)]	0	[Note(4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0	[Note (12)]	0	[Note (14)]	-
3.		-		0		0		0		0		0		0		
4.										**Common Equity Balance** [Average of Beg of Yr & End of Yr CE Balance]: [To ATT-6, Page 1, Line 3, Col A]						-

* Includes both Common and Preferred Stock accounts.

[Note (1)]: FF1, Pg. 112, Ln. 16, Col. d. [From Inputs, Pg. 1, Ln. 9]

[Note (2)]: FF1, Pg. 112, Ln. 16, Col. c. [From Inputs, Pg. 1, Ln. 8]

[Note (3)]: From ATT 8, Ln. 1, Col. A.

[Note (4)]: From ATT 8, Ln. 2, Col. A.

[Note (5)]: From ATT 8, Ln. 1; Col. B + Col. C.

[Note (6)]: From ATT 8, Ln. 2; Col. B + Col. C.

[Note (7)]: From ATT 8, Ln. 1, Col. D.

[Note (8)]: From ATT 8, Ln. 2, Col. D.

[Note (9)]: From ATT 8, Ln. 1, Col. E.

[Note (10)]: From ATT 8, Ln. 2, Col. E.

[Note (11)]: FF1, Pg. 112, Ln. 15, Col. d. [From Inputs, Pg. 1, Ln. 7]

[Note (12)]: FF1, Pg. 112, Ln. 15, Col. c. [From Inputs, Pg. 1, Ln. 6]

[Note (13)]: FF1, Pg. 112, Ln. 12, Col. D [From Inputs, Pg. 1, Ln. 5]

[Note (14)]: FF1, Pg. 112, Ln. 12, Col. C [From Inputs, Pg. 1, Ln. 4]

NorthWestern Corporation (South Dakota)

Attachment 8, PREFERRED STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Date	Preferred Stock Acct 204	Data Source	Premium on Preferred Stock Acct 207	Data Source	Discount on Preferred Stock Acct 213	Data Source	Gain/(Loss) On Reaq'd Pref Stock Acct 210	Data Source	Other Paid-In Capital - Preferred Accts 208 - 211	Data Source	Total Outstanding Col F = Cols A+B-C+D+E
		Col A		Col B		Col C		Col D		Col E		COL F
1.	12/31/20xx	0	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0
2.	12/31/20xx	0	[Note (2)]	0	[Note (4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0
3.								**Avg of B of Yr and E of Yr Pref Stock** [To ATT 6, Pg. 1, Col. A, Ln. 2]:				0
4.								**Preferred Dividends** [Note 11]:				0
5.								**Average Cost Rate** [Ln 4 / Ln 3] [To ATT 6, Pg. 1, Col. C, Ln. 2]:				0.00%

Note (1): FF1, Pg. 112, Ln. 3, Col d. [From Inputs, Pg. 1, Ln. 3]

Note (2): FF1, Pg. 112, Ln. 3, Col c. [From Inputs, Pg. 1, Ln. 2]

Note (3): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. d that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (4): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. c that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (5): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. d that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (6): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. c that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (7): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (8): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (9): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. d that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (10): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. c that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (11): FF1, Pg. 118, Ln. 29, Col. c. (Enter as a positive number).

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

GROSS PROCEEDS - LTD OUTSTANDING

Line	Date	Advances from Associated Company LTD		Bonds		Reacquired Bonds		Other Long Term Debt		Total Long Term Debt Outstanding
		Acct 223	Source	Acct 221	Source	Acct 222	Source	Acct 224	Source	Col E= Cols A+B+C+D
		Col A		Col B		Col C		Col D		Col E
1.	12/31/20xx	0	[Note (1)]	-	[Note (3)]	0	[Note (5)]	-	[Note (7)]	-
2.	12/31/20xx	0	[Note (2)]	-	[Note (4)]	0	[Note (6)]	-	[Note (8)]	-
3.		**GROSS PROCEEDS** (Avg of Beg of Yr and End of Yr LTD Gross Outstanding Balances in Col E) [To ATT 6, Pg.1, Ln. 1, Col. A]:								-

Note (1):	FF1, Pg. 112, Line 20, Col d. [From Inputs, Pg. 1, Ln. 15]	Note (5):	FF1, Pg. 112, Ln 19, Col. d. [From Inputs, Pg. 1, Ln. 13]
Note (2):	FF1, Pg. 112, Line 20, Col c. [From Inputs, Pg. 1, Ln. 14]	Note (6):	FF1, Pg. 112, Ln 19, Col. c. [From Inputs, Pg. 1, Ln. 12]
Note (3):	FF1, Pg. 112, Ln 18, Col. D [From Inputs, Pg. 1, Ln. 11]	Note (7):	FF1, Pg. 112, Ln 21, Col. d. [From Inputs, Pg. 1, Ln. 17]
Note (4):	FF1, Pg. 112, Ln 18, Col. C [From Inputs, Pg.1, Ln. 10]	Note (8):	FF1, Pg. 112, Ln 21, Col. c. [From Inputs, Pg. 1, Ln. 16]

NET PROCEEDS

Line	Date		
4.	12/31/20xx	Unamortized balance Premiums (Beg of Yr) [Form 1, Pg. 112, Ln. 22, Col. d] [From Inputs, Pg. 1, Ln. 19]	0
5.	12/31/20xx	Unamortized balance Premiums (End of Yr) [Form 1, Pg. 112, Ln. 22, Col. c] [From Inputs, Pg. 1, Ln. 18]	0
6.		**Avg of Beg & End of Yr Premiums**	0
7.	12/31/20xx	Unamortized balance Discounts (Beg of Yr) [Form 1, Pg. 112, Ln. 23, Col. d] [From Inputs, Pg. 1, Ln. 21]	-
8.	12/31/20xx	Unamortized balance Discounts (End of Yr) [Form 1, Pg. 112, Ln. 23, Col. c] [From Inputs, Pg. 1, Ln. 20]	-
9.		**Avg of Beg & End of Yr Discounts**	-
10.		Gross Proceeds [From Line 3, above]	-
11.		Plus: Unamortized balance Premiums [From Line 6, above]	0
12.		Less: Unamortized balance Discounts [From Line 9, above]	-
13.		**NET PROCEEDS** (Avg of Beg of Yr and End of Yr LTD):	-

General Note: Net long-term average debt balance is used as the divisor to determine LTD debt cost rate. Gross long-term average debt balance is used in the capital structure.

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

LTD COSTS AND EXPENSES (Actual)

Line		
1.	LTD Interest Expense [FF1, Pg. 117, Ln. 62, Col. C] [From Inputs Pg.1, Ln. 24]	0
2.	Amortization Debt Discount and Expense (Acct 428) [FF1, Pg. 117, Ln. 63, Col. c] [From Inputs, Pg. 1, Ln. 25]	0
3.	Amortization of Loss on Reacquired Debt (Acct 428.1) [FF1, Pg. 117, Ln. 64, Col. c] [From Inputs, Pg. 1, Ln. 26]	0
4.	Less: Amort Premium on Debt Credit (Acct 429) [FF1, Pg. 117, Ln. 65, Col. c] [From Inputs, Pg.1, Ln. 27]	0
5.	Less: Amort Gain on Debt Credit (Acct 429.1) [FF1, Pg. 117, Ln. 66, Col. c] [From Inputs, Pg. 1, Ln. 28]	0
5a.	Plus: Interest on Debt to Associated Companies (Acct 430) [FF1, Pg. 117, Ln. 67, Col. c] [From Inputs, Pg. 1, Ln. 40]	0
6.	**TOTAL LTD Interest Amount**	-
7.	Total Long Term Debt Balance (Net Proceeds) [From Pg. 1, Ln. 13, above]	-
8.	**Embedded Cost of Long Term Debt [Line 6/Line 7]** [To ATT 6, Pg. 1, Ln. 1, Col. C]	**#DIV/0!**

ADDENDUM 27 TO ATTACHMENT H, Page 1 of 16
NorthWestern Corporation (South Dakota)

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(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Formula Rate Template Inputs

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Entered Directly From FERC Form No. 1 ("FF1"):

Line No	Account/Description/Classification	Inputs From 2014 FERC Form 1	FF1 Page Location	Template Sheet of the Link
1	Prepayments (165)	5,800,180	111.57c	ATT 5 - Cost Support, Ln. 37
2	Preferred Stock Issued (204) - End of Year	0	112.3c	ATT 8 - Pref Stock, Ln. 2, Col. A
3	Preferred Stock Issued (204) - Beg of Year	0	112.3d	ATT 8 - Pref Stock, Ln. 1, Col. A
4	Unappropriated Undistrib Subsid Earnings (216.1) - End of Yr	0	112.12c	ATT 7 - Com Stock, Ln. 2, Col. G
5	Unappropriated Undistrib Subsid Earnings (216.1) - Beg of Yr	0	112.12d	ATT 7 - Com Stock, Ln. 1, Col. G
6	Accum Other Comp Income (219) - End of Year	0	112.15c	ATT 7 - Com Stock, Ln. 2, Col. F
7	Accum Other Comp Income (219) - Beginning of Year	0	112.15d	ATT 7 - Com Stock, Ln. 1, Col. F
8	Total Proprietary Capital - End of Year (Total Company)	1,477,782,942	112.16c	ATT 7 - Com Stock, Ln. 2, Col. A
9	Total Proprietary Capital - Beginning of Year (Total Company)	1,030,670,372	112.16d	ATT 7 - Com Stock, Ln. 1, Col. A
10	Bonds (221) - End of Year (Total Company)	1,635,205,000	112.18c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. B
11	Bonds (221) - Beginning of Year (Total Company)	1,155,205,000	112.18d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. B
12	(Less) Reacquired Bonds (222) - End of Year	0	112.19c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. C
13	(Less) Reacquired Bonds (222) - Beginning of Year	0	112.19d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. C
14	Advances from Assoc Companies (223) - End of Year	0	112.20c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. A
15	Advances from Assoc Companies (223) - Beginning of Year	0	112.20d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. A
16	Other Long Term Debt (224) - End of Year	0	112.21c	ATT 9 - LTD, Pg. 1, Ln. 2, Col. D
17	Other Long Term Debt (224) - Beginning of Year	0	112.21d	ATT 9 - LTD, Pg. 1, Ln. 1, Col. D
18	Unamortized Premium on Long Term Debt - End of Year	0	112.22c	ATT 9 - LTD, Pg. 1, Ln. 5
19	Unamortized Premium on Long Term Debt - Beginning of Year	0	112.22d	ATT 9 - LTD, Pg. 1, Ln. 4
20	(Less) Unamortized Disc. on Long-Term Debt (Debit) - End of Yr	0	112.23c	ATT 9 - LTD, Pg. 1, Ln. 8
21	(Less) Unamortized Disc. on Long-Term Debt (Debit) - Beg of Yr	0	112.23d	ATT 9 - LTD, Pg. 1, Ln. 7
22	Accumulated Provision for Injuries and Damages (228.2)	711,418	112.28c	ATT 4 - Non-Escrowed Funds, Ln. 4
23	Elec - Taxes Other than Income Taxes (408.1)	6,174,377	115.14g	ATT 2 - Other Taxes, Ln. 22
24	Interest on LTD (427)	63,980,327	117.62c	ATT 9 - LTD, Pg. 2, Ln. 1
25	Amort of Debt Disc & Expenses (428)	6,143,027	117.63c	ATT 9 - LTD, Pg. 2, Ln. 2
26	Amort of Loss on Reacquired Debt (428.1)	1,468,896	117.64c	ATT 9 - LTD, Pg. 2, Ln. 3
27	(less) Amort of Premium on Debt-Credit (429)	0	117.65c	ATT 9 - LTD, Pg. 2, Ln. 4
28	(less) Amort of Gain on Reacquired Debt-Credit (429.1)	0	117.66c	ATT 9 - LTD, Pg. 2, Ln. 5
29	Total Dividends Declared Pref Stock (437)	0	118.29c	ATT 8 - Preferred Stock, Ln. 4, Col. F
30	Electric - Amortization of Other Utility Plant	11,018	200.21c	Appendix A - Ln. 8
31	Total Intangible Plant	102,901	205.5g	Appendix A - Ln. 22
32	Total Electric Plant in Service	597,960,820	207.104g	Appendix A - Ln. 6
33	Trn - Total Transmission Plant	134,030,286	207.58g	ATT 5 - Cost Support, Ln. 1a
34	Transmission Materials & Supplies	1,452,682	227.8.c	Appendix A - Ln. 41
35	Stores Expense Undistributed (Account 163)	0	227.16.c	Appendix A - Ln. 38
36	Total (Acct 190)	28,030,924	234.18c	ATT 1 - ADIT, Pg. 1, Ln. 9
37	Total (Acct 281)	0	273.17k	Line not used
38	Total (Acct 282)	66,919,728	275.9k	ATT 1 - ADIT, Pg. 1, Ln. 18
39	Total (Acct 283)	23,413,737	277.19k	ATT 1 - ADIT, Pg. 1, Ln. 28
40	Interest on Debt to Assoc. Companies	0	117.67c	ATT-9 - LTD, Pg. 2, Ln. 5a
41	Gen - Total General Plant	15,312,076	207.99g	Appendix A - Ln. 21
42	Transmission Accum. Depreciation	54,881,606	219.25c	Line not used
43	General Accum. Depreciation	4,206,553	219.28c	Appendix A - Ln. 29
44	Total Accum Depr Utility Plant	270,870,920	219.29.c	Appendix A - Ln. 7
45	Amortized Investment Tax Credit	245,173	266.8f	ATT 5 - Cost Support, Ln. 103
46	Trn Oper Transmission of Elec by Others	3,903,378	321.96b	ATT 5 - Cost Support, Ln. 50
47	Total Transmission Expenses	6,759,387	321.112b	ATT 5 - Cost Support, Ln. 49
48	A&G Oper Regulatory Commission Expenses	10,025	323.189b	Appendix A - Ln. 58 & ATT - 5, Ln. 63
49	A&G Oper General Advertising Expenses	24,322	323.191b	Appendix A - Ln. 59
50	Total Admin & General Expenses	7,959,730	323.197b	Appendix A - Ln. 54
51	Depreciation Exp (403) - Intangible Plant	0	336.1b	Appendix A - Ln.69
52	Depr Exp Asset Retire (403.1) - Intangible Plant	0	336.1c	Appendix A - Ln. 69
53	Amort Lim Term (404) - Intangible Plant	6,022	336.1d	Appendix A - Ln. 69
54	Amort of Other Intangible Electric Plant (405)	0	336.1e	Appendix A - Ln. 69
55	Depreciation Exp (403) - Transmission Plant	4,129,396	336.7b	Line not used
56	Depr Exp Asset Retire (403.1) - Transmission Plant	0	336.7c	Not used
57	Amort Lim Term (404) - Transmission Plant	0	336.7d	Not used
58	Depreciation Exp (403) - General Plant	942,595	336.10b	Appendix A - Ln. 68
59	Depr Exp Asset Retire (403.1) - General Plant	0	336.10c	Appendix A - Ln. 68
60	Amort Lim Term (404)- General Plant	0	336.10d	Appendix A - Ln. 68
61	Tot Elec O & M Transmission Direct Payroll	1,121,041	354.21b	Appendix A - Ln. 1
62	Tot Elec O & M Admin & General Direct Payroll	3,905,748	354.27b	Appendix A - Ln. 3
63	Total Elec O & M Direct Payroll	12,263,861	354.28b	Appendix A - Ln. 2
64	Transmission Towers and Fixtures	0	206.51.b	Appendix A - Ln. 16
65	Transmission Poles And Fixtures	40,049,770	206.52.b	Appendix A - Ln. 16
66	Distribution Poles, Towers, and Fixtures	35,970,968	206.64.b	Appendix A - Ln. 15
67	Rent from Electric Property	249,759	300.19.b	ATT 3 - Revenue Credits, Ln. 1
68	SD Property Taxes	4,387,649	263.23i	ATT 2 - Other Taxes, Ln. 1
69	ND Property Taxes	7,710	263.37i	ATT 2 - Other Taxes, Ln. 1
70	IA Property Taxes	374,770	263.1.12i	ATT 2 - Other Taxes, Ln. 1
71	Coal Conversion	219,962	263.1.18i	ATT 2 - Other Taxes, Ln. 16
72	Gross Revenue	199,319	263.1.24i	ATT 2 - Other Taxes, Ln. 17
73	Delaware Franchise	19,805	263.1.31i	ATT 2 - Other Taxes, Ln. 15
74	Vehicle Tax	69,614	263.5i	ATT 2 - Other Taxes, Ln. 3
75	Payroll Tax - FICA	685,717	263.7i	ATT 2 - Other Taxes, Ln. 8
76	Payroll Tax - Medicare	198,858	263.14i	ATT 2 - Other Taxes, Ln. 8
77	Payroll Tax - FUT	6,857	263.25i	ATT 2 - Other Taxes, Ln. 9
78	Payroll Tax - FUT-SD	4,114	263.32i	ATT 2 - Other Taxes, Ln. 10

Formula Rate Template Inputs
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Data Input from Company Records and/or Verification Required (Manual Input)

Line No	Account/Description/Classification	Inputs From End of Year	Source of Data	Template Sheet of the Link
1	Federal Income Tax Rate	35%	From Tax Department	Appendix A - Ln. 98
2	State Income Tax Rate	0.00%	From Tax Department	Appendix A - Ln. 99
3	Percent of Federal Tax Eligible for Deduction by South Dakota	0.00%	From Tax Department	Appendix A - Ln. 100
4	State Income Tax Rate	0.00%	From Tax Department	Line not used
5	State Income Tax Rate	0.00%	From Tax Department	Line not used
6	State Income Tax Rate	0.00%	From Tax Department	Line not used
7	Specific FERC 909 Ad costs	150,934	Company Records	ATT 5 - Cost Support, Ln. 64
8	EPRI Annual Membership Dues	6,304	Company Records	Line not used
9	Plant Held for Future Use (Account 105) - Total	0	FF1, 214.47.d	Appendix A - Ln. 26
10	Plant Held for Future Use (Account 105) - Non-Transmission	0	FF1, 214.47.d	Appendix A - Ln. 26
11	Transmission Related Regulatory Expenses	0	FF1, 350.41-44.d	ATT - 5, Ln. 63
12	Plant Held for Future Use (Non-Land) - Transmission Only	0	Company Records	Appendix A - Ln. 26
13	Transmission Gross Plant under SPP tariff	61,524,448	Company Records	Appendix A - Ln. 20
14	Transmission Accumulated Depreciation on assets under SPP tariff	23,630,525	Company Records	Appendix A - Ln. 28
15	Revenues from Directly Assigned Transmission Facilities (ATT 3, Note 2)	0		ATT 5 - Cost Support, Ln. 117
16	Charges billed to Transmission Owner for system integration and transmission costs paid to others that benefit transmission customers and are recorded in Account 565.	0	Verify amount annually	
17	Line left intentionally blank.		Line left intentionally blank.	
18	Other Electric Revenues - Transmission for Others (Schedules 7 & 8)	0	From Acct 457. To: ATT-3, Line 4. Also see ATT 3, Notes 1 & 4	
19	Net revenues associated with Transmission Service Requests, Sponsored Upgrades, and Generation Interconnections for which the load is not included in the divisor.	0	Need to verify during each annual update if there are any such TSR revenues (including TSR revenue from SPP customers not in zone) for load that is NOT included in the UMZ divisor.	
20	Pre-OATT grandfathered Non-Firm Point to Point Service bundled demand revenues for which the load is not included in the divisor received by Transmission Owner and for which the revenues are divided between production and transmission functions.	0	This represents "Point-To-Point" demand revenue margins derived from any "grandfathered" agreements. The non-RQ "Demand Revenues" found in FF1, Pg. 311, Col. h (and page 311 extensions) for these customers should be reduced by the sum of the Demand Charges (costs) found in FF1, Pg. 327, col. j (and page 327 extensions) for these customers.	
21	Annual Depreciation Expense for Transmission Assets under SPP tariff	1,991,439	Company Records from Mgr of Property Acctg	Appendix A - Ln. 67
22	Transmission Pole/Structure Investment (Accts 354+355) under SPP tariff	20,060,654	Company Records from Mgr of Property Acctg	Appendix A - Ln. 17

The Worksheets listed below require Input of Data directly into the Worksheets themselves:

Line	Sheet	Description/Source
23	ATT 1 - ADIT	Accumulated Def Inc Taxes - Verify with Tax Department.
24	ATT 5 - Cost Support	From company records

NorthWestern Corporation (South Dakota)

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Shaded cells are input cells

Line	Description	Notes	FF1 Page # or Instruction	Amount
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b [From Inputs, Pg. 1, Ln. 61]	1,121,041
1a	Transmission under SPP Tariff Factor		[From ATT-5, Ln. 1a]	45.90%
2	Total Wages Expense		p354.28.b [From Inputs, Pg. 1, Ln. 63]	12,263,861
3	Less A&G Wages Expense		p354.27.b [From Inputs, Pg. 1, Ln. 62]	3,905,748
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	8,358,114
5	**Wages & Salary Allocator**		(Line 1 * Line 1a) / Line 4	**6.16%**
	Plant Allocation Factors			
6	Electric Plant in Service		p207.104.g [From Inputs, Pg. 1, Ln. 32]	597,960,820
7	Accumulated Depreciation (Total Electric Plant)		p219.29.c [From Inputs, Pg. 1, Ln. 44]	270,870,920
8	Accumulated Intangible Amortization (Other Utility Plant)	(Note A)	p200.21.c [From Inputs, Pg. 1, Ln. 30]	11,018
9	Total Accumulated Depreciation		(Line 7 + 8)	270,881,938
10	Net Plant		(Line 6 - Line 9)	327,078,882
11	Transmission Gross Plant under SPP tariff (excluding Land Held for Future Use)		(Line 27 - Line 26)	62,473,523
12	**Gross Plant Allocator**		(Line 11 / Line 6)	**10.45%**
13	Transmission Net Plant under SPP tariff (excluding Land Held for Future Use)		(Line 35 - Line 26)	38,583,329
14	**Net Plant Allocator**		(Line 13 / Line 10)	**11.80%**
	T/D Pole Allocation Factor			
15	Gross Distribution Pole/Structure Investment (Acct 364)		p206.64.b [From Inputs, Pg. 1, Ln. 66]	35,970,968
16	Gross Transmission Pole/Structure Investment (Accts 354 + 355)		p206.51.b + p206.52.b [From Inputs, Pg. 1, Lns. 64 & 65]	40,049,770
17	Transmission Pole/Structure Investment (Accts 354 + 355) under SPP tariff		From Inputs, Pg. 2, Line 22	20,060,654
18	Total Pole/Tower Gross Plant		(Line 15 + Line 16)	76,020,738
19	**T/D Revenue Allocation Factor (For Pole Attachment Revenue)**		(Line 17 / Line 18)	**26.39%**
	Plant Calculations			
	Plant In Service			
20	**Transmission Plant In Service under SPP tariff**		[From Inputs, Pg. 2, Ln. 13]	**61,524,448**
21	General		p207.99.g [From Inputs, Pg. 1, Ln. 41]	15,312,076
22	Intangible		p205.5.g [From Inputs, Pg. 1, Ln. 31]	102,901
23	Total General and Intangible Plant		(Line 21 + Line 22)	15,414,977
24	Wage & Salary Allocator		(Line 5)	6.16%
25	**Total General and Intangible Functionalized to Transmission**		(Line 23 * Line 24)	**949,075**
26	**Land Held for Future Use**	(Note C)	[From Inputs, Pg. 2, Lns. 9, 10, & 12]	**0**
27	**Total Plant In Rate Base**		**(Line 20 + Line 25 + Line 26)**	**62,473,523**
	Accumulated Depreciation			
28	Transmission Accumulated Depreciation for assets under SPP tariff	(Note B)	[From Inputs, Pg. 2, Ln. 14]	**23,630,525**
29	General Plant Accumulated Depreciation		p219.28.c [From Inputs, Pg. 1, Ln. 43]	4,206,553
30	Accumulated Intangible Amortization (Other Utility Plant)		(Line 8)	11,018
31	Total Accumulated Depreciation		(Line 29 + 30)	4,217,571
32	Wage & Salary Allocator		(Line 5)	6.16%
33	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 31 * Line 32)	259,669
34	**Total Accumulated Depreciation**		**(Sum Lines 28 + 33)**	**23,890,194**
35	**Total Net Property, Plant & Equipment**		**(Line 27 - Line 34)**	**38,583,329**
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
36	**ADIT**		[From ATT 1, Pg. 1, Ln. 32]	**(5,076,580)**
	Prepayments			
37	Prepayments	(Note A)	[From ATT-5, Ln. 37]	**605,989**
	Materials and Supplies			
38	Undistributed Stores Expense	(Note A)	p227.16.c [From Inputs, Pg. 1, Ln. 35]	0
39	Wage & Salary Allocator		(Line 5)	6.16%
40	Total Undistributed Stores Expense Allocated to Transmission		(Line 38 * Line 39)	0
41	Transmission Materials & Supplies		p227.8.c [From Inputs, Pg. 1, Ln. 34]	1,452,682
42	**Total Materials & Supplies Allocated to Transmission**		(Line 40 + Line 41)	**1,452,682**
	Cash Working Capital			
43	Operation & Maintenance Expense		(Line 66)	1,838,787
44	1/8th Rule		1/8	12.5%
45	**Total Cash Working Capital Allocated to Transmission**		(Line 43 * Line 44)	**229,848**
46	**Non-Escrowed Funds**		[From ATT-4, Line 3, Col. C]	**(83,921)**
47	**Total Adjustment to Rate Base**		(Lines 36 + 37 + 42 + 45 + 46)	**(2,871,982)**
48	**Rate Base**		(Line 35 + Line 47)	**35,711,347**

NorthWestern Corporation (South Dakota)

APPENDIX A

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Description		Note	Source	Amount
	Operations & Maintenance Expense				
	Transmission O&M				
49	Transmission O&M			[From ATT-5, Ln. 49]	3,102,788
50	Less Account 565			[From ATT-5, Ln. 50]	1,791,783
51	Line left intentionally blank				
52	Plus Charges billed to Transmission Owner and booked to Account 565			[From ATT-5, Ln. 52]	0
53	**Transmission O&M**			(Lines 49 - 50)	**1,311,005**
	Allocated Administrative & General Expenses				
54	Total A&G			323.197b [From Inputs, Pg. 1, Ln. 50]	7,959,730
55	Line left intentionally blank				
56	Line left intentionally blank				
57	Line left intentionally blank				
58	Less Regulatory Commission Exp Account 928		(Note D)	p323.189.b [From Inputs, Pg. 1, Ln. 48]	10,025
59	Less General Advertising Exp Account 930.1			p323.191.b [From Inputs, Pg. 1, Ln. 49]	24,322
60	Administrative & General Expenses			Sum (Lines 54 to 55) - Sum (Lines 56 to 59)	7,925,383
61	Wage & Salary Allocator			(Line 5)	6.1568%
62	**Administrative & General Expenses Allocated to Transmission**			(Line 60 * Line 61)	**487,953**
	Directly Assigned A&G				
63	Regulatory Commission Exp Account 928		(Note F)	[From ATT-5, Ln. 63]	0
64	Safety/Peak Alert Advertising Exp (Acct 909)		(Note E)	[From ATT-5, Ln. 64]	39,829
65	**Subtotal - Accounts 909 and 928 - Transmission Related**			(Line 63 + Line 64)	**39,829**
66	**Total Transmission O&M**			**(Lines 53 + 62 + 65)**	**1,838,787**
	Depreciation & Amortization Expense				
	Depreciation Expense				
67	Transmission Depreciation Expense for Assets under SPP tariff		(Note B)	p336.7.b&c&d [From Inputs, Pg. 2, Ln. 21]	**1,991,439**
68	General Depreciation Expense Including Amortization of Limited Term Plant			p336.10.b&c&d [From Inputs, Pg. 1, Lns. 58, 59, & 60]	942,595
69	Intangible Amortization		(Note A)	p336.1.b&c&d&e [From Inputs, Lns. 51, 52, 53, & 54]	6,022
70	Total			(Line 68 + Line 69)	948,618
71	Wage & Salary Allocator			(Line 5)	6.1568%
72	**General Depreciation & Intangible Amortization Allocated to Transmission**			(Line 70 * Line 71)	**58,405**
73	**Total Transmission Depreciation & Amortization**			**(Lines 67 + 72)**	**2,049,844**
	Taxes Other than Income Taxes				
74	**Taxes Other than Income Taxes**			[From ATT-2, Pg. 1, Ln. 14]	**560,782**
75	**Total Taxes Other than Income Taxes**			**(Line 74)**	**560,782**
	Return \ Capitalization Calculations				
	Long Term Interest				
76	**Long Term Interest & Hedging Costs**			[From ATT-9, Pg. 2, Ln. 6]	**71,592,250**
77	**Preferred Dividends**			[From ATT-8, Pg. 1, Ln. 4]	**0**
	Common Stock				
78	Proprietary Capital			[From ATT-7, Pg. 1, Ln. 3, Col. A]	1,254,226,657
79	Less Accumulated Other Comprehensive Income Account 219			[From ATT-7, Pg. 1, Ln. 3, Col. F]	0
80	Less Preferred Stock			[From ATT-8, Pg. 1, Ln. 3, Col. F]	0
81	Less Account 216.1			[From ATT-7, Pg. 1, Ln. 3, Col. G]	0
82	**Common Stock**			(Line 78 - 79 - 80 - 81)	**1,254,226,657**
	Capitalization				
83	Total Long Term Debt (Average)			[From ATT-6, Pg. 1, Ln. 1, Col A]	1,395,205,000
84	Preferred Stock			[From ATT-6, Pg. 1, Ln. 2, Col A]	0
85	Common Stock			[From ATT-6, Pg. 1, Ln. 3, Col A]	1,254,226,657
86	**Total Capitalization**			(Sum Lines 83 to 85)	**2,649,431,657**
87	Debt %	Total Long Term Debt		[From ATT-6, Pg. 1, Ln. 1, Col B]	52.66%
88	Preferred %	Preferred Stock		[From ATT-6, Pg. 1, Ln. 2, Col B]	0.00%
89	Common %	Common Stock		[From ATT-6, Pg. 1, Ln. 3, Col B]	47.34%
90	Debt Cost	Total Long Term Debt		[From ATT-6, Pg. 1, Ln. 1, Col C]	5.13%
91	Preferred Cost	Preferred Stock		[From ATT-6, Pg. 1, Ln. 2, Col C]	0.00%
92	Common Cost	Common Stock		[From ATT-6, Pg. 1, Ln. 3, Col C]	10.97%
93	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 87 * Line 90)	2.70%
94	Weighted Cost of Preferred	Preferred Stock		(Line 88 * Line 91)	0.00%
95	Weighted Cost of Common	Common Stock		(Line 89 * Line 92)	5.19%
96	**Rate of Return on Rate Base (ROR)**			(Sum Lines 93 to 95)	**7.90%**
97	**Investment Return = Rate Base * Rate of Return**			**(Line 48 * Line 96)**	**2,819,522**

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(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Composite Income Taxes

	Income Tax Rates				
98	FIT=Federal Income Tax Rate		(Note G)	[From Inputs, Pg. 2, Ln. 1]	35.00%
99	SIT=State Income Tax Rate or Composite		(Note G)	[From Inputs, Pg. 2, Ln. 2]	0.00%
100	p	(% of fed inc tax deductible for state purposes)	(Note G)	[From Inputs, Pg. 2, Ln. 3]	0.00%
101	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			35.00%
102	T / (1-T)	Tax Gross-Up			53.85%
	ITC Adjustment				
103	Amortized Investment Tax Credit - Transmission Related			[From ATT-5, Ln. 103]	25,615
104	**ITC Adjust. Allocated to Trans. - Grossed Up**	ITC Adjustment x 1 / (1-T)		(Line 103 * (1 / (1-Line 101))	**39,408**
105	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 102 * Line 97 * (1- (Line 93 / Line 96))]	**998,598**
106	**Total Income Taxes**			**(Line 105 - Line 104)**	**959,191**

Revenue Requirement

	Summary				
107	Net Property, Plant & Equipment			(Line 35)	38,583,329
108	Total Adjustment to Rate Base			(Line 47)	(2,871,982)
109	Rate Base			(Line 48)	35,711,347
110	Total Transmission O&M			(Line 66)	1,838,787
111	Total Transmission Depreciation & Amortization			(Line 73)	2,049,844
112	Taxes Other than Income			(Line 75)	560,782
113	Investment Return			(Line 97)	2,819,522
114	Income Taxes			(Line 106)	959,191
115	**Gross Revenue Requirement**			**(Sum Lines 110 to 114)**	**8,228,126**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
116	Transmission Plant In Service under SPP tariff			(Line 20)	61,524,448
117	Revenues from Direct Assigned Transmission F		(Note H)	[From ATT-5, Ln. 117]	0
118	Included Transmission Facilities			(Line 116 - Line 117)	61,524,448
119	Inclusion Ratio			(Line 118 / Line 116)	100.00%
120	Gross Revenue Requirement			(Line 115)	8,228,126
121	**Adjusted Gross Revenue Requirement**			(Line 119 * Line 120)	**8,228,126**
	Revenue Credits & Adjustments				
122	Revenue Credits			[From ATT-3, Ln. 8]	65,907
122a	Refunds and Surcharges (Adjustments to Gross ATRR)				
122b	**Total Revenue Credits and Adjustments**			(Line 122 + Line 122a)	**65,907**
123	**Annual Total Net Revenue Requirement**			**(Line 121 - Line 122b)**	**8,162,218**

Notes:

A Electric portion only.

B Includes only transmission assets under the SPP tariff.

C Includes Transmission portion only.

D Includes all Regulatory Commission Expenses for all Electric jurisdictions.

E Includes safety-related and load/grid congestion management advertising expense included in Account 909 (Product codes ADAS, ADCS, ADPA).

F Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting; as itemized on ATT-5, Ln. 63.

G The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the South Dakota income tax rate, and p = the percentage of federal income tax deductible for South Dakota state income taxes.

H There are no direct assigned transmission facilities on our system as of 12/31/2014. Annual verification/updates will be documented on ATT 5.

ADDENDUM 27 TO ATTACHMENT H, Page 7 of 16
NorthWestern Corporation (South Dakota)

Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 190
(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Account	Identification	(A) YE Balance	(B) 100% Non-Transmission Related	(C) 100% Transmission Related	(D) Plant Related	(E) Labor Related	(F) Total Added to Ratebase	(G) Description
1	190.0	Deferred FIT - Unbilled Revenue	2,173,499			2,173,499			
2	190.0	Deferred FIT - Officers & Directors Deferred Comp.	6,184,058				6,184,058		Deferred compensation, tax deductible when paid
3	190.0	Deferred FIT - Reserves & Accruals	520,050			520,050			
4	190.0	Deferred FIT - Post Retirement Benefits - Pension	98,934				98,934		Relates to pensions - tax funding vs book accrual
5	190.0	Environmental Liability	4,154,036	4,154,036					All natural gas related
6	190.0	Deferred FIT - Non-jurisdictional (SD Gas, NE Gas)	14,900,347	14,900,347					Not South Dakota Electric related
7									
8		**Total**	28,030,924	19,054,383	0	2,693,549	6,282,992		
9		**Conform - [FF1, pg. 234, ln. 18, col. c] (From Inputs Pg. 1, Line 36)**	28,030,924						
10		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	10.45%	6.16%		
11		**Total Transmission**		0	0	281,416	386,834	668,249	
12									
13									
14	282.0	Accum Def FIT - Accel Depr & Amort.	(54,986,224)			(54,986,224)			Accelerated Depreciation & Amortization of non-flow through items
15	282.0	Accum Def FIT - Non-jurisdictional (SD Gas, NE Gas)	(11,933,504)	(11,933,504)					Not South Dakota Electric related
16									
17		**Total**	(66,919,728)	(11,933,504)	0	(54,986,224)	0		
18		**Conform - [FF1, pg. 275, ln. 9, col. k] (Inputs Pg. 1, Line 38)**	(66,919,728)						
19		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	10.45%	6.16%		
20		**Total Transmission**		-	0	(5,744,830)	0	(5,744,830)	
21									
22									
23	283.0	Regulatory Assets	(3,583,885)	(3,583,885)					MGP
24	283.0	FAS109 Flow through deferred taxes	(8,856,636)	(8,856,636)					tax gross up on FAS109 flow through deferred taxes
25	283.0	Non-jurisdictional (SD Gas, NE Gas)	(10,973,216)	(10,973,216)					Not South Dakota Electric related
26									
27		**Total**	(23,413,737)	(23,413,737)	0	0	0		
28		**Conform - [FF1, pg. 277, ln. 19, col. k] (Inputs Pg. 1, Line 39)**	(23,413,737)						
29		**Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]**		0.00%	100.00%	10.45%	6.16%		
30		**Total Transmission**		0	0	0	0	0	
31									
32		**Total ADIT (Ln. 11 + Ln. 20 + Ln 30)**						(5,076,580)	To Appendix A, Line 36

Attachment 2 - Taxes Other Than Income

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Column A	Column B	Column C
	OTHER TAXES:	**Pg. 263 & 263.1 Col (i)**	**Allocator**	**Allocated Amount**
	Currently Included on Appendix A			
	Plant Related:		**Gross Plant Allocator**	
1	Real and Personal Property (State, Municipal or Local) -Current FF1 Year [FF1, Pg. 263, Lns. 23i & 37i; Pg. 263.1, Lns. 12i, 18i, 24i & 31i][From Inputs, Pg. 1, Lns. 68-70]	4,770,129		
2				
3	Vehicle Taxes [From Inputs, Pg. 1, Ln. 74]	69,614		
4				
5				
6				
7	**Total Plant Related [GP Allocator from Appendix A, Ln. 12]**	4,839,743	10.4478%	505,645
	Labor Related:		**Wages & Salary Allocator**	
8	Social Security (FICA/OAB) [FF1, Pg. 263, Ln.5i] [From Inputs, Pg. 1, Ln. 75-76]	884,575		
9	Federal Unemployment Comp. [FF1, Pg. 263, Ln. 7i] [From Inputs, Pg. 1, Ln. 77]	6,857		
10	State Unemployment Comp. [From Inputs, Pg. 1, Lines 78]	4,114		
11				
12				
13	**Total Labor Related [Wages & Sal. Alloc. from Appendix A, Ln.5]**	895,547	6.1568%	55,137
14	**Total Included (Column C, Lines 7 + 13)** [To Appendix A, Line 74]			560,782
	Currently Excluded from Appendix A			
15	Corporate Franchise-Retail [Current Year] [From Inputs, Pg. 1, Ln. 73] [FF1, Pg. 263, Col. i, Lns. 16, 21, & 35; Pg. 263.1, Col. i, Lns. 6, 14, 20, 26, & 33]	19,805		
16	Coal Conversion [From Inputs Pg. 1, Ln. 71]	219,962		
17	SD Gross Receipts Tax [From Inputs, Pg. 2, Ln. 72]	199,319		
18				
19				
20	**Subtotal of Excluded Taxes, [Ln. 15 + Ln. 16 + Ln.17]**	439,087		
21	**Total, Included and Excluded (Column A, Lines 7 + 13 + 20)**	6,174,377		
22	**Total Other Taxes [FF1, pg. 115.14.g] [From Inputs, Pg. 1, Ln. 23]**	6,174,377		
23	Difference (Line 21 - Line 22)	-		

Criteria for Allocation:

A Other Taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Gross Plant Allocator.

B Other Taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

NorthWestern Corporation (South Dakota)

Attachment 3 - Revenue Credits

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

	Account 454 - Rent from Electric Property	
1	Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 1, Ln. 67]	249,759
2	T/D Revenue Allocation Factor [From Appendix A, Ln. 19]	26.39%
3	Rent from Electric Transmission Property [Line 1 x Line 2]	65,907
	Other Electric Revenues (Note 1)	
4	SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 3) [From Inputs, Pg. 2, Ln. 18]	0
5	Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 3) [From Inputs, Pg. 2, Ln. 20]	0
6	Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 2, Ln. 15]	0
7	Other Revenues Associated with Loads Outside of NorthWestern's Zone [From Inputs, Pg. 2, Ln. 19]	0
8	Gross Revenue Credits (sum Lines 3 thru 9) [To Appendix A, Line 122]	65,907

Note 1: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Accounts 457.137 (Firm Point-to-Point) and 457.138 (Non-Firm Point-to-Point). All NorthWestern point-to-point transmission customers are included in the UMZ Load Divisor.

Note 2: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

Note 3: The portion of Point-to-Point revenues collected by SPP and assigned to NorthWestern are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by NorthWestern for "grandfathered" bundled contracts will be included on ATT 3, Ln. 8. See note on "Inputs" worksheet, Pg. 2, Ln. 20 regarding remaining pre-OATT contracts.

NorthWestern Corporation (South Dakota)

Attachment 4, NON-ESCROWED FUNDS

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

The purpose of this worksheet is to individually document the value(s) of the non-escrowed reserve funds that will be credited against working capital. All inputs are derived from the Company's Books and Records, as described.

Line	Description of Reserve:	FERC Reserve Acct	FERC Expense Acct [1]	Balance 12/31/2014 COL. A	Allocator NP COL. B	Working Capital Adjustment (Col. C = Col. A x Col. B) COL. C
1.	Accum Prov for Inj/Damgs	228.2	925	$ 711,418	11.796%	$ 83,921
2.	Other adjustments				11.796%	$ -
3.	**Total** (Ln. 1 + Ln. 2) [Appendix A, Pg. 1, Ln. 46]			$ 711,418		$ 83,921
4.	Conformation [FF1, Pg. 112, Ln. 28, Col. c] [From Inputs, Pg. 1, Ln. 22]			711,418		

[1] Account 925 is the FERC expense account which includes the cost of insurance, the cost of claims not covered by insurance, the re-imbursement from insurance companies, and amounts credited to account 228.2 as Accumulated Provision for Injuries and Damages.

Attachment 5 - Cost Support

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Prepayments			FF1 Amount	Gross Plant Allocator	Functionalized to Transmission	Details
37	Prepayments	FF1 Pg. 111.57.c [From Inputs, Pg. 1, Ln. 1]	5,800,180	10.45%	605,989	

Regulatory Expense Related to Transmission Cost Support:			FF1 Amount	Allocated to transmission	Functionalized to Transmission	Details
63	Regulatory Commission Exp Account 928	FF1 323.189.b [From Inputs, Pg. 1, Ln. 48] & 350.41.d thru 350.44.d [From Inputs, Pg. 2, Ln. 11]	10,025	0.00%	0	

Advertisements:			FF1 Amount	T/D Allocator	Functionalized to Transmission	Details
64	Advertisements FERC 909	FF1 111.57.c [From Inputs, Pg. 2, Ln. 7]	150,934	26.39%	39,829	

ITC Adjustment:			FF1 Amount	GP Allocator	Functionalized to Transmission	Details
103	Amortized Investment Tax Credit	FF1 266.8.f [From Inputs, Pg.1, Ln. 45]	245,173	10.45%	25,615	

Adjustment to Remove Revenue Requirements Associated w/ Excluded Transmission Facilities			Revenues from Direct Assigned Transmission Facilities	General Description of the Direct Assigned Transmission Facilities
117	Revenues from Direct Assigned Transmission Facilities	[From Inputs, Pg. 2, Ln. 15]	0	Direct Assignment Facilities: Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval.

Adjustments to Transmission O&M:			Total	Transmission under SPP Factor	Functionalized to Transmission	Details
49	Transmission O&M	FF1 321.112.b [From Inputs, Pg. 1, Ln. 47]	6,759,387	45.90%	3,102,788	
50	Less Account 565	FF1 321.96.b [From Inputs, Pg. 1, Ln. 46]	3,903,378	45.90%	1,791,783	
52	Plus Charges billed to Transmission Owner and booked to Account 565	[From Inputs, Pg. 2, Ln. 16]	0	45.90%	0	

Adjustments to Transmission Plant for only assets under SPP tariff:			Total Transmission	Transmission under SPP	Details
20	Transmission Assets	FF1 207.58g [From Inputs, Pg. 1, Ln. 33]	134,030,286	61,524,448	
1a	Transmission under SPP Factor	(Transmission under SS divided by Total Transmission)	45.90%		

NorthWestern Corporation (South Dakota)

Attachment 6, WEIGHTED AVERAGE COST OF CAPITAL

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

Line	Type of Capital	Total Company Average Capitalization ($) Balance	Source	Weighted Cost Ratios (%) Col B = Col A/Col A Total	Cost of Capital (%)	Source	Weighted Cost of Capital (%) Col D = Col B x Col C
		Col A		Col B	Col C		Col D
1.	Long Term Debt	1,395,205,000	[Note (1)]	52.66%	5.13%	[Note (4)]	2.70%
2.	Preferred Stock	0	[Note (2)]	0.00%	0.00%	[Note (5)]	0.00%
3.	Common Stock	1,254,226,657	[Note (3)]	47.34%	10.97%		5.19%
4.	Totals	2,649,431,657		100.00%			
5.	**Weighted Average Cost of Capital ("R")**						7.90%

Note(1): From ATT 9, Pg. 1, Ln. 3.

Note (2): From ATT 8, Pg. 1, Ln. 3.

Note (3): From ATT 7, Pg. 1, Ln. 4.

Note(4): From ATT 9, Page 2, Ln. 8

Note (5): From ATT 8, Pg. 1, Ln. 5.

NorthWestern Corporation (South Dakota)

Attachment 7, COMMON STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Total Proprietary Capital*		Preferred Stock								Acc Other Comp Income		Unappropriated Undistributed Subsidiary Earnings		Common Equity Balance
				Outstanding Balance		Premium (Discount)		Gains/(Losses) on Reacq'd Preferred Stock		Other Paid-In Capital (Preferred Stock)						
		Balance	Source	Acct 204	Source	Acct 207, 213-Pfd	Source	Acct 210	Source	Accts 208 - 211	Source	Acct 219	Source	Acct 216.1	Source	
		Col A		Col B		Col C		Col D		Col E		Col F		Col G		Col H (H=A-B-C-D-E-F-G)
Line	Date															
1.	12/31/2013	1,030,670,372	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0	[Note (11)]	0	[Note (13)]	1,030,670,372
2.	12/31/2014	1,477,782,942	[Note (2)]	0	[Note(4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0	[Note (12)]	0	[Note (14)]	1,477,782,942
3.		1,254,226,657		0		0		0		0		0		0		
4.										**Common Equity Balance** [Average of Beg of Yr & End of Yr CE Balance]: [To ATT-6, Page 1, Line 3, Col A]						1,254,226,657

* Includes both Common and Preferred Stock accounts.

[Note (1)]: FF1, Pg. 112, Ln. 16, Col. d. [From Inputs, Pg. 1, Ln. 9]

[Note (2)]: FF1, Pg. 112, Ln. 16, Col. c. [From Inputs, Pg. 1, Ln. 8]

[Note (3)]: From ATT 8, Ln. 1, Col. A.

[Note (4)]: From ATT 8, Ln. 2, Col. A.

[Note (5)]: From ATT 8, Ln. 1; Col. B + Col. C.

[Note (6)]: From ATT 8, Ln. 2; Col. B + Col. C.

[Note (7)]: From ATT 8, Ln. 1, Col. D.

[Note (8)]: From ATT 8, Ln. 2, Col. D.

[Note (9)]: From ATT 8, Ln. 1, Col. E.

[Note (10)]: From ATT 8, Ln. 2, Col. E.

[Note (11)]: FF1, Pg. 112, Ln. 15, Col. d. [From Inputs, Pg. 1, Ln. 7]

[Note (12)]: FF1, Pg. 112, Ln. 15, Col. c. [From Inputs, Pg. 1, Ln. 6]

[Note (13)]: FF1, Pg. 112, Ln. 12, Col. D [From Inputs, Pg. 1, Ln. 5]

[Note (14)]: FF1, Pg. 112, Ln. 12, Col. C [From Inputs, Pg. 1, Ln. 4]

NorthWestern Corporation (South Dakota)

Attachment 8, PREFERRED STOCK

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

		Preferred Stock		Premium on Preferred Stock		Discount on Preferred Stock		Gain/(Loss) On Reaq'd Pref Stock		Other Paid-In Capital - Preferred		Total Outstanding
		Acct 204	Data Source	Acct 207	Data Source	Acct 213	Data Source	Acct 210	Data Source	Accts 208 - 211	Data Source	Col F = Cols A+B-C+D+E
Line	Date	Col A		Col B		Col C		Col D		Col E		COL F
1.	12/31/2013	0	[Note (1)]	0	[Note (3)]	0	[Note (5)]	0	[Note (7)]	0	[Note (9)]	0
2.	12/31/2014	0	[Note (2)]	0	[Note (4)]	0	[Note (6)]	0	[Note (8)]	0	[Note (10)]	0
3.							**Avg of B of Yr and E of Yr Pref Stock** [To ATT 6, Pg. 1, Col. A, Ln. 2]:					0
4.							**Preferred Dividends** [Note 11]:					0
5.							**Average Cost Rate** [Ln 4 / Ln 3] [To ATT 6, Pg. 1, Col. C, Ln. 2]:					0.00%

Note (1): FF1, Pg. 112, Ln. 3, Col d. [From Inputs, Pg. 1, Ln. 3]

Note (2): FF1, Pg. 112, Ln. 3, Col c. [From Inputs, Pg. 1, Ln. 2]

Note (3): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. d that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (4): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. c that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (5): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. d that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (6): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. c that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (7): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (8): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (9): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. d that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (10): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. c that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (11): FF1, Pg. 118, Ln. 29, Col. c. (Enter as a positive number).

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

GROSS PROCEEDS - LTD OUTSTANDING

Line	Date	Advances from Associated Company LTD		Bonds		Reacquired Bonds		Other Long Term Debt		Total Long Term Debt Outstanding
		Acct 223	Source	Acct 221	Source	Acct 222	Source	Acct 224	Source	Col E= Cols A+B+C+D
		Col A		Col B		Col C		Col D		Col E
1.	12/31/2013	0	[Note (1)]	1,155,205,000	[Note (3)]	0	[Note (5)]	-	[Note (7)]	1,155,205,000
2.	12/31/2014	0	[Note (2)]	1,635,205,000	[Note (4)]	0	[Note (6)]	-	[Note (8)]	1,635,205,000
3.		**GROSS PROCEEDS** (Avg of Beg of Yr and End of Yr LTD Gross Outstanding Balances in Col E) [To ATT 6, Pg.1, Ln. 1, Col. A]:								1,395,205,000

Note (1):	FF1, Pg. 112, Line 20, Col d. [From Inputs, Pg. 1, Ln. 15]	Note (5):	FF1, Pg. 112, Ln 19, Col. d. [From Inputs, Pg. 1, Ln. 13]
Note (2):	FF1, Pg. 112, Line 20, Col c. [From Inputs, Pg. 1, Ln. 14]	Note (6):	FF1, Pg. 112, Ln 19, Col. c. [From Inputs, Pg. 1, Ln. 12]
Note (3):	FF1, Pg. 112, Ln 18, Col. D [From Inputs, Pg. 1, Ln. 11]	Note (7):	FF1, Pg. 112, Ln 21, Col. d. [From Inputs, Pg. 1, Ln. 17]
Note (4):	FF1, Pg. 112, Ln 18, Col. C [From Inputs, Pg.1, Ln. 10]	Note (8):	FF1, Pg. 112, Ln 21, Col. c. [From Inputs, Pg. 1, Ln. 16]

NET PROCEEDS

Line	Date		
4.	12/31/2013	Unamortized balance Premiums (Beg of Yr) [Form 1, Pg. 112, Ln. 22, Col. d] [From Inputs, Pg. 1, Ln. 19]	0
5.	12/31/2014	Unamortized balance Premiums (End of Yr) [Form 1, Pg. 112, Ln. 22, Col. c] [From Inputs, Pg. 1, Ln. 18]	0
6.		**Avg of Beg & End of Yr Premiums**	0
7.	12/31/2013	Unamortized balance Discounts (Beg of Yr) [Form 1, Pg. 112, Ln. 23, Col. d] [From Inputs, Pg. 1, Ln. 21]	-
8.	12/31/2014	Unamortized balance Discounts (End of Yr) [Form 1, Pg. 112, Ln. 23, Col. c] [From Inputs, Pg. 1, Ln. 20]	-
9.		**Avg of Beg & End of Yr Discounts**	-
10.		Gross Proceeds [From Line 3, above]	1,395,205,000
11.		Plus: Unamortized balance Premiums [From Line 6, above]	0
12.		Less: Unamortized balance Discounts [From Line 9, above]	-
13.		**NET PROCEEDS** (Avg of Beg of Yr and End of Yr LTD):	1,395,205,000

General Note: Net long-term average debt balance is used as the divisor to determine LTD debt cost rate. Gross long-term average debt balance is used in the capital structure.

NorthWestern Corporation (South Dakota)

Attachment 9, LONG-TERM DEBT

(For Rate Year Beginning October 1, 2015, Based on December 31, 2014 Data)

LTD COSTS AND EXPENSES (Actual)

Line		
1.	LTD Interest Expense [FF1, Pg. 117, Ln. 62, Col. C] [From Inputs Pg.1, Ln. 24]	63,980,327
2.	Amortization Debt Discount and Expense (Acct 428) [FF1, Pg. 117, Ln. 63, Col. c] [From Inputs, Pg. 1, Ln. 25]	6,143,027
3.	Amortization of Loss on Reacquired Debt (Acct 428.1) [FF1, Pg. 117, Ln. 64, Col. c] [From Inputs, Pg. 1, Ln. 26]	1,468,896
4.	Less: Amort Premium on Debt Credit (Acct 429) [FF1, Pg. 117, Ln. 65, Col. c] [From Inputs, Pg.1, Ln. 27]	0
5.	Less: Amort Gain on Debt Credit (Acct 429.1) [FF1, Pg. 117, Ln. 66, Col. c] [From Inputs, Pg. 1, Ln. 28]	0
5a.	Plus: Interest on Debt to Associated Companies (Acct 430) [FF1, Pg. 117, Ln. 67, Col. c] [From Inputs, Pg. 1, Ln. 40]	0
6.	**TOTAL LTD Interest Amount**	71,592,250
7.	Total Long Term Debt Balance (Net Proceeds) [From Pg. 1, Ln. 13, above]	1,395,205,000
8.	**Embedded Cost of Long Term Debt [Line 6/Line 7]** [To ATT 6, Pg. 1, Ln. 1, Col. C]	**5.13%**

ATTACHMENT 3

DIRECT TESTIMONY AND EXHIBITS OF ADRIEN M. MCKENZIE

Attachment 5

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation	**)**	**Docket No. ER15-____-000**

DIRECT TESTIMONY AND EXHIBITS
OF
ADRIEN M. MCKENZIE, CFA

ON BEHALF OF

NORTHWESTERN CORPORATION

JUNE 29, 2015

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE, CFA

TABLE OF CONTENTS

EXHIBITS TO DIRECT TESTIMONY

Exhibit No.	**Description**
NWE-101	Qualifications of Adrien M. McKenzie
NWE-102	Summary of Results
NWE-103	Risk Measures – National Group
NWE-104	FERC Two-Stage DCF Model
NWE-105	Electric Utility Risk Premium – FERC ROE
NWE-106	Capital Asset Pricing Model
NWE-107	Expected Earnings Approach
NWE-108	Allowed ROEs – National Group
NWE-109	Electric Utility Risk Premium – State ROE
NWE-110	Empirical Capital Asset Pricing Model
NWE-111	Risk Premium – Natural Gas Pipelines
NWE-112	DCF Model – Non-Utility Group

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

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. The details of my qualifications and experience are included in Exhibit No. NWE-101 attached to my testimony.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Federal Energy Regulatory Commission ("FERC" or "Commission") my independent analysis of a fair return on equity ("ROE") for NorthWestern Corporation, d/b/a NorthWestern Energy ("NorthWestern" or the "Company").

Q5. HOW IS YOUR TESTIMONY ORGANIZED?

A5. After briefly summarizing the operations and finances of NorthWestern, I present my conclusions and recommendations regarding a fair ROE for the Company. I then apply the Commission's two-step discounted cash flow ("DCF") model set forth in Opinion Nos. 531 and 531-A[1] to estimate the current cost of equity for a comparable-risk group of other electric utilities. I refer to these sixteen utilities as the "National Group." Consistent with Opinion No. 531, my analyses also examines 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. Along with reference to state-allowed ROEs, 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,[2] and my recommended ROE relies on these same factors as well.

Next, I evaluate these quantitative results by reference to additional benchmarks based on a risk premium approach using ROEs authorized by state regulators; the empirical CAPM ("ECAPM"), which is a derivative of the traditional CAPM model; Commission-approved ROEs for natural gas pipelines; projected bond yields, as applied to the risk premium, CAPM, and ECAPM approaches; and a DCF analysis based on a select group of low risk non-utility firms.

II. NORTHWESTERN ENERGY

Q6. BRIEFLY DESCRIBE NORTHWESTERN.

A6. NorthWestern is engaged in providing regulated electric and natural gas utility service to approximately 692,000 customers in Montana, South Dakota, and

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[1] *Martha Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 ("Opinion No. 531"), *reh'g granted for further consideration*, Docket No. EL11-66-002 (issued Aug. 20, 2014), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014) ("Opinion No. 531-A").
[2] *Id.* at P 146.

Nebraska. The Company engages in the generation, transmission, and distribution of electricity, as well as the purchase, transmission, distribution, and storage of natural gas. At year-end 2014, NorthWestern had total, Company-wide assets of approximately $5.0 billion, with total revenues of approximately $1.2 billion. NorthWestern's retail electric and natural gas operations are subject to the jurisdictions of the Montana Public Service Commission, the Nebraska Public Service Commission, and the South Dakota Public Utilities Commission.

NorthWestern's generating capacity requirements are met through a combination of approximately 1,250 megawatts ("MW") of company-owned facilities and jointly owned power plants, including 633 MW associated with eleven hydroelectric generating facilities and associated assets recently purchased from PPL Montana, LLC. The Company's transmission network includes approximately 6,700 miles of lines in Montana and 3,500 miles of overhead and underground lines in South Dakota. NorthWestern's South Dakota division, which is not physically interconnected with its transmission system in Montana, is a member of the Mid-Continent Area Power Pool and is fully subsumed within the footprint of the Western Area Power Administration ("WAPA").

Q7. WILL NORTHWESTERN BECOME A MEMBER OF A REGIONAL TRANSMISSION ORGANIZATION ("RTO")?

A7. Yes. NorthWestern anticipates that its South Dakota division will be integrated into the Southwest Power Pool, Inc. ("SPP") in October 2015. At that time, the SPP Open Access Transmission Tariff ("OATT") will supersede NorthWestern's South Dakota OATT, NorthWestern will transfer operational control of its transmission to SPP, and the Company will participate as a transmission-owning member in the SPP integrated transmission planning process.

Q8. WHAT CREDIT RATINGS ARE ASSIGNED TO NORTHWESTERN?

A8. NorthWestern has been assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P") and a senior unsecured debt credit rating of "A3" from Moody's Investor Services, Inc. ("Moody's"). Meanwhile, Fitch Ratings Ltd. ("Fitch") has assigned an issuer default rating of "BBB+" to NorthWestern.

Q9. HOW WILL NORTHWESTERN RECOVER THE COSTS, INCLUDING ITS ROE, ASSOCIATED WITH ITS TRANSMISSION INVESTMENTS?

A9. NorthWestern intends to use a formula rate under the Southwest Power Pool transmission tariff that will enable it to recover its annual transmission revenue requirements. This formula is addressed in the testimony of Kendall G. Kliewer. ROE will be a fixed input in the formula rate template.

III. RETURN ON EQUITY FOR NORTHWESTERN

Q10. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A10. This section of my testimony presents my conclusions regarding a fair ROE for NorthWestern. 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 NorthWestern be set at 10.47%. I then address how an ROE at this level meets the Commission's policy goal of supporting investment in electric transmission infrastructure. Finally, I explain that including a 50 basis point incentive adder associated with NorthWestern's membership in an RTO is consistent with Commission policy and precedent.

A. Importance of Regulatory Standards

Q11. WHAT IS THE ROLE OF ROE IN SETTING A UTILITY'S RATES?

A11. 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*[3] and *Hope*,[4] 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.

Q12. WHAT ULTIMATELY GOVERNS THE SELECTION OF A FAIR ROE?

A12. The Commission has recognized that a reasonable point-estimate ROE should be determined based on the facts specific to each proceeding.[5] That point estimate must also meet the standards mandated by the Supreme Court.[6] 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*."[7] This determination requires the Commission to consider all of the available evidence and identify an ROE that is just, reasonable, and sufficient to support NorthWestern'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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[3] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

[4] *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*").

[5] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc*., 106 FERC ¶ 61,302 at P 8 (2004).

[6] *See, e.g.,id.* at PP 13-14. The Commission observed that,

> [W]e 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*, 262 U.S. at 693).

[7] Opinion No. 531 at P 144.

Q13. PLEASE DESCRIBE YOUR UNDERSTANDING OF OPINION NO. 531.

A13. In Opinion No. 531, the Commission adopted a two-step DCF methodology for use in evaluating a just and reasonable ROE for electric utilities.[8] The Commission also recognized that the results of its two-step DCF model were affected by unrepresentative financial inputs related to capital market conditions that were anomalous when compared to the historical record.[9] Because of the anomalous conditions in capital markets, the Commission stated that it had "less confidence that the midpoint of the zone of reasonableness . . . accurately reflects the equity returns necessary" to attract capital.[10]

Under those circumstances, in order to ensure that the standards in *Hope* and *Bluefield* were met, the Commission recognized that it was "necessary and reasonable" to consider the results of other ROE models and benchmarks,[11] which are widely employed in regulatory proceedings and utilized in the financial community. These other ROE models and benchmarks are used to gain insight into the effects of anomalous capital market conditions on a point estimate ROE from within the DCF range of returns.[12]

The alternative benchmarks the Commission considered were as follows: A risk premium analysis, a capital asset pricing model ("CAPM") analysis, and an expected earnings analysis.[13] The Commission also considered evidence of ROEs approved by state commissions to determine whether an upward adjustment to the

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[8] Opinion No. 531, 147 FERC ¶ 61,234 at P 8.
[9] *Id.* P 145.
[10] *Id.*
[11] *Id.*
[12] *Id*.
[13] *Id.* at P 147.

central tendency of the DCF results was necessary.[14] The Commission explained that setting an ROE at a level below the ROEs set by state commissions "would put interstate transmission investments at a competitive disadvantage in the capital market in contrast with more conventional electric utility activities."[15]

Q14. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

A14. 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. On the other hand, the lack of a stable regulatory environment can create difficulties in raising the necessary capital to address transmission infrastructure needs, which will ultimately lead to increased costs or other adverse consequences for customers.

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[14] *Id.* at P 148.
[15] *Id*. at P 150.

B. Summary and Conclusions

Q15. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR NORTHWESTERN?

A15. Based on the results of my analyses, I recommend a base ROE for NorthWestern of 10.47%.

Q16. PLEASE SUMMARIZE THE RESULTS OF THE COMMISSION'S TWO-STEP DCF ANALYSIS.

A16. The results of my analyses are summarized in Exhibit No. NWE-102. Page 1 of Exhibit No. NWE-102 displays the results of the primary methods relied on by the Commission in Opinion No. 531. In addition to referencing the published five-year earnings per share ("EPS") growth forecast from IBES,[16] I also applied the Commission's two-step method using projected EPS growth rates from The Value Line Investment Survey ("Value Line"). With respect to the DCF method, I conclude that:

- Application of the two-step DCF methodology based on EPS growth estimates from IBES results in an adjusted ROE zone of reasonableness of 7.13% to 12.26%, a median value of 8.68%, and a midpoint of the upper half of the range of 10.47%;
- Application of the two-step DCF methodology based on EPS growth rates from Value Line results in an adjusted ROE zone of reasonableness of 6.09% to 10.64%, a median value of 8.84%, and a midpoint of the upper half of the range of 9.74%;
- The Commission has recognized that determining a point estimate ROE from within the DCF zone is not a mechanical, arithmetic exercise; but instead requires critical evaluation of DCF estimates in light of current capital market conditions and against the results of other methods;
- Considering current capital market conditions, values at the low end of the DCF range impart a downward bias to the results;

[16] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters. I obtained these IBES growth rates from http://finance.yahoo.com, which is the recognized source of IBES data used to apply the Commission's DCF approach.

- An ROE from the upper end of the DCF range is consistent with the Commission's recent findings and is warranted in light of continued anomalous capital market conditions.

Q17. IS THIS CONCLUSION REINFORCED BY YOUR EVALUATION OF ALTERNATIVE ROE METHODS?

A17. Yes. My application of the risk premium, CAPM, and expected earnings methods demonstrates that the median value resulting from the Commission's two-step DCF method is far below investors' required return. These methods show that, as in Opinion No. 531, the appropriate ROE should be set significantly above the median or midpoint of the DCF range. As summarized on page 1 of Exhibit No. NWE-102:

- The utility risk premium approach based on Commission-approved ROEs for electric utilities implies an ROE point estimate of 10.36%;
- The forward-looking CAPM estimates produce an ROE range of 7.93% to 12.61%, with a median of 10.43%;
- Earned returns for the electric utility industry are expected to average 10.62%, and fall in a range of 8.67% to 12.84% 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 10.28%;
- Midpoint cost of equity estimates associated with these quantitative methods ranged from 10.27% to 10.75%, with the average of the individual midpoint estimates being 10.50%; and
- All of these results demonstrate that the median values resulting from the Commission's two-step DCF method are far too low to be considered reasonable.

Q18. DO STATE-APPROVED ROES ALSO SUPPORT AN ROE FOR NORTHWESTERN WELL ABOVE THE MEDIAN VALUE IMPLIED BY THE TWO-STEP DCF MODEL?

A18. Yes. As shown on Exhibit No. NWE-108, the state-approved ROEs currently reported for the utilities in the National Group by Value Line fell in a range of

9.19% to 10.67%, with a median of 10.10%. Meanwhile, as shown on page 1 of Exhibit No. NWE-104, the median result of the IBES-based DCF model is 8.68%. Just as in Opinion No. 531, the significant discrepancy between state-approved ROEs for the proxy group and the 8.68% DCF median "serves as an indicator that an upward adjustment . . . is necessary to satisfy *Hope* and *Bluefield*."[17] 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.[18]

Q19. WHAT CONCLUSIONS DO YOU REACH REGARDING THE RESULTS OF THE DCF MODEL?

A19. In Opinion No. 531, 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.[19] 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. As my testimony explains, 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 have continued.

My analysis therefore replicates the Commission's use of alternative ROE methodologies to test the results of the DCF model and inform the determination of a just and reasonable ROE from within the DCF zone. As in Opinion No. 531,

[17] Opinion No. 531 at P 148.
[18] *Id.* at P 149.
[19] *Id.* at P 145.

alternative methodologies show that use of the median DCF result would not produce a just and reasonable result, and support a just and reasonable ROE from the upper end of the DCF range of reasonableness.

Q20. WHAT DID YOU CONCLUDE AS TO A FAIR AND REASONABLE BASE ROE FOR NORTHWESTERN?

A20. Based on the results of my analyses, I recommend a base ROE of 10.47% for NorthWestern, which represents the midpoint of the upper end of the IBES-based DCF zone of reasonableness. The weight of empirical evidence in this case demonstrates the inadequacy of a base ROE equal to the median of the IBES-based DCF range, which would fail to meet *Hope* and *Bluefield*. My recommended base ROE of 10.47% is supported by the results of alternative ROE benchmarks and the continuation of the aberrational capital market conditions recognized by the Commission, both of which support an ROE for NorthWestern from the upper end of the DCF zone of reasonableness.

Q21. IS A 10.47% BASE ROE FOR NORTHWESTERN SUPPORTED BY OTHER BENCHMARKS?

A21. Yes. Alternative tests not applied by the Commission in Opinion No. 531 consistently support an ROE in the upper half of the DCF zone, and confirm the reasonableness of a 10.47% base ROE for NorthWestern. The results of these analyses are summarized below, and on page 2 of Exhibit No. NWE-102:

- The utility risk premium approach based on state-approved ROEs for electric utilities implies an ROE point estimate of 10.06%;
- The ECAPM approach results in a zone of reasonableness of 8.68% to 12.72%, with a median of 11.08%;
- 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 10.48%;

- After incorporating projected bond yields, the risk premium, CAPM, and ECAPM methods resulted in median cost of equity estimates ranging from 10.85% to 11.53%;
- DCF estimates for a low-risk group of non-utility firms suggest a cost of equity in the range of 7.07% to 12.74%, with a median of 10.34%; and
- Taken together, the overall average of the median ROEs resulting from these alternative benchmarks equals 10.86%.

C. Consistency with Commission Policy Goals

Q22. IS A 10.47% BASE ROE FOR NORTHWESTERN CONSISTENT WITH ESTABLISHED COMMISSION POLICY TO SUPPORT INVESTMENT IN ELECTRIC TRANSMISSION INFRASTRUCTURE?

A22. Yes. The Commission's regulatory actions have been successful in supporting 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. 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.[20]

The Commission has recognized the need to support transmission infrastructure investment by adjusting its methods and instituting reforms, as

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

exemplified by Order No. 1000.[21] 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.

Q23. WILL ROES THAT ARE BELOW THE LEVEL INDICATED BY APPROPRIATE BENCHMARKS UNDERMINE TRANSMISSION INVESTMENT?

A23. Yes. 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 effects on other state and Federal government policy objectives, i.e., renewables development, could be significant, in our view.

My 10.47% base ROE recommendation is appropriate in light of NorthWestern's need to attract capital to transmission infrastructure and the imperative of meeting the *Hope* and *Bluefield* standards.

Q24. HAS THE COMMISSION RECOGNIZED THE IMPORTANCE OF REGULATORY CERTAINTY AND CONSISTENCY IN FOSTERING TRANSMISSION DEVELOPMENT?

A24. Yes. Transparency and stability are important tenets of utility ratemaking and as the Commission has stated, it "strives to provide regulatory certainty through

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[21] Order No. 1000, 136 FERC ¶ 61,051 (2011).

consistent approaches and actions."[22] With respect to ROE in particular, the Commission has recognized the potential disincentive to investment stemming from uncertainties over the administrative process leading to a determination of a fair ROE. In *Order No. 679-A* the Commission concluded that "our hearing procedures for determining ROE can create uncertainty for investors," and noted that:

> Although our processes are designed to provide a just and reasonable return, we recognize that there can be significant uncertainty as to the ultimate return because of the uncertainties associated with administrative determinations (e.g., selection of the proxy group, changes in growth rates, etc.) This can itself constitute a substantial disincentive to new investment.[23]

D. Incentive ROE is Reasonable

Q25. HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR PARTICIPATION IN AN RTO SUCH AS SPP IS APPROPRIATE?

A25. 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.[24] I support increasing the base ROE by a 50 basis point incentive adder to recognize that NorthWestern will be a member of SPP and the transmission facilities of its South Dakota division will be under the operational control of SPP.

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[22] http://www.ferc.gov/about.asp.
[23] *Order No. 679-A*, 117 FERC ¶ 61,345 at P 69 (2006).
[24] *See, e.g., Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at PP 15-16 (2007).

Q26. WHAT ROE IS INDICATED FOR NORTHWESTERN AFTER INCORPORATING AN INCENTIVE FOR RTO MEMBERSHIP?

A26. Combining the 50 basis-point RTO incentive adder with my recommended base ROE of 10.47% implies a total ROE of 10.97%. Because this result falls well below the 12.26% upper bound of the IBES-based ROE range of reasonableness, it meets the Commission's policy guidance governing incentive-based ROEs.[25]

IV. CAPITAL MARKET ESTIMATES

Q27. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A27. 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 is within the range 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 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.

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[25] Commission policy requires that the total ROE of a utility including the impact of an incentive must fall within the zone of reasonableness. *See, e.g., Order No. 679*, 116 FERC ¶ 61,057 at P 93 (2006).

A. Economic Standards

Q28. WHAT ROLE DOES ROE PLAY IN A UTILITY'S RATES?

A28. 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.

Q29. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A29. 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.

Q30. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A30. 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.

Q31. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A31. 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.

Q32. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A32. 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.

Q33. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A33. 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

Q34. HOW DID YOU IMPLEMENT THE DCF METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR NORTHWESTERN?

A34. 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. 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. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and alternative ROE benchmarks 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.

Q35. WHAT SPECIFIC PROXY GROUP DID YOU RELY ON FOR YOUR ANALYSIS?

A35. Consistent with the approach adopted by the Commission in Opinion No. 531, 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 corporate credit ratings of BBB-, BBB, or BBB+ by S&P; and
5. Electric utilities that have been assigned long-term issuer ratings of Baa1, A3, or A2 by Moody's.

As shown on Exhibit No. NWE-103, the National Group is composed of sixteen comparable-risk utilities.

Q36. WHAT WAS THE BASIS FOR THE RANGE OF CREDIT RATINGS USED TO IDENTIFY THE NATIONAL GROUP?

A36. 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.[26] 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.[27] The credit ratings criteria used to identify the National Group are consistent with the BBB S&P corporate credit rating and A3 Moody's issuer rating assigned to NorthWestern.

Q37. WHAT OTHER RISK MEASURES DID YOU EXAMINE?

A37. 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 risk of a stock, and incorporates elements of stock price stability and financial strength.[28] The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including

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[26] Opinion No. 531 at P 107.

[27] *See, e.g., S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 53; *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008).

[28] 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).

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.

Q38. WHAT ARE THE AVERAGE RISK MEASURES ASSIGNED TO YOUR PROXY GROUP?

A38. Risk measures for the National Group and NorthWestern are shown on Exhibit No. NWE-103, 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++	0.77
NorthWestern	BBB	A3	3	B+	0.70

Q39. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH THE NATIONAL GROUP AND NORTHWESTERN?

A39. As shown above, the Company's S&P corporate credit rating of BBB is equal to the average for the National Group. Meanwhile, NorthWestern's higher Moody's issuer rating and lower beta value suggest less risk, while its lower Value Line Safety Rank and Financial Strength Rating suggest more risk than for the National Group. Considered together, this comparison of objective measures, which incorporate 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 NorthWestern are generally comparable to those of the firms in the National Group.

Q40. YOUR NATIONAL GROUP INCLUDES ONLY 16 COMPANIES, WHEREAS THE PROXY GROUP USED IN OPINION NO. 531 HAD 38 COMPANIES. PLEASE EXPLAIN THE REASON FOR THIS DIFFERENCE.

A40. While the changing status of major mergers and acquisitions also impacts proxy group composition over time, the smaller size of my National Group is primarily due to differences in the comparable risk bands under the Commission's screening criteria using S&P and Moody's ratings, which are specific to each case. Opinion No. 531 established a single ROE for a group of transmission owning utilities. Accordingly, the proxy group criteria in that case reflected the broad range of credit ratings for all of the participating utilities, which resulted in a comparable risk band spanning five notches from A to BBB- based on S&P's corporate credit ratings and a six notch band from A1 to Baa3 based on credit ratings from Moody's.[29] Meanwhile, as indicated above, applying the Commission's comparable risk criteria using NorthWestern's ratings results in a much narrower band of BBB+ to BBB- based on S&P and A2 to Baa1 based on Moody's. In addition, because the Commission applies the S&P and Moody's screens independently, the discrepancy between NorthWestern's BBB S&P rating and the Company's A3 rating from Moody's acts to further narrow the number of eligible utilities.

Q41. YOU EXPLAINED ABOVE THAT YOU CONSIDERED CERTAIN VALUE LINE RISK MEASURES IN ADDITION TO S&P AND MOODY'S RATINGS. DID YOU USE THESE VALUE LINE MEASURES TO ELIMINATE ANY COMPANIES THAT WOULD OTHERWISE HAVE BEEN IN THE PROXY GROUP?

A41. No. While I believe the Value Line risk measures presented in Table 1 provide additional confirmation that the investment risks of the National Group are generally comparable to those of NorthWestern, I did not use these indicators to eliminate any companies that would otherwise have been in the proxy group.

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[29] Opinion No. 531 at P 108.

C. DCF Model

Q42. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A42. 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 current market prices, we can back into the discount rate, or cost of equity, to what investors implicitly used in bidding the stock to that price.

Q43. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A43. 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.

Q44. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY?

A44. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[30]

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

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and
g = Investors' long-term growth expectations.

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.

Q45. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A45. 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-

[30] 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.

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.

Q46. WHAT IS THE DISTINCTION BETWEEN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES AND THE CONSTANT GROWTH MODEL OUTLINED ABOVE?

A46. 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.

Q47. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE NATIONAL GROUP?

A47. As indicated on page 1 of Exhibit No. NWE-104, an average dividend yield was developed for each electric utility in the proxy group during the six months from November 2014 through April 2015. This calculation was made by dividing the indicated dividend in each month by the corresponding average of the monthly low and high stock prices. Consistent with the dividend yield calculations adopted by the Commission in the Appendix to Opinion No. 531 that established the DCF results in that proceeding,[31] I used the most recent dividend declared to determine the indicated annual dividend in each month.

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[31] *Id.* at Appendix. Use of the most recent indicated dividend is necessary to replicate the dividend yields calculated and relied on by the Commission in Opinion No. 531.

Apart from being consistent with the actual calculations underlying the DCF results presented in Opinion No. 531, use of the most recent declared dividend is also more congruent with the assumptions of the DCF approach, which is a forward-looking model. Use of a six-month historical average stock price may be a practical accommodation to "even out" short-term volatility in a utility's stock price, but the purpose of the DCF model is to reflect investors' forward-looking expectations, and the familiar "D_1" component of the DCF model is based on dividends for the coming year, not those paid in past periods. As a result, use of the most recent indicated annual dividend, coupled with the Commission's customary 1 + 0.5*g* adjustment, provides a better approximation of investors' dividend expectations for the coming year. Just as it is preferable to employ current estimates of investors' expected growth, rather than values published at the beginning of the six-month analysis period, so too is it appropriate to reflect the utility's most recent dividend payments. Use of the current indicated dividend achieves a better alignment between investors' forward-looking expectations and the representative stock price.

Q48. WHAT GROWTH RATE DID YOU USE TO ADJUST THIS CURRENT DIVIDEND YIELD?

A48. In Opinion No. 531 the Commission relied on the weighted average of the IBES EPS growth rate and the projected growth rate in nominal Gross Domestic Product ("GDP") in developing the DCF estimates it relied on in that proceeding. While the logic and assumptions of the Commission's two-step method dictate that the analysts' EPS growth rate alone should be used to reflect growth over the coming year, this issue has a very minor impact on the DCF calculations in this testimony, and I have elected to adjust the dividend yield using the weighted average growth rate, as was done in Opinion No. 531.[32]

Q49. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A49. The first growth rate, which is intended to represent expectations over the short-term, is represented by analysts' EPS growth projections specific to each individual utility in the proxy group. As noted above, the second growth rate is based on long-term forecasts of growth in nominal GDP.

Q50. WHAT WAS THE SOURCE OF THE IBES GROWTH RATES USED IN YOUR APPLICATION OF THE COMMISSION'S TWO-STEP DCF METHOD?

A50. 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 growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates."[33]

Q51. HOW DID YOU ARRIVE AT YOUR PROJECTED GROWTH RATE IN NOMINAL GDP, REPRESENTING THE SECOND STAGE OF THE COMMISSION'S DCF MODEL?

A51. The Commission has a long history of relying on three independent sources for GDP growth projections in applying the two-step DCF approach in natural gas pipeline proceedings.[34] More recently, the Commission has relied on the long-

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[32] I estimate that use of the near-term IBES growth rate in adjusting the dividend yield would increase the cost of equity results on the order of 2 basis points.

[33] Opinion No. 531 at P 89.

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

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.[35]

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 3 of Exhibit No. NWE-104. 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 4.36%.

Q52. WHAT WEIGHTING DID YOU ASSIGN THESE RESPECTIVE GROWTH RATES TO ARRIVE AT THE SINGLE *"G"* COMPONENT OF THE TWO-STEP DCF MODEL?

A52. Following the practice adopted in Opinion No. 531, 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.

Q53. WHAT WERE THE RESULTS OF YOUR IBES-BASED DCF ANALYSIS?

A53. 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. NWE-104. As shown there, these individual DCF estimates ranged from 4.54% to 12.26%.

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[35] *See* Opinion No. 531-A.

Q54. HOW ELSE DID YOU APPLY THE COMMISSION'S TWO-STEP DCF MODEL?

A54. As shown on page 2 of Exhibit No. NWE-104, I also applied the Commission's two-step DCF model using the projected EPS growth rates published by Value Line.

Q55. HAS THE COMMISSION PREVIOUSLY RELIED ON VALUE LINE PROJECTIONS IN APPLYING THE DCF MODEL?

A55. Yes. The Commission has long recognized the importance of incorporating alternative growth rates in estimating the cost of equity using the DCF model. In fact, it was the recognition that estimates can and do vary that prompted the Commission to consider alternative growth measures in applying the DCF model. For example, in *Southern California Edison Co.*, the Commission supplemented its reliance on a growth rate calculated using Value Line data and used projections from IBES to corroborate the Value Line results and "frame the zone of reasonableness."[36]

Q56. DOES REFERENCE TO VALUE LINE EPS GROWTH PROJECTIONS PROVIDE A MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A56. Yes. Value Line is recognized as being the most widely available source of investment information to investors and there are many citations to textbooks and other sources supporting its usefulness as a guide to investors' expectations. For example, *New Regulatory Finance* concluded that:

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[36] *So. Cal. Edison Co*, 92 FERC ¶ 61,070 at p. 61,263 (2000). The Commission has relied upon Value Line in numerous other ROE decisions. *See, e.g.*, *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008); *Northern Pass Transmission LLC,* 134 FERC ¶ 61,095 (2011); *RITELine Illinois, LLC,* 137 FERC ¶ 61,039 (2011).

> 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."[37]

Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations.[38] Consistent with the Commission's past findings, reference to Value Line's EPS growth projections provides another meaningful benchmark in framing the range of results and evaluating a just and reasonable ROE for NorthWestern.

Q57. WHAT WERE THE RESULTS OF YOUR VALUE LINE-BASED DCF APPLICATION?

A57. After combining the dividend yields and the weighted average of the Value Line and GDP growth projections for each utility, the resulting cost of common equity estimates are shown on page 2 of Exhibit No. NWE-104. As shown there, these individual DCF estimates ranged from 5.10% to 10.64 %.

D. Evaluation of DCF Results

Q58. IN EVALUATING THE RESULTS OF THE DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE UNREASONABLY LOW?

A58. Yes. Consistent with Opinion No. 531, which eliminated reliance on certain low-end outliers, in applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and

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[37] Roger A. Morin, *"New Regulatory Finance," Public Utilities Reports, Inc*. at 71 (2006).

[38] The Commission had noted that Value Line is widely available and relied on by investors. *See, e.g.*, Opinion No. 531 at P 102; *Kern River Gas Transmission Co.*, 129 FERC ¶ 61,240 at P 50 (2009).

economic logic. Accordingly, DCF estimates that are implausibly low should be eliminated when evaluating the results of this method.

Q59. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A59. 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 values 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,[39] and in Opinion No. 531, FERC concluded that, "[t]he 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."[40] 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.[41]

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[39] *See, e.g., Virginia Elec. and Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[40] Opinion No. 531 at P 122.
[41] *Id*.

Q60. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A60. As discussed subsequently, while utility bond yields have declined substantially in response to the Federal Reserve's stimulus policies, 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 BBB bond yield of 7.12% over the period 2016-2020:

TABLE 2
IMPLIED UTILITY BOND YIELDS

	2016-20
Projected AA Utility Yield	
IHS Global Insight (a)	6.43%
EIA (b)	6.17%
Average	6.30%
Current BBB - AA Yield Spread (c)	0.82%
Implied Triple-B Utility Yield	**7.12%**

(a) IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014).
(b) Energy Information Administration, Annual Energy Outlook 2015 (April 2015).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Nov. 2014 - Apr. 2015.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip, which projects that yields on corporate bonds will climb over 200 basis points through 2020.[42]

[42] *Blue Chip Financial Forecasts*, Vol. 34, No. 6 (Jun. 1, 2015).

The Commission references a 100 basis point spread over public utility bond as a starting place in evaluating low-end values, but that approach is affected when, as here, anomalously low bond yields do not reflect expectations for the future. As a result, adding a margin of approximately 100 basis points to a six-month historical bond yield average produces a threshold that is too low to reflect investors' required returns going forward. This conclusion is further supported by economic studies that show that risk premiums are higher when interest rates are at very low levels. Under these conditions, the low end of the DCF range is skewed downward, and falls far below what investors require to accept the risks of an equity investment in electric transmission.

Q61. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE NATIONAL GROUP?

A61. As indicated on page 1 of Exhibit No. NWE-104, I eliminated a low-end estimate of 4.54%. Monthly yields on BBB bonds reported by Moody's averaged approximately 4.6% over the six months ended April 2015,[43] with a DCF value of 4.54% falling below this threshold. As shown on page 2 of Exhibit No. NWE-104, I also eliminated a low end DCF estimate of 5.10% in evaluating the results of my Value Line-based DCF analysis. This value is less than 100 basis points above the historical average yield on Baa-rated utility bonds and is properly eliminated under the Commission's test of reasonableness. Considering expectations for higher capital costs, remaining low-end values in the 6% to 7% range continue to impart a downward bias to the DCF results, which supports adopting an ROE for NorthWestern from within the upper end of the zone of reasonableness.

[43] Moody's, CreditTrends, http://credittrends.moodys.com/chartroom.asp?c=3.

Q62. DID YOU EXCLUDE DCF VALUES AT THE HIGH END OF THE RANGE?

A62. No. As the Commission recently noted, "the high-end outlier test is intended to screen out companies whose growth rates are unsustainably high."[44] 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 "the high-end outlier issue . . . is moot because the two-step DCF methodology assumes that the long-term growth rate of all proxy companies is equal to GDP, and is therefore sustainable."[45] As a result, the Commission concluded that a long-term growth rate based on GDP is sustainable and the issue of evaluating high-end values is now moot.

Moreover, the upper end of the IBES-based and Value Line-based DCF ranges for the National Group were set by cost of equity estimates of 12.26% and 10.64%, respectively. These high-end DCF estimates fall far below the 17.7% threshold formerly referenced by the Commission.[46] Similarly, the 7.59% (based on IBES) and 7.12% (based on Value Line) growth rates underlying these respective cost of equity estimates are 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.[47] Accordingly, these cost of equity estimates are properly included.

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[44] Opinion No. 531-B at P 79.
[45] *Id.*
[46] *See, e.g., ISO New England*, 109 FERC ¶ 61,147 at P 205 (2004); *So. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57.
[47] *So. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57.

Q63. WHAT RANGE OR RETURNS WERE INDICATED BY YOUR IBES-BASED AND VALUE LINE-BASED DCF STUDIES?

A63. As shown on page 1 of Exhibit No. NWE-104, the adjusted range of my IBES-based DCF analysis is 7.13% to 12.26%. The median of the IBES-based DCF returns is 8.68% and the upper-end midpoint value is 10.47%. As shown on page 2 of Exhibit No. NWE-104, after eliminating an unrepresentative low-end value, the adjusted range of my Value Line-based DCF analysis is 6.09% to 10.64%, with a median value of 8.84%, and an upper end midpoint value of 9.74%.[48]

V. SELECTION OF AN ROE WITHIN THE DCF RANGE OF REASONABLENESS

Q64. PLEASE EXPLAIN HOW THE COMMISSION SELECTED AN ROE WITHIN THE RANGE OF REASONABLENESS IN OPINION NO. 531.

A64. The Commission considered a range of evidence, including alternative methods to the two-step DCF model for calculating ROEs, to determine whether it should apply its traditional policy of setting the ROE at the central tendency (median or midpoint, depending on the situation) of the range of DCF estimates produced for the proxy group. These alternative methodologies demonstrated that, due to anomalous market conditions, the Commission should depart from its traditional approach and set the ROE at the upper end of the DCF range. In that case, the Commission found that the correct point in the range was the midpoint of the upper end of the DCF range.

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[48] While my application of the two-step DCF model follows Commission precedent, it should not be considered an endorsement of this method. I believe that the Commission's determination in Opinion No. 531 to consider the results of alternative methods in evaluating where to place the just and reasonable ROE within the DCF-determined zone of reasonableness was correct and, when properly applied, can result in a conclusion that satisfies the *Hope* and *Bluefield* standards.

Q65. HAVE YOU APPLIED A SIMILAR APPROACH IN THIS CASE?

A65. Yes. I first describe how anomalous market conditions continue to exist that undermine the ability of the Commission's two-step DCF approach to reflect investors' required return. I then apply the same alternative methodologies used by the Commission in Opinion No. 531 and find that the ROE should be set at the midpoint of the upper end of the ROE range determined using the IBES-based DCF results.

A. Anomalous Capital Market Conditions

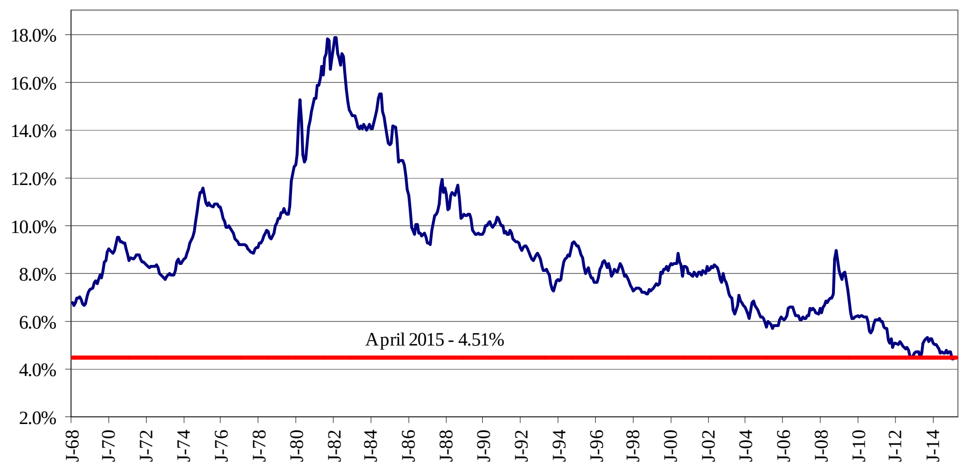
Q66. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE BY SIMPLE APPLICATION OF THE TWO-STEP DCF METHOD?

A66. No. Current capital market conditions continue to reflect the Federal Reserve's unprecedented monetary policy actions in the aftermath 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.

Q67. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A67. The yields on utility bonds remain near their lowest levels in modern history. Figure 1 compares the April 2015 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 over recent decades. Similarly, while 10-year Treasury bond yields may reflect a modest increase from all-time lows of less than 2.0%, they are hardly comparable to historical levels.[49] Federal Reserve President Charles Plosser observed that U.S. interest rates are unprecedentedly low, and "outside historical norms."[50]

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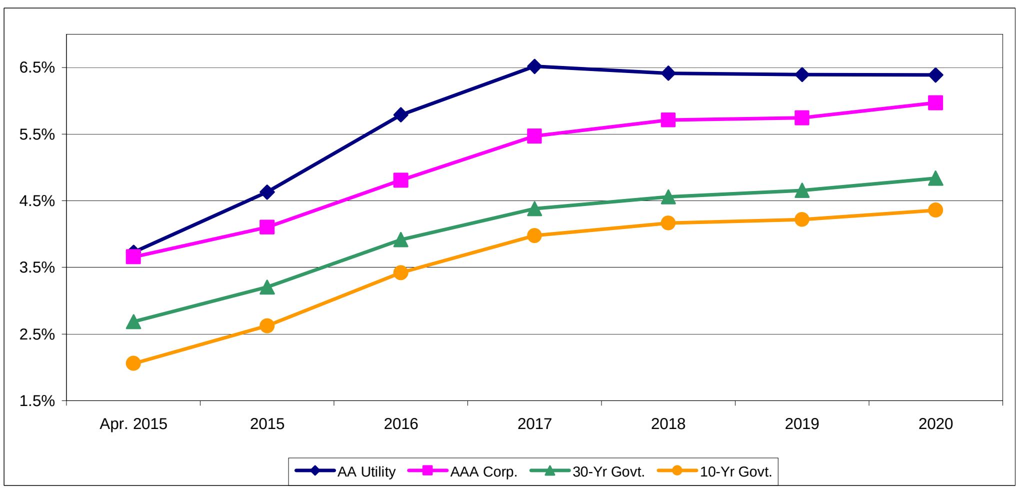
[49] The average yield on 10-year Treasury bonds for the six months ended April 2015 was 2.06%. Over the 1968-2014 period illustrated on Figure 1, 10-year Treasury bond yields averaged 6.75%.
[50] Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," *CNBC* (Nov. 11, 2014).

Q68. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

A68. No. Investors continue to anticipate that interest rates will increase significantly from present levels. As shown below, Figure 2 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"):

FIGURE2
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015)
IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
Energy Information Administration, Annual Energy Outlook 2015 (April 2015)
Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014)

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 present low level of interest rates is an anomaly and will not be sustained.

Q69. DOES THE CESSATION OF FURTHER ASSET PURCHASES BY THE FEDERAL RESERVE MARK A DEPARTURE FROM THE ANOMALOUS CONDITIONS CHARACTERIZING CAPITAL MARKETS?

A69. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400 – $500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Table 3 below charts the course of the Federal Reserve's asset purchase program:

TABLE 3
FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES

(Billion $)

2008	$ 410
2009	$ 1,618
2010	$ 1,939
2011	$ 2,423
2012	$ 2,512
2013	$ 3,597
2014	$ 4,097
2015*	$ 4,069

* at June 4.

As illustrated above, far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities now amount to more than $4 trillion,[51] which is an all-time high.

For now, the Federal Reserve is maintaining its policy of reinvesting principal payments 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. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.[52]

This continued investment maintains the downward pressure on interest rates that is one hallmark of the stimulus program and the anomalous capital market conditions recognized by the Commission in Opinion No. 531.

Q70. HAS THE FEDERAL RESERVE ANNOUNCED ITS INTENTION TO ALTER ITS UNPRECEDENTED POLICY GOING FORWARD?

A70. Yes. The Federal Reserve has stated its commitment to "normalize" its monetary policy stance, including guiding policies and actions during the normalization process. These include taking steps to raise the federal funds rate and other short-term interest rates to more normal levels and to reduce the Federal Reserve's securities holdings by ending its policy of reinvesting principal payments on Treasury and agency-backed debt securities. As the Federal Open Market Committee made clear:

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[51] *Federal Reserve Statistical Release*, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1.
[52] Federal Open Market Committee, *Press Release* (Apr. 29, 2015).

> The Committee intends that the Federal Reserve will, in the longer run, hold no more securities than necessary to implement monetary policy efficiently and effectively, and that it will hold primarily Treasury securities, thereby minimizing the effect of Federal Reserve holdings on the allocation of credit across sectors of the economy.[53]

Of course, the corollary to these observations is that ending this policy of reinvestment is likely to place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. Apart from higher rates, normalization also implies significant uncertainties. As a *Financial Analysts Journal* article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is so vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[54]

Federal Reserve Chair Janet Yellen recently highlighted the potential disruption associated with a spike in long-term interest rates as monetary policy is normalized, noting that "When the Fed decides it's time to begin raising rates, these term premiums could move up and we could see a sharp jump in long-term rates."[55]

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[53] Federal Open Market Committee, "Policy Normalization Principles and Plans," *Press Release* (Sep. 17, 2014).

[54] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," *Financial Analysts Journal* (Nov./Dec. 2013).

[55] Michael Flaherty and Anna Yukhananov, "Yellen cites 'potential dangers' in U.S. stock valuations," *Reuters* (May 6, 2015).

Q71. HAS THE COMMISSION ADDRESSED THE NATURE OF THESE ANOMALOUS CONDITIONS?

A71. 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. As SNL Financial reported to investors, Chair LaFleur "stressed that FERC detailed in previous orders the many factors that led the Commission to conclude anomalous economic conditions exist, and she suggested that it would take something more than just a small change in interest rates to change that conclusion."[56] There has been no fundamental shift in economic or capital market conditions since April 2013, when the updated data considered as the basis for the Commission's findings in Opinion No. 531 was submitted, and no sudden alteration to these anomalous conditions since Opinion No. 531 was issued.

For example, Table 4 compares six-month average bond yields at the end of the record period in Docket No. EL11-66 with those immediately prior to the date of the Commission's Opinion No. 531 and in April 2015:[57]

TABLE 4
COMPARISON OF YIELD BENCHMARKS

	BBB Utility		30-Yr Treasury		10-Yr Treasury	
Six-Month Average	**%**	**Change**	**%**	**Change**	**%**	**Change**
Mar-13 EL11-66 Record	4.62%	--	3.00%	--	1.83%	--
May-14 Opinion No. 531	4.98%	36	3.64%	64	2.74%	91
Apr-15	4.55%	-7	2.69%	-31	2.06%	23

[56] Boshart, Glen, "FERC asked to lower ROE for Duke's Fla. Subsidiary; are more ROE challenges in the offing?," *SNL Financial* (Aug. 13, 2014).
[57] The changes referenced in this table are basis point changes relative to the Docket No. EL11-66 Record percentages identified in the first row of the table.

As illustrated above, these benchmarks indicate that conditions are now more congruous with those prevailing during the evidentiary period in Docket No. EL11-66 than at the time the Commission issued Opinion No. 531.

Q72. IS THERE TANGIBLE EVIDENCE THAT ANOMALOUS CAPITAL MARKET CONDITIONS AFFECT THE RESULTS OF THE COMMISSION'S DCF MODEL?

A72. Yes. A collateral consequence of anomalous capital market conditions is their impact on the screening of DCF results. 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.[58] 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. Moreover, reference to a static, 100-basis point threshold incorrectly assumes that equity risk premiums are constant, regardless of prevailing bond yields. As I discuss later in my testimony, 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 expand. Thus, with bond yields remaining at historic lows, retaining low-end DCF values on the basis of a 100 basis point threshold causes the range of DCF estimates to be skewed downward.

[58] *See, e.g., So. Cal Edison Co.*, 131 FERC ¶ 61,020 at P 55.

Under these conditions, this static test of low-end results 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. 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 from within the zone of reasonableness.

Q73. WHAT OTHER EVIDENCE INDICATES THAT CURRENT CAPITAL MARKET CONDITIONS UNDERMINE THE RELIABILITY OF THE TWO-STEP DCF RESULTS?

A73. Apart from the direct effect on the evaluation of low-end values, empirical evidence also indicates that the results of the Commission's DCF model are distorted by current capital market conditions. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Recognizing the frailties associated with a mechanical reliance on a rote application of the DCF method, the Commission has stressed the need to carefully evaluate DCF results against a number of well-accepted benchmarks to ensure that the *Hope* and *Bluefield* standards are met.

Q74. IS IT POSSIBLE TO PINPOINT THE EXACT MECHANISM BY WHICH ANOMALOUS CAPITAL MARKET CONDITIONS ARE TRANSLATED INTO DOWNWARD-BIASED DCF ESTIMATES?

A74. No. Based on a series of very restrictive assumptions, DCF theory reduces the actions, opinions, and expectations of all investors down to a dividend yield and growth component, with the only observable parameter being the market price of the stock. There is no direct link between this model and bond yields (historical, current, or expected), Federal Reserve policies, relative risk perceptions, or any other data input from the capital markets or the economy. As a result, while we can observe the end-result of our best attempt to apply the DCF model in a way that mirrors investors' expectations, it is simply not possible to pinpoint just how the many exogenous factors ultimately influence DCF estimates. But as the Commission has recognized, this does not absolve DCF values from critical evaluation, both against observable benchmarks such as bond yields and the results of other methods and approaches, and most importantly, the *Hope* and *Bluefield* standards.

Q75. IS THE COMMISSION'S REDUCED CONFIDENCE IN THE DCF MEDIAN WARRANTED WHEN CAPITAL MARKET CONDITIONS ARE ANOMALOUS?

A75. Yes. The Commission correctly explained in Opinion No. 531 that "*any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula*,"[59] and noted that one form of distortion included "those produced by historically anomalous capital market conditions."[60] As the Commission

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[59] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (emphasis added).
[60] *Id.*

explained, when conditions associated with a model are outside of the normal range, there is a risk (referred to as "model risk") that the theoretical model will fail to predict or represent the real phenomenon that is being modeled.[61] In those circumstances, the Commission has "less confidence" that the point of central tendency of the proxy group zone of reasonableness satisfies the standards of *Hope* and *Bluefield*.[62]

In my opinion, the Commission should consider alternative methods and ROE benchmarks in all conditions and in all cases, because the DCF model – like any model – faces model risk and is not infallible. The Commission's reduced confidence in the central tendency of the DCF results is particularly appropriate, however, when anomalous capital market conditions undermine the ability of the DCF approach to reasonably reflect investor expectations.[63] 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 when evaluating a fair ROE for NorthWestern from within the zone of reasonableness.

B. Risk Premium Approach – FERC ROEs

Q76. BRIEFLY DESCRIBE THE RISK PREMIUM APPROACH.

A76. 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

[61] *Id.* at n.286.
[62] *Id.* at P 145.
[63] *See, e.g.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 71; Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

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.

Q77. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A77. 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 NorthWestern.

Q78. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE MERITS OF THIS RISK PREMIUM APPROACH?

A78. Yes. The Commission has previously considered evidence of alternative ROE benchmarks in evaluating a fair ROE, including the risk premium approach.[64] Most recently, the Commission's decision in Opinion No. 531 adopted the risk premium approach as an informative indicator of investors' required rate of return.[65] I am recommending the same approach in this proceeding.

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[64] *See, e.g., Distrigas of Mass. Corp.*, 41 FERC ¶ 61,205 at p. 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.").

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

Q79. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH?

A79. I based my estimates of equity risk premiums for utilities on a study 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 FERC-jurisdictional transmission operations.[66] Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q80. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR NORTHWESTERN?

A80. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk 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.

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[66] *Id.* at PP 145, 150.

Q81. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A81. 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 the same approach which was relied on by the Commission in its evaluation of a fair ROE in Opinion No. 531.[67] On page 3 of Exhibit No. NWE-105, 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 2014. As shown there, these equity risk premiums for electric utilities averaged 4.77%, and the yield on public utility bonds averaged 5.90%.

Q82. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A82. 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. 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 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.

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[67] *Id.* at PP 146-47.

Q83. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A83. Yes. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature.[68] 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.[69]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[70] As the Commission has concluded, "[t]he 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."[71]

Q84. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A84. 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

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[68] *See, e.g.*, E. F. Brigham, D.K. Shome & S.R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Fin. Mgmt.* (Spring 1985); R.S. Harris & F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Fin. Mgmt.* (Summer 1992).
[69] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 128 (2006).
[70] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Inc., Formula Rate Plan FRP-5 (Revised Mar. 2010), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf.
[71] Opinion No. 531 at P 147.

common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q85. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING ROES AUTHORIZED BY THE COMMISSION?

A85. Based on the regression output between the interest rates and equity risk premiums displayed on page 6 of Exhibit No. NWE-105, the equity risk premium for electric utilities increased approximately 77 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. NWE-105, with an average six-month historical yield on Baa public utility bonds at April 2015 of 4.55%, this implied a current equity risk premium of 5.81% for electric utilities. Adding this equity risk premium to the average six-month historical yield on Baa utility bonds implies a current cost of equity of 10.36%.[72]

C. Capital Asset Pricing Model

Q86. PLEASE DESCRIBE THE CAPM.

A86. 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

[72] Because the average S&P and Moody's ratings for the National Group fall in the Baa category, my risk premium analysis was based on the average yield for Baa utility bonds.

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 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 incorporates forward-looking expectations that are consistent with the assumptions of this approach.

Q87. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A87. I used the same approach considered by the Commission in establishing a fair ROE in Opinion No. 531.[73] 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. NWE-106. 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.

[73] Opinion No. 531 at P 146.

I obtained the dividend yield for each firm from Value Line. The growth rate is equal to the average of the earnings per share growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, these estimates imply an average growth rate over five years of 8.9%. Combining this average growth rate with a year-ahead dividend yield of 2.4% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.3%. Subtracting a 2.7% risk-free rate based on the six-month average yield on 30-year Treasury bonds at April 2015 produces a market equity risk premium of 8.6%.

Q88. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A88. 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.[74]

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[74] Morin, *supra* note 58, at 71.

The fact that investors rely on Value Line betas in evaluating expected returns for utility common stocks provides strong support for this approach.

Q89. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A89. 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.[75]

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.[76] 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.

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[75] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.
[76] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at Errata Table 7-6 (2015).

Q90. WHAT IS THE IMPLIED ROE FOR THE NATIONAL GROUP USING THE CAPM APPROACH?

A90. As shown on page 1 of Exhibit No. NWE-106, after adjusting for the impact of firm size, the forward-looking CAPM approach implied a median cost of equity of 10.43% for the National Group, with the average and midpoint being 10.33% and 10.27%, respectively.

D. Expected Earnings Approach

Q91. WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE ROE FOR NORTHWESTERN?

A91. 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 . . . 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.[77]

[77] Opinion No. 531 at P 147.

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.

Q92. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A92. 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.

Q93. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A93. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.62% over its 2018-2020 forecast horizon.[78] 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. NWE-107. In *Southern California Edison Co.*, 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.[79] Accordingly, consistent with the Commission's findings and the theory underlying this approach, I made an adjustment to compute an average rate of return.[80] As shown on Exhibit No. NWE-107, Value Line's projections for the National Group resulted in an adjusted range of expected rates of return from 8.67% to 12.84%.[81]

E. State Allowed ROEs

Q94. WHAT ARE THE STATE-APPROVED ROES FOR THE NATIONAL GROUP?

A94. As shown on Exhibit No. NWE-108, the state-approved ROEs reported to investors by Value Line for the utilities in the National Group fell in a range of 9.19% to 10.67%, with a median of 10.10%.

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[78] The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
[79] *So. Cal. Edison Co.*, 92 FERC ¶ 61,070 at p. 61,263 & n.38.
[80] Use of an average return in developing the rate of return is well supported. *See, e.g.*, Morin, *supra* note 58, at 305-306, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's prior findings.
[81] The midpoint, median, and average values were 10.75%, 9.73%, and 9.97%, respectively.

F. Selecting a Just and Reasonable ROE within the DCF Range

Q95. PLEASE SUMMARIZE HOW THE COMMISSION USED THESE ALTERNATIVE METHODOLOGIES IN OPINION NO. 531 TO SELECT AN ROE IN THE UPPER HALF OF THE RANGE OF REASONABLENESS.

A95. In Opinion No. 531, the Commission recognized that the mechanical application of the two-step DCF model could undermine a utility's ability to attract capital for new investment, noting that in that case an ROE based on the measure of central tendency from the two-step DCF results would violate the *Hope* and *Bluefield* standards:[82]

> [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.[83]

Under these circumstances, the Commission found it "necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies … to gain insight into the potential impacts of these unusual capital market conditions."[84] The Commission found that the results of the same risk premium, CAPM, and expected earnings approaches described earlier in my testimony, as well as consideration of state-allowed ROEs,

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[82] Opinion No. 531 at P 142.
[83] *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.
[84] Opinion No. 531 at P 145.

supported a finding that an upward adjustment from the central tendency of the DCF results was warranted.[85] Based on its evaluation of the results of the alternative ROE benchmarks, the Commission approved an ROE at the midpoint of the upper end of the DCF zone of reasonableness.

Q96. HAVE YOU FOLLOWED THE SAME APPROACH HERE?

A96. Yes. I recommend a base ROE for NorthWestern of 10.47%, which represents the midpoint of the upper end of the two-step DCF range based on IBES projected EPS growth rates. As my testimony documents, the anomalous capital market conditions that characterized the record in Opinion No. 531 continue to be present, and the 8.68% median of the IBES-based DCF analysis falls far below the ROE necessary to meet the requirements of *Hope* and *Bluefield.* Accordingly, I have considered the results of the same alternative ROE benchmark approaches referenced by the Commission in evaluating a just and reasonable ROE from within the upper end of the DCF zone of reasonableness. My end-result recommendation is consistent with the Commission's reliance on the midpoint of the upper end of the DCF zone to establish the ROE in Opinion No. 531, as well as the case-specific evidence presented in my testimony and the *Hope* and *Bluefield* requirements.

VI. OTHER ROE BENCHMARKS

Q97. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A97. This section presents alternative tests to demonstrate that my recommended ROE based on the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances that apply to NorthWestern.

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[85] Opinion No. 531 at P 146-150.

Specifically, I test my recommended ROE for NorthWestern against a series of relevant benchmarks that measure the cost of equity based on: (1) a risk premium approach using ROEs approved by state regulators; (2) the empirical CAPM; (3) Commission-approved ROEs for natural gas pipelines; (4) projected bond yields, as applied to the risk premium, CAPM, and ECAPM approaches; and (5) a DCF analysis based on a select group of low risk non-utility firms. These other benchmarks provide additional guidance that is relevant in corroborating my recommendation based on the end-result of the primary methods discussed previously.

A. Risk Premium – State ROEs

Q98. HOW ELSE DID YOU USE THE RISK PREMIUM APPROACH IN YOUR ANALYSIS?

A98. 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 state 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. NWE-109, 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 2014.[86] As shown there, over this period these equity risk premiums for electric utilities averaged 3.57%, and the yield on public utility bonds averaged 8.58%.

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[86] My analysis encompasses the entire period for which published data is available.

Q99. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM APPROACH BASED ON ROES APPROVED BY STATE REGULATORS?

A99. As shown on page 1 of Exhibit No. NWE-109, adding an equity risk premium corresponding to current interest rate levels to the average yield on Baa utility bonds for the six-months ending April 2015 of 4.55% implies a current cost of equity for electric utilities of 10.06%.

B. Empirical Capital Asset Pricing Model

Q100. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A100. 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*:

> [S]everal 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.[87]

[87] Morin, *supra* note 58, 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.

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.

Q101. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE ECAPM?

A101. 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 connection with the traditional CAPM. As shown on page 1 of Exhibit No. NWE-110, applying the forward-looking ECAPM approach to the firms in the National Group results in a cost of equity range of 8.68% to 12.72% after adjusting for firm size, with a median of 11.08%.[88]

C. Gas Pipeline ROEs

Q102. DO NATURAL GAS PIPELINE RETURNS PROVIDE A MEANINGFUL BENCHMARK TO EVALUATE A FAIR BASE ROE FOR NORTHWESTERN?

A102. Yes. 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

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[88] The midpoint and average ECAPM results based on historical bond yields were 10.70% and 10.84%, respectively, after adjusting for firm size.

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 and 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 . . . .[89]

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.[90]

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 because of differences between the two industries. In *Southern California Edison Co.*, 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."[91] Fourteen years have passed since this statement was made,

[89] *Williston Basin Interstate Pipeline Co.*, Prepared Direct and Answering Testimony of Commission Staff Witness George M Shriver, III at P 17, Docket No. RP00-107-000 (Jun. 7, 2000).
[90] Opinion No. 531 at P 8.
[91] *So. Cal. Edison Co.*, 92 FERC ¶ 61,070 at p. 61,261.

however, and as noted above, the Commission recognized in Opinion No. 531 that the electric industry and its restructuring have matured, which confirms that reference to gas company ROEs is relevant.

Q103. HOW DID YOU USE THE INFORMATION CONTAINED IN ROE DETERMINATIONS FOR NATURAL GAS PIPELINES TO DEVELOP AN ROE BENCHMARK FOR ELECTRIC UTILITIES?

A103. 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 2014 are presented on pages 4 and 5 of Exhibit No. NWE-111. The average annual ROE, the corresponding average bond yields, and implied risk premiums are summarized on page 3 of Exhibit No. NWE-111. Consistent with state and Commission-approved ROEs for electric utilities, the implied equity risk premiums for gas pipelines increase as interest rates decline, and vice versa.

Q104. WHAT CURRENT COST OF EQUITY IS IMPLIED FOR AN ELECTRIC UTILITY BASED ON THESE ALLOWED GAS PIPELINE ROES?

A104. As shown on page 1 of Exhibit No. NWE-111, adding an equity risk premium corresponding to current interest rate levels to the average yield on Baa utility bonds for the six-months ending April 2015 of 4.55% implies a current cost of equity for natural gas pipelines of 12.65%. As shown in the lower portion of page

3 of Exhibit No. NWE-111, the average ROE for natural gas pipelines has exceeded the ROE approved by the Commission for electric utilities by 2.17% between 2006 and 2014. Subtracting this spread from the 12.65% current risk premium estimate for natural gas pipelines results in a current implied ROE for an electric utility of 10.48%, if one were to assume that the risk spread between utilities and pipelines should remain constant.

D. Projected Bond Yields

Q105. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE RISK PREMIUM, CAPM, AND ECAPM APPROACHES?

A105. Yes. As discussed earlier, there is widespread consensus that interest rates are currently anomalous, and will increase materially as the economy continues to strengthen and the Federal Reserve normalizes its monetary policies. 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 historical average 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.

Q106. WHAT RISK PREMIUM COST OF EQUITY ESTIMATES ARE PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A106. As shown on page 2 of Exhibit No. NWE-105, incorporating a forecasted yield for 2016-2020 and adjusting for changes in interest rates since the study period implied an equity risk premium based on Commission-authorized ROEs of 3.83% for electric utilities. Adding this equity risk premium to the implied average yield on BBB public utility bonds for 2016-2020 of 7.12% resulted in an implied cost of equity of 10.95%.

As shown on page 2 of Exhibit No. NWE-109, applying the risk premium approach based on ROEs for electric utilities authorized by state regulators and incorporating average forecasted yields for 2016-2020 implied a cost of equity of approximately 11.53%.

Meanwhile, my risk premium analysis based on the Commission's findings for natural gas pipelines implied a cost of equity estimate of 10.85% based on the forecasted yield for utility bonds (Exhibit No. NWE-111, page 2).

Q107. DID YOU ALSO APPLY THE CAPM AND ECAPM USING FORECASTED BOND YIELDS?

A107. Yes. As shown on page 2 of Exhibit No. NWE-106, applying the CAPM using a forecasted Treasury bond yield for 2016-2020 implied an ROE range of 8.56% to 12.70% after adjusting for the impact of relative size.[92]

As shown on page 2 of Exhibit No. NWE-110, incorporating a forecasted Treasury bond yield for 2016-2020 implied an ECAPM range of 9.16% to 12.79% after adjusting for the impact of relative size.[93]

E. Low-Risk Non-Utility DCF Model

Q108. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR NORTHWESTERN?

A108. 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."

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[92] The midpoint, median, and average values of the adjusted CAPM estimates were 10.63%, 10.97%, and 10.76%, respectively.

[93] The midpoint, median, and average of the adjusted ECAPM results based on projected bond yields were 10.97%, 11.48%, and 11.15%, respectively.

Q109. WHY DID YOU INCLUDE A DCF ANALYSIS FOR THIS NON-UTILITY GROUP?

A109. The primary reason I have examined DCF results for this Non-Utility Group is that utilities, such as NorthWestern, need to compete with non-regulated firms for capital. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. 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, but with other investment opportunities of comparable risk.[94] 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.

Q110. WHAT AUTHORITY CAN YOU POINT TO FOR CONSIDERING THE RETURNS OF UNREGULATED ENTITIES?

A110. Going as far back as the *Bluefield* and *Hope* cases, it has been accepted practice to consider required returns for non-utility companies, and with sound justification. 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

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[94] 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.

attended by corresponding, risks and uncertainties[.]"[95] 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."[96] As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q111. ARE DCF RESULTS FOR THE NON-UTILITY GROUP A USEFUL ADJUNCT WHEN APPLYING THE DCF MODEL?

A111. Yes. The results of the non-utility group make estimating the cost of equity using the DCF model more reliable. 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.

Q112. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A112. 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

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[95] *Bluefield*, 262 U.S. at 692.
[96] *Hope*, 320 U.S. at 603.

of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.70 or less; and (5) have investment grade credit ratings from S&P.

Q113. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE NATIONAL GROUP?

A113. Table 5 compares the Non-Utility Group with the National Group across the same five indicators of investment risk discussed earlier:

TABLE 5
COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	A2	1	A+	0.66
National Group	BBB	Baa1	2	B++	0.77
NorthWestern	BBB	A3	3	B+	0.70

As shown above, the average risk indicators for the Non-Utility 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 NorthWestern—are greater than those of the firms in the Non-Utility Group.

The 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 par with utilities, with the average dividend yield for the group approaching 3%.

Q114. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A114. As shown on Exhibit No. NWE-112, 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 EPS growth rate based on projections from IBES and Value Line. As shown there, my DCF analysis for the Non-Utility Group resulted in an ROE range of 7.07% to 12.74%, with a median of 10.34%.[97] 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. Considering that the investment risks of the Non-Utility Group are lower than those of the National Group, these results understate investors' required rate of return for NorthWestern.

Q115. 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?

A115. 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."[98] 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

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[97] The midpoint and average values were 9.90% and 10.00%, respectively.
[98] Opinion No. 531 at P 146 n.288.

utility industry and its willingness to adopt the same two-step DCF approach used to establish ROEs for natural gas pipelines,[99] 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 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.[100]

For these same reasons, if electric transmission investments 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 away from electric transmission to other competing investment opportunities. As the Commission

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[99] *Id.* at P 32.

[100] Wolfe Research, “FERConomics: Risk to Transmission Base ROE in Focus,” *Utilities & Power* (June 11, 2013).

noted in Opinion No. 531, utilities “must compete for capital with other utilities (*and companies in other sectors*) throughout the nation.”[101]

Q116. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A116. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. NWE-102. The results of these alternative benchmarks confirm my conclusion that a base ROE of 10.47% for NorthWestern is reasonable.[102]

Q117. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A117. Yes.

[101] Opinion No. 531 at P 96 (emphasis supplied).

[102] While I did not make an explicit adjustment to the results of my quantitative methods to include an adjustment for flotation costs, this is another legitimate consideration that supports the reasonableness of my evaluation of a just and reasonable base ROE for NorthWestern in this case.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NorthWestern Corporation) **Docket No. ER15-___-000**

AFFIDAVIT

I, the undersigned, being duly sworn, depose and state, that the above and foregoing Prepared Testimony of Adrien M. McKenzie is the testimony of the undersigned, and that the testimony and exhibits sponsored by me, to the best of my knowledge, information and belief, are true, correct, accurate and complete.

Adrien M. McKenzie

Subscribed and sworn to before me this
26 day of June, 2015

My Commission expires:

Notary Public

ELISE BURNS
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires May 31, 2018

ELISE BURNS
NOTARY PUBLIC
EXP
5-31-2018
DISTRICT OF COLUMBIA

EXHIBIT NO. NWE-101

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q 1. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A 1. This exhibit describes my background and experience and contains the details of my qualifications.

Q 2. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A 2. I received 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. 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. I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in proceedings filed with the Federal Energy Regulatory Commission ("FERC" or "the Commission"), the Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Kansas State Corporation Commission, the Kentucky Public Service Commission, the Montana Public Service Commission, the Oregon Public Utilities Commission, the South Dakota Public Utilities Commission, the Washington Utilities and Transportation Commission, the West Virginia Public Service 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. A resume containing the details of my qualifications and experience is attached below.

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

ADRIEN M. McKENZIE

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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 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, participate in settlement negotiations, 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.

SUMMARY OF RESULTS

PRIMARY METHODS

Two-Step DCF	**Range**	**Median**	**Middle Top Half**
IBES Growth	7.13% -- 12.26%	8.68%	10.47%
Value Line Growth	6.09% -- 10.64%	8.84%	9.74%

Alternative Benchmark Methods	**Range**	**Midpoint**	**Median**	**Average**
Risk Premium - FERC ROE (a)		10.36%	10.36%	10.36%
CAPM - Historical Bond Yield	7.93% -- 12.61%	10.27%	10.43%	10.33%
Expected Earnings				
Industry (a, b)		10.62%	10.62%	10.62%
Proxy Group	8.67% -- 12.84%	10.75%	9.73%	9.97%
Summary - Alternative Methods				
Average	**8.30% -- 12.72%**	**10.50%**	**10.28%**	**10.32%**
Median	**8.30% -- 12.72%**	**10.49%**	**10.40%**	**10.35%**
Allowed ROE - Proxy Group	**9.19% -- 10.67%**	**9.93%**	**10.10%**	**10.09%**

(a) Point estimate value.
(b) Average for Value Line Electric Utility industry group.

CHECKS OF REASONABLENESS

	Range	Midpoint	Median	Average
Risk Premium				
State ROE (a)		10.06%	10.06%	10.06%
FERC Gas Pipelines (a)		10.48%	10.48%	10.48%
Empirical CAPM	8.68% -- 12.72%	10.70%	11.08%	10.84%
Projected Bond Yields				
Risk Premium				
FERC ROE (a)		10.95%	10.95%	10.95%
State ROE (a)		11.53%	11.53%	11.53%
FERC Gas Pipelines (a)		10.85%	10.85%	10.85%
CAPM	8.56% -- 12.70%	10.63%	10.97%	10.76%
Empirical CAPM	9.16% -- 12.79%	10.97%	11.48%	11.15%
Non-Utility DCF	7.07% -- 12.74%	9.90%	10.34%	10.00%
Summary - All Methods				
Average		**10.68%**	**10.86%**	**10.74%**
Median		**10.70%**	**10.95%**	**10.84%**

(a) Point estimate value.

NATIONAL GROUP **Exhibit No. NWE-103**

RISK MEASURES

			(a)	(b)	(c)			(d)
			S&P	**Moody's**	**Value Line**			
			Corporate	**Long-term**	**Safety**	**Financial**		**Market**
	Company	**SYM**	**Rating**	**Rating**	**Rank**	**Strength**	**Beta**	**Cap**
1	ALLETE	ALE	BBB+	A3	2	A	0.80	$2,267
2	Ameren Corp.	AEE	BBB+	Baa1	2	B++	0.75	$9,767
3	American Elec Pwr	AEP	BBB	Baa1	2	A	0.70	$26,995
4	Avista Corp.	AVA	BBB	Baa1	2	A	0.80	$2,003
5	Black Hills Corp.	BKH	BBB	Baa1	2	B++	0.95	$2,107
6	DTE Energy Co.	DTE	BBB+	A3	2	B++	0.75	$14,004
7	Edison International	EIX	BBB+	A3	2	A	0.75	$19,467
8	El Paso Electric	EE	BBB	Baa1	2	B++	0.70	$1,442
9	Empire District Elec	EDE	BBB	Baa1	2	B++	0.70	$1,017
10	IDACORP, Inc.	IDA	BBB	Baa1	2	B++	0.80	$2,975
11	NorthWestern Corp.	NWE	BBB	A3	3	B+	0.70	$2,436
12	PG&E Corp.	PCG	BBB	Baa1	3	B+	0.65	$24,660
13	Portland General Elec.	POR	BBB	A3	2	B++	0.80	$2,717
14	Sempra Energy	SRE	BBB+	Baa1	2	A	0.80	$26,120
15	TECO Energy	TE	BBB+	Baa1	2	B++	0.85	$4,344
16	Westar Energy	WR	BBB+	Baa1	2	B++	0.75	$4,747
			BBB	**Baa1**	**2**	**B++**	**0.77**	**$9,192**

(a) Corporate credit rating from www.standardandpoors.com (retrieved May 5, 2015).
(b) Long-term rating from www.moodys.com (retrieved May 5, 2015).
(c) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
(d) www.valueline.com (retrieved May 19, 2015).

IBES GROWTH

		(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	3.77%	1.0273	3.87%	6.00%	4.36%	5.45%	9.32%		
2	Ameren Corp.	3.77%	1.0268	3.88%	5.85%	4.36%	5.35%	9.23%		
3	American Elec Pwr	3.60%	1.0243	3.68%	5.10%	4.36%	4.85%	8.54%		
4	Avista Corp.	3.80%	1.0239	3.89%	5.00%	4.36%	4.79%	8.68%		
5	Black Hills Corp.	3.13%	1.0306	3.23%	7.00%	4.36%	6.12%	9.35%		
6	DTE Energy Co.	3.29%	1.0223	3.37%	4.51%	4.36%	4.46%	7.83%		
7	Edison International	2.59%	1.0096	2.62%	0.70%	4.36%	1.92%	4.54%		
8	El Paso Electric	2.90%	1.0306	2.99%	7.00%	4.36%	6.12%	9.11%		
9	Empire District Elec	3.82%	1.0239	3.91%	5.00%	4.36%	4.79%	8.70%		
10	IDACORP, Inc.	2.95%	1.0206	3.01%	4.00%	4.36%	4.12%	7.13%		
11	NorthWestern Corp.	3.52%	1.0239	3.61%	5.00%	4.36%	4.79%	8.39%		
12	PG&E Corp.	3.40%	1.0230	3.48%	4.71%	4.36%	4.59%	8.07%		
13	Portland General Elec.	2.99%	1.0230	3.06%	4.72%	4.36%	4.60%	7.66%		
14	Sempra Energy	2.54%	1.0337	2.63%	7.93%	4.36%	6.74%	9.37%		
15	TECO Energy	4.50%	1.0379	4.67%	9.20%	4.36%	7.59%	12.26%		
16	Westar Energy	3.62%	1.0186	3.69%	3.40%	4.36%	3.72%	7.41%		
	Range of Reasonableness							**4.54%**	**--**	**12.26%**
	Adjusted Range of Reasonableness (h)							**7.13%**	**--**	**12.26%**
	Midpoint							**9.69%**		
	Median							**8.68%**		
	Average							**8.74%**		

(a) Six-month average dividend yield for Nov. 2014 - Apr. 2015.
(b) 1 + 0.5 x (f).
(c) (a) x (b).
(d) www.finance.yahoo.com (May 22, 2015).
(e) See Exhibit No. NWE-104, page 3.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).
(h) Excludes highlighted values.

VALUE LINE GROWTH

		(a)	(b)	(c)	(d)	(e)	(f)	(g)		
		Dividend Yield			Growth Rate					
	Company	6-Mo. Average	Adjustment	Adjusted	V Line	GDP	Weighted	Cost of Equity		
1	ALLETE	3.77%	1.0306	3.88%	7.00%	4.36%	6.12%	10.00%		
2	Ameren Corp.	3.77%	1.0239	3.87%	5.00%	4.36%	4.79%	8.65%		
3	American Elec Pwr	3.60%	1.0256	3.69%	5.50%	4.36%	5.12%	8.81%		
4	Avista Corp.	3.80%	1.0306	3.92%	7.00%	4.36%	6.12%	10.04%		
5	Black Hills Corp.	3.13%	1.0223	3.20%	4.50%	4.36%	4.45%	7.66%		
6	DTE Energy Co.	3.29%	1.0273	3.38%	6.00%	4.36%	5.45%	8.84%		
7	Edison International	2.59%	1.0173	2.64%	3.00%	4.36%	3.45%	6.09%		
8	El Paso Electric	2.90%	1.0189	2.95%	3.50%	4.36%	3.79%	6.74%		
9	Empire District Elec	3.82%	1.0173	3.88%	3.00%	4.36%	3.45%	7.34%		
10	IDACORP, Inc.	2.95%	1.0106	2.98%	1.00%	4.36%	2.12%	5.10%		
11	NorthWestern Corp.	3.52%	1.0289	3.62%	6.50%	4.36%	5.79%	9.41%		
12	PG&E Corp.	3.40%	1.0356	3.52%	8.50%	4.36%	7.12%	10.64%		
13	Portland General Elec.	2.99%	1.0273	3.07%	6.00%	4.36%	5.45%	8.53%		
14	Sempra Energy	2.54%	1.0356	2.63%	8.50%	4.36%	7.12%	9.75%		
15	TECO Energy	4.50%	1.0273	4.62%	6.00%	4.36%	5.45%	10.07%		
16	Westar Energy	3.62%	1.0273	3.72%	6.00%	4.36%	5.45%	9.18%		
	Range of Reasonableness							**5.10%**	**--**	**10.64%**
	Adjusted Range of Reasonableness (h)							**6.09%**	**--**	**10.64%**
	Midpoint								**8.37%**	
	Median								**8.84%**	
	Average								**8.78%**	

(a) Six-month average dividend yield for Nov. 2014 - Apr. 2015.
(b) 1 + 0.5 x (f).
(c) (a) x (b).
(d) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
(e) See Exhibit No. NWE-104, page 3.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).
(h) Excludes highlighted values.

GDP GROWTH RATE

	Source	2019	2040	2045	2069	Compound Annual Growth Rate
		Nominal GDP ($ Billions)				
(a)	**IHS Global Insight**	21,909.00		66,911.00		4.39%
(b)	**Energy Information Administration**					
	Real GDP	18,296	29,898			
	GDP Deflator	1.190	1.730			
		21,772	51,724			4.21%
(c)	**SSA Trustees Report**	22,578			202,053	4.48%
	Average GDP Growth Rate					**4.36%**

(a) IHS Global Insight, *The U.S. Economy, The 30-Year Focus* (First Quarter 2015) at Table 1.
(b) Energy Information Administration, *Annual Energy Outlook 2015* (April 2015).
(c) Social Security Administration, *2014 OASDI Trustees Report*, Table VI.G6.-Selected Economic Variables.

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Average Yield Over Study Period	5.90%
(b)	Baa Utility Bond Yield - Historical	4.55%
	Change in Bond Yield	-1.35%
(c)	Risk Premium/Interest Rate Relationship	-0.7707
	Adjustment to Average Risk Premium	1.04%
(a)	Average Risk Premium over Study Period	4.77%
	Adjusted Risk Premium	**5.81%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield - Historical	4.55%
	Adjusted Equity Risk Premium	5.81%
	Risk Premium Cost of Equity	**10.36%**

(a) See Exhibit No. NWE-105, p. 3.
(b) Six-month average yield for Nov. 2014 - Apr. 2015 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit No. NWE-105, p. 6.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Average Yield Over Study Period	5.90%
(b)	Baa Utility Bond Yield 2016-2020	7.12%
	Change in Bond Yield	1.22%
(c)	Risk Premium/Interest Rate Relationship	-0.7707
	Adjustment to Average Risk Premium	-0.94%
(a)	Average Risk Premium over Study Period	4.77%
	Adjusted Risk Premium	**3.83%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield 2016-2020	7.12%
	Adjusted Equity Risk Premium	3.83%
	Risk Premium Cost of Equity	**10.95%**

(a) See Exhibit No. NWE-105, p. 3.
(b) Based on data from IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); Energy Information Administration, Annual Energy Outlook 2015 (April 2015); & Moody's Investors Service at www.credittrends.com.
(c) See Exhibit No. NWE-105, 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	10.83%	7.25%	3.58%
2009	10.85%	7.06%	3.79%
2010	10.59%	5.98%	4.62%
2011	10.68%	5.57%	5.12%
2012	10.82%	4.86%	5.97%
2013	10.17%	4.98%	5.18%
2014	10.15%	4.80%	5.35%
		5.90%	4.77%

(a) Exhibit No. NWE-105, 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%
Oct-06	ER04-157	Bangor Hydro-Elec. Co.	11.14%
Nov-06	ER05-925	Westar Energy Inc.	10.80%
May-07	ER07-284	San Diego Gas & Elec.	11.35%
Aug-07	ER06-787	Idaho Power Co.	10.70%
Sep-07	ER06-1320	Wisconsin Elec. Pwr. Co.	11.00%
Nov-07	ER08-10	Pepco Holdings, Inc.	10.80%
Jan-08	ER07-583	Commonwealth Edison Co.	11.00%
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	EL05-19	Southwestern Public Service	9.33%
Apr-08	ER08-92	Virginia Elec. & Power Co.	10.90%
May-08	EL06-109	Duquesne Light Co.	10.90%
Jun-08	ER07-549	NSTAR Elec. Co.	10.90%
Jul-08	ER08-375	So. Cal Edison (a)	9.54%
Jul-08	ER07-562	Trans-Allegheny	11.20%
Jul-08	ER07-1142	Arizona Public Service Co.	10.75%
Aug-08	ER08-1207	Virginia Elec. & Power Co.	10.90%
Aug-08	ER08-686	Pepco Holdings, Inc.	11.30%
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%
Dec-08	ER07-694	New England Pwr. Co.	11.14%
Feb-09	ER08-1584	Black Hills Power Co.	10.80%
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	ER09-745	Baltimore Gas & Elec.	11.30%
Jun-09	ER08-552	Niagara Mohawk Pwr. Co.	11.00%
Jun-09	ER07-1069	AEP - SPP Zone	10.70%
Jun-09	ER08-1457	PPL Elec. Utilities Corp.	11.10%
Jun-09	ER08-1457	PPL Elec. Utilities Corp.	11.14%
Jun-09	ER08-1457	PPL Elec. Utilities Corp.	11.18%
Jun-09	ER08-281	Oklahoma Gas & Elec.	10.60%
Aug-09	ER09-187	So. Cal Edison (b)	10.04%

ALLOWED ROE

Date	Docket No.	Utility	Base ROE
Aug-09	ER07-1344	Westar Energy Inc.	10.80%
Nov-09	ER08-1588	Kentucky Utilities Co.	11.00%
Nov-09	ER09-1762	Westar Energy Inc.	10.80%
Dec-09	ER08-313	Southwestern Public Service Co.	10.77%
Jan-10	ER09-628	National Grid Generation LLC	10.75%
Sep-10	ER10-160	So. Cal Edison (c)	10.33%
Oct-10	ER08-1329	AEP - PJM Zone	10.99%
Dec-10	ER10-230	Kansas City Power & Light Co.	10.60%
Dec-10	ER11-1952	So. Cal Edison	10.30%
Feb-11	ER11-2377	Northern Pass Transmission	10.40%
Apr-11	ER10-355	AEP Transcos - PJM	10.99%
Apr-11	ER10-355	AEP Transcos - SPP	10.70%
May-11	EL10-80	Ameren	12.38%
May-11	EL11-13	Atlantic Grid Operations	10.09%
Jun-11	ER11-3352	PJM & PSE&G	11.18%
Aug-11	ER10-992	Northern States Power Co.	10.20%
Oct-11	ER10-1377	Northern States Power Co. (MN)	10.40%
Oct-11	ER11-2895	Duke Energy Carolinas	10.20%
Oct-11	ER11-4069	RITELine	9.93%
Oct-11	ER10-516	South Carolina Elec. & Gas	10.55%
Dec-11	ER12-296	PJM & PSE&G	11.18%
Feb-12	ER08-386	PATH	10.40%
Jun-12	ER11-2853	Public Service Co. of Colorado	10.10%
Jun-12	ER11-2853	Public Service Co. of Colorado	10.40%
Jun-12	ER12-1593	DATC Midwest Holdings	12.38%
May-13	ER12-778	Puget Sound Energy	9.80%
May-13	ER12-778	Puget Sound Energy - PSANI	10.30%
May-13	ER11-3643	PacifiCorp	9.80%
May-13	ER11-2560	Entergy Arkansas	10.20%
May-13	ER12-2554	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%
May-14	ER13-941	San Diego Gas & Electric	9.55%
May-14	ER14-1608	Public Service Electric & Gas	11.18%
Jun-14	EL11-66	Bangor Hydro-Elec. Co.	10.57%
Oct-14	ER12-1589	Public Service Co. of Colorado	9.72%
Oct-14	EL13-86	Public Service Co. of Colorado	9.72%

(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.

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.94774
R Square	0.89821
Adjusted R Square	0.88367
Standard Error	0.00255
Observations	9

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000402	0.000402029	61.77111474	0.000102053
Residual	7	0.000046	6.50837E-06		
Total	8	0.000448			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.09319	0.00585	15.92887704	9.32606E-07	0.07936	0.10703	0.07936	0.10703
X Variable 1	-0.77065	0.09805	-7.859460207	0.000102053	-1.00251	-0.53879	-1.00251	-0.53879

CAPM - HISTORICAL BOND YIELD

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	2.4%	8.9%	11.3%	2.7%	8.6%	0.80	9.58%	$2,267	1.74%	11.32%
2	Ameren Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	0.75	9.15%	$9,767	0.91%	10.06%
3	American Elec Pwr	2.4%	8.9%	11.3%	2.7%	8.6%	0.70	8.72%	$26,995	-0.36%	8.36%
4	Avista Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	0.80	9.58%	$2,003	1.74%	11.32%
5	Black Hills Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	0.95	10.87%	$2,107	1.74%	12.61%
6	DTE Energy Co.	2.4%	8.9%	11.3%	2.7%	8.6%	0.75	9.15%	$14,004	0.63%	9.78%
7	Edison International	2.4%	8.9%	11.3%	2.7%	8.6%	0.75	9.15%	$19,467	0.63%	9.78%
8	El Paso Electric	2.4%	8.9%	11.3%	2.7%	8.6%	0.70	8.72%	$1,442	1.71%	10.43%
9	Empire District Elec	2.4%	8.9%	11.3%	2.7%	8.6%	0.70	8.72%	$1,017	1.71%	10.43%
10	IDACORP, Inc.	2.4%	8.9%	11.3%	2.7%	8.6%	0.80	9.58%	$2,975	1.60%	11.18%
11	NorthWestern Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	0.70	8.72%	$2,436	1.74%	10.46%
12	PG&E Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	0.65	8.29%	$24,660	-0.36%	7.93%
13	Portland General Elec.	2.4%	8.9%	11.3%	2.7%	8.6%	0.80	9.58%	$2,717	1.60%	11.18%
14	Sempra Energy	2.4%	8.9%	11.3%	2.7%	8.6%	0.80	9.58%	$26,120	-0.36%	9.22%
15	TECO Energy	2.4%	8.9%	11.3%	2.7%	8.6%	0.85	10.01%	$4,344	1.06%	11.07%
16	Westar Energy	2.4%	8.9%	11.3%	2.7%	8.6%	0.75	9.15%	$4,747	1.06%	10.21%
	Range of Reasonableness							**8.29% -- 10.87%**			**7.93% -- 12.61%**
	Midpoint							**9.58%**			**10.27%**
	Median							**9.15%**			**10.43%**
	Average							**9.28%**			**10.33%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 22, 2015).
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved May 24, 2015) and www.valueline.com (retrieved May 22, 2015).
(c) Six-month average yield on 30-year Treasury bonds for Nov. 2014 - Apr. 2015 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
(e) www.valueline.com (retrieved May 19, 2015).
(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015); "2015 Ibbotson SBBI Classic Yearbook," at Errata Table 7-6 (2015).

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Implied**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**Cost of Equity**
1	ALLETE	2.4%	8.9%	11.3%	4.5%	6.8%	0.80	9.94%	$2,267	1.74%	11.68%
2	Ameren Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	0.75	9.60%	$9,767	0.91%	10.51%
3	American Elec Pwr	2.4%	8.9%	11.3%	4.5%	6.8%	0.70	9.26%	$26,995	-0.36%	8.90%
4	Avista Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	0.80	9.94%	$2,003	1.74%	11.68%
5	Black Hills Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	0.95	10.96%	$2,107	1.74%	12.70%
6	DTE Energy Co.	2.4%	8.9%	11.3%	4.5%	6.8%	0.75	9.60%	$14,004	0.63%	10.23%
7	Edison International	2.4%	8.9%	11.3%	4.5%	6.8%	0.75	9.60%	$19,467	0.63%	10.23%
8	El Paso Electric	2.4%	8.9%	11.3%	4.5%	6.8%	0.70	9.26%	$1,442	1.71%	10.97%
9	Empire District Elec	2.4%	8.9%	11.3%	4.5%	6.8%	0.70	9.26%	$1,017	1.71%	10.97%
10	IDACORP, Inc.	2.4%	8.9%	11.3%	4.5%	6.8%	0.80	9.94%	$2,975	1.60%	11.54%
11	NorthWestern Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	0.70	9.26%	$2,436	1.74%	11.00%
12	PG&E Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	0.65	8.92%	$24,660	-0.36%	8.56%
13	Portland General Elec.	2.4%	8.9%	11.3%	4.5%	6.8%	0.80	9.94%	$2,717	1.60%	11.54%
14	Sempra Energy	2.4%	8.9%	11.3%	4.5%	6.8%	0.80	9.94%	$26,120	-0.36%	9.58%
15	TECO Energy	2.4%	8.9%	11.3%	4.5%	6.8%	0.85	10.28%	$4,344	1.06%	11.34%
16	Westar Energy	2.4%	8.9%	11.3%	4.5%	6.8%	0.75	9.60%	$4,747	1.06%	10.66%
	Range of Reasonableness							**8.92% -- 10.96%**			**8.56% -- 12.70%**
	Midpoint							**9.94%**			**10.63%**
	Median							**9.60%**			**10.97%**
	Average							**9.71%**			**10.76%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 22, 2015).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved May 24, 2015) and www.valueline.com (retrieved May 22, 2015).

(c) Average yield on 30-year Treasury bonds for 2016-20 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014).

(d) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).

(e) www.valueline.com (retrieved May 19, 2015).

(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015); "2015 Ibbotson SBBI Classic Yearbook," at Errata Table 7-6 (2015).

EXPECTED EARNINGS APPROACH

NATIONAL GROUP

		(a)	(b)	(c)		
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**		
1	ALLETE	9.50%	1.0240	9.73%		
2	Ameren Corp.	9.50%	1.0238	9.73%		
3	American Elec Pwr	10.50%	1.0198	10.71%		
4	Avista Corp.	9.00%	1.0170	9.15%		
5	Black Hills Corp.	8.50%	1.0205	8.67%		
6	DTE Energy Co.	10.00%	1.0310	10.31%		
7	Edison International	11.50%	1.0274	11.81%		
8	El Paso Electric	9.00%	1.0212	9.19%		
9	Empire District Elec	8.50%	1.0205	8.67%		
10	IDACORP, Inc.	8.50%	1.0199	8.67%		
11	NorthWestern Corp.	10.00%	1.0200	10.20%		
12	PG&E Corp.	9.50%	1.0301	9.79%		
13	Portland General Elec.	9.00%	1.0357	9.32%		
14	Sempra Energy	12.50%	1.0268	12.84%		
15	TECO Energy	11.00%	1.0135	11.15%		
16	Westar Energy	9.50%	1.0128	9.62%		
	Range of Reasonableness			**8.67%**	**--**	**12.84%**
	Midpoint			**10.75%**		
	Median			**9.73%**		
	Average			**9.97%**		

(a) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).

ALLOWED ROE

NATIONAL GROUP

	Company	(a) Allowed ROE
1	ALLETE	10.38%
2	Ameren Corp.	9.19%
3	American Elec Pwr	10.28%
4	Avista Corp.	9.73%
5	Black Hills Corp.	9.83%
6	DTE Energy Co.	10.50%
7	Edison International	10.45%
8	El Paso Electric	NA
9	Empire District Elec	NA
10	IDACORP, Inc.	10.00%
11	NorthWestern Corp.	10.00%
12	PG&E Corp.	10.40%
13	Portland General Elec.	9.68%
14	Sempra Energy	10.20%
15	TECO Energy	10.67%
16	Westar Energy	10.00%
	Range of Reasonableness	**9.19% -- 10.67%**
	Midpoint	**9.93%**
	Median	**10.10%**
	Average	**10.09%**

(a) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.58%
(b)	Average Utility Bond Yield - Historical	4.03%
	Change in Bond Yield	-4.55%
(c)	Risk Premium/Interest Rate Relationship	-0.4266
	Adjustment to Average Risk Premium	1.94%
(a)	Average Risk Premium over Study Period	3.57%
	Adjusted Risk Premium	**5.51%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield - Historical	4.55%
	Adjusted Equity Risk Premium	5.51%
	Risk Premium Cost of Equity	**10.06%**

(a) Exhibit No. NWE-109, page 3.
(b) Six-month average yield for Nov. 2014 - Apr. 2015 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) Exhibit No. NWE-109, page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.58%
(b)	Average Utility Bond Yield 2016-2020	6.60%
	Change in Bond Yield	-1.98%
(c)	Risk Premium/Interest Rate Relationship	-0.4266
	Adjustment to Average Risk Premium	0.84%
(a)	Average Risk Premium over Study Period	3.57%
	Adjusted Risk Premium	**4.41%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield 2016-2020	7.12%
	Adjusted Equity Risk Premium	4.41%
	Risk Premium Cost of Equity	**11.53%**

(a) Exhibit No. NWE-109, page 3.
(b) Based on data from IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); Energy Information Administration, Annual Energy Outlook 2015 (April 2015); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. NWE-109, 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%
2014	9.91%	4.42%	5.49%
Average	12.16%	8.58%	3.57%

(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

Regression Statistics	
Multiple R	0.92317
R Square	0.85224
Adjusted R Square	0.84845
Standard Error	0.00508
Observations	41

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005798	0.005798237	224.9453642	8.76517E-18
Residual	39	0.001005	2.57762E-05		
Total	40	0.006804			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07234	0.00257	28.18692101	1.5191E-27	0.06715	0.07753	0.06715	0.07753
X Variable 1	-0.42656	0.02844	-14.99817869	8.76517E-18	-0.48409	-0.36904	-0.48409	-0.36904

ECAPM - HISTORICAL BOND YIELD

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		(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	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.01%	$2,267	1.74%	11.75%
2	Ameren Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.69%	$9,767	0.91%	10.60%
3	American Elec Pwr	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.37%	$26,995	-0.36%	9.01%
4	Avista Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.01%	$2,003	1.74%	11.75%
5	Black Hills Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.95	75%	6.1%	8.3%	10.98%	$2,107	1.74%	12.72%
6	DTE Energy Co.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.69%	$14,004	0.63%	10.32%
7	Edison International	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.69%	$19,467	0.63%	10.32%
8	El Paso Electric	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.37%	$1,442	1.71%	11.08%
9	Empire District Elec	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.37%	$1,017	1.71%	11.08%
10	IDACORP, Inc.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.01%	$2,975	1.60%	11.61%
11	NorthWestern Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.37%	$2,436	1.74%	11.11%
12	PG&E Corp.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	9.04%	$24,660	-0.36%	8.68%
13	Portland General Elec.	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.01%	$2,717	1.60%	11.61%
14	Sempra Energy	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.01%	$26,120	-0.36%	9.65%
15	TECO Energy	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.85	75%	5.5%	7.6%	10.33%	$4,344	1.06%	11.39%
16	Westar Energy	2.4%	8.9%	11.3%	2.7%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.69%	$4,747	1.06%	10.75%
	Range of Reasonableness												**9.04% -- 10.98%**			**8.68% -- 12.72%**
	Midpoint												**10.01%**			**10.70%**
	Median												**9.69%**			**11.08%**
	Average												**9.79%**			**10.84%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 22, 2015).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved May 24, 2015) and www.valueline.com (retrieved May 22, 2015).

(c) Six-month average yield on 30-year Treasury bonds for Nov. 2014 - Apr. 2015 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).

(f) www.valueline.com (retrieved May 19, 2015).

(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015); "2015 Ibbotson SBBI Classic Yearbook," at Errata Table 7-6 (2015).

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		(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	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.80	75%	4.1%	5.8%	10.28%	$2,267	1.74%	12.02%
2	Ameren Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.75	75%	3.8%	5.5%	10.03%	$9,767	0.91%	10.94%
3	American Elec Pwr	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.70	75%	3.6%	5.3%	9.77%	$26,995	-0.36%	9.41%
4	Avista Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.80	75%	4.1%	5.8%	10.28%	$2,003	1.74%	12.02%
5	Black Hills Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.95	75%	4.8%	6.5%	11.05%	$2,107	1.74%	12.79%
6	DTE Energy Co.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.75	75%	3.8%	5.5%	10.03%	$14,004	0.63%	10.66%
7	Edison International	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.75	75%	3.8%	5.5%	10.03%	$19,467	0.63%	10.66%
8	El Paso Electric	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.70	75%	3.6%	5.3%	9.77%	$1,442	1.71%	11.48%
9	Empire District Elec	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.70	75%	3.6%	5.3%	9.77%	$1,017	1.71%	11.48%
10	IDACORP, Inc.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.80	75%	4.1%	5.8%	10.28%	$2,975	1.60%	11.88%
11	NorthWestern Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.70	75%	3.6%	5.3%	9.77%	$2,436	1.74%	11.51%
12	PG&E Corp.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.65	75%	3.3%	5.0%	9.52%	$24,660	-0.36%	9.16%
13	Portland General Elec.	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.80	75%	4.1%	5.8%	10.28%	$2,717	1.60%	11.88%
14	Sempra Energy	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.80	75%	4.1%	5.8%	10.28%	$26,120	-0.36%	9.92%
15	TECO Energy	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.85	75%	4.3%	6.0%	10.54%	$4,344	1.06%	11.60%
16	Westar Energy	2.4%	8.9%	11.3%	4.5%	6.8%	25%	1.7%	0.75	75%	3.8%	5.5%	10.03%	$4,747	1.06%	11.09%
	Range of Reasonableness												**9.52% -- 11.05%**			**9.16% -- 12.79%**
	Midpoint												**10.28%**			**10.97%**
	Median												**10.03%**			**11.48%**
	Average												**10.10%**			**11.15%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 22, 2015).
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved May 24, 2015) and www.valueline.com (retrieved May 22, 2015).
(c) Average yield on 30-year Treasury bonds for 2016-20 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014).
(d) Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. at 190 (2006).
(e) The Value Line Investment Survey (Mar. 20, May 1, & May 22, 2015).
(f) www.valueline.com (retrieved May 19, 2015).
(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015); "2015 Ibbotson SBBI Classic Yearbook," at Errata Table 7-6 (2015).

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	5.90%
(b)	Average Baa Utility Bond Yield - Historical	4.55%
	Change in Bond Yield	-1.35%
(c)	Risk Premium/Interest Rate Relationship	-0.8574
	Adjustment to Average Risk Premium	1.16%
(a)	Average Risk Premium over Study Period	6.94%
	Adjusted Risk Premium	**8.10%**

Implied Cost of Equity - Gas Pipelines

(b)	Average Baa Utility Bond Yield - Historical	4.55%
	Adjusted Equity Risk Premium	8.10%
	Risk Premium Cost of Equity - Gas Pipeline	**12.65%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.17%**
	Implied Electric ROE	**10.48%**

(a) See Exhibit No. NWE-111, p. 3.
(b) Six-month average yield for Nov. 2014 - Apr. 2015 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit No. NWE-111, p. 6.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	5.90%
(b)	Average Baa Utility Bond Yield - Projected 2016-2020	7.12%
	Change in Bond Yield	1.22%
(c)	Risk Premium/Interest Rate Relationship	-0.8574
	Adjustment to Average Risk Premium	-1.04%
(a)	Average Risk Premium over Study Period	6.94%
	Adjusted Risk Premium	**5.89%**

Implied Cost of Equity

(b)	Average Baa Utility Bond Yield - Projected 2016-2020	7.12%
	Adjusted Equity Risk Premium	5.89%
	Risk Premium Cost of Equity - Gas Pipeline	**13.01%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.17%**
	Implied Electric ROE	**10.85%**

(a) See Exhibit No. NWE-111, p. 3.
(b) Based on data from IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); Energy Information Administration, Annual Energy Outlook 2015 (April 2015); & Moody's Investors Service at www.credittrends.com.
(c) See Exhibit No. NWE-111, 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	13.04%	6.33%	6.71%
2008	12.86%	7.25%	5.61%
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	11.48%	4.98%	6.50%
2014	13.58%	4.80%	8.78%
		5.90%	6.94%

Year	Average Pipeline ROE	(c) Average Electric Base ROE	Spread
2006	12.86%	11.01%	1.85%
2007	13.04%	10.96%	2.08%
2008	12.86%	10.83%	2.03%
2009	13.18%	10.85%	2.33%
2010	12.61%	10.59%	2.02%
2011	13.31%	10.68%	2.63%
2012	12.65%	10.82%	1.83%
2013	11.48%	10.17%	1.32%
2014	13.58%	10.15%	3.44%
			2.17%

(a) Exhibit No. NWE-111, pp. 4-5.
(b) Moody's Investors Service, www.credittrends.com.
(c) Exhibit No. NWE-105, 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%
Dec-07	CP07-8	Guardian Pipeline, L.L.C.	14.00%
Jan-08	RP07-38	Eastern Shore Natural Gas Co.	13.60%
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%
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%

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
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	RP04-274	Kern River Gas Transmission Co.	11.55%
Feb-09	CP09-3	T.W. Phillips Pipeline Corp.	14.00%
Jun-09	RP08-350	Southern Star Central Pipeline, Inc.	11.25%
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	Kinetica Energy Express, LLC	11.59%
Oct-13	RP10-1398	El Paso Natural Gas Co.	10.55%
Jun-14	CP13-73	Sierrita Gas Pipeline, LLC.	14.00%
Dec-14	CP14-68	Texas Eastern Transmission, LP	12.75%
Dec-14	CP13-499	Constitution Pipeline Co., LLC	14.00%

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.80386
R Square	0.64619
Adjusted R Square	0.59564
Standard Error	0.00624
Observations	9

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000498	0.00049763	12.78441361	0.009029928
Residual	7	0.000272	3.89248E-05		
Total	8	0.000770			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.11999	0.01431	8.386338107	6.73667E-05	0.08616	0.15382	0.08616	0.15382
X Variable 1	-0.85740	0.23980	-3.575529836	0.009029928	-1.42443	-0.29037	-1.42443	-0.29037

DCF MODEL **Exhibit No. NWE-112**

NON-UTILITY GROUP

			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Dividend Yield			Growth Rate			
	Company	Industry Group	6-Mo. Average	Adjustment	Adjusted	IBES	V-Line	Average	Cost of Equity
1	Church & Dwight	Household Products	1.66%	1.0464	1.74%	9.55%	9.00%	9.28%	11.01%
2	Coca-Cola	Beverage	3.14%	1.0258	3.22%	4.83%	5.50%	5.17%	8.38%
3	Colgate-Palmolive	Household Products	2.22%	1.0476	2.32%	8.03%	11.00%	9.52%	11.84%
4	ConAgra Foods	Food Processing	2.79%	1.0374	2.89%	8.47%	6.50%	7.49%	10.38%
5	Gen'l Mills	Food Processing	3.28%	1.0279	3.37%	5.66%	5.50%	5.58%	8.95%
6	Kellogg	Food Processing	3.01%	1.0229	3.08%	4.15%	5.00%	4.58%	7.65%
7	Kimberly-Clark	Household Products	3.16%	1.0410	3.29%	6.90%	9.50%	8.20%	11.49%
8	McDonald's Corp.	Restaurant	3.58%	1.0270	3.68%	6.78%	4.00%	5.39%	9.07%
9	PepsiCo, Inc.	Beverage	2.72%	1.0397	2.82%	6.36%	9.50%	7.93%	10.75%
10	Procter & Gamble	Household Products	3.08%	1.0356	3.19%	6.73%	7.50%	7.12%	10.30%
11	Smucker (J.M.)	Food Processing	2.39%	1.0309	2.47%	5.36%	7.00%	6.18%	8.65%
12	Target Corp.	Retail Store	2.77%	1.0492	2.90%	12.18%	7.50%	9.84%	12.74%
13	Verizon Communic.	Telecom Services	4.53%	1.0348	4.69%	5.93%	8.00%	6.97%	11.66%
14	Wal-Mart Stores	Retail Store	2.34%	1.0234	2.40%	4.34%	5.00%	4.67%	7.07%
	Range of Reasonableness								**7.07% -- 12.74%**
	Midpoint								**9.90%**
	Median								**10.34%**
	Average								**10.00%**

(a) Six-month average dividend yield for Nov. 2014 - Apr. 2015.
(b) 1 + 0.5 x (f).
(c) (a) x (b).
(d) www.finance.yahoo.com (retrieved May 22, 2015).
(e) The Value Line Investment Survey (Feb. 27, Mar. 13, Mar. 20, Mar. 27, Apr. 10, Apr. 24, May 1, May 22, 2015).
(f) Average of (d) and (e).
(g) (c) + (f).