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March 4, 2014

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

Re: Cheyenne Light, Fuel and Power Company
Docket No. ER14-___-000
Transmission Rates Filing

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (FPA) and Part 35.13[1] of the implementing regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"), Cheyenne Light, Fuel and Power Company ("Cheyenne Light") hereby submits this filing to amend its Open Access Transmission Tariff ("OATT") to change the rates for Cheyenne Light's transmission services ("Rates"), as further described below. The portions of Cheyenne Light's currently effective OATT related to transmission service pricing contain no rates and function as placeholders to indicate that the rates for transmission service are subject to future determination. These "placeholders" are being revised to include the fixed stated rates. Cheyenne Light and its affiliate Black Hills Power, Inc. ("Black Hills Power") are constructing the Cheyenne Prairie Generation Station, a jointly owned natural gas-fired generation unit with a nominal capacity of 132 MW net output located near Cheyenne, Wyoming ("Cheyenne Prairie"). Once that generation facility comes on-line, Cheyenne Light will provide transmission services under its OATT to both its affiliate, Black Hills Power and to itself. Cheyenne Light respectfully requests that the Commission accept the Rates on 60 days' notice, effective May 3, 2014, without suspension as a change in rate, and grant any waivers to the Section 35.13 requirements that the Commission may deem necessary.

[1] 18 C.F.R. § 35.13 (2013).

I. Communications

All communications and service related to this filing should be directed to the following:

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Manager
FERC Tariff Administration & Policy
Black Hills Corporation
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Rapid City, SD 57709-1400
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kenna.hagan@blackhillscorp.com

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2000 K Street, NW
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Senior Managing Counsel
Black Hills Corporation
625 Ninth Street
Rapid City, SD 57701
Tel: (605) 721-2516
Fax: (605) 719-9966
todd.brink@blackhillscorp.com

II. Description of Cheyenne Light and Related Utility

Cheyenne Light, a wholly-owned subsidiary of Black Hills Corporation, is a vertically integrated public utility with its primary office in Cheyenne, Wyoming. A corporate organizational chart depicting Cheyenne Light's relationship with Black Hills Corporation and other affiliates is included as Attachment A hereto for reference. Cheyenne Light is engaged in the business of generating, transmitting, and distributing electricity to approximately 40,500 electric customers in southeastern Wyoming. Cheyenne Light owns 25 miles of transmission lines (115kV and above) and participates in wholesale markets throughout the West. The Cheyenne Light system is completely surrounded by the transmission systems of the Western Area Power Administration ("WAPA"), and the limited transmission facilities owned by Cheyenne Light have been used exclusively to serve its retail load. There is no third party customer under the Cheyenne Light OATT and Cheyenne Light has received no requests for transmission services under the OATT.

Black Hills Power, an affiliate of Cheyenne Light and also a wholly-owned subsidiary of Black Hills Corporation, is a vertically integrated public utility, doing business under the laws of the State of South Dakota. Black Hills Power is engaged in the business of generating, transmitting, and distributing electricity to retail customers in South Dakota, Wyoming, and Montana. Black Hills Power owns over 600 miles of transmission lines (115kV or above) and serves more than 68,000 electric customers in South Dakota, Montana and Wyoming and participates in wholesale markets throughout the West.

Pursuant to a Generation Dispatch and Energy Management Agreement ("GDEMA") between Cheyenne Light and Black Hills Power, on file with the Commission,[2] Black Hills Power performs generation dispatch and energy management services to manage the dispatch of Black Hills Power's and Cheyenne Light's generating resources on a system-wide, least-cost basis. Black Hills Power integrates Cheyenne Light's generating resources and loads into its resource and demand mix and provides Cheyenne Light with hourly load-following service.

III. Cheyenne Light Open Access Transmission Tariff

Cheyenne Light has a Commission-accepted OATT, initially accepted for filing by the Commission in Docket ER09-858-000, effective March 18, 2009.[3] Cheyenne Light's OATT has subsequently been amended to incorporate various changes in compliance with the Commission's requirements for an OATT. Also, in compliance with Order No. 714, Cheyenne Light's baseline OATT was filed in Docket Number ER13-119-00 on October 12, 2012. The Commission accepted the baseline OATT for filing, effective October 13, 2012, as requested.[4] Other changes to comply with Commission requirements or to adopt revised *pro forma* OATT language have been filed by Cheyenne Light with the Commission.[5]

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[2] *Black Hills Power, Inc.*, Docket Nos. ER07-943-000, ER07-943-001 (Dec. 28, 2007) (unpublished delegated letter order) (accepting for filing the GDEMA, effective January 1, 2008, as requested); *Black Hills Power, Inc.*, Docket No. ER12-2046-000 (Aug. 13, 2012)(unpublished delegated letter order accepting amended GDEMA)(accepted for filing, effective July 1, 2013, as requested).

[3] *Cheyenne Light, Fuel & Power Co.*, Docket No. ER09-858-000, (April 27, 2009) (unpublished delegated letter order).

[4] *Cheyenne Light, Fuel & Power Co.*, Docket No. ER13-119-000 (Sept. 26, 2013) (unpublished delegated letter order).

[5] *Cheyenne Light, Fuel & Power Co.*, 142 FERC ¶ 61,206 (2013) (accepting for filing OATT amendments in compliance with Order No. 1000 transmission planning requirement and requiring additional compliance filings); *Cheyenne Light, Fuel & Power Co.*, Docket No. ER13-309-000 (Dec. 27, 2012) (unpublished delegated letter order) (accepting for filing an unauthorized use penalty);

Cheyenne Light has not provided any transmission services to third parties under its OATT and has not had any potential transmission service customer request service under its OATT. The portions of its currently effective OATT related to transmission service pricing contain no rates but only placeholders that indicate that the rates for transmission service are subject to future determination. Cheyenne Light provides reactive power and voltage control service from its generation resources under a reactive power rate schedule accepted for filing in Docket No. ER09-1203-000.[6]

As background, prior to its acquisition by Black Hills Corporation in 2005, service over Cheyenne Light's transmission system was provided for in the OATTs of its prior owners. Initially Cheyenne Light was owned by Public Service Company of Colorado ("PSCO") and was included in that company's OATT.[7] The PSCO tariffs were superseded by the tariffs for the New Century, Inc. ("New Century") companies after New Century was created through the merger of PSCO and Southwestern Public Service Company.[8] The New Century tariffs were superseded by the tariff for the Xcel Energy Inc. companies ("Xcel Companies") after Xcel acquired New Century.[9] Subsequently, when Black Hills Corporation acquired Cheyenne Light, the Xcel Companies' tariff was revised to remove all

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Cheyenne Light, Fuel & Power Co., Order No. 1000 Interregional Compliance Filing, Docket No. ER13-1471-000 (filed on May 10, 2013) (pending before the Commission); *Cheyenne Light, Fuel & Power Co.*, Docket No. ER13-2427-000 (Nov. 4, 2013) (unpublished delegated letter order) (accepting for filing revised Attachment K in compliance with Order No. 1000); *Cheyenne Light, Fuel & Power Co.*, Docket No. ER14-382-000 (Jan. 13, 2014) (unpublished delegated letter order) (accepting for filing OATT amendments in conformance with Order No. 764); *Cheyenne Light, Fuel & Power Co.*, Order No. 784 OATT Compliance Filing, Docket No. ER14-798-000 (filed on Dec. 20, 2013) (pending before the Commission).

[6] *Cheyenne Light, Fuel & Power Co.*, Docket No. ER09-1203-000 (Apr. 27, 2009) (unpublished delegated letter order). While reactive power service is classified by the Commission for certain purposes as other transmission service, the reactive power and control service provided under the rate schedule accepted for filing in Docket No. ER09-1203-000 is not related to the transmission service that Cheyenne Light proposes to provide under the Rates. *See* FERC Form 1–Electric Utility Annual Report, General Instructions IX, description of "OS" as the classification for "Other Transmission Service."

[7] *Allegheny Power System, Inc., et al.*, 80 FERC ¶ 61,143 (July 31, 1997), Order on Rehearing, 85 FERC ¶61,235 (Nov. 16, 1998).

[8] *New Century Services, Inc.*, Docket No. OA97-691 (March, 11, 1999) (unpublished delegated letter order).

[9] *Northern States Power Company, et al.*, 90 FERC ¶ 61,020 (Jan. 12, 2000).

references to Cheyenne Light.[10] Consequently, while in the past Cheyenne Light was included under certain OATTs, since its acquisition by Black Hills Corporation in 2005, it has not been a transmission service provider under an OATT containing rates for transmission service.

IV. Reason for the Proposed Tariff Changes

Cheyenne Light and Black Hills Power are constructing the Cheyenne Prairie Generation Station, a jointly owned natural gas-fired generation unit with a nominal capacity of 132 MW net output located near Cheyenne, Wyoming.[11] Cheyenne Light will have an undivided 58% ownership interest in Cheyenne Prairie, and Black Hills Power will have the remaining 42% undivided ownership interest. Cheyenne Prairie is currently expected to be synchronized to the transmission grid on or about May 1, 2014, and test energy will flow thereafter.

Cheyenne Light is in the process of constructing transmission additions, which include additions necessary to interconnect Cheyenne Prairie to the bulk transmission system. The new transmission facilities will be wholly owned by Cheyenne Light. One line drawings of Cheyenne Light's transmission system are included as Attachment B and Attachment C. Below is a summary table of the new additions and anticipated in-service dates.

[10] *Revisions to Xcel Energy Services Inc. OATT to Remove Cheyenne Light, Fuel and Power Company as a Transmission Service Provider,* Docket No. ER05-535-000 (March 11, 2005) (unpublished delegated letter order).

[11] Cheyenne Light's ownership share of Cheyenne Prairie's output will improve Cheyenne Light's ability to serve its retail load in and around Cheyenne, Wyoming. Currently (before the addition of the Cheyenne Prairie), Cheyenne Light owns one generating resource, the coal-fired Wygen II unit, and purchases the remainder of its requirements through power purchase agreements. The capacity and energy produced by Cheyenne Prairie are needed to ensure that the retail customers of Cheyenne Light and Black Hills Power continue to enjoy safe and reliable electric service. The new transmission facilities will enable Cheyenne Prairie to interconnect with the bulk electric transmission system.

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Description of New Facilities	Anticipated In-Service Date
115 kV substation at Cheyenne Prairie and approximately two miles of a double circuit 115 kV transmission line extension from Cheyenne Prairie that will tie into the existing system	April 2014
115 kV transmission lines from South Cheyenne to Corlett	May 2014
115 kV substation at South Cheyenne	July 2014
115 kV transmission lines from South Cheyenne to North Range and Happy Jack to North Range	August 2014
115 kV substation at Data Center and 115 kV double circuit transmission lines that will interconnect with North Range	March 2015

Cheyenne Light intends to offer transmission services under its OATT over its existing transmission facilities as well as the new transmission facilities. The test year for the Period I cost of service model is a historical test year for the twelve months ending December 31, 2012. The transmission facilities included in the rate base and cost of service for the Rate are derived from Period II and are the 115 kV transmission lines, substation equipment and other related facilities to support the 115 kV system, including those that were placed in service after December 31, 2012, and through the forecasted test year of Period II, July 1, 2014 to June 30, 2015. Cheyenne Light's transmission system is located in WAPA's Colorado-Missouri Region balancing authority area.

V. Description of the Proposed Rates

Cheyenne Light respectfully requests that the Commission accept the Rates to be effective on sixty days' notice, May 3, 2014, without suspension. Cheyenne Light is requesting an order from the Commission placing rates in effect for May 3, 2014 to ensure that the new generation plant can flow test energy under all circumstances in accordance with the plant's commissioning schedule.

The filing includes a proposed ROE of 10.6%, which is the average median of three primary risk analysis models (a discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM") and an equity risk premium approach based on allowed ROEs for electric utilities). Each method is commonly relied on in regulatory proceedings. The requested ROE is supported by the testimony of Dr. William Avera and Mr. Adrien McKenzie, Exhibit No. CLP-100 ("ROE Testimony"). The ROE Testimony also supports a range of reasonableness for Cheyenne Light of 7.5% to 15.9%, based on individual DCF cost of equity estimates depicted on page 3 of Exhibit No. CLP-104. The ROE Testimony demonstrates that the requested ROE is just and reasonable.

This filing includes Rates for the following transmission services under the Cheyenne Light OATT: Scheduling, System Control and Dispatch Service under Schedule 1; Reactive Supply and Voltage Control from Generation or Other Sources Service under Schedule 2; Regulation and Frequency Response Service under Schedule 3[12]; Energy Imbalance Services under Schedule 4; Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service under Schedule 7; and Non-Firm Point-To-Point Transmission Service under Schedule 8. Cheyenne Light also submits a revised OATT Attachment H, showing the Annual Transmission Revenue Requirement for Network Integration Transmission Service. Revised and clean tariff sheets are included as Attachment D.

The chart below provides information on the proposed fixed stated rates in summary format:

Schedule 1 Rates Scheduling System Control & Dispatch	
Term of Reservation	**Rate**
Annual	$2.77 kW/Year
Monthly	$0.230 kW/Month
Weekly	$0.05 kW/Week
Daily Off Peak	$0.008 kW/Day
Daily On Peak	$0.009 kW/Day
Hourly Off Peak	$0.32 MW/hour
Hourly On Peak	$0.55 MW/hour

[12] Cheyenne Light's Schedule 3 amendments pursuant to Order No. 784 are pending before the Commission in Docket No. ER14-798-000. *Cheyenne Light, Fuel & Power Co.*, Order No. 784 OATT Compliance Filing, Docket No. ER14-798-000 (filed on Dec. 20, 2013). The amended Schedule 3 submitted with this filing reflects the previously submitted Schedule 3 amendments.

Schedule 7 Rates Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service	
Term of Reservation	**Rate**
Annual	$34.70 kW/Year
Monthly	$2.89 kW/Month
Weekly	$0.67 kW/Week
Daily Off Peak	$0.095 kW/Day
Daily On Peak	$0.111 kW/Day
Hourly Off Peak	$3.96 MW/hour
Hourly On Peak	$6.95 MW/hour

Schedule 8 Rates Non-Firm Point-To-Point Transmission Service	
Term of Reservation	**Rate**
Annual	$34.70 kW/Year
Monthly	$2.89 kW/Month
Weekly	$0.67 kW/Week
Daily Off Peak	$0.095 kW/Day
Daily On Peak	$0.111 kW/Day
Hourly Off Peak	$3.96 MW/hour
Hourly On Peak	$6.95 MW/hour

Note: The on peak hourly rates are subject to daily and weekly caps consistent with Commission precedent.

VI. Filing Requirements of Section 35.13

Cheyenne Light submits this filing as a change in rate under Commission Rule 35.13. However, because Cheyenne Light's currently effective OATT contains placeholders rather than fixed stated rates for transmission services, not all subparts of Rule 35.13 are relevant to Cheyenne Light's filing. To the extent that the Commission deems that this filing does not meet certain of those requirements, Cheyenne Light respectfully requests that, considering the specific circumstances, the Commission waive such requirements.

a. Documents Submitted with the Tariff Change – Section 35.13(b)(3)

This filing includes the following materials:

1. The testimony of Alan Heintz regarding the cost of service and the description of Mr. Heintz's qualifications (Exhibit Nos. CLP-1 to 2)

2. Statements for Period I (historical) based on the applicable sections of Statements AA through BM[13] (Exhibit Nos. CLP-3 to 39)

3. Statements for Period II (forecasted) based on the applicable sections of Statements AA through BM (Exhibit Nos. CLP-40 to 77)

4. The testimony of William Avera and Adrien McKenzie on the return on equity underlying the cost of capital included in the cost of service (Exhibit Nos. CLP-100 to 113)

5. Corporate organizational chart (Attachment A)

6. Map or single line diagram of the Transmission Facilities (Attachment B)

7. Technical one line diagram of the Transmission Facilities (Attachment C)

8. Revised Tariff Sheets in Redline and Plain Text (Attachment D)

9. Attestation of Ivan Vancas, Vice President – Operations Services of Cheyenne Light (Attachment E)

10. Index to Exhibits (including Statements submitted to support cost of service for proposed rates) (Attachment F)

11. Workpapers of Mr. Alan Heintz in support of Exhibit Nos. CLP-1 through 77. (Attachment G)

b. Date on Which the Utility Proposes to Make the Tariff Change Effective – Section 35.13(b)(2)

Cheyenne Light requests an effective date of May 3, 2014.

[13] Certain Statements are inapplicable because the services provided do not include power and are not related to generation. Further detail is provided at footnote 14, *infra*.

c. The Names and Addresses of Persons to Whom a Copy of the Tariff Change Has Been Posted – Section 35.13(b)(3)

There are currently no customers under the OATT. The names and addresses of the persons to whom a copy of this filing has been posted are identified below:

Wyoming Public Service Commission
Office of Consumer Advocate
Hansen Building
2515 Warren Ave. Suite 300
Cheyenne, WY 82002

Wyoming Public Service Commission
Chris Petrie, Chief Counsel
Hansen Building
2515 Warren Ave. Suite 300
Cheyenne, WY 82002

South Dakota Public Utilities Commission
Capitol Building, First Flr.
500 East Capitol Ave.
Pierre, SD 57501

Montana Public Service Commission
1701 Prospect Ave.
P.O. Box 202601
Helena, MT 59620-2601

Montana Consumer Counsel
111 Last Chance Gulch, Suite B
Helena, MT 59601

d. Brief Description of the Proposed Rates – Section 35.13(b)(4)

See supra Section V.

e. Statement of the Reasons for the Tariff Change – Section 35.13(b)(5)

See supra Section IV.

f. Showing Regarding Requisite Agreement to the Tariff Change – Section 35.13(b)(6)

In this instance, the requirement to obtain agreement to the tariff changes and rates proposed is not applicable because Cheyenne Light currently has no customers under the OATT. That is, no entity takes service under the OATT, has entered into a service agreement under the OATT and/or has requested service under the OATT. Prospectively, in connection with Cheyenne Prairie coming on-line, Cheyenne Light will take network transmission service under the OATT and Black Hills Power will take firm point-to-point transmission service under the OATT. Other than Black Hills Power and Cheyenne Light, no other customers are anticipated to take service under the OATT. To the extent that other customers do seek transmission service, Cheyenne Light will provide service pursuant to the terms and conditions of the OATT that provide open access to any eligible customer.

g. Statement about Expenses or Costs Included in Cost-of-Service Statements – Section 35.15(b)(7)

No expenses included in the cost-of-service statements for Period I or II submitted to support this filing have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

h. Information Relating to the Tariff Change and Proposed Rate – Section 35.13(c)

The information required by Section 35.13(c) relating to revenues under the proposed rate schedules is contained in Statements BG and BH for Period II. *See* Exhibit Nos. CLP-71 and 72. There are no specifically assignable facilities that have been or will be installed or modified in order to supply service under the rates submitted herewith.

i. Cost-of-service information, Periods I and II Data – Sections 35.13(d)(1), (2) and Section 35.13(h)

1. Cost Support for Proposed Rates

Cost-of-service data for Periods I and II are provided in the statement form required by 18 C.F.R. Section 35.13(h). Both cost of service models and resulting rates were derived using traditional FERC ratemaking principles. A list of each statement submitted is included as part of Attachment F (Index to Exhibits) hereto. Specifically, Exhibit Nos. CLP-3 through 39, contain the relevant[14] Statements AA-BM for Period I (Year ending December 31, 2012).

[14] Cheyenne Light respectfully requests waiver of the need to submit certain of the statements described in 18 C.F.R. Section 35.13(h). For example, Cheyenne Light proposes to adopt rates for transmission services only in this filing. Accordingly, Statements BC, BD, BF, BI, and BM should be inapplicable to the present filing for both Periods I and II because those particular statements relate to generation and/or fuel related items such as fuel balances. Statement BE is also inapplicable for this submittal for Periods I and II; Statements BG and BH are not applicable for Period I. Also, Cheyenne Light requests waiver, to the extent necessary, of the need to submit Statement BL for Period I because 18 C.F.R. Section 35.13(h)(37) provides that the statement is provided "[i]n support of the design of the changed rate," (emphasis added) and thus implies that it is not required for Period I.

Exhibit Nos. CLP-40 through 77 contain certain[15] of Statements AA-BM for Period II (July 1, 2014 to June 30, 2015).

Testimony supporting the cost basis is provided in the attached testimony of Alan C. Heintz (Exh. No. CLP-1). The Heintz testimony and the accompanying cost of service analyses support annual fixed costs for the transmission system of $6,848,030. The annual fixed costs are developed consistent with traditional FERC ratemaking practices. The calculations establishing this revenue requirement are specified in the statements accompanying the Heintz testimony, consisting of certain of Statements AA through BM and associated workpapers. Statement BK for Period II, Exhibit No. CLP-75, to the Heintz testimony shows the fixed net revenue requirement for the transmission plant, *i.e.*, the total annual costs less variable operations and maintenance ("O&M") expenses. The revenue requirement is traditional in that it is the sum of Return on Rate Base, Income Tax, Fixed O&M, Depreciation, and Taxes Other than Income Taxes. The revenue requirement is a traditional, non-levelized calculation in that the Return is the product of the Rate of Return times Rate Base, where Rate Base is Net Plant (Gross Plant net of Accumulated Depreciation) less accumulated deferred income taxes (or ADIT), plus additions to Rate Base – Materials and Supplies, Prepaid Items and Cash Working Capital.

Period II is the test year that derives the rates in this filing and is the 12 month period from July 1, 2014 to June 30, 2015. Thus, the cost of service is based on estimated O&M expenses, booked Depreciation expense and Taxes Other than Income Taxes expected to be incurred by Cheyenne Light during that period. Investment in plant, accumulated depreciation, accumulated deferred income taxes, inventories and prepaid expenses are also estimated for Cheyenne Light's test year ending June 30, 2015.

2. Return on Equity and Capital Structure

The proposed rates are based on an ROE of 10.6% for Cheyenne Light's transmission plant. The expert testimony of Dr. William Avera and Adrien McKenzie, Exhibit No. CLP-100 along with supporting exhibits CLP-101-113, describes the derivation of this ROE and explains why it is justified based on the Commission's precedent, policy objectives and recent decisions, capital market and industry trends, independent estimates of the fair rate of return on equity for benchmark groups, and Cheyenne Light's risk profile compared to these groups. The ROE Testimony also supports an ROE zone of reasonableness for Cheyenne Light of 7.5%-15.9%, based on the individual DCF cost of equity estimates shown on page 3 of Exhibit No. CLP-104, after eliminating outliers.

[15] *See supra* note 14.

As noted above, the ROE Testimony averages the medians of three primary risk analysis models: a DCF model, an ECAPM and an equity risk premium approach based on allowed ROEs for electric utilities. Page 1 of Exhibit No. CLP-102 displays the ROE ranges and measures of central tendency resulting from the Avera and McKenzie applications of the DCF, ECAPM, and risk premium methods.

The Avera and McKenzie application of the DCF methodology results in a zone of reasonableness with a midpoint of 11.7% and a median of 9.8%. The utility risk premium approach implies an ROE point estimate in the 10.4% to 10.6% range. Finally, the forward-looking ECAPM estimates are encompassed by an ROE range of 9.5% to 13.8%. The ROE Testimony explains that the overall average of the median cost of equity estimates resulting from alternative applications of the DCF, ECAPM, and risk premium approaches is 10.6%. The ROE Testimony also provides further detail to support a conclusion that the 10.6% ROE is also "consistent with the other measures of central tendency".

For purposes of completeness, the ROE Testimony includes an application of the particular DCF approach that has been referenced by the Commission in past proceedings. However, the ROE Testimony makes clear that Dr. Avera and Mr. McKenzie consider the other methods described in their testimony that result in the 10.6% ROE to provide a superior guide to investors' expectations under current capital market conditions.

As to Cheyenne Light's proposal that the Commission rely on alternative applications of the DCF, ECAPM, and risk premium approaches to support a conclusion that Cheyenne Light should have a 10.6% ROE, the ROE Testimony points out that FERC has recognized that it will consider on a case specific basis how its methods should be modified to achieve a balanced outcome.[16] The ROE Testimony also notes that the Commission has acknowledged the dangers of inflexible criteria in evaluating a fair ROE.[17]

The ROE Testimony recognizes that the Commission in the past has focused on a very specific DCF approach. Dr. Avera and Mr. McKenzie testify that they believe the results of the alternative methods they identify must be considered collectively to establish a reasonable ROE for Cheyenne Light. The ROE Testimony points out that the Commission has recognized that "[i]n some instances, the DCF methodology alone may be inappropriate."[18] The ROE Testimony also notes that when FERC first established the

[16] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 Fed. Reg. 1152 at P 63 (Jan. 10 2007), *on reh'g*, 119 FERC ¶ 61,062 (2007).
[17] *Commonwealth Edison Co.*, 124 FERC ¶ 61,231 at P 22 n. 30 (2008).
[18] *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 at 61,913 n. 90 (1990), *vacated on other grounds*, 931 F.2d 949 (D.C. Cir. 1991).

variant of DCF methodology that it now employs, the Commission noted expressly that "[s]hould circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary."[19] The ROE Testimony provides detail on the anomalous circumstances that justify such a reevaluation. For example, despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. The ROE Testimony notes that investors do not anticipate that these low interest rates will continue into the future. The approach adopted in the ROE Testimony accounts for the reality of current capital markets and considers near-term forecasts for public utility bond yields in evaluating a reasonable base ROE for Cheyenne Light.

In sum, the rates proposed in this submittal are appropriately cost-based. They also fully reflect the nature of the transmission services provided.

j. Workpapers – Section 35.15(d)(5)

Workpapers supporting this filing are submitted as Excel spreadsheets in Attachment G.

k. Attestation – Section 35.13(d)(6)

An attestation by Ivan Vancas, Vice President – Operations Services of Cheyenne Light, is attached as Attachment E hereto.

l. Testimony and Exhibits

To provide support for its proposed transmission rates and related changes to its OATT, Cheyenne Light presents the testimony of two witnesses, as described above in Section V. In accordance with Section 18 C.F.R. Section 35.15(e)(2), the materials submitted in Exhibit Nos. CLP-1 through 77 and CLP-100 through 113 are intended to serve as Cheyenne Light's pre-filed written testimony to the extent this matter is set for hearing.

VII. Waiver Request

Cheyenne Light is submitting this information to support the proposed rates, which implement changes to the OATT, without condition, modification, or hearing. To the extent necessary, however, Cheyenne Light respectfully requests that the Commission waive any filing requirements contained in 18 C.F.R. Part 35 not met by this filing.

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[19] *Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at 61,261 (2000) (history omitted).

VIII. Conclusion

Cheyenne Light, accordingly, requests that the Commission accept the Rates described in this document for filing, effective May 3, 2014, without condition, modification, or hearing-type proceedings.

Very truly yours,

BRACEWELL & GIULIANI LLP

/s/ Catherine P. McCarthy
Catherine McCarthy
Davison Grant

Counsel to Cheyenne Light, Fuel and Power Company

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CHEYENNE LIGHT, FUEL AND POWER COMPANY   Docket No. ER14- _______

DIRECT TESTIMONY OF ALAN C. HEINTZ

March 3, 2014

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A. My name is Alan C. Heintz. My business address is 1155 15th Street, NW, Suite 400, Washington, D.C. 20005. I am employed by the energy consulting firm of Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"). My position is Vice President.

Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. I provide consulting services on matters relating to power sales, transmission, and ancillary service issues associated with the Federal Energy Regulatory Commission's ("FERC" or "Commission") open access transmission service and FERC's Order Nos. 888, 889, 2000, 679, and 890. I have provided consulting services to numerous Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO"), including the transmission owners of the Midwest Independent Transmission System Operator, Inc. ("MISO"), to Desert STAR, to such entities as American Transmission Company, LLC and Trans-Elect, Inc., and to participants in other ISOs and RTOs, including Alliance, Grid Florida, New York ISO, Sterns Independent System Administrator, ISO New England Inc., and California ISO.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by the FERC from November 1985 to February 1995. I served as a Public Utilities specialist in the [Electric] Rate Filings Branch from November 1985 to October 1989. In November 1989, I was promoted to section Chief in the Division of [Electric] Applications, and was responsible for supervising the review of the terms, conditions, and rates of electric rate applications for such services as interchange power, requirements power, and transmission. During my tenure with the FERC, I prepared or supervised the preparation of memoranda recommending acceptance, rejection, deficiency, or investigation in hundreds of cases. These included cases that set important precedents on electric transmission pricing, such as the merger compliance transmission tariffs for Northeast Utilities, the first generation of Open Access Transmission tariffs ("OATT") filed by utilities such as Entergy Services, Louisville Gas & Electric Co., PacifiCorp, Kansas City Power & Light Co., American Electric Power Co., and the Pennsylvania Electric Company case involving Genentech Papers, Inc. I also taught a one-year course to FERC Staff and gave several presentations to the Edison Electric Institute Interconnection and Interchange Arrangements Committee on the pricing of power and transmission services.

From February 1995 through October 2000, I was Vice President of Stone & Webster Management Consultants, Inc. In this position, I provided consulting services to numerous electric utilities on matters involving requirements and off-system power rates, and rate and implementation strategies for developing OATT filings, and organizing ISOs and RTOs. I also assisted several utilities in preparing their retail delivery services filings. I joined R. J. Redden Associates, Inc. in November 2000 as a Vice President, where I continued providing consulting services to the electric industry. I joined BWMQ in February 2004.

Q. PLEASE SUMMARIZE YOUR OTHER EXPERIENCE TESTIFYING BEFORE REGULATORY BODIES AND COURTS ON UTILITY-RELATED MATTERS.

A. During my tenure at the FERC, I was assigned to the Commission's advisory staff and, therefore, was precluded from testifying before the FERC. However, while at the FERC, I presented cases publicly to the FERC Commissioners at their bi-weekly public meetings and was the technical contact to the Commissioners in numerous cases. Since leaving the employ of FERC, I have filed testimony before the FERC in numerous proceedings. I have also testified before the British Columbia Utilities Commission in Canada, the Illinois Commerce Commission, the Maine Public Utilities Commission, the United States Court of Federal Claims, and the United States District Court in Florida. A summary of the testimony I have filed in various proceedings is shown in Exhibit No. CLP-2.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received the degree of Bachelor of Science in Business and the degree of Bachelor of Arts in Economics from the University of Colorado, Boulder, Colorado, in May 1982. I also received the degree of Master of Business Administration in Finance from the George Washington University in Washington, DC, in December 1988.

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain and support Statements AA through BM, Periods I and II, which support Cheyenne Light, Fuel and Power Company's

("Cheyenne") proposed rates for transmission service and Scheduling, System Control and Dispatch Service ("Schedule 1") under its OATT.

Exhibit No. CLP-3 through 77 consist of Statements AA-BM for Periods I and II.

Q. DOES CLFP PROPOSE TO CHARGE THE RATES THAT ARE SUPPORTED BY THE REVENUE REQUIREMENT SHOWN IN STATEMENT BK FOR PERIOD II?

A. Yes. CLFP proposes to charge the rates to all wholesale customers, Point-to-Point and Network Services. The rates supported by the filing and the proposed settlement rates can be found in Statement BL for Period II.

Q. WHAT IS THE RATE OF RETURN ON EQUITY ("ROE") REQUESTED BY COMPANY IN THIS FILING?

A. The ROE used in both Period I and Period II to calculate CLFP's revenue requirement is 10.6% and is supported by witnesses William Avera and Adrien McKenzie in Exhibit No. CLP-100.

Q. PLEASE DESCRIBE THE DOCUMENTS AND MATERIALS YOU HAVE REVIEWED IN PREPARING THIS TESTIMONY.

A. I have reviewed CLFP's 2012 FERC Form 1 and numerous spreadsheets and workpapers provided to me by CLFP which incorporate data from CLFP's financial statements and budgets.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COST STUDY.

A. The Period II cost of service analysis demonstrates that the FERC jurisdictional revenue requirement for service provided to the only projected transmission customer Black Hills Power, Inc. is $347,029 for the 10 MW of service that it is estimated they will begin taking later this year.

Q. WHAT IS THE TEST PERIOD FOR THIS FILING?

A. CLFP's cost support consists of Period I Statements AA-BM for the 12 calendar months ending December 31, 2012 and Period II Statements AA-BM for the 12 calendar months ending June 30, 2015. Period II is the test period. Period II data is developed as part of the company's corporate budgeting process.

III. DISCUSSION OF STATEMENTS AA-BM

Q. PLEASE DESCRIBE STATEMENTS AA-AY FOR PERIODS I AND II, RESPECTIVELY.

A. I will discuss only the Statements for Period II (the 12 months ending June 30, 2015) unless those for Period I require special comment. Statements AA, AB and AC are the financial statements: (1) Statement AA is the balance sheet as of the end of the test period; (2) Statement AB consists of the statements of income for the twelve months ending June 30, 2015; and Statement AC is the statement of retained earnings.

Statement AD shows the (13 monthly) balances of electric plant by functional classification. Statement AE shows the (13 monthly) balances of accumulated depreciation and amortization by functional classification.

Statement AF sets out accumulated deferred income taxes; the regulatory liability associated with FAS 109, and deferred investment tax credits.

Statement AG shows plant held for future use, accumulated deferred income taxes and regulatory assets related to the implementation of FAS 109.

Q. PLEASE CONTINUE WITH A DESCRIPTION OF THE STATEMENTS.

A. Statement AH shows a summary and detail by FERC account of total operation and maintenance expenses for the 12 months ended June 30, and the basis for classification to demand and energy.

Statement AI provides electric wages and salaries by function, and allocation of production wages and salaries into demand an energy components, for the twelve months ended June 30.

Statement AJ is a summary of depreciation and amortization expenses, functionalized.

Statement AK sets out Taxes Other Than Income Taxes for the twelve months ended June 30, 2015, including revenue taxes, real estate and property taxes, payroll taxes and other non-income taxes.

Statement AL is a summary of the components of average working capital, including 45 days cash requirement for operation and maintenance expenses exclusive of fuel and purchased power expenses, and the average of 13 monthly balances for major prepayment items, including materials and supplies, and fuel inventories.

Statement AM presents CWIP according to functional classification for the period ended June 30. Company is not including CWIP in rate base in this filing.

Statement AN gives the thirteen month average balance of notes payable for the period ended June 30.

Statement AO sets forth methodologies for the computation of gross AFUDC rate.

Statement AP presents Allowance for Funds Used During Construction (AFUDC) capitalized and interest synchronization for the twelve months ended June 30.

Statements AQ, AR, AS, and AT provide a detailed listing of the Federal income tax computations (there is no state income tax) and a functional itemization of deferred taxes and associated amortization of regulatory assets and liabilities associated with FAS 109 for the twelve months ended June 30. The computations are based on the forecast data for Period II.

Q. DOES CLFP'S PERIOD II COST OF SERVICE STUDY REFLECT COMPREHENSIVE INCOME TAX NORMALIZATION?

A. Yes. The estimated amount of deferred taxes that will be included in net income in the twelve-month period ended June 30 (Period II), is detailed in statement AR.

Q. PLEASE CONTINUE DESCRIBING THE STATEMENTS.

A. Statement AU shows revenue credits. These are discussed in more detail later in my testimony.

Statement AV shows the capital structure, rate of return on equity and overall rate of return that is supported in testimony by CLFP witnesses William Avera and Adrien McKenzie.

Statement AW details the weighed cost of short-term debt for the twelve-month period ending June 30, and the cost of short-term debt on an annualized end of period basis for that same time period.

Statement AX indicates that there are no base revenues subject to refund for Period I and Period II as a result of any proceedings before the Commission.

Statement AY sets out the development of the composite income tax rate.

Q. PLEASE DESCRIBE STATEMENTS BB, BD, BE, BF, AND BJ, AND HOW YOU PREPARED THEM.

A. Statement BB, for Period II, shows the coincident demands of the wholesale and retail customer loads are those forecast and supported by Company.

Statement BD is not applicable to transmission rates.

Statement BE shows that there is no transmission plant that is specifically assigned to customers.

Statement BJ provides a tabular summary referencing statements and exhibits to the location in Statement BK of the information required.

Q. WHAT INFORMATION IS CONTAINED IN STATEMENT BK?

A. Statement BK utilizes the total company plant investment, by function, and related plant and operating cost and tax data (as specified in other "Statements") to develop the annual cost of the service at issue.

The revenue requirement is developed on the traditional basis as the sum of Operating & Maintenance Expenses ("O&M"), Depreciation Expense, Taxes Other Than Income Taxes ("Other Taxes", or "OT"), Income Taxes and Return on Rate Base. Return on Rate Base is developed in the usual manner as the product of the requested Overall Rate of Return ("ROR") (see Statement AV) and Rate Base, the largest component of which is plant in service at original cost less accumulated depreciation ("net plant"). Plant balances are developed as 13 month averages where the functionalized accounting data is available. Rate base also includes subtractive adjustments related to Accumulated Deferred Income Taxes ("ADIT"), including Account No. 255 (Deferred ITC – Statement AF). Additive adjustments include Account No. 190 balances, the effect of removal of FAS 109 (Accounts 182.3 and 254) and the several components of an allowance for Working Capital – Prepayments, Materials and Supplies and Cash Working Capital ("CWC"). CWC is calculated as one-eighth of O&M expenses excluding fuel and purchased power expense.

Q. DOES RATE BASE INCLUDE A SHARE OF GENERAL PLANT, NET OF ACCUMULATED DEPRECIATION?

A. Yes. General plant is functionalized on the basis of the Wages & Salaries ("W&S") allocator.

Q. PLEASE DESCRIBE HOW EXPENSES ARE FUNCTIONALIZED.

A. Consistent with FERC-accepted practices, O&M expenses specifically identified by function in the Uniform System of Accounts are appropriately assigned to functions in Schedule BK. Administrative & General expenses are functionalized on the basis of the W&S function factor, with the exception of Property Insurance, which is functionalized on a Gross P-T-D plant factor (or gross plant).

Depreciation expenses are directly assigned to functions, except for General Plant depreciation expense, which is functionalized on W&S.

Other Taxes allocated to the FERC-jurisdictional wholesale customers consist only of real estate and property taxes and payroll-related taxes. Real estate and property taxes are functionalized on gross plant, and payroll taxes are functionalized on W&S.

Income tax expense is calculated on the basis of the return requirement developed from the filed capital structure, and the interest deduction is synchronized to rate base.

Q. PLEASE DISCUSS HOW REVENUE CREDITS WERE DEVELOPED ON STATEMENT BK.

A. Revenue credits for total company are developed on Statement AU, consisting of the balances of Accounts 447, 454 and 456. Since there are no short term nor non-firm transmission services at this time, nor is there an expectation for these services. Therefore, there are no revenue credits.

Q. PLEASE DISCUSS CLFP'S PROPOSED RATE DESIGN (STATEMENT BL).

A. Statement BL shows the calculated rate applicable for transmission service and Schedule 1 service. On Statement BL, I show the revenue requirement divided by the firm load for both transmission service and Schedule 1 service. Statement BL shows the calculation for the rate of $2.89/kW/Mo for transmission service and the rate of $0.23/kW/Mo for Schedule 1 service.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cheyenne Light, Fuel and Power	Docket No. EL14-___-000

VERIFICATION

WASHINGTON, D.C.)

I, Alan C. Heintz, being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information, and belief.

Alan C. Heintz

Subscribed and sworn to before me, the undersigned notary public, the 4th day of March, 2014.

Notary Public

My Commission expires on June 30, 2014

STEPHANIE J. WILKERSON NOTARY PUBLIC DISTRICT OF COLUMBIA

SUMMARY OF TESTIMONY EXPERIENCE
ALAN C. HEINTZ

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
1	FERC	ER95-836-000	Maine Public Service Company	Maine Public Service Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
2	FERC	ER95-854-000	Kentucky Utilities Company	Kentucky Utilities Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
3	FERC	ER95-1686-000 ER96-496-000	Northeast Utilities Service Company	Northeast Utilities Service Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
4	FERC	ER96--58-000	Allegheny Power Services Corporation	Allegheny Power Services Corporation	1995 & 1996	Rates, Terms and Conditions for Open Access Transmission Services
5	FERC	OA96-138-000	Consolidated Edison Company of New York, Inc.	Consolidated Edison Company of New York, Inc.	1997	Rates, Terms and Conditions for Open Access Transmission Services
6	FERC	ER96-1208-000	Interstate Power Company	Interstate Power Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
7	British Columbia Utilities Commission		British Columbia Hydro and Power Authority	Bonneville Power Administration	1997	Rates, Terms and Conditions for Open Access Transmission Services

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
8	FERC	ER98-1438-000 EC98-24-000	Cincinnati Gas & Electric Company, et al. (Midwest Independent System Operator)	Midwest ISO Transmission Owners	1998 & 1999	Rates, Terms and Conditions for Midwest ISO Tariff
9	FERC	EC98-2770-000 ER98-2770-000 ER98-2786-000	American Electric Power Company, Inc. and Central & Southwest Corporation	Midwest Independent System Operator Transmission Owners	1999	Reasonableness of the conditions to be placed on the merging parties
10	Illinois Commerce Commission	99-0117	Commonwealth Edison Company	Commonwealth Edison Company	1998	Cost of service for Retail Distribution Services Tariff
11	FERC	ER99-3110-000	Nevada Power Company	Nevada Power Company	1998	Rates, Terms and Conditions for Open Access Transmission Services
12	FERC	ER99-4415-000	Illinois Power Company	Illinois Power Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
13	FERC	ER99-4470-000	Commonwealth Edison Company	Commonwealth Edison Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
14	U.S. District Court, FL	92-35-CIV-ORL-3A22	Florida Municipal Power Agency vs. Florida Power and Light Company	Florida Power and Light Company	1999	Rates, Terms and Conditions for Network Service in an anti-trust case
15	U.S. Court of Federal Claims, DC	97-268C	Carolina Power & Light Company vs. U.S. Department of Energy	Carolina Power & Light Company	1999	Cost recovery of Decontamination & Decommissioning Fund Assessments

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
16	FERC	ER98-496-006 ER98-2160-004	San Diego Gas & Electric	Dynegy	1999	Rates for Must Run units
17	FERC	ER00-980-000	Bangor Hydro Electric Company	Bangor Hydro Electric Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
18	Maine Public Utilities Commission	99-185	Bangor Hydro Electric Company	Bangor Hydro Electric Company	2000	Rates, Terms and Conditions for Open Access Transmission Services
19	FERC	EL00-98-000, et al.	Dynegy Power Marketing, Inc, et al.	Dynegy Power Marketing, Inc.	2000	Nexus between fuel and emissions costs and the market prices in California
20	Illinois Commerce Commission	No. 01-0423	Commonwealth Edison Company	Commonwealth Edison Company	2001	Direct, Rebuttal and Surrebuttal: Cost of service for Retail Distribution Services Tariff
21	FERC	ER01-2992	Commonwealth Edison Company	Commonwealth Edison Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
22	FERC	ER01-123.004	Midwest ISO Transmission Owners	Midwest ISO Transmission Owners	2001	Super Region Adjustment for the MISO/ARTO Super Region
23	FERC	ER01-2999	Illinois Power Company	Illinois Power Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
24	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Revised treatment of Network Upgrades

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
25	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Uncertainties that support a higher ROE
26	FERC	EL000-95-045, et.al	San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the CALISO…	Dynegy, Mirant, Reliant and Williams	2001 & 2002	Costing of emissions and start-up costs
27	FERC	EC02-23 & ER02-320	Trans-Elect, Inc., et. al	Trans-Elect, Inc.	2001 & 2002	Support of rates and ratemaking methodology for new transmission company
28	FERC		Sithe New Boston, LLC	Sithe New Boston, LLC	2001 & 2002	Cost of Service for Must Run Unit
29	FERC	RM01-12	FERC Technical Conference	SeTrans	2002	Allocation of FTRs/CRRs
30	FERC	EL02-111	Midwest ISO & PJM	Midwest ISO Transmission Owners	2002	Through and Out Rates
31	FERC	ER02-2595	Midwest ISO	Midwest ISO Transmission Owners	2002	Cost Allocation for FTR and Market Administration
32	FERC	ER03-37	Sierra Pacific Resources	Sierra Pacific and Nevada Power	2003	Ancillary Service Rates
33	FERC	ER03-626	Empire District Electric Co.	Empire District Electric Co.	2003	Cost of Service; Wholesale Requirements Customers
34	FERC	EL-02-25-001, et. al	Intermountain, Holy Cross, Yampa and Aquila	Public Service Co. of Colorado	2003	Fuel Adjustment Clause

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
35	FERC	ER03-959	Exelon Framingham LLC, et al.	Exelon Framingham LLC, et al.	2003	Production Cost of Service
36	FERC	ER03-1187	MidWest Generation, LLC	Commonwealth Edison	2003	Black Start Rates
37	FERC	ER03-1223	Montana Megawatts I, LLC, et al.	Montana Megawatt	2003	Production Formula Rates
38	FERC	ER03-1335	Commonwealth Edison	Commonwealth Edison	2003	Transmission Tariff Rates
39	FERC	ER03-1354	Black Hills Power Company, et al.	Black Hills Power Company, et al.	2003	Joint transmission Tariff Rates
40	FERC	ER03-1328	Sierra Pacific Resources	Nevada Power	2003	Transmission Tariff Rates
41	FERC	EL02-111, et. Al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Long-term Transmission Pricing Plan
42	FERC	ER05-14	Sierra Pacific Resources	Sierra Pacific	2004	Transmission Tariff Rates
43	FERC	ER05-26	Mirant Kendall, LLC	Mirant Kendall, LLC	2004	Reliability Must Run Agreement and Rates
44	Illinois Commerce Commission	No.04-0779	NICOR Gas Company	NICOR Gas Company	2004	Distribution Service Embedded Cost of Service Study
45	FERC	ER05-163	Milford Power Company LLC	Milford Power Company LLC	2004	Reliability Must Run Agreement and Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
46	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Seams Elimination
47	FERC	EL00-95, et. al	SDG&E V. Sellers, et al.	Portland General Electric Company	2005	California Refund Proceeding
48	FERC	ER05-447	Midwest ISO	Midwest ISO Transmission Owners	2005	Schedule 10 & 17 Recovery for Grandfathered Agreements
49	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
50	FERC	ER05-860	Whiting Clean Energy	Whiting Clean Energy	2005	Cost Based Power Rates
51	FERC	ER05-903	Con. Ed. Energy Mass., Inc.	Con. Ed. Energy Mass., Inc.	2005	Reliability Must Run Agreement and Rates
52	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
53	FERC	ER05-1050	AmerGen Energy Company, L.L.C.	AmerGen Energy Company, L.L.C.	2005	Reactive power charges
54	Illinois Commerce Commission	No.05-0597	Commonwealth Edison Co.	Commonwealth Edison Co.	2005	Distribution Service Embedded Cost of Service Study
55	FERC	ER05-1179	Berkshire Power Company, LLC	Berkshire Power Company, LLC	2005	Reliability Must Run Agreement and Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
56	FERC	ER05-1243	Basin Electric Power Cooperative	Basin Electric Power Cooperative	2005	Revised Transmission Cost of Service
57	FERC	ER05-1304 & ER05-1305	Mystic I, LLC and Mystic Development, LLC	Mystic I, LLC and Mystic Development, LLC	2005	Reliability Must Run Agreement and Rates
58	FERC	ER05-273	Midwest ISO	Midwest ISO Transmission Owners	2005	Proper Pricing for Regional Non-firm Redirects
59	FERC	ER05-515	PHI and BGE	PHI and BGE	2005	Transmission Formula Rates
60	FERC	EL05-19	Southwestern Public Service Company	Southwestern Public Service Company	2005	Production rates and Fuel Adjustment Clause,
61	FERC	ER06-427	Mystic Development, LLC	Mystic Development, LLC	2006	Reliability Must Run Agreement and Rates
62	FERC	ER06-822	Fore River Development, LLC	Fore River Development, LLC	2006	Reliability Must Run Agreement and Rates
63	FERC	ER06-819	Consolidated Edison Energy Massachusetts, Inc	Consolidated Edison Energy Massachusetts, Inc	2006	Reliability Must Run Agreement and Rates
64	FERC	ER07-169	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2006	Ancillary service rates
65	FERC	ER06-1549	Duquesne Light Company	Duquesne Light Company	2006	Transmission Formula Rates
66	FERC	ER07-170	Ameren Energy, Inc.	Ameren Energy, Inc.	2006	Ancillary service rates
67	FERC	ER06-787	Idaho Power	Idaho Power	2006 & 2007	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
68	FERC	ER07-562	Trans-Allegheny Interstate Line Company	Trans-Allegheny Interstate Line Company	2007	Transmission Formula Rates
69	FERC	ER07-583	Commonwealth Edison	Commonwealth Edison	2007	Transmission Formula Rates
70	FERC	ER07-1171	Arizona Public Service Co.	Arizona Public Service Co.	2007	Transmission Formula Rates
71	Illinois Commerce Commission	No. 07-0566	Commonwealth Edison Co.	Commonwealth Edison Co.	2007	Distribution Service Embedded Cost of Service Study
72	FERC	ER07-1371	Sierra Pacific Resources	Sierra Pacific Resources	2007	Transmission Rates
73	FERC	ER08-281	Oklahoma Gas & Electric	Oklahoma Gas & Electric	2007	Transmission Formula Rates
74	FERC	ER08-313	Southwestern Public Service	Southwestern Public Service	2007	Transmission Formula Rates
75	FERC	ER08-386	Potomac-Appalachian Transmission Highline, LLC	Potomac-Appalachian Transmission Highline, LLC	2007	Transmission Formula Rates
76	FERC	ER08-374	Atlantic Path 15, LLC	Atlantic Path 15, LLC	2007	Transmission Rates
77	Illinois Commerce Commission	No. 08-0363	NICOR Gas Company	NICOR Gas Company	2008	Distribution Service Embedded Cost of Service Study
78	FERC	ER08-951	PSEG Energy Resources & Trade, LLC	PSEG Energy Resources & Trade, LLC	2008	Reactive Power Charges
79	FERC	ER08-1233	Public Service Gas & Electric Company	Public Service Gas & Electric Company	2008	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
80	FERC	ER08-1457	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2008	Transmission Formula Rates
81	FERC	ER08-1584	Black Hills Power	Black Hills Power	2008	Transmission Formula Rates
82	FERC	ER08-1600	Basin Electric Power Coop	Basin Electric Power Coop	2008	Transmission Rates
83	FERC	ER09-36	Prairie Wind Transmission, LLC	Prairie Wind Transmission, LLC	2008	Transmission Formula Rates
84	FERC	ER09-35	Tallgrass Transmission, LLC	Tallgrass Transmission, LLC	2008	Transmission Formula Rates
85	FERC	ER09-75	Pioneer Transmission, LLC	Pioneers Transmission, LLC	2008	Transmission Formula Rates
86	FERC	ER09-255	Nebraska Public Power District	Nebraska Public Power District	2008	Transmission Formula Rates
87	FERC	ER09-528	ITC Great Plains, LLC	ITC Great Plains, LLC	2009	Transmission Formula Rates
88	Illinois Commerce Commission	ER08-0532	Commonwealth Edison Co.	Commonwealth Edison Co.	2009	Distribution Service Embedded Cost of Service Study
89	FERC	ER08-370 & EL09-22	Missouri River Energy Services & MISO	Otter Tail Power Co.	2009	Formula Transmission Rate
90	FERC	ER10-152	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2009	Revised Depreciation Method
91	FERC	ER09-1727	ALLETE, INC	ALLETE. INC	2009	Formula Transmission Rate
92	FERC	ER10-230	KCP&L	KCP&L	2009	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
93	FERC	ER10-455	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2009	Reactive Power Rates
94	FERC	ER10-516	SCE&G	SCE&G	2010	Formula Transmission Rates
95	FERC	ER10-962	Union Electric Company	Union Electric Company	2010	Reactive Power Rates
96	FERC	ER10-1149	FP&L	FP&L	2010	Formula Transmission Rates
97	FERC	ER10-1418	Exelon Generation	Exelon Generation	2010	Reliability Must Run
98	FERC	ER10-1782	Tampa Electric Company	Tampa Electric Company	2010	Formula Transmission Rates
99	FERC	ER10-2061	Tampa Electric Company	Tampa Electric Company	2010	Formula Production Rates
100	FERC	ER05-6	Midwest ISO	MISO Transmission Owners	2010	Seams Elimination
101	FERC	ER11-2127	Terra Gen Dixie Valley	Terra Gen Dixie Valley	2010	Transmission Rates
102	FERC	ER09-1148	PPL Electric Utilities	PPL Electric Utilities	2011	Formula Transmission Rates
103	FERC	ER11-3643	PacifiCorp	PacifiCorp	2011	Formula Transmission Rates
104	FERC	ER11-3826	Black Hills	Black Hills	2011	Transmission Rates
105	FERC	ER11-3643	Puget Sound Energy	Puget Sound Energy	2012	Formula Transmission Rates
106	FERC	ER12-1378	CLECO	CLECO	2012	Formula Transmission Rates
107	FERC	ER12-1593	DATC	DATC	2012	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
108	FERC	ER12-2274	PSE&G	PSE&G	2012	Abandonment Costs
109	FERC	ER12-2554	Transource Missouri, LLC	Transource Missouri, LLC	2012	Formula Transmission Rate
110	FERC	ER13-1187	MidAmerican	MidAmerican	2013	Depreciation Rates under Formula
111	FERC	ER13-1207	PacifiCorp	PacifiCorp	2013	Regulation Service
112	FERC	EL13-48	PHI Companies	PHI Companies	2013	Complaint involving Formula Rates
113	FERC	ER13-1207	PacifiCorp	PacifiCorp	2013	Depreciation Rates under Formula
114	FERC	ER13-1605	NV Energy	NV Energy	2013	Transmission and Ancillary Service Rates
115	FERC	ER13-782	ITC	ITC	2013	Transmission Formula Rate
116	FERC	ER13-1962 & EL13-76	Midcontinent ISO & AERG	AERG/AEM	2013	Reliability Must Run
117	FERC	ER14-108	Entergy	Entergy	2013	Reactive Power Rates

CHEYENNE LIGHT, FUEL AND POWER COMPANY
BALANCE SHEET -- ASSETS
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-3
PERIOD I
STATEMENT AA

Title of Account	2011	2012
UTILITY PLANT		
Utility Plant	416,300,956	441,400,625
Construction Work in Progress	11,684,553	24,088,060
TOTAL Utility Plant	427,985,509	465,488,685
(Less) Accum. Prov. for Depr. Amort. Depl.	98,080,166	105,095,539
Net Utility Plant	329,905,343	360,393,146
TOTAL Other Property and Investments	329,905,343	360,393,146
CURRENT AND ACCRUED ASSETS		
Cash	364,901	631,456
Accounts Receivable	28,488,160	13,441,893
Inventories	7,595,771	6,912,218
Prepayments	941,006	992,634
Other	5,326,314	5,092,541
TOTAL Current and Accrued Assets	42,716,152	27,070,742
DEFERRED DEBITS		
Unamortized Debt Exp	1,309,468	1,237,352
Other Regulatory Assets	24,578,254	25,779,396
Other	7,730,468	8,313,494
TOTAL Deferred Debits	33,618,190	35,330,242
TOTAL Assets and Other Debits	$ 406,239,685	$ 422,794,130

Note: Ties to 2012 FERC Form 1, pages 110-113.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
BALANCE SHEET -- LIABILITIES
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-3
PERIOD I
STATEMENT AA

Title of Account	2011	2012
CAPITALIZATION		
Common Shareholder Equity	$ 177,090,274	$ 175,965,410
Preferred Securities	0	0
Long-term Debt	127,000,000	127,000,000
TOTAL Proprietary Capital & Long-Term Debt	304,090,274	302,965,410
OTHER NONCURRENT LIABILITIES		
Capital Leases		
Accumulated Provision for Damages and Injuries	51,203	56,465
Accumulated Provision for Pensions and Benefits	0	93,691
Other Noncurrent Liabilities	0	0
Asset Retirement Obligations	217,529	226,825
TOTAL Other Noncurrent Liabilities	268,732	376,981
CURRENT LIABILITIES		
Short term Debt		
Current Debt Maturities		
Accounts Payable	16,489,413	29,060,605
Customer Deposits	1,632,651	1,813,142
Accrued Dividends, Intererest and Taxes	2,738,142	4,175,525
Accrued Misellaneous & Other	3,493,127	3,228,635
TOTAL Current & Accrued Liabilities	24,353,333	38,277,907
DEFERRED CREDITS		
Deferred Income Taxes & ITC	70,244,712	75,494,153
Other Regulatory Liabilities	3,538,393	3,436,462
Customer Advances for Construction	3,744,241	2,243,217
Accrued Other		
TOTAL Deferred Credits	77,527,346	81,173,832
TOTAL Liab and Other Credits	$ 406,239,685	$ 422,794,130

Note: Ties to 2012 FERC Form 1, pages 110-113.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
INCOME STATEMENT
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-4
PERIOD I
STATEMENT AB

Title of Account	2011	2012
UTILITY OPERATING INCOME		
Operating Revenues	$ 165,610,893	$ 159,493,259
Operating Expenses		
Operating & Maintenance Expense	119,985,091	113,083,622
Depreciation & Amortization Expense	11,447,784	11,932,967
Regulatory Debits (net)		
Taxes Other Than Income	2,978,020	3,751,900
Income Taxes -- Federal and Other	(3,369,695)	2,886,726
Provision for Deferred Income Taxes	11,539,611	4,805,042
Other	(45,206)	(43,384)
TOTAL Utility Operating Expenses	142,535,605	136,416,873
Net Utility Operating Income	23,075,288	23,076,386
Other Income		
Other Income	792,579	612,112
Other Income Deductions	158,258	162,305
Taxes on Other Income	5,717	1,953
TOTAL Other Income -- Net	628,604	447,854
Earnings before Interest & Preferred	23,703,892	23,524,240
Interest Charges		
Interest Expense	7,827,350	7,714,119
(Less) Allowance for Borrowed Funds Used During Construction	(88,892)	(121,743)
Net Interest Charges	7,916,242	7,835,862
Earnings before Preferred & Extraordinary Items	15,787,650	15,688,378
Preferred Dividends and Extradordinary Items	0	0
Net Income	$ 15,787,650	$ 15,688,378

Note: Ties to 2012 FERC Form 1, pages 114-117.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
STATEMENT OF RETAINED EARNINGS
Calendar Years 2011 & 2012
Units: $000s

Exh. CLP-5
PERIOD I
STATEMENT AC

Item	2011	2012
Unappropriated Balance - Beginning of Year	$ 39,184,033	$ 40,471,683
Equity Earnings of Subsidiary Company		(16,813,242)
Balance Transferred from Income	15,787,650	15,688,378
Transfers from Account 216.1	(14,500,000)	
Unappropriated Balance - End of Year	$ 40,471,683	$ 39,346,819
Appropriated Retained Earnings		
Change in Accounting Method for Unbilled Revenue		
Total Retained Earnings	$ 40,471,683	$ 39,346,819

Note: Ties to 2012 FERC Form I, pg 118 & 119

CHEYENNE LIGHT, FUEL AND POWER COMPANY
UTILITY PLANT IN SERVICE
December 2011 through December 2012
Units: $000s

Exh. No. CLP-6
PERIOD I
STATEMENT AD

UTILITY PLANT IN SERVICE

Month/Yr	Production	Transmission	Distribution	General	Intangible	Electric Common	Total
Dec-11	$ 182,716,932	$ 5,867,274	$ 129,799,426	$ 3,010,785	$ 168,500	$ 5,120,996	$ 326,683,913
Jan-12	182,768,073	5,867,277	130,155,228	3,059,829	168,500	5,123,032	327,141,939
Feb-12	182,768,073	5,867,075	130,990,996	3,099,668	168,500	5,123,032	328,017,344
Mar-12	182,871,222	5,857,776	131,714,485	3,272,701	168,500	4,780,771	328,665,455
Apr-12	182,901,625	5,867,767	133,949,292	2,915,878	168,500	4,805,900	330,608,962
May-12	182,930,265	8,337,411	135,748,180	2,925,870	168,500	4,794,583	334,904,809
Jun-12	183,219,200	8,319,574	138,936,899	2,969,164	168,500	4,817,531	338,430,868
Jul-12	183,174,489	8,257,354	139,400,064	3,000,504	168,500	4,858,156	338,859,067
Aug-12	183,190,891	9,078,377	139,688,793	2,999,768	168,500	4,859,013	339,985,342
Sep-12	184,681,766	9,244,976	140,179,303	3,040,798	168,500	5,127,581	342,442,924
Oct-12	184,099,317	9,244,976	140,511,852	3,040,663	168,500	5,129,836	342,195,144
Nov-12	184,099,317	9,244,976	141,880,516	3,035,173	168,500	5,127,077	343,555,559
Dec-12	184,542,754	10,366,408	142,345,868	3,962,063	168,500	4,954,608	346,340,201
13 Month Average	$ 183,381,840	$ 7,801,632	$ 136,561,608	$ 3,102,528	$ 168,500	$ 4,970,932	$ 335,987,041

	GSU's Booked to Transmission
Dec-11	$ 1,570,095
Jan-12	$ 1,570,095
Feb-12	$ 1,570,095
Mar-12	$ 1,570,095
Apr-12	$ 1,570,095
May-12	$ 1,570,095
Jun-12	$ 1,570,095
Jul-12	$ 1,570,095
Aug-12	$ 1,570,095
Sep-12	$ 1,570,095
Oct-12	$ 1,570,095
Nov-12	$ 1,570,095
Dec-12	$ 1,570,095
13 Month Average	$ 1,570,095

Note: (1) December 2011 & 2012 electric numbers tie to Form I, pages 204/205, rows 5 & 46, and pages 206/207, rows 58, 75, 99 & 104. The total number also ties to pages 200/201, row 3.
(2) The remaining months are pulled from the company's internal financial records.
(3) The "13 Month Average" amounts go forward to:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study
(4) The "13 Month Average" GSU amounts go forward to:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
ACCUMULATED DEPRECIATION
December 2011 through December 2012
Units: $000s

Exh. No. CLP-7
PERIOD I
STATEMENT AE

ACCUMULATED DEPRECIATION

Month/Yr	Intangible	Production	Transmission	Distribution	General	Electric Common	Total
Dec-11	$ 169,610	$ 16,175,531	$ 1,920,195	$ 42,925,499	$ 912,804	$ 2,724,318	$ 64,827,957
Jan-12	169,616	16,576,161	1,931,356	43,230,443	937,977	2,759,488	65,605,041
Feb-12	169,605	16,975,166	1,942,328	43,427,275	963,314	2,794,367	66,272,055
Mar-12	168,326	17,244,129	1,938,678	43,924,494	960,979	2,440,644	66,677,250
Apr-12	168,330	17,641,611	1,949,735	44,123,115	986,373	2,474,423	67,343,587
May-12	168,196	18,024,232	1,961,593	44,183,555	1,022,205	2,533,509	67,893,290
Jun-12	168,225	18,424,091	1,977,738	43,908,667	1,044,902	2,567,509	68,091,132
Jul-12	168,266	18,825,445	1,990,956	44,221,720	1,061,987	2,601,728	68,870,102
Aug-12	168,203	19,200,209	2,005,237	44,355,972	1,078,521	2,649,975	69,458,117
Sep-12	168,167	19,592,880	1,969,967	44,533,347	1,094,718	2,685,011	70,044,090
Oct-12	168,214	19,446,316	1,985,806	44,739,504	1,112,247	2,709,843	70,161,930
Nov-12	168,189	19,840,425	2,000,785	44,952,944	1,124,621	2,730,959	70,817,923
Dec-12	168,207	$ 20,239,680	$ 2,887,027	$ 44,361,624	$ 1,343,243	$ 2,647,185	71,646,966
13 Month Average	$ 168,550	$ 18,323,529	$ 2,035,492	$ 44,068,320	$ 1,049,530	$ 2,639,920	$ 68,285,342

Note: (1) December 2011 & 2012 electric numbers tie to Form I, pages 200/201, row 33, and page 219, rows 20 through 29.
(2) The remaining months are pulled from the company's internal financial records.
(3) The "13 Month Average" category amounts go forward to:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SPECIFIED DEFERRED CREDITS
Calendar Years 2011 and 2012
Units: $000s

EOY AVERAGES

Exh. No. CLP-8
PERIOD I
STATEMENT AF

Specified Deferred Credits	Total	Production	Transmission	Distribution	General & Intangible
#254 Deferred Tax Excess FAS 109 & Unamort. ITC	$ 236,473	$ 131,661	$ 5,624	$ 99,188	
#255 Acc. Deferred Investment Tax Credit	208,495	113,796	4,841	84,742	2,030
Allocation % for acct #411.4 activity		54.6%	2.3%	40.6%	1.0%
Amount Charged to #411.4	36,343	19,836	844	14,772	354
#282-283 Acc. Deferred Income Tax					
NPLT	(37,658,288)	(23,494,902)	(825,297)	(13,338,089)	
Pension (W&S)	126,837	56,708	2,912	67,217	
Other (see workpaper AF WP2)	(11,657,289)	(11,493,463)	-	(163,826)	
Total ADIT	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	-
Total Deferred Credits	$ (48,980,246)	$ (34,817,861)	$ (817,544)	$ (13,349,956)	$ 2,030

Specified Deferred Credits	Account #254 FAS109	Account #255 ADIT Credit	Account #282 ADIT	Account #283 ADIT	Total
12/31/2011 (Form I, pg 266, 274, 276, 278)	$ 250,656	$ 226,666	$ (46,022,113)	$ (9,316,619)	
12/31/2012 (Form 1, pg 267, 275, 277, 278)	222,290	190,323	(53,242,200)	(9,133,819)	
BOY/EOY Average	$ 236,473	$ 208,495	$ (49,632,156)	$ (9,225,219)	$ (58,648,881)

Note: (1) The amounts in the following rows:
#254 Deferred Tax Excess FAS 109 & Unamortized ITC
#255 Amount Charged to #411.4
Total ADIT flow forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SPECIFIED DEFERRED CREDITS
Calendar Years 2011 and 2012
Units: $000s

PERIOD I
Workpaper #1 for Statement AF

(I) ACCOUNT 254 Deferred Tax Excess FAS 109 & Unamortized ITC

#254 Deferred Tax Excess FAS 109 & Unamortized ITC Account		Balance 12/31/2011	Balance 12/31/2012	Average
254300	ITC			$ -
254300	FAS109	$ 250,656	$ 222,290	236,473
		$ 250,656	$ 222,290	
Total 254				$ 236,473

(I) ACCOUNT 255 (INVESTMENT TAX CREDITS):

Description	Balance 12/31/2011	Balance 12/31/2012	Average
10% Electric Utility	$ 226,666	$ 190,323	$ 208,495
		-	-
			-
			-
			-
			-
			-
			-
			-
			-
Total	$ 226,666	$ 190,323	$ 208,495
Amount Charged to Account #411.4		$ 36,343	

Note: (1) Year-end 2011 & 2012 Account 254 Deferred Tax Excess FAS 109 & Unamortized ITC numbers tie to FERC Form I, page 278, rows 7 and 9.

(2) Year-end 2012 & 2013 Account 255 (Investment Tax Credits) tie to FERC Form I, pages 266 and 267, row 8.

(3) The "Totals" row amounts from this worksheet go forward to: Statement AF-Specified Deferred Credits

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEFERRED TAX LIABILITY ACCOUNTS
Calendar Years 2011 and 2012
Units: $s

PERIOD I
Workpaper #2 for Statement AF

	BALANCE 12/31/2011	BALANCE 12/31/2012	Average	Gas	Common Plant Related	Common Labor Related	Electric Allocated W&S	Electric Allocated NPLT	Electric Production	Electric Trans	Electric Distribution
			-								
ELECTRIC											
481A Adjustment - Unit of Property	(1,502,511)	(1,502,511)	(1,502,511)					(1,502,511)			
Acquisition Costs	(40,001)	(40,001)	(40,001)					(40,001)			
Amortization	(3,368,515)	(4,457,904)	(3,913,209)						(3,913,209)		
Capitalized Interest	1,573,613	1,573,613	1,573,613						1,573,613		
Contributions In Aid Of Const-Elec	557,189	908,669	732,929					732,929			
Cost Of Removal-Elect	(848,418)	(870,395)	(859,406)					(859,406)			
Depreciation	(22,442,984)	(24,351,699)	(23,397,342)					(23,397,342)			
Facts And Circumstances-Elect	(673,862)	(1,272,147)	(973,004)					(973,004)			
Repair Allowance	(1,074,875)	(1,074,875)	(1,074,875)					(1,074,875)			
Sec 162 Ordinary & Necessary Busin	(130,521)	(130,521)	(130,521)						(130,521)		
Sec 481(A)-Tolling	(773,079)	(773,079)	(773,079)					(773,079)			
Section 174 Develop & Engineer Cos	(6,387,318)	(6,387,318)	(6,387,318)						(6,387,318)		
Unit of Property	(976,672)	(2,474,845)	(1,725,758)					(1,725,758)			
UTP - Property Balance Deferred	-	(370,697)	(185,349)						(185,349)		
FIN 48 Adjustment	-	408,388	204,194					204,194			
GAS											
Contributions In Aid Of Const-Gas	428,019	729,497	578,758	578,758							
Cost Of Removal-Gas	(207,182)	(233,840)	(220,511)	(220,511)							
Depreciation - Gas	(8,438,569)	(10,337,926)	(9,388,248)	(9,388,248)							
Facts And Circumstances-Gas	(78,509)	(263,852)	(171,180)	(171,180)							
COMMON											
Book/Tax Gain Difference	(562,986)	(1,350,258)	(956,622)		(956,622)						
Cost Of Removal -- Common	(2,275)	(2,893)	(2,584)		(2,584)						
Depreciation - Other	(1,072,658)	(967,606)	(1,020,132)		(1,020,132)						
								-			
TOTAL DEFERRED TAX LIABILITY (ACCT 282)	(46,022,113)	(53,242,200)	(49,632,156)	(9,201,181)	(1,979,338)	-	-	(29,408,854)	(9,042,784)	-	-
(12/31/2011 & 2012 Balance agrees to Form I, pg 274/2	(46,022,113)	(53,242,200)	Check Figure								
Electric											
Equity Afudc	(3,941,172)	(3,972,350)	(1,986,175)					(1,986,175)			
Equity Afudc Adjustment	11,347	15,557	(1,962,807)					(1,962,807)			
Deferred Costs	(353,009)	(338,999)	(163,826)								(163,826)
Deferred Energy	(3,626,598)	(4,548,348)	(2,450,679)						(2,450,679)		
Reg Energy Efficient Asset	-	(225,611)	(1,926,104)					(1,926,104)			
Deferred Rate Case	-	(4,658)	(2,329)					(2,329)			
Common											
Oci Derivative -- Interest Rate Swap	(1,296,525)	-	(648,262)		(648,262)						
Performance Plan Bonus	1,843	2,130	1,987			1,987					
Results Compensation/Bonus/Etc	128,025	173,387	150,706			150,706					
Reaquired Bond Loss	(166,421)	(151,539)	(158,980)		(158,980)						
Prepaid Expenses	(74,109)	(83,383)	(78,746)		(78,746)						
Derivatives Oci Noncurrent Assets	1,292,355	1,254,835	1,273,595		1,273,595						
Derivatives Oci Noncurrent Liabili	(1,292,358)	(1,254,838)	(1,273,598)		(1,273,598)						
TOTAL DEF.TAX LIABILITY (ACCT 283000/283110)	(9,316,619)	(9,133,819)	(9,225,219)	-	(885,991)	152,693	-	(5,877,416)	(2,450,679)	-	(163,826)
(12/31/2011 & 2012 Balance agrees to Form I, pg 276/2	(9,316,619)	(9,133,818)									
TOTALS	$ (55,338,733)	$ (62,376,018)	$ (58,857,375)	$ (9,201,181)	$ (2,865,329)	$ 152,693	$ -	$ (35,286,270)	$ (11,493,463)	$ -	$ (163,826)
Common Allocator					82.78%	83.07%					
Electric Portion			(49,188,740)		(2,372,018)	126,837	$ -	$ (35,286,270)	$ (11,493,463)	$ -	$ (163,826)
Gas Portion			(9,668,635)								

Note: (1) Year-end 2011 & 2012 Total Account 282 Deferred Tax Liability amounts tie to FERC Form I, pages 274 & 275, row 9.
(2) Year-end 2011 & 2012 Total Account 283 Deferred Tax Liability amounts tie to FERC Form I, pages 276 & 277, row 19.
(3) The "Totals" row amounts from this worksheet go forward to: Statement AF-Specified Deferred Credits

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SPECIFIED PLANT ACCOUNTS AND DEFERRED DEBITS
December 2011 through December 2012
Units: $s

Exh. No. CLP-9
PERIOD I
STATEMENT AG

Property Held for Future Use -- Account 105

	Balance 12/31/2011	Balance 12/31/2012	Average Balance
Production	-	-	-
Transmission	-		-
Distribution	10,914		10,914
General	-		-
Common	-	-	-
Total	10,914	-	5,457

Account 182.3 -- Regulatory Assets

	13 Month Ave. Balance
Other Reg. Assets FAS 109	$ 3,930,117

Accumulated Deferred Income Taxes -- Account 190 Electric

	Allocator	Production	Transmission	Distribution	Total Ave. Balance
Direct	Direct	112,307		-	112,307
Benefit Related	W&S	1,428,609	70,027	1,693,351	3,195,322
Miscellaneous	NPLT	888,366	31,205	504,327	1,423,898
Subtotal		2,429,282	101,232	2,197,677	4,731,527

Note: (1) Year-end 2011 & 2012 Total Account 105 Property Held for Future Use amounts tie to FERC Form I, page 214, row 47.

(2) Thirteen month average balance of Account 182.3-Other Regulatory Assets FAS 109 comes from workpaper Statement AG_WP1.

(3) Accumulated Deferred Income Taxes -- Account 190 amounts come from workpaper Statement AG_WP2. The Total Average Balance ties to the amount on workpaper Statement AG_WP1.

(3) The Average Balance numbers for each of the categories on this Statement AG go forward to the following worksheets:

Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
SPECIFIED DEFERRED DEBITS Statement AG Workpaper #1
Calendar Years 2011 & 2012
Units: $s

Unit	Acct	Year	Period			Balance
50502		2011	12		$	5,816,711
50502		2012	12			7,427,042
				Average	$	6,621,877

Regulatory Tax Asset - FAS 109

Unit	Acct	Year	Period		Balance
50502	182390	2011	12	$	3,929,824
50502	182390	2012	1		3,929,473
50502	182390	2012	2		3,929,122
50502	182390	2012	3		3,928,771
50502	182390	2012	4		3,928,421
50502	182390	2012	5		3,928,070
50502	182390	2012	6		3,927,719
50502	182390	2012	7		3,927,368
50502	182390	2012	8		3,927,017
50502	182390	2012	9		3,926,666
50502	182390	2012	10		3,926,316
50502	182390	2012	11		3,925,965
50502	182390	2012	12		3,956,793
				$	3,930,117

Note: (1) Year-end 2011 & 2012 balances in Account 190-Accumulated Deferred Income Taxes tie to FERC Form I, page 234, row 18, columns b & c.

(2) Year-end 2011 & 2012 balances in Account 182.3-Regulatory Deferred Income Taxes-FAS 109 tie to FERC Form I, page 232, row 27, columns b & f.

(3) The Average Balance amounts for Account 190-Accumulated Deferred Income Taxes tie to Statement AG, Total Average Balance of Account 190.

(4) The Average Balance amounts for Account 182-310-Regulatory Deferred Income Taxes-FAS 109 move forward to Statement AG.

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
DEFERRED TAX ASSET ACCOUNTS Statement AG Workpaper #2
Calendar Years 2011 & 2012
Units: $s

	FINAL BALANCE 12/31/2011	Per 10K END BAL 12/31/2012	Average	Gas	Common Plant Related	Common Labor	Allocated W&S	Allocated NPLT	Distribution	Production
ELECTRIC			$ -					$ -		
Line Extension	169,806	(113,766)	28,020					28,020	-	
Investment Tax Credit	79,334	66,673	73,004						-	73,004
FAS 109-ITC	42,712	35,895	39,304						-	39,304
Other	158,588	4,815	81,702					81,702		
			-						-	
GAS			-						-	
Line Extention Dep	660,338	498,386	579,362	579,362						
Deferred Costs	96,912	427,901	262,407	262,407						
Investment Tax Credit	83,377	77,746	80,562	80,562						
FAS 109-ITC	44,891	41,859	43,375	43,375						
									-	
COMMON										
Other										
Pension	647,758	316,214	481,986			481,986				
Retiree Healthcare	2,308,946	2,489,454	2,399,200			2,399,200				
Vacation	83,718	57,769	70,744			70,744				
Net Operating Loss Carryforward	(2,829,473)	-	(1,414,737)		(1,414,737)					
Disability Liability	171,884	168,985	170,435		170,435					
Bad Debt Reserve	963,926	950,087	957,007		957,007					
FAS 109	66,970	52,550	59,760		59,760					
FAS 109 Retiree Healthcare (190)	2,000,769	-	1,000,385		1,000,385					-
FAS 109 retiree Healthcare (190)	-	755,262	377,631		377,631					
Reg Pension	735,910	-	367,955			367,955				
Reg Pension	-	1,007,189	503,595			503,595				
Reacquired Bond Gain	330,708	303,149	316,929		316,929					
Investment Tax Credit - Other	339	210	275		275					
Employee Group Insurance	22,303	19,763	21,033			21,033				
ARO FASB 143 Asset	22,775	26,029	24,402		24,402					
Rollover Adjustments	(41,400)		(20,700)		(20,700)					
Workmans Compensation	(4,381)	8,763	2,191			2,191				
R & D Credit Carryover		187,301	93,651		93,651					
UTP - Accrued Interest B/S Inactive		39,975	19,988		19,988					
UTP - Accrued Interest B/S Expense		4,928	2,464		2,464					
	$ 5,816,710	$ 7,427,137	$ 6,621,924	$ 965,705	$ 1,587,487	$ 3,846,703	$ -	$ 109,722	$ -	$ 112,307
Common Allocator					82.78%	83.07%				
Electric Portion			4,731,527		1,314,177	3,195,322	$ -	$ 109,722	$ -	$ 112,307
Gas Portion			1,890,396	965,705	273,310	651,381				

Note: (1) Year-end 2011 & 2012 balances in Account 190-Accumulated Deferred Income Taxes tie to FERC Form I, page 234, row 18, columns b & c.

(2) The categorized total amounts for the average Account 190-Accumulated Deferred Income Taxes move forward to Statement AG.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

Operation and Maintenance Expenses	Total Year
Production	$ 66,401,461
Transmission	11,750,217
Distribution	2,573,114
Customer Accounts	1,103,729
Customer Service	601,067
Sales Expenses	538
Administrative and General	6,741,442
Total	$ 89,171,568

Note: (1) The source for these totals are the following Schedule AH pages.
(2) The totals for each of the categories on this Statement AH go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

FERC Account		Demand	Energy	Total
	Production			
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering			
501	Fuel			
502	Steam Expenses			
503	Steam from Other Sources			
504	Steam Transferred - Credit			
505	Electric Expenses			
506	Miscellaneous Steam Power Expenses			
507	Rents			
	Total Operation	-	-	-
Maintenance				
510	Maintenance Supervision and Engineering			
511	Maintenance of Structures			
512	Maintenance of Boiler Plant			
513	Maintenance of Electric Plant			
514	Maintenance of Miscellaneous Steam Plant			
	Total Maintenance	-	-	-
	Total Power Production Expenses - Steam Plant	-	-	-
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	-	-	-
518	Fuel	-	-	-
519	Coolants and Water	-	-	-
520	Steam Expenses	-	-	-
521	Steam from Other Sources	-	-	-
522	Steam Transferred - Credit	-	-	-
523	Electric Expenses	-	-	-
524	Miscellaneous Steam Power Expenses	-	-	-
525	Rents	-	-	-
	Total Operation			-
Maintenance				
528	Maintenance Supervision and Engineering	-	-	-
529	Maintenance of Structures	-	-	-
530	Maintenance of Reactor Plant Equipment	-	-	-
531	Maintenance of Electric Plant	-	-	-
532	Maintenance of Miscellaneous Steam Plant	-	-	-
	Total Maintenance			-
	Total Power Production Expenses - Nuclear Plant			-

Note: (1) Totals for FERC accounts 500 - 532 tie to FERC Form 1, page 320, rows 4 through 41, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

		Demand	Energy	Total
	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	-	-	-
536	Water for Power	-	-	-
537	Hydraulic Expenses	-	-	-
538	Electric Expenses	-	-	-
539	Misc. Hydraulic Power Gen. Expenses	-	-	-
540	Rents	-	-	-
	Total Operation			-
Maintenance				
541	Maintenance Supervision and Engineering	-	-	-
542	Maintenance of Structures	-	-	-
543	Maint. of Reservoirs, Dams & Waterways	-	-	-
544	Maintenance of Electric Plant	-	-	-
545	Maintenance of Misc. Hydroelectric Plant	-	-	-
	Total Maintenance			-
	Total Power Production Expenses -- Hydroelectric			-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering			
547	Fuel			
548	Generation Expenses			
549	Miscellaneous Other Power Gen. Expenses			
550	Rents			
	Total Operation	-	-	-
Maintenance				
551	Maintenance Supervision and Engineering			
552	Maintenance of Structures			
553	Maintenance of Generation & Electric Plant			
554	Maintenance of Misc. Other Power Gen.			
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Other Power	-	-	-
	Other Power Supply Expenses			
Operation				
555	Purchased Power			
556	System Control and Load Dispatching			
557	Other Expenses			
	Total Operation	-	-	-
	Total Power Production Expenses	$ -	$ -	$ 66,401,461

Note: (1) Totals for FERC accounts 535 - 545 tie to FERC Form 1, page 320, rows 44 through 59, column b.
(2) Totals for FERC accounts 546 - 557 tie to FERC Form 1, page 321, rows 62 through 80, column b.
(3) Note that Account 557 reflects a retail fuel deferral.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

	Transmission Expenses		
Operation			
560	Operation Supervision and Engineering	$	107,908
561	Load Dispatching (561.1 through 561.4)		101,791
561	Reliability & Studies (561.5 through 561.8)		166,984
562	Station Expenses		
563	Overhead Line Expenses		
564	Underground Line Expenses		
565	Transmission of Electricity of Others		11,384,117
566	Miscellaneous Transmission Expenses		(10,583)
567	Rents		
	Total Operation		11,750,217
Maintenance			
568	Maintenance Supervision and Engineering		
569	Maintenance of Structures		
570	Maintenance of Station Equipment		
571	Maintenance of Overhead Lines		
572	Maintenance of Underground Lines		
573	Maintenance of Miscellaneous Transm. Plant		
	Total Maintenance		-
	Total Transmission Expenses		11,750,217
	Distribution Expenses		
Operation			
580	Operation Supervision and Engineering		
581	Load Dispatching		
582	Station Expenses		
583	Overhead Line Expenses		
584	Underground Line Expenses		
585	Street Lighting and Signal System Expenses		
586	Meter Expenses		
587	Customer Installation Expenses		
588	Miscellaneous Distribution Expenses		
589	Rents		
	Total Operation		-
Maintenance			
590	Maintenance Supervision and Engineering		
591	Maintenance of Structures		
592	Maintenance of Station Equipment		
593	Maintenance of Overhead Lines		
594	Maintenance of Underground Lines		
595	Maintenance of Line Transformers		
596	Maintenance of Street Lighting and Signal Systems		
597	Maintenance of Meters		
598	Maintenance of Miscellaneous Distribution Plant		
	Total Maintenance		-
	Total Distribution Expenses	$	2,573,114

Note: (1) Totals for FERC accounts 560 - 573 tie to FERC Form 1, page 321, rows 83 through 112, column b.
(2) Totals for FERC accounts 580 - 598 tie to FERC Form 1, page 322, rows 134 through 156, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

		Customer Accounts Expenses	
Operation			
901		Supervision	
902		Meter Reading Expenses	
903		Customer Records and Collection Expenses	
904		Uncollectible Accounts	
905		Miscellaneous Customer Accounts Expenses	
		Total Customer Accounts Expenses	1,103,729
		Customer Service and Information Expenses	
Operation			
907		Supervision	
908		Customer Assistance Expenses	
909		Informational and Instructional Expenses	
910		Miscellaneous Customer Service and Information Expenses	
		Total Customer Service and Information Expenses	601,067
		Sales Expenses	
Operation			
911		Supervision	
912		Demonstrating and Selling Expenses	
913		Advertising Expenses	
916		Miscellaneous Sales Expenses	
		Total Sales Expenses	538
		Administrative and General Expenses	
Operation			
920		Administrative and General Salaries	3,854,195
921		Office Supplies and Expenses	763,248
922		Administrative Expenses Transferred - Credit	(10,117)
923		Outside Services Employed	748,362
924		Property Insurance	159,333
925		Injuries and Damages	387,284
926		Employee Pensions and Benefits	48,713
927		Franchise Requirements	
928		Regulatory Commission Expenses	24,833
929		Duplicate Charges - Credit	
930.1		General Advertising Expenses (See Next Page)	187,184
930.2		Miscellaneous General Expenses (See Next Page)	192,137
931		Rents	120,765
		Total Operation	6,475,937
Maintenance			
935		Maintenance of General Plant	265,505
		Total Administrative and General Expenses	$ 6,741,442

Fuel Expenses

	Steam Generation Acct. 501		Nuclear Generation Acct. 518	Other Generation Acct. 547	Purchased Power Acct. 555	Total
January						
February						
March						
April						
May						
June	NOT USED FOR TRANSMISSION COST OF SERVICE					
July						
August						
September						
October						
November						
December						
Total		-	-		-	-

Note: (1) Totals for FERC accounts 901 - 905 tie to FERC Form 1, page 322, rows 159 through 164, column b.
(2) Totals for FERC accounts 907 - 935 tie to FERC Form 1, page 323, rows 167 through 197, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

Details of Accounts 930.1 and 930.2

Account 930.1		
General Advertising	$	187,184
Total Account 930.1		187,184
Account 930.2		
Industry Association Dues		46,040
Publishing and Distribution Information to Stockholders		3,514
Other Miscellaneous Expense		16,001
Director Fees and Expenses		96,405
Travel		5,039
Supplies		1,416
GAAP to FERC (Acct 930299)		23,722
Total Account 930.2	$	192,137

(v) 928.000 REGULATORY COMMISSION EXPENSES, DETAIL:

Description	FERC	non-FERC	Total
Jurisdictional Assessment		$ 6,180	$ 6,180
Expenses incurred by the Company in connection with formal cases before regulatory commissions.		16,444	$ 16,444
Professional Services and Other Expenses (Other than Officers or Employees)			$ -
Employee related expenses			$ -
Totals	$ -	$ 22,624	$ 22,624

Note: (1) These detailed amounts for accounts 930.1, 930.2 and 928 come from the Company's books and records.
Further details of accounts 930.1, 930.2 and 928 are contained in the workpapers.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WAGES AND SALARIES
Calendar Year 2012
Units: $s

Exh. No. CLP-11
PERIOD I
Statement AI

Electric Utility Wages and Salaries

Included in Operation and Maintenance Expenses

	Total
Production	$ 1,821,980
Transmission	93,563
Regional Market	
Distribution	920,161
Customer Accounts	748,550
Customer Service	490,908
Sales Expenses	
Administrative and General	2,963,212
Total Wages and Salaries Included in O&M Expenses	$ 7,038,374
Wages & Salaries Excluding A&G	$ 4,075,162

Note: (1) Total wages and salaries by category come from FERC Form I, page 354, rows 20-28, column b.

(2) The totals for each of the categories on this Statement AI go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Function	Depreciable Plant Base Form 1, pg 337-337.1	Depreciation Expense Annual Form 1, pg 336
Production Plant	$ 184,321	$ 4,762,036
Transmisson Plant	7,994	163,458
Distribution Plant	143,339	3,855,356
General, Common & Intangible Plant	13,866	807,467
Total Depr Amortization Expense	$ 349,520	9,588,317
Limited Term Amortization (Acct. 404)		
Total Depreciation & Amortiztion Expense		$ 9,588,317

Note: (1) Annual depreciation expense come from FERC Form 1, page 336, rows 1 - 12, columns b & d.
(2) Depreciable plant base ties to FERC Form 1, pages 337-337.1, subtotals in column b.
(3) The annual depreciation expense totals, by category, go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Account	Description		Annual Rate
	Steam Production Plant		
310		$ -	
311		8,540	2.77%
312		95,207	2.77%
314		71,004	2.39%
315		9,468	2.50%
316		102	5.72%
317			
	Sub-total	184,321	
	Other Production Plant		
340		-	
341		-	
342		-	
343		-	
344		-	
345		-	
346		-	
347		-	
	Sub-total	-	
	Total Production Plant	184,321	
	Transmission Plant		
350		-	
352		732	2.15%
353		4,270	1.92%
354		364	2.98%
355		1,541	2.29%
356		1,087	2.35%
357			
358			
359			
	Total Transmission Plant	$ 7,994	

Note: (1) Depreciable plant base by FERC account comes from FERC Form 1, page 337, column b.
(2) Annual depreciation rate by FERC account comes from FERC Form 1, page 337, column e.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Account	Description	Depr Plant Base	Annual Rate
	Distribution Plant		
360		-	
361		658	2.54%
362		14,578	2.65%
364		20,174	2.79%
365		19,531	2.80%
366		6,743	2.69%
367		37,108	2.69%
368		19,169	2.77%
369		14,590	2.64%
370		880	4.01%
372		2,012	3.82%
373		7,896	2.80%
	Total Distribution Plant	143,339	
	General Plant		
389		-	
390		3,012	2.79%
391.1		1,911	3.72%
391.2		4,093	9.00%
392		189	4.98%
393		2,040	4.98%
394		62	4.98%
395		643	9.00%
396		1,866	4.98%
397		50	4.98%
398		-	
399.1		-	
	Total General Plant	13,866	
	Total Depreciable Plant	349,520	

Note: (1) Depreciable plant base by FERC account comes from FERC Form 1, pages 337-337.1, column b.
(2) Annual depreciation rate by FERC account comes from FERC Form 1, pages 337-337.1, column e.

CHEYENNE LIGHT, FUEL AND POWER COMPANY	Exh. No. CLP-13
TAXES OTHER THAN INCOME TAXES	PERIOD I
Calendar Year 2012	STATEMENT AK
Units: $s	

	Annual Total
Revenue taxes	
Real estate and property taxes (incl. Ad volorem)	1,194,583
Payroll taxes (incl. "Insurance contributions")	6,856
Business	
Franchise	1,083,117
Miscellaneous taxes (incl. Reg. Commission)	269,470
	$ 2,554,026
Income	2,594,767
Total per FM 1	$ 5,148,793

Note: (1) Taxes other than income come from FERC Form 1, page 263, column i.

(2) The *total* Taxes Other Than Income amount goes forward to:

Statement BJ-Summary Data Tables

The Taxes Other Than Income *category amounts* go forward to:

Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WORKING CAPITAL
December 2011 through December 2012
Units: $s

Exh. No. CLP-14
PERIOD I
STATEMENT AL

SUMMARY

		Average
Fuel Inventories (non-nuc.)		N/A
Materials & Supplies -- Transmission		-
Property Insurance	$	123,836
Other Prepayments		759,124
Total		882,960

Materials and Supplies

	Production	Transmission	Distribution	Construction & Other	Total
Dec-11	2,332,965		47,470	3,103,882	5,484,317
Dec-12	2,371,719		53,889	3,161,601	5,587,209
Beg/End Avg.	2,352,342	-	50,680	3,132,742	5,535,763

Prepayments and Insurance

	Property Insurance	Other Prepayments	Other Direct - Prod. & Dist.	Total
13 Mo. Avg.	$ 123,836	$ 95,837	$ 663,287	$ 882,960

Note: (1) Materials and Supplies come from FERC Form 1, page 227, columns b & c.
(2) The Prepayments amounts come from Statement AL_WP1.
(3) The average Working Capital category amounts go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WORKING CAPITAL
December 2011 through December 2012
Units: $s

PERIOD I
Workpaper for Statement AL

Prepayments

Period I	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	13 Mo. Ave
Insurance														
														-
165002 Prepaid Insurance	$ 184,822	$ 163,868	$ 142,914	$ 121,961	$ 101,007	$ 80,053	$ 59,099	$ 55,416	$ 34,260	$ 13,104	$ 240,003	$ 217,787	$ 195,571	$ 123,836
														-
														-
														-
Total Insurance Prepayments	184,822	163,868	142,914	121,961	101,007	80,053	59,099	55,416	34,260	13,104	240,003	217,787	195,571	123,836
Other Prepayments														
														-
165004 Prepaid Maintenance	12,448	11,316	10,185	9,053	7,921	6,790	5,658	4,527	3,395	2,263	1,132	10,692	9,801	7,322
165012 Prepaid Other	40,967	40,967	80,627	76,661	72,695	68,729	64,763	60,797	56,831	52,865	48,899	44,933	40,967	57,746
165013 Prepaid Transmission Deposits	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	30,769
														-
														-
														-
Total Other Prepayments	53,415	52,283	90,812	85,714	80,616	125,519	120,421	115,324	110,226	105,128	100,031	105,625	100,768	95,837
Electric Production Prepayments														
														-
165013 Prepaid Coal	702,769	660,388	387,178	660,388	705,662	683,806	696,295	685,367	718,152	657,265	672,877	696,295	696,295	663,287
														-
														-
														-
														-
														-
														-
														-
														-
Total Electric Production Prepayments	702,769	660,388	387,178	660,388	705,662	683,806	696,295	685,367	718,152	657,265	672,877	696,295	696,295	663,287
Total Prepayments	$ 941,006	$ 876,539	$ 620,904	$ 868,063	$ 887,285	$ 889,378	$ 875,815	$ 856,107	$ 862,638	$ 775,497	$ 1,012,911	$ 1,019,707	$ 992,634	$ 882,960

Note: (1) Beginning and ending Prepayments balances tie to FERC Form 1, page 111, row 57, columns b (ending balance) & d (beginning balance).

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CONSTRUCTION WORK IN PROGRESS
December 2011 through December 2012

Exh. No. CLP-15
PERIOD I
STATEMENT AM

CWIP IS NOT INCLUDED IN RATE BASE

CHEYENNE LIGHT, FUEL AND POWER COMPANY
NOTES PAYABLE
December 2011 through December 2012
Units: $000s

Exh. No. CLP-16
PERIOD I
Statement AN

	Electric
December '11	$ -
January '12	-
February	-
March	-
April	-
May	-
June	-
July	-
August	-
September	-
October	-
November	-
December '12	-
Total	-
13 Mo. Avg.	$ -

Note: (1) Monthly balances in Notes Payable come from the companies books and records.
(2) The average Notes Payable balance goes forward to the following worksheet:
Statement BJ-Summary Data Tables

CHEYENNE LIGHT, FUEL AND POWER COMPANY
RATE FOR ALLOWANCE FOR FUNDS
USED DURING CONSTRUCTION
Calendar Year 2012
Units: $s

Exh. No. CLP-17
PERIOD I
STATEMENT AO

Note: The Company used 7.986% AFUDC rate in 2012. This rate was within the FERC guidelines. The calculation of the AFUDC is shown below.

Input Values

S = Average Short-Term Debt for year 2011	=	$	884,278
RS = Short-Term Debt Interest Rate	=		5.38%
D = Long-Term Debt, Year End 2011	=	$	127,000,000
RD = Long-Term Debt Interest Rate	=		6.15%
P = Preferred Stock, Year End 2011	=	$	-
RP = Preferred Stock Cost Rate	=		0.00%
C = Common Equity, Year End 2011	=	$	177,090,274
RC = Commony Equity Cost Rate (Authorized per PSCN)	=		9.60%
W = Average CWIP plus Nuclear Fuel In Process	=	$	14,213,633

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction
= (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))
AI = 2.743% 6.00%
AI= 6.000%

AE = Rate for Allowance for Other Funds used during Construction
= (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))
AE = 5.243% 2.37%
AE= 2.37%

Gross Nominal Rate =	7.986%
Effective annual Rate (Semi-Annual Compounding	8.146%
Effective Monthly Rate (Semi-Annual Compounding)	0.655%

Notes: (1) AFUDC notes and numbers come from the company's books and records.
(2) This is a standalone worksheet; these numbers flow to no other statements.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
FEDERAL INCOME TAX DEDUCTIONS -- INTEREST
Calendar Year 2012
Units: $000s

Exh. No. CLP-18
PERIOD I
STATEMENT AP

Long Term Interest Expense	Rate Base	Weighted LTD Rate (%)	Long Term Interest
Transmission	$ 5,050,281	2.539%	$ 128,234
All Other	213,718,290	2.539%	5,426,607
Total	$ 218,768,571		$ 5,554,840

Acct. 431 -- Other Interest Expense

Other Interest Expense	$ 109,183
Total	$ 109,183
Account 432 (see Stmt AB)	$ 121,743

Note: (1) Long Term Interest Expense - Rate Base amounts come from Statement BK.
(2) Long Term Interest Expense - Weighted LTD Rates come from Statement AV.
(3) Total Account 431 - Other Interest Expense ties to FERC Form 1, page 117, row 68, column c. Detailed amounts come from company's books & records.
(4) Account 432 - Allowance for Borrowed Funds Used During Construction amounts come from FERC Form 1, page 117, row 69, column c.
(5) The totals from this statement go forward to the following worksheet:
Statement BJ-Summary Data Tables

CHEYENNE LIGHT, FUEL AND POWER COMPANY
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST
Calendar Year 2012
Units: $000s

Exh. No. CLP-19
PERIOD I
STATEMENT AQ

Additions to Income Before Taxes

Contributions in Aid in Construction	$	1,004	NPLT
Nondeductible and Deferred Taxes		(2,355)	NPLT
Employee Benefits		-	W&S
Other		34	NPLT
Allowance for Funds Used During Construction		(38)	NPLT
Total Additions to Income Before Taxes	$	(1,355)	

Allocators		
Production		-
Distribution		-
NPLT		(1,355)
W&S		-
Total	$	(1,355)

Deductions from Income Before Taxes

Cost of Removal		64	NPLT
Employee Benefits		-	W&S
Line Extension Deposits		1,501	NPLT
Deferred Revenue		2,594	NPLT
Tax Depreciation in Excess of Book Depreciation		17,244	NPLT
Other		250	NPLT
NOL Carry forward		-	NPLT
Total Reductions to Income Before Taxes	$	21,653	

Allocators		
Production		-
Distribution/Retail		-
Transmission		-
NPLT		21,653
W&S		-
Total	$	21,653

Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2 for details on the source for these amounts.

(2) The total "Allocators" by category go forward to the following worksheet:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY — PERIOD I
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST — Workpaper #1 to Statement AQ
Calendar Year 2012
Units: $000s

Federal Income Tax Deductions
- Other Than Interest

	Total	Statement BK Allocator	WP#2 Ref #
Additions to Income Before Taxes			
Contributions in Aid in Construction	$ 1,004	NPLT	1
Nondeductible and deferred taxes	(2,355)	NPLT	2
Employee Benefits	-	W&S	3
Other	34	NPLT	4
Allowance for Funds Used During Construction	(38)	NPLT	12
Total Additions to Income Before Taxes	(1,355)		
Reductions to Income Before Taxes			
Cost of Removal	-	NPLT	5
Employee Benefits	64	W&S	6
Line Extension Deposits	-	NPLT	7
Deferred Revenue	1,501	NPLT	8
Tax Depreciation in Excess of Book Depreciation	2,594	NPLT	9
Other	17,244	NPLT	10
NOL Carry forward	250	NPLT	11
Total Reductions to Income Before Taxes	21,653		
Federal Income Tax Deductions - Other Than Interest	(23,008)	Ties to 2012 CP	

Reconciliation to FERC Form 1 pg 261

Total federal income tax deductions (above)	23,008	Does not tie to FERC Form 1 because AQ WP 1 and 2 are electric only and the FERC Form is for all products.
Additional deductions per FF1 Pg 261	23,008	
FERC Form 1 Page 261		
Net income per books (line 1)	15,689	
Federal income taxes (line 12)	7,661	
Pre-tax income	23,350	
Net taxable income (line 27)	-	
Additional deductions per FERC Form 1	$ (23,350)	

Notes:

(1) Source for the numbers on this worksheet is Statement AQ_WP2. Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2 for details on the source for these amounts.

(2) The total "Additions to Income Before Taxes" and "Reductions to Income Before Taxes" amounts go forward to the following worksheet:
Statement AQ-Federal Income Tax Deductions Other Than Interest

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST Workpaper #2 to Statement AQ
Calendar Year 2012
Units: $s

	Ref #	ELECTRIC 12 MONTHS ENDING DEC 12
increase to income = positive		
PERMANENT & FLOW-THRU ITEMS		
Equity AFUDC Perm	12	$ (38,432)
SUBTOTAL PERM ITEMS & FLOW-THRU		(38,432)
NORMALIZED ITEMS		
Net Operating Loss	2	(2,354,562)
Reg Energy Efficient Asset	10	(249,824)
Deferred Energy	8	(2,633,574)
Deferred Costs	8	40,030
Deferred Rate Case	4	33,850
Line Extension Deposits	7	(1,501,025)
Contributions in Aid of Const-Elec	1	1,004,229
Cost of Removal-Elec	5	(63,712)
Depreciation	9	(16,717,391)
Facts and Circumstances-Elect	9	(482,139)
Unity of Property	9	(44,495)
SUBTOTAL NORMALIZED		(22,968,613)
TOTAL ADJUSTMENTS		$ (23,007,045)

Notes:
(1) Source for these numbers is the company's books and records.
Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2
for details on the source for these amounts.
(2) These amounts are summarized, and move forward, to the following worksheet:
Statement AQ-Federal Income Tax Deductions Other Than Interest

CHEYENNE LIGHT, FUEL AND POWER COMPANY
INCOME TAX ADJUSTMENTS -- ACCOUNT 410.1
Calendar Year 2012
Units: $000s

Exh. No. CLP-20
PERIOD I
STATEMENT AR

		Allocator/Assignment				
	TOTAL	NPLT	W&S	DISTRIBUTION	PRODUCTION	TRANSMISSION
FERC Account 190 - Accumulated Deferred Income Taxes						
Line Extension Deposits	(749,148)	(749,148)				
NOL Carryforward	1,661,437	1,661,437				
	912,289	912,289	-	-	-	-
FERC Account 282 - Accumulated Deferred						
Amortization	(1,089,389)				(1,089,389)	
Cost of Removal-Elec	(22,299)	(22,299)				
Depreciation	(5,851,087)	(5,851,087)				
Facts and Circumstances-Elec	(645,934)	(645,934)				
Unity of Property	(1,498,173)	(1,498,173)				
UTP - Property Balance Deferred	(370,697)				(370,697)	
	(9,477,579)	(8,017,493)	-	-	(1,460,086)	-
FERC Account 283 - Accumulated Deferred Income Taxes - Other Property						
Income Taxes - Other Property						
Deferred Energy	(1,159,637)	(1,159,637)				
Reg Energy Efficient Asset	(225,611)	(225,611)				
Deferred Rate Case	(16,506)	(16,506)				
	(1,401,754)	(1,401,754)	-	-	-	-
Totals	$ (9,967,044)	$ (8,506,958)	$ -	$ -	$ (1,460,086)	$ -

Notes:

(1) Source for the numbers on this worksheet is the company's books and records. Please refer to the workpapers for Statement AR and AR_WP1 for details on the source for these amounts.

(2) The "Allocator/Assignment" totals by category go forward to the following worksheet: Statement BK-Cost of Service Study

(3) Note that there are no amounts in account #411.1

CHEYENNE LIGHT, FUEL AND POWER COMPANY — PERIOD I
FEDERAL TAX ADJUSTMENTS — Workpaper to Statement AR
Calendar Year 2012
Units: $000s

Reconciliation of FERC Form 1 page 115

Per FERC Form 1 page 115 line 17 (electric only)	$	15,192,613
Prior period adjustments including IRS audit & misc		(5,225,569)
		9,967,044
Statement AR		
Account 190		912,289
Account 282		(9,477,579)
Account 283		(1,401,754)
	$	(9,967,044)

Note: (1) Source for the numbers on this worksheet is the company's books and records. Please refer to the workpapers for Statement AR and AR_WP1 for details on the source for these amounts.
(2) The three "Statement AR" amounts, by account, come directly from that statement.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
ADDITIONAL STATE INCOME TAX DEDUCTIONS
Calendar Year 2012
Units: $000s

Exh. No. CLP-21
PERIOD I
STATEMENT AS

There were no additional state tax deductions for 2012

Deductions from Book Income to Determine Taxable Income:

	Amount
Total	$ -

Additions to Book Income to Determine Taxable Income:

	Amount
Total	$ -

Source: Corporate Records

There were no additional state tax adjustments

CHEYENNE LIGHT, FUEL AND POWER COMPANY
REVENUE CREDITS
Calendar Year 2012
Units: $s

Exh. No. CLP-23
PERIOD I
STATEMENT AU

FERC Account	Description	12 mos of 2012 Revenue Credits Amount
456	Short-term Firm & Non-Firm Transmission of Electricity - Thrid Party Transactions	$ -
	Other Revenue Credits	-
447	Sales for Resale - Transmission Component of Offsystem Sales	-
	Total Transmission Revenue Credits	$ -

Note: (1) Source for the numbers on this worksheet is Statement AU_WP1.
(2) The "Total Transmission Revenue Credits" go forward to the following worksheet:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
REVENUE CREDITS
Calendar Year 2012
Units: $s

PERIOD I
Workpaper for Statement AU

El PASO	AcctGL	ClsDescription					
	456175			456175 Total	456170	456170 Total	Grand Total
CustShortName	Third Party Firm Transmission	Third Party Long-Term Transmission	TSA Long Term Transmission		Non Firm Transmission		
N/A							
Grand Total							

Pole Attachment Fees		
Total		-
		-

Note: (1) Source for the numbers on this worksheet is a query of the company's books and records.
(2) The three totals (Pole Attachment Fees; 456170; 447010) move forward to the following worksheet:
Statement AU-Revenue Credits

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CAPITAL STRUCTURE
Year End 2012
Units: $000s

Exh. No. CLP-24
PERIOD I
STATEMENT AV

Component	Amount	Share (%)	Cost Rate (%)	Weighted Cost (%)
Long-Term Debt	$ 127,000,000	41.9%	6.06%	2.54%
Preferred Securities	-	-	-	-
Common Equity	175,965,410	58.1%	10.60%	6.16%
Total	$ 302,965,410	100.0%		8.70%

Note: (1) All source numbers (except ROE) on this Statement AV come from the workpapers for this statement.

(2) The capital structure and ROE come from, and are supported by, Company records.

(3) The Total Weighted Cost of Capital moves forward to the following worksheet:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WEIGHTED COST OF CAPITAL December 31, 2012

PERIOD I
Workpaper #1 to Statement AV

Line No.	Rate	Description (a)	(b) Amount Outstanding	(c) BALANCE Unamortized Discount	(d) Unamortized Premium	(e) Debt Exp.	(f) Net Proceeds	(g) ANNUAL REQUIREMENT Interest Expense	(h) Annual Amortization Discount (Premium)	(i) Debt Expense	(j) Annual Cost	(k) Embedded Cost %	(l) Cumulative Cost %
							(b)+(c)+(d)+(e)	(rate*(b))			(g)+(h)+(I)	(j)/(f)	
1		**General and Refunding Mortgage Bonds**											
2													
3		First Mortgage Bonds	110,000,000			766,349	110,766,349	7,337,000		35,893	7,372,893	6.66	6.66
4		Industrial Development Bonds (due 2021)	7,000,000			289,936	7,289,936	155,400		0	155,400	2.13	6.38
5		Industrial Development Bonds (due 2027)	10,000,000			181,068	10,181,068	221,480		0	221,480	2.18	6.04
6											0		6.04
7											0		6.04
8													
9	**2.44%**	Revolving Credit Facility (2)	0	0	0	0	0	0	0	0	0		6.04
10													
11		Note Payable to Assoc Companies (Acct 233)	5,284,237				5,284,237	98,649			98,649	1.87	5.88
12											0		5.88
13											0		5.88
14											0		5.88
15													
16											0		5.88
17											0		5.88
18													
19		**Total Long-Term Debts**	127,000,000	0	0	0	127,000,000	0	0	0	0	0.00	0.00
20													
21						0	ST Debt			0	ST Debt		
22						0	Preferred			0	Preferred		
23						1,237,353	#181			35,893	#181		
24		**Footnotes**				#REF!	#189			#REF!	#189		
25						0	#257			0	#257		
26		(1) Floating Rate Debt - Interest is calculated monthly				**#REF!**	**Total**			**#REF!**	**Total**		
27													
28		(2) Revolving credit facility which allows borrowing up to $600,000,000. Variable rate interest on amount outstanding											
29													
30		(3) Converted Series 2006B ($13M) to variable demand notes wherein NPC is the sole holder of the bonds and recevies all interest payments. Consrquently, there is no interest expense asociated with these issues and the debt remains outstanding											
31													
32		(4) Tendered and repurchased											
33													

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CORPORATE STRUCTURE -- COMMON EQUITY
Year End 2012
Units: $000s

PERIOD I
Workpaper #2 for Statement AV

	(a)	(b)
Line No.	Description	Total Common Stock Equity
1	Total Proprietary Capital	$175,965,410
2	(less) Preferred Stock	0
3	(less) Accumulated Other Comprehensive Income (Acct. 291)	0
4	(less) Unappropriated Undistributed Subsidiary Earnings (Acct. 216.1)	0
5	Common Equity (line 1 - line 2 - line 3 - line 4)	$ 175,965,410

Notes:

(1) These capital amounts come from FERC Form 1, page 112, column c, lines 16, 3, 15, & 12 (in the order the amounts appear above).

(2) The *total* Common Equity goes forward to the following worksheet:
Statement AV-Capital Structure

Cost of Short-Term Debt

Short term debt is not considered in the cost of service.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OTHER RECENT AND PENDING RATE CHANGES
December 2011 through December 2012

Exh. No. CLP-26
PERIOD I
STATEMENT AX

None

CHEYENNE LIGHT, FUEL AND POWER COMPANY
INCOME AND REVENUE TAX DATA
Calendar Year 2012

Exh. No. CLP-27
PERIOD I
STATEMENT AY

A	Federal Income Tax Rate	35.0000%
B	Nominal State Income Tax Rate	
		0.0000%
	Composite SIT	0.0000%

C Deductibility of State Income Taxes:

All state income and franchise taxes are deductible for Federal income tax purposes.

D Revenue Tax Rate (Not Included in Transmission Revenue Requirement)

Rate Names

Not Necessary if not to be filed.

Sum	0.0000%

Note: The mill assessment is included in account #928. There is no expense related to the remaining taxes. The utility merely acts as a tax collector.

E	Proportion of Federal Income Tax Deductible For State Income (weighed, if more than one state)	0.0000%

Note: (1) All source numbers on this Statement AY come from the company's books and records.

(2) These Income & Revenue Tax Percentages go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY | Exh. No. CLP-28
CUSTOMER RATE GROUPS -- FERC JURISDICTION | PERIOD I
Calendar Year 2012 | STATEMENT BA

OATT Transmission Service

Network Customers
Retail Load

Long-Term Firm Transmission Service
None

Short-Term Firm & Non-Firm Transmission Service
None

CHEYENNE LIGHT, FUEL AND POWER COMPANY
TRANSMISSION SYSTEM LOAD
Calendar Year 2012
Units: MW

Exh. No. CLP-29
PERIOD I
STATEMENT BB

System Peak	1/11	2/6	3/2	4/24	5/21	6/25	7/20	8/8	9/10	10/24	11/26	12/10
Hour	18	20	19	14	13	16	16	17	16	19	18	1/18
Total Native Load	**166**	**160**	**155**	**144**	**146**	**184**	**187**	**182**	**162**	**153**	**164**	**174**
Network Load (For Others)												
L-T Firm Contracts (P-P & Other)												
Total Transmission System Load (MW)	**166**	**160**	**155**	**144**	**146**	**184**	**187**	**182**	**162**	**153**	**164**	**174**

Note: (1) Monthly peak load amounts tie to FERC Form 1, page 400, column b.
Details of that load come from the company's books and records.
(2) The "12 Coincident Peak Average" goes forward to the following worksheet: Statement BL
(3) Measured Load Coincident to Peak
(4) Contract Demand

12 Coincident Peak ("CP") Average: 165

Not Applicable

Not Applicable

None

None

NOT NEEDED

Not Applicable

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SUMMARY DATA TABLES
Units: $000s

Exh. No. CLP-36
PERIOD I
STATEMENT BJ

Statement	Description		Function/ Sub-Function		13-Month Average
AD	Cost of Plant		Production	$	183,381,840
			Transmission		7,801,632
			Distribution		136,561,608
			General/Intangible		8,241,960
			Common		
				$	335,987,041
AE	Accumulated Depreciation and Amortization		Production	$	18,323,529
			Transmission		2,035,492
			Distribution		44,068,320
			General/Intangible		3,858,000
			Common		
				$	68,285,342
AF	Specified Deferred Credits				
		Account 255	Production	$	113,796
			Transmission		4,841
			Distribution		84,742
			Total	$	203,380
		Account 281			-
		Account 282/283	Production	$	(34,931,657)
			Transmission		(822,385)
			Distribution		(13,434,698)
			Total	$	(49,188,740)

Statement	Description		Function/ Sub-Function		Beg of Yr/End of Yr Average
AG	Specified Plant Accts and Deferred Debits				
		Account 105	Production	$	-
			Transmission		-
			Distribution		11
			General		-
			Total	$	11
		Account 182	Total	$	3,930
		Account 190	Production	$	2,429
			Transmission		101
			Distribution		2,198
			Total	$	4,728
					Annual Amount
AH	Operating & Maintenance Expenses		Production	$	66,401
			Transmission		11,750
			Distribution		2,573
			General		6,741
			Total	$	87,466
AI	Wages & Salaries		Production	$	1,822
			Transmission		94
			Distribution		-
			General		920
			Common		-
			Total	$	2,836
AJ	Depreciation & Amortization Expense		Production	$	4,762,036
			Transmission		163,458
			Distribution		3,855,356
			General		807,467
			Total	$	9,588,317

Units: $000s

Statement	Description	Function/ Sub-Function		Annual Amount
AK	Taxes Other Than Income	Total	$	2,554
				13-Month Average
AL	Working Capital	Fuel Supplies		
		M & S -- Transmission		-
		Prepayments		883
		Total	$	883
AM	Construction Work In Process			
		Production	$	-
		Transmission		-
		Distribution		-
		General		-
		Total	$	-
AN	Notes Payable		$	-

Statement	Description	Function/ Sub-Function		Year-to-Date
AP	Fed Income Tax Deductions-Interest			
	Account 431	Other Interest	$	109,183
	Account 432	Total	$	121,743
	Long Term Interest Exp	Transmission	$	128,234
		All Other		5,426,607
		Total	$	5,554,840
AQ	Income Tax Deductions-Other Than Interest			
	Additions to Book Income		$	(1,355)
	Deductions from Book Income		$	21,653
AR	Income Tax Deductions			
	Acct 410.1 - Provision for Deferred Income Taxes - Debit			
		Account 281		
		Account 282		(9,477,579)
		Account 283		(1,401,754)
		Account 190		912,289
		Summary Account 410.1	$	(9,967,044)
	Acct 411.1 - Provision for Deferred Income Taxes - Credit			
		Account 281	$	-
		Account 282		-
		Account 283		-
		Account 190		-
		Summary Account 411.1	$	-

Units: $000s

Statement	Description	
AS	Additional State Income Tax Deductions	No additional state income tax deductions.
AT	State Tax Adjustments	No state income tax deductions.
AV	Rate of Return	

Cost of Capital	NPC	Percent Of Total	Cost	Weighted Cost
Long -Term Debt	$ 127,000,000	41.9000%	6.06%	2.54%
Preferred Stock	-	-	-	-
Common Equity	175,965,410	58.1000%	10.60%	6.16%
Total	$ 302,965,410	100.00%		8.70%

Statement	Description		
AW	Cost of Short-Term Debt	Not Included in the Capital Structure for return purposes, therefoe, not considered in COS.	
AY	Income & Revenue Tax Rate Data	Nominal Federal Income Tax Rate	35.00%
		Nomital State Income Tax Rate	
		Total	0.00%

Units: $000s

TRANSMISSION REVENUE REQUIREMENT

Summary of Results

Line	Description	Source	Total Electric	Production	Transmission	Distribution	All Other
	Rate Base						
1	Gross Plant in Service	Sch 2 ; Page 1	$ 335,987,041	$ 187,066,770	$ 7,990,862	$ 140,929,408	$ 327,996,178
2	Depreciation Reserve	Sch 2 ; Page 1	(68,285,342)	(20,048,417)	(2,124,069)	(46,112,855)	(66,161,272)
3	Net Utility Plant		267,701,699	167,018,353	5,866,793	94,816,553	261,834,906
4	Accumulated Deferred Income Taxes	Sch 3 ; Page 1	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
5	Other Subtractive Adjustments	Sch 3 ; Page 1	-	-	-	-	-
6	Materials & Supplies	Sch 3 ; Page 2	-	-	-	-	-
7	Prepaids and Other	Sch 3 ; Page 2	759	53	2	703	757
8	Cash Working Capital	Sch 3 ; Page 2	9,711	8,678	52	980	9,658
9	Acct. 190 and Other Additive Adjustments	Sch 3 ; Page 2	245,142	136,278	5,819	103,045	239,323
10	Total Rate Base		218,768,571	132,231,705	5,050,281	81,486,584	213,718,290
	Operating Expenses						
12	Total O&M Expense	Sch 4 ; Page 1	77,686	69,422	419	7,843	77,267
13	Total Depreciation Expense	Sch 4 ; Page 2	9,588,317	5,123,050	181,997	4,283,271	9,406,320
14	Total Other Taxes	Sch 4 ; Page 3	2,554	818	35	1,701	2,519
15	Subtotal - O&M & Other		9,668,557	5,193,290	182,451	4,292,814	9,486,106
16	Net Federal Income Taxes	Sch 5 ; Page 1	(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
17	Net State Income Taxes	Sch 5 ; Page 3	-	-	-	-	-
18	Total Operating Expense		1,521,905	$ (871,794)	61,523	$ 2,332,173	1,460,381
19	Return on Rate Base	l. 10 * l. 33	$ 19,027,922	$ 11,501,170	$ 439,260	$ 7,087,491	$ 18,588,661
20	Total Cost of Service -- Before Exclusions		$ 20,549,826	$ 10,629,376	$ 500,784	$ 9,419,665	$ 20,049,043
21	Inclusion Ratio						
22	Total Transmission Plant	Sch 2; Page 1			$ 7,801,632		
23	Excluded Transmission Plant (GSUs)	Statement AD			$ 1,570,095		
24	Adjusted Transmission Plant	l. 22 - l. 23			$ 6,231,537		
25	Inclusion Ratio	l. 24 / l. 22			79.87%		
26	Adjusted Cost of Service	l. 25 * l. 20			400,000		
27	Less Revenue Credits	Statement AU			$ -		
28	Pro Forma Adjustment	l. 27 * % rate increase			$ -		
29	Net cost of Service (Excluding Schedule 1)	l. 26 - l. 27 - l. 28			$ 400,000		
30	Schedule 1 Gross Revenue Requirement	Sch 4; Page 1; l. 13			$ 102		
31	Less Revenue Credits (Company Records)						
32	Schedule 1 Net Revenue Requirement	l. 30 - l. 31			$ 102		
33	Rate of Return on Rate Base	Statement AV	8.70%	8.70%	8.70%	8.70%	8.70%

Units: $000s

Electric Plant in Service - Statement AD

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production Plant		183,381,840	183,381,840			183,381,840
2	Transmission Plant		7,801,632		7,801,632		-
3	Distribution Plant		136,561,608			136,561,608	136,561,608
4	Gross P, T, D Plant		327,745,081	183,381,840	7,801,632	136,561,608	319,943,448
5	Total General and Electric Common Plant		8,073,460				
6	Total Intangible Plant		168,500				
7	Total General, Electric Commmon & Intangible		8,241,960		-		
8	Gen. & Intang. Functionalized	W&S	8,241,960	3,684,930	189,230	4,367,800	8,052,730
9	Gross Electric Plant in Service (l.4 + l.8)		335,987,041	187,066,770	7,990,862	140,929,408	327,996,178

Depreciation Reserve - Statement AE

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
11	Production Plant		18,323,529	18,323,529			18,323,529
12	Transmission Plant		2,035,492		2,035,492		-
13	Distribution Plant		44,068,320			44,068,320	44,068,320
14	Gross P, T, D Plant		64,427,341	18,323,529	2,035,492	44,068,320	62,391,849
15	Total General, Electric Commmon & Intangible	W&S	3,858,000	1,724,888	88,577	2,044,535	3,769,423
16	Total Depreciation Reserve (l. 14 + l. 15)		68,285,342	20,048,417	2,124,069	46,112,855	66,161,272

Units: $000s

Net Electric Plant

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production Plant		165,058,311	165,058,311	-	-	165,058,311
2	Transmission Plant		5,766,140		5,766,140		-
3	Distribution Plant		92,493,288	-	-	92,493,288	92,493,288
4	Net P, T, D Plant		263,317,739	165,058,311	5,766,140	92,493,288	257,551,599
5	General & Intangible Net Plant		4,383,960	1,960,042	100,653	2,323,265	4,283,307
6	Net Electric Plant in Service (l. 4 + l. 5)		267,701,699	167,018,353	5,866,793	94,816,553	261,834,906

Units: $000s

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Subtractive Adjustments -- Statement AF						
1	Accum. Deferred ITC -- Acct. 255		-	-	-	-	-
2	Accum. Deferred Inc.Taxes (Acct. 281)		-	-	-	-	-
3	Accum. Deferred Inc.Taxes (Acct. 282 & 283)	NPLT	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
4	Subtotal Accum. Deferred Taxes (l. 1 through l. 3)		(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
5	Other Subtractive Adjustments		-	-	-	-	-
6	Total Subtractive Adjustments (l. 4 + l. 5)		(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)

Units: $000s

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Additive Adjustments -- Statement AG						
						-	-
1	Accum. Deferred Inc. Taxes (Acct. 190)	NPLT	4,728	2,429	101	2,198	4,627
	Land Held for Future Use (Acct. 105)						
2	Production	Direct	-	-			-
3	Transmission	Direct	-		-		-
4	Distribution	Direct	11			11	11
5	General Functionalized	W&S	-	-	-	-	-
6	Total Land for Future Use		11	-	-	11	11
	CWIP Land						
7	Transmission						
8	Other						
9	Total CWIP Land		-	-	-	-	-
	Other Additive Adjustments (FAS 109)						
10	FAS 109 (acct 182.3) (Statement AG)	NPLT	3,930	2,188	93	1,648	3,837
11	less FAS 109 (acct 254.02) (Statement AF)	NPLT	236,473	131,661	5,624	99,188	230,849
12	Total Other Additive Adjust.		240,403	133,849	5,718	100,837	234,686
13	Total Additive Adjustments (l. 1 + l. 6 + l. 9 + l. 12)		245,142	136,278	5,819	103,045	239,323

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Working Capital						
14	Materials and Supplies (Beg/End Yr Avg) --Transmission Only		-		-		-
15	Prepayments	Statement AL					
16	Property Insurance	GPLT	-	-	-	-	-
17	Other Prepayments	Direct	663			663	663
18	Other Prepayments	GPLT	96	53	2	40	94
19	Total Prepayments		759	53	2	703	757
	Cash Working Capital (Auto Calculation)						
20	(One eighth O&M less fuel and PP)	(auto calculation)	9,711	8,678	52	980	9,658
21	Total Working Capital (l.14 + l.19 + l.20)		10,470	8,731	55	1,684	10,415

Units: $000s

Expenses Statement AH

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Production O&M						
	Energy Related Production O&M						
1	Fuel		-	-			-
2	Purchased Power		-	-			-
3	Other		-	-			-
4	Gas Steam Energy Related		-				
5	Total Energy Related		-	-	-	-	-
	Demand Related Production O&M						
6	Purchased Power		-	-			-
7	Other Demand Related		-	-			-
8	Fixed Fuel (Storage & Maintenance)		-				
9	Gas Steam Demand Related		-				
10	Total Demand Related		-	-	-	-	-
11	Total Production O&M		66,401	66,401	-	-	66,401
	Transmission O&M						
12	Total		11,750		11,750		-
13	Less Acct 561.1 thru 561.4 -- Schedule 1 Ancillary		(102)		(102)		
14	Less Acct. 565 (Tx by Others)		(11,384)		(11,384)		-
15	Transmission O&M (adjusted)		264		264		-
	Distribution O&M						
16	Distribution O&M		2,573			2,573	2,573
17	Customer Accounting		1,104			1,104	1,104
18	Customer Service & Information		601			601	601
19	Sales		1			1	1
	Administrative & General						
20	Property Insurance	GPLT	159	89	4	67	156
21	Regulatory Commission Expense	Direct	25		-	23	25
22	Other Labor Related	W&S	6,557	2,932	151	3,475	6,407
23	Total Admin & General		6,741	3,020	154	3,564	6,587
24	Total O&M Expense (l. 11 + l.15 through 19 + l. 23)		77,686	69,422	419	7,843	77,267

Units: $000s

Depreciation Expense Statement BJ

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production		4,762,036	4,762,036			4,762,036
2	Transmission		163,458		163,458		-
3	Distribution		3,855,356			3,855,356	3,855,356
4	General & Intangible	W&S	807,467	361,014	18,539	427,915	788,928
5	Total Depreciation Expense (l. 1 thru l. 4)		9,588,317	5,123,050	181,997	4,283,271	9,406,320

Units: $000s

Other Taxes and Miscellaneous Expenses

Line	Description	Statement AK Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Taxes Other than Income						
1	Revenue Taxes	GPLT	-	-	-	-	-
2	Real Estate and Property Taxes	GPLT	1,195	665	28	501	1,166
3	Payroll Taxes	W&S	7	3	0	4	7
4	Franchise Taxes	Direct	1,083			1,083	1,083
5	Business Tax	GPLT	-	-	-	-	-
6	Miscellaneous Taxes	GPLT	269	150	6	113	263
7	Total Taxes Other than Income (l. 1 through l. 4)		2,554	818	35	1,701	2,519

CHEYENNE LIGHT, FUEL AND POWER COMPANY
COST OF SERVICE STUDY
Calendar Year 2012
Units: $000s

TRANSMISSION REVENUE REQUIREMENT

Exh. No. CLP-37
PERIOD I
STATEMENT BK
Schedule 5

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Federal Income Tax						
	Federal Income Tax Deductions						
1	Interest Expense (Auto - Synchronized)	Statement AV	5,554,840	3,357,548	128,234	2,069,058	5,426,607
	Other Deductions	Statement AQ					
2	Plant Related	NPLT	21,653	13,509	475	7,669	21,178
3	Labor Related	W&S	0	0	0	0	-
4	Production	Direct	0	0			-
5	Transmission	Direct	0		0		-
6	Retail/Distribution	Direct	0			0	0
7	Total Other Deductions		21,653	13,509	475	7,669	21,178
8	Total Deductions (l. 1 + l. 7)		5,576,493	3,371,057	128,708	2,076,728	5,447,785
	Federal Income Tax Additions	Statement AQ					
7	Plant Related	NPLT	(1,355)	(845)	(30)	(480)	(1,325)
8	Labor Related	W&S	0	0	0	0	-
9	Production	Direct	0	0			-
10	Transmission	Direct	0		0		-
11	Retail/Distribution	Direct	0			0	0
12	Total Additions		(1,355)	(845)	(30)	(480)	(1,325)
13	Net Deductions and Additions (l. 8 - l. 12)		5,577,848	3,371,903	128,738	2,077,208	5,449,110
	Federal Income Tax Adjustments	Statement AR					
	Fed. Prov. Deferred Inc. Tax (410.1)						
12	Plant Related	NPLT	(8,506,958)	(5,307,468)	(186,433)	(3,013,057)	(8,320,525)
13	Labor Related	W&S	0	0	0	0	-
	Production	Direct	(1,460,086)	(1,460,086)			(1,460,086)
	Transmission	Direct	0		0		
14	Retail/Distribution	Direct	0			0	0
15	Total Fed. Def. Inc. Tax		(9,967,044)	(6,767,554)	(186,433)	(3,013,057)	(9,780,611)

Units: $000s

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Investment Tax Credits						
	Amortized Investment Tax Credit						
1	Production	Statement AF	19,836	19,836			19,836
2	Transmission	Statement AF	844		844		-
3	Distribution	Statement AF	14,772			14,772	14,772
4	General & Intangible	W&S	354	158	8	188	346
5	Total Investment Tax Credit		35,805	19,994	852	14,959	34,953
	Preliminary Summary -- Adjustments						
6	Total Fed. Def. Inc. Tax (410.1)	Sch 5; Page 1	(9,967,044)	(6,767,554)	(186,433)	(3,013,057)	(9,780,611)
7	Total Amortized ITC		(35,805)	(19,994)	(852)	(14,959)	(34,953)
8	Total Federal Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
	Federal Tax Computation						
9	Return on Rate Base	Sch 1; Page 1	19,027,922	11,501,170	439,260	7,087,491	18,588,661
10	Net Deductions and Additions		(5,577,848)	(3,371,903)	(128,738)	(2,077,208)	(5,449,110)
11	Total Federal Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
12	Base for FIT Calculation		3,447,224	1,341,719	123,237	1,982,268	3,323,987
	FIT Factor (= FIT Rate/(1-FIT Rate)		53.846%	53.846%	53.846%	53.846%	53.846%
13	Preliminary Fed. Income Tax (Payable)		1,856,197	722,464	66,358	1,067,375	1,789,839
14	Total Fed. Income Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
15	Net Federal Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)

Units: $000s

ł On Return (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	State Income Tax						
	State Income Tax Adjustments						
1							
2							
3	Total State Inc. Tax Adjustments		-	-	-	-	-
	SIT Calculation						
4	Return on Rate Base		19,027,922	11,501,170	439,260	7,087,491	18,588,661
5	Net Deductions and Additions		5,577,848	(3,371,903)	(128,738)	(2,077,208)	5,706,586
6	Proportion of FIT Deductible for State Inc.		0.00%	0.00%	0.00%	0.00%	0.00%
7	Net Federal Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
8	Total State Inc. Tax Adjustments		0	0	0	0	0
9	Base for SIT Calculation		16,459,118	2,064,183	189,595	3,049,643	16,269,523
	SIT Factor (= SIT Rate/(1-SIT Rate)		0.00%	0.00%	0.00%	0.00%	0.00%
10	Preliminary State Income Tax (Payable)		0	0	0	0	-
11	Total State Income Tax Adjustments		0	0	0	0	0
12	Net State Income Tax		0	0	0	0	0
	Cost of Service Computation						
13	Total Op. Exp. Excl. Inc. & Rev. Taxes		9,668,557	5,193,290	182,451	4,292,814	9,486,106
14	Return on Rate Base		19,027,922	11,501,170	439,260	7,087,491	18,588,661
15	Net Fed Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
16	Net State Income Tax Allowable		0	0	0	0	0
17	Cost of Service Ex. Rev. Taxes		20,549,826	10,629,376	500,784	9,419,665	20,049,043
18	Revenue Tax Factor		1	1	1	1	1
19	Total Cost of Service		20,549,826	10,629,376	500,784	9,419,665	20,049,043

FUNCTIONALIZATION FACTORS SUMMARY

	Factors	Reference		Production	Transmission	Distribution	Source
1	Gross Plant, Including GP&I	GPLT	100.000%	55.677%	2.378%	41.945%	Sch 2, page 1
2	Net Plant, Including GP&I	NPLT	100.000%	62.390%	2.192%	35.419%	Sch. 2, page 2
3	Salaries & Wages, Excl. A&G	W&S	100.000%	44.709%	2.296%	52.995%	Statement AI

CHEYENNE LIGHT, FUEL AND POWER COMPANY
RATE DESIGN
Calendar Year 2012
Units: $s

Exh. No. CLP-38
PERIOD I
STATEMENT BL

Transmission Rate			Schedule 1	
ATRR	$	399,999,940	$	101,791
12CP (KW)		164,750		164,750
Monthly Rate	$	202.33	$	0.051
	Per KW		Per MW	

Not Applicable

Cheyenne Light Fuel and Power
BALANCE SHEET
June 31, 2015

Exhibit No. CLP-40
Period II
Statement AA

	DESCRIPTION	JUNE 2014	JUNE 2015
	ELECTRIC PLANT AT ORIGINAL COST:		
x	Plant in Service	$424,254,373	$584,878,152
x	Less accumulated depreciation (enter negative)	($61,935,555)	($79,586,881)
	Net plant in service	$362,318,818	$505,291,272
x	Construction work in progress	$143,775,855	$21,415,757
	Property Under Capital Leases		
	Completed Construction not Classified		-
x	Plant Acquisition Adjustments	$4,942,723	$4,942,723
	Plant Held For Future Use		
	Total	$511,037,395	$531,649,751
x	OTHER PROPERTY AND INVESTMENTS	$11,798,459	$13,634,607
	CURRENT ASSETS:		
x	Cash and Prepayments	($313,309)	($313,309)
x	Deferred Current Assets	$189,947	$189,947
x	Net Receivables	20,020,489	21,091,353
x	Fuel Stock	793,865	842,162
x	Materials and supplies	6,211,638	7,131,639
x	Prepayments	228,052	228,052
x	Accrued Utility Revenues	$9,430,855	$5,556,680
xx	Total	$36,561,537	$34,726,523
	DEFERRED ASSETS	$27,514,673	$28,863,028
	TOTAL ASSETS	$586,912,065	$608,873,910

Source: Company Records

Cheyenne Light Fuel and Power
BALANCE SHEET
June 31, 2015

Exhibit No. CLP-40
Period II
Statement AA

	DESCRIPTION	JUNE 2014	JUNE 2015
	CAPITALIZATION:		
	Common Stock		
	Other Paid in Captial	$ 136,618,590	$ 136,618,590
	Retained earnings	65,939,000	84,869,062
	Accumulated Other Comprehensive Income		
		$ 202,557,590	$ 221,487,652
	Cumulative preferred stock		
	Long - term debt & other non-current liabilities	$127,000,000	$202,000,000
	Total Capitalization	$329,557,590	$423,487,652
	CURRENT LIABILITIES:		
x	Notes Payables	$114,731,570	$16,748,795
x	Accounts Payable	$16,996,361	$16,907,326
x	Accrued interest & taxes	(1,781,470)	8,149,778
x	Tax Collections Payable	5,122,503	5,169,503
x	Miscellaneous Current & Accrued Liabilities	1,968,834	1,992,834
		$137,037,799	$48,968,237
	DEFERRED CREDITS AND OTHER LIABILITIES:		
	Accumulated deferred investment tax credits		
	Customers' advances for construction		
	Accumulated deferred taxes on income - electric only	59,364,371	59,615,167
	Obligation under Capital Lease		
	Other	60,952,305	76,802,854
		$120,316,676	$136,418,021
	TOTAL CAPITALIZATION AND LIABILITIES	$586,912,065	$608,873,910
Source:	Company Records	27329907.92	18,767,076.15
	Tie out to budget	$614,241,973	$627,640,985.96

Cheyenne Light Fuel and Power
INCOME STATEMENT
Fiscal Years

		DESCRIPTION	JUNE 2014	JUNE 2015
1		UTILITY OPERATING INCOME		
2	x	OPERATING REVENUES	$ 175,379,957	$ 194,976,536
3				
4		OPERATING EXPENSES AND TAXES		
5	x	Operation Expense	114,996,263	123,835,581
6	x	Maintenance Expense	4,954,966	5,808,642
7	x	Depreciation Expense	13,141,586	17,638,074
8		Amort. & Depl. Of Utility Plant		0
9		Amort. Of Utility Plant Acq. Adj.		
10		Amort. of Property Losses, Unrecove. Plant and Reg. Study Costs		
11	x	Taxes Other Than Income	4,092,186	4,640,571
12		Income Taxes - Federal	(1,948,838)	14,145,542
13		Income Taxes - Other	(377,605)	-
14		Provision for Deferred Income Taxes	20,555,061	54,217
15		(Less) Provision for Deferred Income Taxes - Credits	(8,435,804)	0
16		Investment Tax Credit Adj.	(25,090)	0
17		(Less) Gains from Disp. Of Utility Plant		
18		(Less) Gains from Disposition of Allowances		
19		TOTAL OPERATING EXPENSE	$ 146,952,725	$ 166,122,626
20		TOTAL UTILITY OPERATING INCOME	$ 28,427,232	$ 28,853,910
21				
22		OTHER INCOME		
23		NONUTILITY OPERATING INCOME		
24		Revenues From Merchandising, Jobbing & Contract Work		$ -
25		(Less) Costs and Exp. of Merchandizing, etc.		-
26		Revenues from Nonutility Operations		
27		(Less) Expenses of Nonutility Operations	(58,411)	(58,411)
28		Nonoperating Rental Income		
29		Equity in Earnings of Subsidiary Companies		
30		Interest and Dividend Income	251,517	75,481
31		Allowance for Funds Used During Construction	-	-
32		Miscellaneous Nonoperating Income	13,149	-
33		Gain on Disposition of Property		
34		TOTAL OTHER INCOME	206,255	17,070
35				
36		TOTAL OTHER INCOME DEDUCTIONS		
37				
38		TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS		
39		Taxes Other than Income Taxes		$ -
40		Income Taxes - Federal	(12,446)	(12,446)
41		Income Taxes Other		-
42		Provision for Deferred Income Taxes		
43		(Less) Prov. for Def. Income Taxes Credit		
44		TOTAL TAXES ON OTHER INCOME AND DEDUCTIONS	$ (12,446)	$ (12,446)
45		NET OTHER INCOME AND DEDUCTIONS	$ 218,701	$ 29,516
46				
47		INTEREST CHARGES		
48		Interest on Long-Term Debt	$ 7,633,350	$ 8,619,364
49		Amortization of Debt Discount and Expense	164,529	294,905
50		Amortization of Loss on Reacquired Debt	21,259	
51		Loss on Reacquired Capital Stock	59,593	
52		(Less) Amort of Premium on Debt - Credit		
53		(Less) Amortization of Gain on Reacquired Debt - Credit		
54		Interest on Debt to Assoc. Companies	7,815	7,815
55		Other Interest Expense	2,269,611	1,554,612
56		(Less) Allowance for Borrowed Funds Used During Construction	(339,461)	(523,333)
57		NET INTEREST CHARGES	9,816,696	9,953,363
58				
59		NET INCOME	$ 18,829,237	$ 18,930,063

Soruce: Company Records

(a)	(b)
UNAPPROPRIATED RETAINED EARNINGS	
Balance at beginning of period	$65,939,000
Balance Transferred from Income	$18,930,063
Unrealized Loss on Investment	
Dividends Declared - Preferred Stock	
Dividends Declared - Common Stock	
Transfers from Unappropriated Undistributed Subsidiary Earnings	
Balance at End of Year	$84,869,062
Appropriated Retained Earnings	
Total Retained Earnings	$84,869,062
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS	
Balance Beginning of Year	NA
Equity in Earnings for Year	NA
Less Dividends Received	NA
Balance at end of period	NA

Source: Company Records

Cheyenne Light Fuel and Power
UTILITY PLANT IN SERVICE
June 30 2015 Forecast

Exhibit No. CLP-43
Period II
Statement AD

UTILITY PLANT IN SERVICE

Month/Yr	Production	Transmission Service at Issue	Distribution	General/Intan.	Other Utility	Total	
6	187,462,693	33,976,698	155,249,564	10,460,459	7,990,379	395,139,793	
7	187,462,693	33,976,698	155,865,888	10,540,594	8,043,987	395,889,861	
8	187,462,693	33,976,698	156,482,212	10,620,730	8,097,596	396,639,929	
9	187,462,693	33,976,698	157,098,536	10,700,865	8,151,204	397,389,996	
10	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
11	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
12	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
1	303,557,195	33,976,698	157,798,536	10,700,865	8,151,204	514,184,498	
2	303,557,195	36,379,691	158,498,536	10,700,865	8,151,204	517,287,491	
3	303,557,195	47,752,426	168,069,536	10,700,865	8,151,204	538,231,227	
4	307,709,034	47,752,426	168,769,536	10,700,865	8,151,204	543,083,065	
5	307,919,033	47,752,426	169,469,536	10,700,865	8,151,204	543,993,064	
6	308,020,807	47,752,426	170,169,536	10,700,865	8,151,204	544,794,839	
13 Month Average	268,834,063	38,400,229	160,674,387	10,663,879	8,126,462	486,699,020	
Beg/End Average	247,741,750	40,864,562	162,709,550	162,709,550	10,580,662	8,070,792	632,676,866

Note: GSU Transformers are recorded in Production

Source: Company Records

ACCUMULATED DEPRECIATION

Month/Yr	Production	Transmission Service at Issue	Distribution	General/Intan.	Other Utility	Total
6	24,520,071	3,228,415	47,966,071	4,608,834	4,682,116	85,005,507
7	24,959,046	3,297,218	48,328,460	4,651,884	4,735,608	85,972,215
8	25,398,021	3,366,021	48,692,281	4,695,261	4,789,457	86,941,041
9	25,836,996	3,434,823	49,057,535	4,738,965	4,843,663	87,911,983
10	26,580,711	3,503,626	49,422,789	4,782,670	4,897,868	89,187,664
11	27,324,426	3,572,429	49,788,043	4,826,374	4,952,074	90,463,346
12	28,068,141	3,641,232	50,153,297	4,870,079	5,006,279	91,739,028
1	28,811,857	3,710,035	50,520,179	4,913,783	5,060,485	93,016,338
2	29,555,572	3,783,704	50,888,688	4,957,487	5,114,690	94,300,141
3	30,299,287	3,880,402	51,279,450	5,001,192	5,168,896	95,629,226
4	31,053,174	3,977,101	51,671,839	5,044,896	5,223,101	96,970,111
5	31,807,576	4,073,800	52,065,855	5,088,601	5,277,307	98,313,138
6	32,562,227	4,170,498	52,461,500	5,132,305	5,331,512	99,658,042
13 Month Average	28,213,623	3,664,562	50,176,614	4,870,179	5,006,389	91,931,368
Beg/End Average	28,541,149	3,699,457	50,213,786	4,870,569	5,006,814	92,331,774

Note: GSU Transformers are recorded in Production.
Note: Accumulated Amortization for Intangible Plant appears in Other Production on Page 219 of the Form No. 1, it is moved to Intangible Plant on this Statement.
Source: Company Records

ACCUMULATED DEFERRED INVESTMENT TAX CREDIT -- ACCOUNT 255

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	78,227	13,082	46,754	3,103	2,365	143,532
End	62,021	10,372	37,068	2,460	1,875	113,796
Average	70,124	11,727	41,911	2,782	2,120	128,664

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 281

Year	Production	Transmission	Distribution	General	Common	Total
Beginning		-	-	-	-	-
End		-	-	-	-	-
Average		-	-	-	-	-

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 282

Year	Production	Electric Only Transmission	Distribution	General	Common	Total
Beginning	31,589,952	4,740,293	14,506,745	760,628	409,620	52,007,238
End	31,742,289	4,763,153	14,576,701	764,296	411,595	52,258,034
Average	31,666,120	4,751,723	14,541,723	762,462	410,608	52,132,636

FAS 109 Only (ACCOUNT 254)

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	-	-	-	-	-	195,271
End	-	-	-	-	-	195,271
Average		-			-	195,271

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 283
Deferred Energy Only & DSM Programs

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	2,202,410	-	1,011,391	53,030	28,558	3,295,390
End	2,202,410	-	1,011,391	53,030	28,558	3,295,390
Average	2,202,410	-	1,011,391	53,030	28,558	3,295,390

Other Acct 283

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743
End	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743
Average	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743

Total Acct. 283

Beginning	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133
End	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133
Average	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133

Source:
Company Records

Property Held for Future Use -- Account 105 (Transmission Only)

	Balance 6/30/2014	Balance 6/30/2015	Average Balance
Transmission	-	-	-
General	-	-	-
Common	-	-	-
Total	-	-	-

Source: Company's Records

Account 182.3 -- Regulatory Assets

	Balance 6/30/2014	Balance 6/30/2015	Average Balance
Def. PRB FAS 109	3,988,499	4,018,499	4,003,499
Other Reg. Assets	-	-	-
Total	3,988,499	4,018,499	4,003,499

Accumulated Deferred Income Taxes -- Account 190

	Allocator	Production	Transmission	Distribution	Total Ave Balance
State Jurisdictional					
Direct	Direct	-	-	-	-
Benefit Related	W&S	753,193	178,621	345,881	1,277,695
Miscellaneous	NPLT	3,168,812	463,730	1,455,182	5,087,724
Subtotal		3,922,004	642,351	1,801,064	6,365,419
FERC Jurisdictional					
Plant Related		-		-	-
FAS 109		-		-	-
Subtotal		-	-	-	-
Grand Total		3,922,004	642,351	1,801,064	6,365,419

Source: Company's Records

Cheyenne Light Fuel and Power
SPECIFIED PLANT ACCOUNTS AND DEFERRED DEBITS — Period II
June 30 2015 Forecast — Statement AG Workpaper 1

Accumulated Deferred Income Taxes -- Account 190

	6/30/2014	6/30/2015	Average Balance	Allocated W&S	Allocated NPLT
State Jurisdictional					
Pension FAS 158	66,066	66,066	66,066	66,066	
Line Extension Deposits	1,908,958	4,181,858	3,045,408		3,045,408
State Inc Tax	-	-	-		-
Bad Deb Reserve	662,567	662,567	662,567		662,567
Retiree Health Plan	1,211,629	1,211,629	1,211,629	1,211,629	
Other	1,379,749	1,379,749	1,379,749		1,379,749
Subtotal	5,228,969	7,501,869	6,365,419	1,277,695	5,087,724
FERC Jurisdictional					
Plant Related	-	-	-		
FAS 109	-	-	-		
Subtotal	-	-	-		
Grand Total	5,228,969	7,501,869	6,365,419		

	6/30/2014	6/30/2015	Allocation to electric *
State Jurisdictional			
Pension FAS 158	125,600	125,600	52.6%
Line Extension Deposits	1,908,958	4,181,858	100.0%
State Inc Tax	-	-	0.0%
Bad Deb Reserve	839,755	839,755	78.9%
Retiree Health Plan	2,303,478	2,303,478	52.6%
Other	1,921,656	1,921,656	71.8%
Subtotal	7,099,447	9,372,347	

* Used the same allocator as in the state rate case.

Source: Company's Records

Regulatory Tax Asset - FAS 109

Unit	Acct	Year	Period	Balance
50502	182390	2013	12	$ 3,988,499
50502	182390	2012	1	3,929,473
50502	182390	2012	2	3,929,122
50502	182390	2012	3	3,928,771
50502	182390	2012	4	3,928,421
50502	182390	2012	5	3,928,070
50502	182390	2012	6	3,927,719
50502	182390	2012	7	3,927,368
50502	182390	2012	8	3,927,017
50502	182390	2012	9	3,926,666
50502	182390	2012	10	3,926,316
50502	182390	2012	11	3,925,965
50502	182390	2012	12	3,956,793
				$ 3,930,117

Operation and Maintenance Expenses	Total Year
Production	64,161,809
Transmission	763,596
Distribution	3,295,271
Customer Accounts	830,529
Customer Service	602,130
Sales Expenses	6,745
Administrative and General	10,950,133
Total	80,610,212

Source: Following Tables

FERC Account		Demand	Energy	Total
Production				
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering		-	
501	Fuel		-	8,272,020
502	Steam Expenses		-	4,069,028
503	Steam from Other Sources		-	-
504	Steam Transferred - Credit		-	-
505	Electric Expenses		-	-
506	Miscellaneous Steam Power Expenses		-	-
507	Rents	-	-	-
	Total Operation	-	-	12,341,048
Maintenance				
510	Maintenance Supervision and Engineering			-
511	Maintenance of Structures			-
512	Maintenance of Boiler Plant			3,309,799
513	Maintenance of Electric Plant			-
514	Maintenance of Miscellaneous Steam Plant		-	-
	Total Maintenance	-	-	3,309,799
	Total Power Production Expenses - Steam Plant	-	-	15,650,847
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	-	-	-
518	Fuel	-	-	-
519	Coolants and Water	-	-	-
520	Steam Expenses	-	-	-
521	Steam from Other Sources	-	-	-
522	Steam Transferred - Credit	-	-	-
523	Electric Expenses	-	-	-
524	Miscellaneous Steam Power Expenses	-	-	-
525	Rents	-	-	-
	Total Operation	-	-	-
Maintenance				
528	Maintenance Supervision and Engineering	-	-	-
529	Maintenance of Structures	-	-	-
530	Maintenance of Reactor Plant Equipment	-	-	-
531	Maintenance of Electric Plant	-	-	-
532	Maintenance of Miscellaneous Steam Plant	-	-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses - Nuclear Plant	-	-	-

Source: Company Records

	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	-	-	-
536	Water for Power	-	-	-
537	Hydraulic Expenses	-	-	-
538	Electric Expenses	-	-	-
539	Misc. Hydraulic Power Gen. Expenses	-	-	-
540	Rents	-	-	-
	Total Operation	-	-	-
Maintenance				
541	Maintenance Supervision and Engineering	-	-	-
542	Maintenance of Structures	-	-	-
543	Maint. of Reserviors, Dams & Waterways	-	-	-
544	Maintenance of Electric Plant	-	-	-
545	Maintenance of Misc. Hydroelectric Plant	-	-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Hydroelectric	-	-	-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering		-	-
547	Fuel			2,757,785
548	Generation Expenses		-	-
549	Miscellaneous Other Power Gen. Expenses		-	610,152
550	Rents	-	-	-
	Total Operation	-	-	3,367,937
Maintenance				
551	Maintenance Supervision and Engineering		-	-
552	Maintenance of Structures		-	-
553	Maintenance of Generation & Electric Plant		-	402,601
554	Maintenance of Misc. Other Power Gen.		-	-
	Total Maintenance	-	-	402,601
	Total Power Production Expenses -- Other Power			3,770,538
	Other Power Supply Expenses			
Operation				
555	Purchased Power (p. 326, 327)			44,091,282
556	System Control and Load Dispatching		-	649,142
557	Other Expenses			-
	Total Operation	-	-	44,740,424
	Total Power Production Expenses	-	-	64,161,809

Source: Company Records

	Transmission Expenses	
Operation		
560	Operation Supervision and Engineering	202,810
561	Load Dispatching	545,666
562	Station Expenses	-
563	Overhead Line Expenses	-
564	Underground Line Expenses	-
565	Transmission of Electricity by Others	-
566	Miscellaneous Transmission Expenses	-
567	Rents	-
	Total Operation	748,476
Maintenance		
568	Maintenance Supervision and Engineeering	-
569	Maintenance of Structures	-
570	Maintenance of Station Equipment	-
571	Maintenance of Overhead Lines	-
572	Maintenance of Underground Lines	-
573	Maintenance of Miscellaneous Transm. Plant	15,120
	Total Maintenance	15,120
	Total Transmission Expenses	763,596

Source: Company Records

Distribution Expenses

Operation		
580	Operation Supervision and Engineering	-
581	Load Dispatching	-
582	Station Expenses	-
583	Overhead Line Expenses	-
584	Underground Line Expenses	-
585	Street Lighting and Signal System Expenses	-
586	Meter Expenses	-
587	Customer Installation Expenses	-
588	Miscellaneous Distribution Expenses	2,003,916
589	Rents	-
	Total Operation	2,003,916
Maintenance		
590	Maintenance Supervision and Engineeering	-
591	Maintenance of Structures	-
592	Maintenance of Station Equipment	-
593	Maintenance of Overhead Lines	-
594	Maintenance of Underground Lines	-
595	Maintenance of Line Transformers	-
596	Maintenance of Street Lighting and Signal Systems	-
597	Maintenance of Meters	-
598	Maintenance of Miscellaneous Distribution Plant	1,291,355
	Total Maintenance	1,291,355
	Total Distribution Expenses	3,295,271

Source: Company Records

		Customer Accounts Expenses		
Operation				
	901	Supervision		-
	902	Meter Reading Expenses		372
	903	Customer Records and Collection Expenses		333,532
	904	Uncollectible Accounts		103,886
	905	Miscellaneous Customer Accounts Expenses		392,739
		Total Customer Accounts Expenses		830,529
		Customer Service and Information Expenses		
Operation				
	907	Supervision		-
	908	Customer Assistance Expenses		602,130
	909	Informational and Instructional Expenses		-
	910	Miscellaneous Customer Service and Information Expenses		-
		Total Customer Service and Information Expenses		602,130
		Sales Expenses		
Operation				
	911	Supervision		-
	912	Demonstrating and Selling Expenses		6,745
	913	Advertising Expenses		-
	916	Miscellaneous Sales Expenses		-
		Total Sales Expenses		6,745
		Administrative and General Expenses		
Operation				
	920	Administrative and General Salaries		6,812,918
	921	Office Supplies and Expenses		1,360,974
	922	Administrative Expenses Transferred - Credit	Enter Negative	-
	923	Outside Services Employed		972,239
	924	Property Insurance		270,130
	925	Injuries and Damages		575,059
	926	Employee Pensions and Benefits		25,452
	927	Franchise Requirements		
	928	Regulatory Commission Expenses (See Next Page)		78,900
	929	Duplicate Charges - Credit	Enter Negative	-
	930.1	General Advertising Expenses (See Next Page)		145,109
	930.2	Miscellaneous General Expenses (See Next Page)		247,180
	931	Rents		106,423
		Total Operation		10,594,385
Maintenance				
	935	Maintenance of General Plant		355,748
		Total Administrative and General Expenses		10,950,133

Source: Company Records

Account 930.1

Customer Communications	58,043
Community Relations	29,022
Communications Marketing	47,886
Management & Administration	-
Hiring - Internet Advertising	10,157
Other Miscellaneous	-
Total Account 930.1	145,108

Account 930.2

Annual Meeting Costs	-
Shareholder Relations Costs	-
Board of Directors	121,446
Executive Communications	-
Management & Administration	-
Transfer Agent Costs	-
External Financing Costs	-
Load Research	-
Planning Studies	-
Human Resources Benefits	-
Vehicle Program Administration	-
Dues & Membership Fees	70,572
Trees Program	-
Other Miscellaneous	55,162
Total Account 930.2	247,180

Account 928.000 (Regulatory Commission Expenses)

FERC	-
All Other	-
FERC Transmission Rate Case ($150k ÷ 3 years)	-
Total Account 928	78,900

Source: Company Records

Fuel Expenses

	Steam Generation Acct. 501	Nuclear Generation Acct. 518	Other Generation Acct. 547	Purchased Power Acct. 555	Total
July	674,177		-	4,122,049	4,796,226
August	674,177		-	4,079,348	4,753,524
September	652,123		-	3,960,500	4,612,623
October	674,177		235,427	3,218,904	4,128,507
November	652,123		274,007	3,183,733	4,109,863
December	674,177		298,407	3,541,398	4,513,981
January	731,509		391,666	3,977,604	5,100,779
February	660,718		307,294	3,368,252	4,336,263
March	731,509		541,819	3,864,474	5,137,802
April	707,912		41,667	3,594,078	4,343,657
May	731,509		294,424	3,785,984	4,811,917
June	707,912		373,075	3,394,958	4,475,945
Total	8,272,020	0	2,757,785	44,091,282	55,121,087

Source: Company Records

Electric Utility Wages and Salaries

Included in Operation and Maintenance Expenses

Operation and Maintenance Expenses	Total Year
Production	-
Transmission	252,098
Distribution	1,020,135
Customer Accounts	242,451
Customer Service	286,858
Sales Expenses	1,741
Administrative and General	3,518,845
Total Wages and Salaries Included in O&M Expenses	5,322,128
Wages & Salaries Excluding A&G	1,803,283

Source: Company Records

FERC Account		Demand	Energy	Total
Production				
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering		0	-
501	Fuel			-
502	Steam Expenses	0	0	962,553
503	Steam from Other Sources	0	0	-
504	Steam Transferred - Credit	0	0	-
505	Electric Expenses	0	0	-
506	Miscellaneous Steam Power Expenses	0	0	-
507	Rents	0	-	-
	Total Operation	-	-	962,553
Maintenance				
510	Maintenance Supervision and Engineering		0	-
511	Maintenance of Structures	0	0	-
512	Maintenance of Boiler Plant		0	962,605
513	Maintenance of Electric Plant		0	-
514	Maintenance of Miscellaneous Steam Plant	0	-	-
	Total Maintenance	-	-	962,605
	Total Power Production Expenses - Steam Plant			1,925,157
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	0	0	-
518	Fuel	0	0	-
519	Coolants and Water	0	0	-
520	Steam Expenses	0	0	-
521	Steam from Other Sources	0	0	-
522	Steam Transferred - Credit	0	0	-
523	Electric Expenses	0	0	-
524	Miscellaneous Steam Power Expenses	0	0	-
525	Rents	0	0	-
	Total Operation			-
Maintenance				
528	Maintenance Supervision and Engineering	0	0	-
529	Maintenance of Structures	0	0	-
530	Maintenance of Reactor Plant Equipment	0	0	-
531	Maintenance of Electric Plant	0	0	-
532	Maintenance of Miscellaneous Steam Plant	0	0	-
	Total Maintenance			-
	Total Power Production Expenses - Nuclear Plant			-

	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	0	0	-
536	Water for Power	0	0	-
537	Hydraulic Expenses	0	0	-
538	Electric Expenses	0	0	-
539	Misc. Hydraulic Power Gen. Expenses	0	0	-
540	Rents	0	0	-
	Total Operation			-
Maintenance				
541	Maintenance Supervision and Engineering	0	0	-
542	Maintenance of Structures	0	0	-
543	Maint. of Reserviors, Dams & Waterways	0	0	-
544	Maintenance of Electric Plant	0	0	-
545	Maintenance of Misc. Hydroelectric Plant	0	0	-
	Total Maintenance			-
	Total Power Production Expenses -- Hydroelectric			-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering		0	-
547	Fuel		0	-
548	Generation Expenses		0	-
549	Miscellaneous Other Power Gen. Expenses		0	-
550	Rents		0	-
	Total Operation			-
Maintenance				
551	Maintenance Supervision and Engineering		0	-
552	Maintenance of Structures		0	-
553	Maintenance of Generation & Electric Plant		0	-
554	Maintenance of Misc. Other Power Gen.		-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Other Power			-
	Other Power Supply Expenses			
Operation				
555	Purchased Power	0		-
556	System Control and Load Dispatching	0	0	299,257
557	Other Expenses		-	-
	Total Operation	-	-	299,257
	Total Power Production Expenses			-

	Transmission Expenses	
Operation		
560	Operation Supervision and Engineering	82,961
561	Load Dispatching	165,616
562	Station Expenses	
563	Overhead Line Expenses	
564	Underground Line Expenses	
565	Transmission of Electricity of Others	
566	Miscellaneous Transmission Expenses	
567	Rents	
	Total Operation	248,577
Maintenance		
568	Maintenance Supervision and Engineeering	
569	Maintenance of Structures	
570	Maintenance of Station Equipment	
571	Maintenance of Overhead Lines	
572	Maintenance of Underground Lines	
573	Maintenance of Miscellaneous Transm. Plant	3,521
	Total Maintenance	3,521
	Total Transmission Expenses	252,098

Distribution Expenses		
Operation		
580	Operation Supervision and Engineering	
581	Load Dispatching	
582	Station Expenses	
583	Overhead Line Expenses	
584	Underground Line Expenses	
585	Street Lighting and Signal System Expenses	
586	Meter Expenses	
587	Customer Installation Expenses	
588	Miscellaneous Distribution Expenses	702,901
589	Rents	
	Total Operation	702,901
Maintenance		
590	Maintenance Supervision and Engineeering	
591	Maintenance of Structures	
592	Maintenance of Station Equipment	
593	Maintenance of Overhead Lines	
594	Maintenance of Underground Lines	
595	Maintenance of Line Transformers	
596	Maintenance of Street Lighting and Signal Systems	
597	Maintenance of Meters	
598	Maintenance of Miscellaneous Distribution Plant	317,234
	Total Maintenance	317,234
	Total Distribution Expenses	1,020,135

		Customer Accounts Expenses	
Operation			
	901	Supervision	-
	902	Meter Reading Expenses	189
	903	Customer Records and Collection Expenses	62,645
	904	Uncollectible Accounts	-
	905	Miscellaneous Customer Accounts Expenses	179,617
		Total Customer Accounts Expenses	242,451
		Customer Service and Information Expenses	
Operation			
	907	Supervision	-
	908	Customer Assistance Expenses	286,858
	909	Informational and Instructional Expenses	-
	910	Miscellaneous Customer Service and Information Expenses	-
		Total Customer Service and Information Expenses	286,858
		Sales Expenses	
Operation			
	911	Supervision	-
	912	Demonstrating and Selling Expenses	1,741
	913	Advertising Expenses	-
	916	Miscellaneous Sales Expenses	-
		Total Sales Expenses	1,741
		Administrative and General Expenses	
Operation			
	920	Administrative and General Salaries	3,518,742
	921	Office Supplies and Expenses	
	922	Administrative Expenses Transferred - Credit	
	923	Outside Services Employed	
	924	Property Insurance	
	925	Injuries and Damages	
	926	Employee Pensions and Benefits	
	927	Franchise Requirements	
	928	Regulatory Commission Expenses	
	929	Duplicate Charges - Credit	
	930	General Advertising & Miscellaneous General Expenses (See Next Page)	
	931	Rents	
		Total Operation	3,518,742
Maintenance			
	935	Maintenance of General Plant	103
		Total Administrative and General Expenses	3,518,845

Function	Depreciable Plant Balances (EOY)	Depreciation Rate (Percent)	Depreciation Amount Annual
Production Plant			
Prior to October 1, 2014 (CPGS)	303,557,195	2.81%	2,132,489
Subsequent to October 1, 2014 (CPGS)	308,020,807	2.94%	6,791,859
Transmisson Plant			
Bulk Plant	38,400,229	2.43%	933,126
Direct Assignment		0%	-
Distribution	-	0%	-
Generation Step-Up	-	0%	-
Total Transmission Plant	38,400,229	2.43%	933,126
Distribution Plant			
Bulk Plant	-	0%	
Direct Assignment	-	0%	
Distribution	160,674,387	2.79%	4,482,815
Generation Step-Up	-	0%	
Other Distribution	-	0%	
Total Distribution Plant	160,674,387	2.79%	4,482,815
General Plant			
Distribution	-	0%	-
Power Marketing	-	0%	-
Production	-	0%	-
Retail Services	-	0%	-
Transmission	-	0%	-
Total General Plant	10,663,879	2.25%	239,937.29
Other Utility Plant			
Distribution	-	0%	-
Power Marketing	-	0%	-
Production	-	0%	-
Retail Services	-	0%	-
Transmission	-	0%	-
Total Other Utility Plant	8,126,462	7.98%	648,491.64
Total Depreciation and Amortization Expense	525,885,765		15,228,718

Depreciation rates from Statement J Wyoming State Rate case.

Sources: Company Records

Cheyenne Light Fuel and Power
TAXES OTHER THAN INCOME
June 30 2015 Forecast

Exhibit No. CLP-50
Period II
Statement AK

Real Estate and Personal Property		2,025,902
Payroll Taxes		707,530
Gross Receipts Taxes		216501.6
Miscellaneous Taxes		1,817,183
	Total Taxes Other than Income:	4,767,117

Source: Company Records

	13 Month Average	Average Beg/End Yr.	End of Year
Fuel Inventories (non-nuc.)	-	-	-
Materials & Supplies	6,202,967	5,955,275	6,415,275
Property Insurance	61,627	25,445	33,194
Other Prepayments	677,346	688,737	643,490
Total	6,941,940	6,669,457	7,091,960

Fuel Inventories

	Coal	Oil	Natural Gas	Other	Total
December					
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
13 Mo. Avg.	-	-	-	-	-
Beg/End Avg.	-	-	-	-	-

Materials and Supplies

	Production	Transmission	Distribution	General	Total
July	2,638,376	46,460	2,778,437	32,002	5,495,275
August	2,638,376	46,460	2,778,437	32,002	5,495,275
September	2,638,376	46,460	2,778,437	32,002	5,495,275
October	3,558,376	46,460	2,778,437	32,002	6,415,275
November	3,558,376	46,460	2,778,437	32,002	6,415,275
December	3,558,376	46,460	2,778,437	32,002	6,415,275
January	3,558,376	46,460	2,778,437	32,002	6,415,275
February	3,558,376	46,460	2,778,437	32,002	6,415,275
March	3,558,376	46,460	2,778,437	32,002	6,415,275
April	3,558,376	46,460	2,778,437	32,002	6,415,275
May	3,558,376	46,460	2,778,437	32,002	6,415,275
June	3,558,376	46,460	2,778,437	32,002	6,415,275
July	3,558,376	46,460	2,778,437	32,002	6,415,275
13Mo. Avg.	3,346,068	46,460	2,778,437	32,002	6,202,967
Beg/End Avg.	3,098,376	46,460	2,778,437	32,002	5,955,275

Source: Company Records

Prepayments and Insurance

	Property Insurance	Other Prepayments
July	29,536	750,691
August	18,260	778,378
September	6,984	712,394
October	127,921	722,908
November	116,080	751,920
December	104,240	747,063
January	92,399	636,142
February	80,558	670,555
March	68,717	642,489
April	56,876	493,723
May	45,035	628,957
June	33,194	643,490
July	21,354	626,784
13 Mo. Avg.	61,627	677,346
Beg/End Avg.	25,445	688,737

Source: Company Records

Not applicable for this transmission filing

	Steam Production	Nuclear (a) Production	Other Production	Transmission	Total
December	-	0	0	-	-
January		0	0		-
February		0	0		-
March		0	0		-
April		0	0		-
May		0	0		-
June		0	0		-
July		0	0		-
August		0	0		-
September		0	0		-
October		0	0		-
November		0	0		-
December		0	0		-
13 Mo. Avg.	-	0	-	-	-

	Distribution	General	Common
12/31/1999	-	-	0
12/31/2000	-	-	0
Average	-	-	0

Notes:
(a) Excludes Nuclear Fuel

	Total Company	Electric
July	112,893,389	94,830,447.00
August	113,118,653	95,019,668.73
September	42,826,841	35,974,546.71
October	39,786,978	33,421,061.65
November	47,275,436	39,711,366.56
December	33,202,952	27,890,479.82
January	28,121,641	23,622,178.03
February	23,897,897	20,074,233.36
March	23,037,252	19,351,291.33
April	18,051,104	15,162,926.94
May	17,334,531	14,561,005.99
June	14,848,021	12,472,337.62
July	10,831,135	9,098,153.40
Total	525,225,830	441,189,697
13 Mo. Avg.	40,401,987	33,937,669

Cheyenne Light Fuel and Power
RATE FOR ALLOWANCE FOR FUNDS
USED DURING CONSTRUCTION
June 30 2015 Forecast

Exhibit No. CLP-54
Period II
Statement AO

Company forecasts a 7.722 % AFUDC rate in 2015 . A comparison of the AFUDC rate used during the year with the FERC formula rate derived using forecast through 12/31/15. shows that Company is within FERC guidelines. This calculation of AFUDC is shown below.

Input Values

S = Average Short-Term Debt for year	=	$	-
RS = Short-Term Debt Interest Rate	=		0.00%
D = Long-Term Debt, Year End	=	$	302,000,000
RD = Long-Term Debt Interest Rate	=		5.76%
P = Preferred Stock, Year End	=	$	-
RP = Preferred Stock Cost Rate	=		0.00%
C = Common Equity, Year End	=	$	316,087,378
RC = Commony Equity Cost Rate (Authorized)	=		10.60%
W = Average CWIP plus Nuclear Fuel In Process	=	$	10,225,326

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction
= (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))
AI = 2.813%

AE = Rate for Allowance for Other Funds used during Construction
= (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))
AE = 0.000%

Gross Nominal Rate =	2.813%
Effective annual Rate (Semi-Annual Compounding)	2.833%
Effective Monthly Rate (Semi-Annual Compounding)	0.233%

Soruce: Company Records

Cheyenne Light Fuel and Power
FEDERAL INCOME TAX DEDUCTIONS -- INTEREST
June 30 2015 Forecast

Exhibit No. CLP-55
Period II
Statement AP

Account 432		CWIP Taking AFUDC	AFUDC Expenditure	AFUDC Debt Acct. 432
Electric				
	Production	$ 3,096,964	87,114	87,114
	Transmission	$ 1,690,030	47,539	47,539
	Distribution	$ 12,057,536	339,166	339,166
	General	$ 1,760,260	49,514	49,514
	Subtotal	$ 18,604,789	$ 523,333	$ 523,333
	Other Utility Plant	0	0	0
	Total	$ 18,604,789	$ 523,333	$ 523,333

Source: Company Records

Long Term Interest Expense		Rate Base	Weighted LTD Rate (%)	Long Term Interest
	Transmission	31,476,233	2.79%	877,431
	All Other	322,931,326	2.79%	9,002,034
	Total	354,407,559		9,879,465

Source: Statement BK

Acct. 431 -- Other Interest Expense

90-Day Notes	
Customer Svc Deposits	$ 174,000
Bank Facility Fees	
Miscellaneous	$ 63,000
Total	$ 237,000

Source: Company Records

Pretax Net Income 40,570,738

Additions to Income Before Taxes

Description of Each Item		Total
BAD DEBT RESERVE	$	-
BONUS		-
WORKERS COMP		-
DEFERRED REVENUE		-
DEFERRED COSTS		5,169,916
OTHER		
REG RETIREE HEALTHCARE ASSET		-
FAS 143 (ARO)		-
LINE EXTENSION DEP ELEC		6,494,000
GAIN DEFERRAL		-
FAS 106 RETIREE LIAB		-
ACCR LITIGATION LIAB		-
REG PSC PENSION ASSET		
REG ENGY EFF ASSET		452,592
CONTRIBUTIONS IN AID OF CONST		102,804
DERIVATIVE (AOCI)		
Total Additions to Income	$	12,219,312

Deductions from Income Before Taxes

Description of Each Item		Total
INTEREST EXPENSE	$	-
VACATION		-
PENSION FAS 87		-
COST OF REMOVAL		(342,863)
EQUITY ADUFC		-
ACCELERATED DEPRECIATION ELEC		(2,719,393)
INS RESERVE LIAB		-
LT RATE CASE ASSET		(81,390)
REG RESA RIDER ASSET		-
SEVERANCE		-
REG ACCR FAC ELEC		(241,069)
NET OPERATING LOSS CARRYFORWARD		(8,989,502)
GOODWILL AMORT		-
REG ASSET ARO LIABILITY		-
Total Deductions from Income	$	(12,374,217)

Source: Company Records

Cheyenne Light Fuel and Power
INCOME TAX ADJUSTMENTS - ACCOUNT 410.1
June 30 2015 Forecast

Exhibit No. CLP-57
Period II
Statement AR

Provision for Deferred Income Taxes

	Allocator/Assignment					
	TOTAL	NPLT	W&S	DISTRIBUTION	PRODUCTION	TRANSMISSION
FERC Account 190 - Accumulated Deferred Income Taxes						
Line Extension Deposits	2,272,900	2,272,900				207,168
NOL Carryforward	(3,146,326)	(3,146,326)				(286,778)
	(873,426)	(873,426)	-	-	-	(79,610)
FERC Account 282 - Accumulated Deferred						
Cost Of Removal-Elect	(120,002)	(120,002)				(10,938)
Depreciation	(951,788)	(951,788)				(86,752)
Facts And Circumstances-Elect	(84,374)	(84,374)				(7,690)
Contributions in Aid of Const	35,981	35,981				3,280
	(1,120,182)	(1,120,182)	-	-	-	(102,101)
FERC Account 283 - Accumulated Deferred Income Taxes - Other Property						
Deferred Costs	1,809,471	1,809,471				164,927
Reg Energy Efficient Asset	158,407	158,407				14,438
Deferred Rate Case	(28,487)	(28,487)				(2,596)
	1,939,391	1,939,391	-	-	-	176,769
Total	(54,217)	(54,217)	-	-	-	(4,942)

Notes:

(1) The "Allocator/Assignment" totals by category go forward to the following worksheet:
Statement BK-Cost of Service Study

(2) Note that there are no amounts in account #411.1

Source: Company Records

None for Cheyenne Light Fuel & Power

Deductions from Book Income to Determine Taxable Income:

	Amount
State Tax Depreciation	
Other (Specify)	
Other (Specify)	
Other (Specify)	
Total	0

Additions to Book Income to Determine Taxable Income:

	Amount
Book Depreciation	
Other (Specify)	
Other (Specify)	
Other (Specify)	
Total	0

Source:

None

Source: Company Records

Cheyenne Light Fuel and Power
REVENUE CREDITS
June 30 2015 Forecast

Exhibit No. CLP-60
Period II
Statement AU

FERC Account	Description	Total Company Amount	Ancillary Service Schedule 2	Revenue Credits SF, OS, NF Service
454	Transmission Only			
456	Transmission For Others	$ 819,836	$ 783,836	$ -
447	Sales for Resale (transmission)			
	Total	$ 819,836	$ 783,836	$ -

Source: Company Records

	Component	Form No. 1	End of Year Amounts Amount	Share (%)	Cost Rate (%)		Weighted Cost (%)
1	Long-Term Debt	see Note #3	194,000,000	46.0%	6.060%	Note #2	2.79%
2	Preferred Stock	p. 112 3 c		0.0%	0.000%		0.00%
3	Common Equity	see Note #1	185,310,192	54.0%	10.600%		5.72%
4	Total		379,310,192	100.0%			8.51%

	Note #1:		
5	Proforma Adjustment to Ec	p. 112, 16 d	42,428,938
6	Adjusted Equity		227,739,130
7			
8	Total		421,739,130

Note #1
Adjustment to reflect future retained earnings and equity infusion

Source: Company Records

Cost of Short-Term Debt

Short term debt is not considered in the cost of service, since it is not included in the capital structure

Rate Orders Acted Upon During, or After, Period II

None.

Cheyenne Light Fuel and Power	Exhibit No. CLP-64
INCOME AND REVENUE TAX DATA	Period II
June 30 2015 Forecast	Statement AY

A	Federal Income Tax Rate	35.0000%
B	Nominal State Income Tax Rate	
	Wyoming	0.0000%
C	Deductibility of State Income Taxes:	
	(Provide Statement)	
D	Revenue Tax Rate	
	Description of Each Tax Rate	
		0.0000%
	Sum	0.0000%
E	Proportion of Federal Income Tax Deductible For State Income (weighed, if more than one state)	0.0000%

Source: Company Records

OATT Transmission Service

Long-Term Firm Point-to-Point Customers

Black Hills Power

Short-Term Firm Point-to-Point Customers

None

Network Customers

Cheyenne Light Fuel and Power

Other Long-Term Firm Service

None
None
None
None

Non-Firm Transmission Service

None

Cheyenne Light Fuel and Power
ALLOCATION DEMAND AND CAPABILITY DATA
June 30 2015 Forecast

Exhibit No. CLP-66
Period II
Statement BB

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	**12cp**
Native Retail Load	p. 401	199	190	180	170	179	189	195	186	185	187	180	208	**187**
Other Transmission Service Loads :														
Black Hills Power Point to Point		10	10	10	10	10	10	10	10	10	10	10	10	10
Other														
None														
None														
Total Transmission System Load		209	200	190	180	189	199	205	196	195	197	190	218	197

Not applicable for this transmission filing

Not applicable for this transmission filing

Not applicable for this transmission filing

Not applicable for this transmission filing

Cheyenne Light Fuel and Power
PROPOSED AND PRESENT REVENUES
June 30 2015 Forecast

Exhibit No. CLP-71
Period II
Statement BG & BH

Long-Term Firm Point-to-Point Customers	Average MW	Proposed Rate	Present Rate	Proposed Revenue	Present Revenue	Increase	% Increase
Black Hills Power	10	2.89	NA	$ 347,029		NA	NA

Short-Term Firm Point-to-Point Customers	(1) Annual Transmisison Charges At Present Rate	(2) Proposed Rate ($/kW/Month)	(3) Present Rate ($/kW/Month)	(4) % Increase (2)/(3)	(5) Annual $ Increase (1)x(4)
	NA	2.89	NA	NA	NA

Network Customers	Average Customer Peaks	Average Total Peaks	Proposed Schedule H	Present Schedule H	Proposed Revenues	Present Revenues	$ Increase
Third Party Network	NA	NA	2.89	NA	NA	NA	NA

(1) Applicable to Firm Point-to-Point Transmission Service only.

See Statement BG

Not applicable for this transmission filing

Statement	Description	Function/ Sub-Function	Beginning/Ending Average
AD	Cost of Plant	Production	247,741,750
		Transmission	40,864,562
		Distribution	162,709,550
		General	10,580,662
		Common	-
AE	Accumulated Depreciation and Amortizati	Production	28,541,149
		Transmission	3,699,457
		Distribution	50,213,786
		General	4,870,569
		Common	-
AF	Specified Deferred Credits		
	Account 255	Total	70,124
	Account 281	Total	-
	Account 282	Total	52,132,636
	Account 283	Total	7,357,133

Statement	Description	Function/ Sub-Function	Beg of Yr/End of Yr Average
AG	Specified Plant Accts and Deferred Debits		
	Account 105	Total	
	Account 182	Total	4,003,499
	Account 190	Total	6,365,419
			Annual Amount
AH	Operating & Maintenance Expenses	Production	64,161,809
		Transmission	763,596
		Distribution	3,295,271
		General	10,950,133
		Total	79,170,809
AI	Wages & Salaries	Production	-
		Transmission	252,098
		Distribution	1,020,135
		General	3,518,845
		Common	-
		Total	4,791,078
AJ	Depreciation & Amortization Expense	Production	-
		Transmission	933,126
		Distribution	4,482,815
		General	239,937
		Total	5,655,878

Statement	Description	Function/ Sub-Function	Annual Amount
AK	Taxes Other Than Income		
	Real Estate & Personal Property		2,025,902
	Payroll Taxes		707,530
	Other		-
	Total		2,733,432
			13-Month Average
AL	Working Capital	Fuel Supplies	-
		Materials & Suppli	6,202,967
		Prepayments	677,346
		Total	6,880,313
AM	Construction Work In Process		
		Production	-
		Transmission	-
		Distribution	-
		General	-
		Total	-
AN	Notes Payable		33,937,669

Statement	Description	Function/ Sub-Function	Year-to-Date
AP	Fed Income Tax Deductions-Interest		
	Account 431	Other Interest	237,000
	Account 432	Total	523,333
	Long Term Interest Exp	Transmission	877,431
		All Other	9,002,034
		Total	9,879,465
AQ	Income Tax Deductions-Other Than Interest		
	Additions to Book Income		12,219,312
	Deductions from Book Income		(12,374,217)
AR	Income Tax Deductions		
	Acct 410.1 - Provision for Deferred Income Taxes - Debit		
	Account 281		-
	Account 282	Total	(1,120,182)
	Account 283	Total	1,939,391
	Account 190	Total	(873,426)
	Summary Account 410.1	Total	(54,217)
	Acct 411.1 - Provision for Deferred Income Taxes - Credit		
	Account 281	Total	-
	Account 282	Total	-
	Account 283	Total	-
	Account 190	Total	-
	Summary Account 411.1	Total	-

Statement	Description	
AS	Additional State Income Tax Deductions	No additional state income tax deductions.
AT	State Tax Adjustments	No state income tax deductions.
AV	Rate of Return	

Cost of Capital	Amount	Percent Of Total	Cost	Weighted Cost
Long -Term Debt	194,000,000	46.0000%	6.06%	2.79%
Preferred Stock	-	0.0000%	0.00%	0.00%
Common Equity	185,310,192	54.0000%	10.60%	5.72%
Total	379,310,192	100.00%		8.51%

Statement	Description		
AW	Cost of Short-Term Debt	Not Included in the Capital Structure for return purposes, therefoe, not considered in COS.	
AY	Income & Revenue Tax Rate Data	Nominal Federal Income Tax Rate	35.00%
		Nomital State Income Tax Rate Colorado	0.00%
		Revenue Tax Rate	0.00%

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Summary of Results

Line	Description	Source	Total Electric	Transmission At Issue	All Other
	Rate Base				
1	Gross Plant in Service	Sch 2 ; Page 1	486,699,020	41,027,108	445,671,911
2	Depreciation Reserve	Sch 2 ; Page 1	(91,931,368)	(5,045,300)	(86,886,067)
3	Net Utility Plant		394,767,652	35,981,808	358,785,844
4	Accumulated Deferred Taxes	Sch 3 ; Page 1	(56,765,883)	(5,473,399)	(51,292,484)
5	Other Subtractive Adjustments	Sch 3 ; Page 1	-	-	-
6	Materials & Supplies	Sch 2 ; Page 2	6,170,965	46,460	6,124,505
7	Fuel Inventory	Sch 2 ; Page 2	-	-	-
8	Prepaids and Other	Sch 2 ; Page 2	738,973	62,293	676,680
9	Cash Working Capital	Sch 2 ; Page 2	3,130,432	216,720	2,913,713
10	Acct. 190 and Other Additive Adjust.	Sch 3 ; Page 2	6,365,419	642,351	5,723,068
11	Total Rate Base		354,407,559	31,476,233	322,931,326
	Operating Expenses				
12	Total O&M Expense		80,164,546	1,733,759	78,430,787
13	Total Depreciation Expense		15,228,718	1,057,327	14,171,391
14	Total Other Taxes		4,550,615	422,872	4,127,744
16	Subtotal - O&M & Other		99,943,880	3,213,958	96,729,921
17	Net Federal Income Taxes		10,756,565	954,941	9,801,625
18	Net State Income Taxes		-	-	-
19	Total Operating Expense		110,700,445	4,168,899	106,531,546
20	Return on Rate Base		$ 30,165,754	$ 2,679,131	$ 27,486,623
21	Total Cost of Service		140,866,199	6,848,030	134,018,169
22	Revenue Credits (Statement AU; allocated on TP)		$ 783,836	$ -	
23	Net Cost of Service			6,848,030	
24	Current Revenue Requirement			$ -	
25	Revenue Increase			$ 6,848,030	
26	Allowed Rate of Return (after tax; Statement AV)		8.51%	8.51%	8.51%
27	Schedule 1 Service: Scheduling, System Control and Dispatch Service Annual Revenue Requirement -- Schedule 4, Page 1			$ 545,666	

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Electric Plant in Service

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
1	Production Plant		268,834,063		268,834,063
2	Transmission Plant At Issue		38,400,229	38,400,229	-
3	Distribution Plant		160,674,387		160674386.7
4	Gross Electric P, T, D Plant		467,908,679	38,400,229	429,508,449
6	General & Intangible Plant Functionalized	W&S	18,790,341	2,626,879	16,163,462
7	Gross Electric Plant in Service		486,699,020	41,027,108	445,671,911
				14%	

Depreciation Reserve

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
1	Production Plant		28,213,623		28,213,623
2	Transmission Plant At Issue		3,664,562	3,664,562	-
4	Distribution Plant		50,176,614		50,176,614
5	Gross Electric P, T, D Plant		82,054,799	3,664,562	78,390,238
6	Gen. Plant Depr. Resv. Functionalized	W&S	9,876,568	1,380,739	8,495,830
7	Total Depreciation Reserve (l. 5 + l. 6)		91,931,368	5,045,300	86,886,067

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Net Electric Plant

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
1	Production Plant		240,620,439		240,620,439
2	Transmission Plant At Issue		34,735,668	34,735,668	-
3	Transmission Plant Excluded				-
4	Distribution Plant		110,497,772	-	110,497,772
5	Net P, T, D Plant		385,853,879	34,735,668	351,118,212
6	General & Intangible Net Plant		8,913,773	1,246,140	7,667,632
7	Net Electric Plant in Service		394,767,652	35,981,808	358,785,844

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Subtractive Adjustments				
1	Accum. Deferred ITC -- Acct. 255		128,664	11,727	116,937
2	ADIT (Acct. 281)	NPLT	-	-	-
3	ADIT (Acct. 282)	NPLT	52,132,636	4,751,723	47,380,913
4	ADIT (Acct. 283) (Plant)	NPLT	4,061,743	342,391	3,719,352
5	ADIT (Acct. 282 $ 283 Common)	DA	442,840	367,557	75,283
6	Subtotal Accum. Deferred Taxes		56,765,883	5,473,399	51,292,484
	Other Subtractive Adjustments				
7		NPLT	-	-	-
8	Total Subtractive Adjustments		56,765,883	5,473,399	51,292,484

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Additive Adjustments				
	Accum. Deferred Inc. Taxes (Acct. 190)				
1	Functionalized (wp AG)	W&S / NPLT	6,365,419	642,351	5,723,068
2	Subtotal Acct. 190		6,365,419	642,351	5,723,068
	Land Held for Future Use (Acct. 105)				
3	Transmission	TP	-	-	
4	General Functionalized	W&S	-	-	-
5	Total Land for Future Use		-	-	-
6	Total Additive Adjustments (l.2 + l. 5)		6,365,419	642,351	5,723,068

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Working Capital				
	Materials and Supplies				
	Fuel Supplies				
1	Fossil	Direct	-		
2	Nuclear		-		
3	Other		-		
4	Total Fuel Stocks		-	-	-
	Materials and Supplies				
5	Production	DA	3,346,068		3,346,068
6	Transmission	TP	46,460	46,460	-
7	Distribution	DA	2,778,437		2,778,437
8	Total Plant Materials & Supplies		6,170,965	46,460	6,124,505
	Prepayments				
9	Property Insurance	GPLT	61,627	5,195	56,432
10	Other Prepayments	GPLT	677,346	57,098	620,248
11	Total Prepayments		738,973	62,293	676,680
	Cash Working Capital (Auto Calculation)				
12	(One eighth O&M less fuel and PP)	(auto calculation)	3,130,432	216,720	2,913,713
13	Total Working Capital		10,040,371	325,473	9,714,898

O&M Expenses

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Production O&M				
	Energy Related Production O&M				
1	Fuel		11,029,805		11,029,805
2	Purchased Power		44,091,282		44,091,282
3	Other				-
4	Gas Steam Energy Related		9,040,722		9,040,722
5	Total Energy Related		64,161,809	-	64,161,809
	Demand Related Production O&M				
6	Purchased Power				-
7	Other Demand Related		-		-
8	Fixed Fuel (Storage & Maintenance)		-		-
9	Gas Steam Demand Related		-		
10	Total Demand Related		-	-	-
11	Total Production O&M		64,161,809	-	64,161,809
	Transmission O&M				-
12	Total	TP	763,596	763,596	-
12a	Less Acct 561	TP	(545,666)	(545,666)	-
13	Less Acct. 565 (Tx by Others)	TP	-	-	-
14	Transmission O&M (adjusted)		217,930	217,930	-
	Distribution O&M				
15	Distribution O&M		3,295,271		3,295,271
16	Customer Accounting		830,529		830,529
17	Customer Service & Information		602,130		602,130
18	Sales		6,745		6,745
	Administrative & General				
19	Property Insurance	GPLT	270,130	22,771	247,359
20a	Less FERC Annual Fees	TP	-	-	-
20	Less EPRI/Reg.Commission Expense	W&S	100,000	-	100,000
21	A&G Excluding Property Insurance	W&S	10,680,003	1,493,058	9,186,945
22	Total Admin & General		11,050,133	1,515,829	9,534,304
23	Total O&M Expense		80,164,546	1,733,759	78,430,787

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Depreciation Expense

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
1	Production		8,924,348		8,924,348
2	Transmission	TP	933,126	933,126	-
3	Distribution		4,482,815		4,482,815
4	General & Intangible	W&S	888,429	124,202	764,227
5	Total Depreciation Expense		15,228,718	1,057,327	14,171,391

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Other Taxes and Miscellaneous Expenses

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	Taxes Other than Income				
1	Real Estate and Property Taxes	GPLT	2,025,902	170,777	1,855,125
2	Payroll Taxes	W&S	707,530	98,912	608,618
3	Gross Receipts Taxes	NA	0		
4	Miscellaneous Taxes	GPLT	1,817,183	153,182	1,664,000
5	Total Taxes Other than Income		4,550,615	422,872	4,127,744

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	Federal Income Tax				
	Federal Income Tax Deductions				
	Interest Expense (Automatic - Synchronized)		9,879,465	877,431	9,002,034
	Other Deductions				
	Total Deductions	NPLT	12,374,217	1,127,870	11,246,347
	Total Other Deductions		12,374,217	1,127,870	11,246,347
	Total Deductions		22,253,682	2,005,302	20,248,380
	Federal Income Tax Additions				
	Total Additions	NPLT	12,219,312	1,113,751	11,105,561
	Total Additions		12,219,312	1,113,751	11,105,561
	Net Deductions and Additions		10,034,370	891,551	9,142,820
	Federal Income Tax Adjustments				
	Fed. Prov. Deferred Inc. Tax (410.1)				
	Acct. 281	NPLT	-	-	-
	Acct. 282	NPLT	(1,120,182)	(102,101)	(1,018,081)
	Acct. 283	NPLT	1,939,391	176,769	1,762,622
	Acct. 190	NPLT	(873,426)	(79,610)	(793,816)
	Total Fed. Def. Inc. Tax		(54,217)	(4,942)	-49,275
	Fed. Prov. Deferred Inc. Tax (411.1)				
	Acct. 281	NPLT	-	-	-
	Acct. 282	NPLT	-	-	-
	Acct. 283	NPLT	-	-	-
	Acct. 190	NPLT	-	-	-
	Total Fed. Def. Inc. Tax		-	-	-
	Investment Tax Credits				
	Amortized Investment Tax Credit				
	Total Fed. Def. Inc. Tax		0	0	0
	Preliminary Summary -- Adjustments				
	Total Fed. Def. Inc. Tax (410.1)		(54,217)	(4,942)	(49,275)
	Total Fed. Def. Inc. Tax (411.1)		-	-	-
	Total Amortized ITC		-	-	-
	Total Federal Tax Adjustments		(54,217)	(4,942)	(49,275)
	Federal Tax Computation				
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Deductions and Additions		(10,034,370)	(891,551)	(9,142,820)
	Total Federal Tax Adjustments		(54,217)	(4,942)	(49,275)
	Base for FIT Calculation		20,077,167	1,782,639	18,294,528
	FIT Factor (= FIT Rate/(1-FIT Rate)		0.53846	0.53846	0.53846
	Preliminary Fed. Income Tax (Payable)		10,810,782	959,882	9,850,900
	Total Fed. Income Tax Adjustments		(54,217)	(4,942)	(49,275)
	Net Federal Income Tax		10,756,565	954,941	9,801,625

Income Tax Based On Return (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	State Income Tax				
	State Income Tax Adjustments				
	Total State Inc. Tax Adjustments		-	-	-
	SIT Calculation				
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Deductions and Additions		(10,034,370)	(891,551)	(9,142,820)
	Proportion of FIT Deductible for State Inc.		0%	0%	0%
	Net Federal Income Tax Allowable		10,756,565	954,941	9,801,625
	Total State Inc. Tax Adjustments		-	-	-
	Base for SIT Calculation		30,887,949	2,742,521	28,145,428
	SIT Factor (= SIT Rate/(1-SIT Rate)		-	-	-
	Preliminary State Income Tax (Payable)		-	-	-
	Total State Income Tax Adjustments		-	-	-
	Net State Income Tax		-	-	-
	Cost of Service Computation				
	Total Op. Exp. Excl. Inc. & Rev. Taxes		99,943,880	3,213,958	96,729,921
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Fed Income Tax Allowable		10,756,565	954,941	9,801,625
	Net State Income Tax Allowable		-	-	-
	Cost of Service Ex. Rev. Taxes		140,866,199	6,848,030	134,018,169
	Revenue Tax Factor		1.00	1.00	1.00
	Total Cost of Service		140,866,199	6,848,030	134,018,169
	Proposed Revenues		-	6,848,030	
	Excess Revenues				
	Composite Tax Rate				
	Excess Tax				
	Excess Return				
	Total Return Earned		30,165,754	2,679,131	27,486,623

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

FUNCTIONALIZATION FACTORS SUMMARY (Wages & Salaries Adjusted by TP allocator)

Factors	Source		Transmission At Issue	All Other
Gross Plant, Including GP&I (GPLT)	Sch 2, page 1	1.00000	0.08430	0.91570
Net Plant, Including GP&I (NPLT)	Sch 2, page 2	1.00000	0.09115	0.90885
Salaries & Wages, Excl. A&G (W&S)	Statement AI	1.00000	0.13980	0.86020
			1.00000	

Network Integration Service

1	Annual Transmission Revenue Requirement (Schedule H)		6,848,030

Point-to-Point Transmission Service

2	Annual Transmission Revenue Requirement (Schedule 7)		6,848,030
3	Average 12 CP Transmission Loads (kW)		197,333
4	Annual Charge ($/kW/Year)		34.70
5	Monthly Charge ($/kW/Month)		2.89
6	Weekly Charge ($/kW/Week)		0.67
7	Daily Charge - off peak ($/kW/Day)	(Annual Charge / 365)	0.095
7a	Daily Charge - on peak ($kW/Day)	(Annual Charge / 312)	0.111
8	Hourly Charge - off peak ($/MWh)	(Annual Charge/ 8760 x 1000)	3.96
8a	Hourly Charge - on peak ($/MWh)	(Annual Charge/ 4992 x 1000)	6.95

Schedule 1 Service: Scheduling, System Control and Dispatch Service

9	Schedule 1 Revenue Requirement		545,666
10	Average 12 CP Transmission Loads (kW)		197,333
11	Annual Charge ($/kW/Year)		2.77
12	Monthly Charge ($/kW/Month)		0.230
13	Weekly Charge ($/kW/Week)		0.05
14	Daily Charge - off peak ($/kW/Day)	(Annual Charge / 365)	0.008
14a	Daily Charge - on peak ($/kW/Day)	(Annual Charge / 312)	0.009
15	Hourly Charge - off peak ($/MWh)	(Annual Charge/ 8760 x 1000)	0.32
15a	Hourly Charge - on peak ($/MWh)	(Annual Charge / 4992 x 1000)	0.55

This statement shows the calculation of the proposed rates for yearly, monthly, weekly, and daily firm service. The rates are derived from the "Net Cost of Service" amount shown on Statement BK, Schedule 1, page 1. The yearly rate is the Net Cost of Service divided by the average of the forecasted monthly coincident peak loads for the 12 months ending June 2012.
The rates for monthly, weekly, and daily service are "up to" rates derived from the annual rate, and they are consistent with the FERC-approved "Appalachian" methodology.

Not Applicable

UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

	)	
Cheyenne Light, Fuel and	)	Docket No. ER14-____-000
Power Company	)	

PREPARED DIRECT TESTIMONY AND EXHIBITS OF

WILLIAM E. AVERA, PH.D.

AND

ADRIEN M. MCKENZIE

ON BEHALF OF

CHEYENNE LIGHT, FUEL AND POWER COMPANY

March 3, 2014

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CLP-104	DCF Model – National Group
CLP-105	Risk Premium – State ROE
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PREPARED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM E. AVERA AND ADRIEN M. MCKENZIE

I. INTRODUCTION

Q 1. Please state your names and business address.

A1. Our names are William E. Avera and Adrien M. McKenzie. Our business address is 3907 Red River, Austin, Texas.

Q 2. In what capacity are you employed?

A2. We are financial, economic, and policy consultants to business and government.

Q 3. Please describe your educational background and professional experience.

A3. A description of our background and qualifications, including resumes containing the details of our experience, is attached as Exhibit No. CLP-101.

A. Overview

Q 4. What is the purpose of your testimony?

A4. The purpose of our testimony is to present to the Federal Energy Regulatory Commission ("FERC" or "the Commission") our independent analysis of a fair rate of Return on Equity ("ROE") for the jurisdictional wholesale electric utility operations of Cheyenne Light, Fuel and Power Company ("Cheyenne Light" or "the Company").

Q 5. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A5. To prepare our testimony, we used information from a variety of sources that normally would be relied upon by a person in our capacity. We are familiar with

FERC polices and decisions related to ROE and have submitted testimony in numerous proceedings at the Commission dealing with required rates of return for electric utilities. In connection with the present filing, we considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Cheyenne Light. We also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities. These sources, coupled with our experience in the fields of finance and utility regulation, have given us a working knowledge of ROE issues related to Cheyenne Light and the Project it expects to develop and form the basis of our conclusions.

Q 6. How is your testimony organized?

A6. After briefly summarizing the operations and finances of Cheyenne Light, we present our conclusions and recommendations regarding a fair ROE for the Company. Next, we review current conditions in the capital markets and their implications in evaluating a fair ROE for Cheyenne Light. With this background, we conduct well-accepted quantitative analyses to estimate the current cost of equity for a reference group of other electric utilities with comparable investment risks. We refer to these 27 utilities as the "National Group." Our analyses includes applications of the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for electric utilities, which are all methods that are commonly relied on in regulatory proceedings.

Finally, we test our recommended ROE for Cheyenne Light based on the results of alternative ROE benchmarks, including reference to ROEs approved by the Commission for natural gas pipelines, applications of the traditional Capital Asset Pricing Model ("CAPM") and reference to expected rates of return for electric utilities. Further, we corroborate our utility quantitative analyses by applying the DCF model to a group of extremely low risk non-utility firms.

II. CHEYENNE LIGHT, FUEL AND POWER COMPANY

Q 7. Briefly describe Cheyenne Light.

A7. Cheyenne Light supplies electric and natural gas utility service to Wyoming's capital city and vicinity. The Company's electric utility system provides service to approximately 40,500 customers, with Cheyenne Light's peak load being approximately 192 megawatts ("MW"). Cheyenne Light's natural gas distribution system provides service to approximately 35,500 customers. As of December 31, 2013, Cheyenne Light had total capital of approximately $523 million, with operating revenues totaling approximately $127 million.

Q 8. Where does cheyenne light obtain the capital used to finance its investment in utility plant?

A8. As a wholly-owned subsidiary of Black Hills Corp., the Company obtains common equity capital solely from its parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to common equity, Cheyenne Light has access to long-term debt financing by issuing bonds in its own name, or through debt capital allocated to the Company from Black Hills Corp.

Q 9. What credit ratings have been assigned to Black Hills Corp.?

A9. Black Hills Corp. has been assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P"), an issuer credit rating of "Baa1" by Moody's Investor Services, Inc. ("Moody's"), and an issuer default rating of "BBB" by Fitch Ratings Ltd. ("Fitch").

III. RETURN ON EQUITY FOR CHEYENNE LIGHT

Q 10. What is the purpose of this section?

A10. This section presents our conclusions regarding a fair ROE for Cheyenne Light. It also discusses the relationship between the Commission's policy goals and the preservation of a utility's ability to earn a competitive return, to maintain its financial integrity, and to attract capital.

A. Importance of Regulatory Standards

Q 11. What is the role of the 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*[1] and *Hope,*[2] 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.

Q 12. 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. As the Commission explained in *MISO*: "we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (*i.e.*, the midpoint versus the median or mean); it is whether the use of the midpoint is most

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

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

appropriate *in this case*."[3] Accordingly, the paramount consideration in this instance that must be reflected in the choice of a point estimate is the need to ensure that the end result meets the standards mandated by the Supreme Court in *Bluefield* and *Hope*. This determination requires the Commission to consider all of the available evidence and identify an ROE that is just, reasonable, and sufficient to support Cheyenne Light's need to attract capital and earn a competitive return and the Commission's goal of encouraging investment in utility infrastructure.

Q 13. Does it make sense to rely solely on a single mechanical formula in evaluating a fair ROE for Cheyenne Light?

A13. No. It is the result reached, not the method used that determines whether an ROE is just and reasonable. A mechanical policy of referencing only a rote application of a particular formula mistakenly treats the method as an end in and of itself and leaves the Commission with little flexibility when the formula produces a result that fails to reflect a fair and reasonable ROE. The Commission has acknowledged its readiness to consider on a case-by-case basis how its methods should be modified to achieve a balanced outcome,[4] and has noted the dangers of inflexible criteria in evaluating a fair ROE.[5] Utilities and their investors must commit large sums of money and are exposed to many risks over long time horizons when they invest in electric utility infrastructure.

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

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[3] *Midwest Independent Transmission System Operator, Inc.,* 106 FERC ¶ 61,302 at P 8 (2004) (emphasis added) ("*MISO*").

[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 Fed. Reg. 1152 at P 63 (Jan. 10 2007), *on reh'g*, 119 FERC ¶ 61,062 (2007).

[5] *Commonwealth Edison Co.*, 124 FERC ¶ 61,231 at P 22 n. 30 (2008).

> As much as possible, regulators should, in our opinion, have the flexibility to react quickly and prudently to new situations as they develop. This is the sort of flexibility that we believe comes under principles-based regulation rather than rules-based regulation. In the latter, a regulator may attempt to set down every possible rule that can apply to a given situation that may arise in an industry. In the former, the regulator generally has the authority to achieve certain ends and some flexibility in how to achieve them.[6]

Any benefit of consistency is more than outweighed by the risks that an unresponsive, mechanical policy will lead to inadequate returns. Investors react swiftly and negatively to evidence of waning regulatory support, and such an outcome would severely undermine investor confidence and the Commission's policy goals. The Commission previously has recognized the key role of regulatory standards in evaluating a fair ROE, and has affirmed that the preeminent consideration in establishing an ROE is to ensure a reasonable end result.[7]

Q 14. 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 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

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

7 *MISO*, 106 FERC ¶ 61,302 at PP 13-14 ("[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.'" *Bluefield*, 262 U.S. at 693.).

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

Over time, the Commission has relied upon a variety of approaches to determine ROEs that are consistent with the standards prescribed by *Bluefield* and *Hope*. These evolving methods have each acknowledged that reasonableness and stability are essential elements of the Commission's regulatory policy. Indeed, there are important policy reasons that preclude a simplistic reliance on a single, formulaic approach to setting ROEs. It is important to consider a broad array of evidence, including the ROE range of reasonableness, the results of alternative ROE benchmarks, and well-established policy considerations supporting an ROE that is sufficient to attract capital.

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

> The Commission has concluded that requiring the ROE to be set at one of only three possible positions in the range established by reference to the proxy companies does not give the Commission the necessary flexibility required to evaluate the specific circumstances of each case. Thus, the Commission has determined that the parties to a rate proceeding may present evidence they believe is warranted to support any ROE that is within the DCF-derived zone of reasonableness...[8]

Q 15. Have you considered alternative measures of central tendency when evaluating the results of your quantitative methods?

A15. Yes. As discussed above, the evaluation of a company should not be limited to only certain types of evidence or the mechanical application of only a single type of

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

analysis. Rather, ROE analyses should consider a broad array of evidence, including alternative measures of central tendency, the ROE range of reasonableness, the results of alternative ROE benchmarks, and policy considerations supporting an ROE that is sufficient to attract capital. Consistent with this view, we have presented the median, average, and midpoint results of our analyses, which are all relevant in evaluating a fair ROE for Cheyenne Light.

B. Fair ROE for Cheyenne Light

Q 16. What is your conclusion regarding a fair ROE for Cheyenne Light?

A16. Based on the cost of equity estimates produced by our analyses, we recommend a base ROE for Cheyenne Light of 10.6%.

Q 17. Please summarize the results of your ROE analyses.

A17. The results of our analyses are presented in Exhibit No. CLP-102. Page 1 of Exhibit No. CLP-102 displays the ROE ranges and measures of central tendency resulting from our applications of the DCF, ECAPM, and risk premium methods. As shown there:

- Application of the DCF methodology results in an ROE zone of reasonableness of 7.5% to 15.9%, with a midpoint of 11.7% and a median of 9.8%;
- The utility risk premium approach implies an ROE point estimate in the 10.4% to 10.6% range;
- The forward-looking ECAPM estimates are encompassed by an ROE range of 9.5% to 13.8%;
- The overall average of the median cost of equity estimates resulting from alternative applications of the DCF, ECAPM, and risk premium approaches was 10.6%
- The overall average ROE based on our primary methods is 10.7%; and,
- Midpoint cost of equity estimates associated with these quantitative methods ranged from 10.4% to 11.7%. The average of the individual midpoint estimates is 11.1%.

Our recommended 10.6% ROE is equal to the average of the median results from our primary methods,[9] and is consistent with the other measures of central tendency indicated by our analyses.

Q 18. Would you rely on any of these measures individually to determine a just and reasonable ROE?

A18. No. While we are well aware that the Commission has narrowed the focus of its ROE evaluation to a particular variant of the DCF approach, it is our belief that the results of alternative methods must be considered collectively to properly evaluate what is a reasonable ROE for Cheyenne Light. Because the cost of equity is unobservable, it is widely recognized that no single method can be regarded as a panacea; all approaches have advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[10]

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[9] This approach is directly analogous to that used by San Diego Gas & Electric Company in support of its requested 11.3% ROE in Docket No. ER13-941, which was accepted for filing by the Commission, subject to hearing procedures. *San Diego Gas & Electric Co.*, 143 FERC ¶ 61,246 at PP 6 & 22 (2013). Similarly, in Docket No. ER13-2022, the Commission accepted a similar proposal by Pacific Gas and Electric Company, subject to hearing procedures. *Pacific Gas and Electric Co.*, 144 FERC ¶ 61,277 at PP 5 & 18 (2013).

[10] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at 115-116 (2010).

Regulators have customarily considered the results of alternative approaches in determining allowed returns.[11] As the Federal Communications Commission recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[12]

In addition, as we discuss subsequently, current capital market conditions are anomalous. Under these circumstances, and in order to ensure that the *Hope* and *Bluefield* standards are met, 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.

Q 19. Has the Commission also recognized that it may be appropriate to consider the results of alternative methods?

A19. Yes. For example, the Commission concluded in *Distrigas of Massachusetts Corp.* that "no one methodology is preferred to the exclusion of all others. The . . . DCF methodology, which we endorse, is but one analytical tool."[13] FERC also has granted that "[i]n some instances, the DCF methodology alone may be inappropriate,"[14] and in its decision in *Southern California Edison*, which first established the current DCF approach, the Commission noted, "Should circumstances in the industry change, in

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[11] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

[12] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

[13] *Distrigas of Massachusetts. Corp.*, 41 FERC ¶ 61,205 at 61,550 (1987), *modified on reh'g*, 42 FERC ¶ 61,225 (1988).

[14] *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 at 61,913 n. 90 (1990), *vacated on other grounds*, 931 F.2d 949 (D.C. Cir. 1991).

the future, we will reevaluate our methodology, as necessary."[15] While electing not to make "broadly applicable changes to how the Commission has traditionally performed its DCF analysis," *Order No. 679* noted the opinion that "there is a benefit to introducing more information into the analysis process," and FERC indicated a willingness to consider modifications to its standard approach on a case-by-case basis.[16] In *SoCal Edison*, the Commission determined that additional methods could be used to test or corroborate the results of its preferred DCF approach.[17] More recently, the Commission approved an ROE based solely on the results of the CAPM approach.[18]

Q 20. Are you saying that a fair base ROE for Cheyenne Light must be established directly on the alternative analyses you present below?

A20. No. We recognize that the Commission has elected to rely primarily on the DCF model in establishing an ROE zone of reasonableness for utilities under its jurisdiction, and our reference to alternative ROE benchmarks does not constitute a rejection of the DCF approach. However, we believe that it is crucial to consider the results of other methods in evaluating a fair ROE – at the very least in order to either corroborate or call into question the cost of equity estimates produced by the DCF model. The results of the additional methods discussed subsequently in our testimony provide useful information in evaluating a fair ROE from within the DCF zone of reasonableness.

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15 *Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at 61,261 (2000) (history omitted) ("*Southern California Edison*").

16 *Order No. 679* at P 102; Order No. 679-A at P 63.

17 *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 116 (2010) ("*SoCal Edison*").

18 *New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).

Q 21. What ROE zone of reasonableness do you recommend for Cheyenne Light?

A21. We recommend an ROE zone of reasonableness for Cheyenne Light of 7.5% to 15.9%, which is based on the individual DCF cost of equity estimates shown on page 3 of Exhibit No. CLP-104, after eliminating outliers.

Q 22. Is the reasonableness of a 10.6% base ROE for Cheyenne Light supported by other benchmarks?

A22. Yes. A base ROE for Cheyenne Light, or for any electric utility company, does not exist in a vacuum, as investors choose to commit their capital based on expected returns and competing investment opportunities. Accordingly, the reasonableness of an ROE for an individual company may be evaluated by comparison to investors' expected returns for other companies of comparable risk. In this instance, alternative ROE benchmarks (Exhibit No. CLP-102, p. 2) consistently support the reasonableness of a 10.6% ROE for Cheyenne Light:

- Risk premium results based on ROEs approved by the Commission for natural gas pipelines imply a current base cost of equity for an electric utility of approximately 10.5%;

- Application of the traditional CAPM using forward-looking estimates suggests an ROE for electric utilities on the order of 9.0% to 12.0%, or 8.6% to 13.7% after accounting for the impact of firm size;

- After incorporating projected bond yields, the risk premium, ECAPM, and CAPM methods generally resulted in cost of equity estimates above 10.8%;

- Earned returns for the electric utility industry are expected to average 10.4%, and fall in a range of 8.1% to 13.4% for the proxy group of comparable-risk electric utilities;

- DCF estimates for a low-risk group of non-utility firms suggest a cost of equity in the range of 9.6% to 13.1%, with a median of 11.0%;

- Taken together, the overall average of the median ROEs resulting from these alternative benchmarks equals 10.8%; and

- The reasonableness of a 10.6% base ROE is reinforced by the need to consider flotation costs, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond. Moreover, the potential for turmoil in the domestic and global financial markets and continued economic uncertainties exacerbate the risks faced by utilities and their investors.

Q 23. Is the outlook for capital costs relevant in evaluating a fair ROE?

A23. Yes. As demonstrated in our testimony, recent and current bond yields have been uncharacteristically low. As a result, if historical yields were referenced as the benchmark in evaluating a fair ROE, this would serve to bias the results downwards. This further supports the conclusion that a 10.6% base ROE for Cheyenne Light is reasonable and conservative.

Q 24. Is a 10.6% base ROE for Cheyenne Light consistent with established Commission policy to support investment in wholesale electric utility infrastructure?

A24. Yes. The Commission's supportive regulatory actions have been successful in promoting much needed investment in the transmission grid and new generation. Unresponsive, mechanical decision-making that leads to inadequate returns will undermine the Commission's goals and the legislative mandate to promote capital investment in new infrastructure projects. This 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.[19]

Q 25. Does the logic underlying these policies apply equally in this proceeding?

A25. Yes. Under the competitive market paradigm that serves as the foundation for investment choices, investors' expected ROE is the key economic signal that allocates scarce capital among competing opportunities. Utility planning and investment decisions are determined in part by competitive market forces, and the allowed ROE is the primary lynchpin in determining the flow of investment capital to new facilities. Apart from the impact that economic and market turmoil can have on the availability of capital, utilities seeking to fund investments in plant and equipment must compete with alternative uses, and the funding necessary to support investment only will be allocated if investors anticipate an opportunity to earn an ROE that is sufficient to compensate for the associated risks.

Establishing a fair ROE for Cheyenne Light that is competitive with other alternatives available to investors is essential to support the continued ability to attract capital on reasonable terms. The Commission has recognized the need to support wholesale power markets by adjusting its methods and instituting reforms in response to changed circumstances, as exemplified by *Order No. 1000*.[20] Evaluating a fair base ROE for Cheyenne Light against alternative measures of the zone of reasonableness, and considering the results of well-accepted ROE benchmarks and expectations for higher capital costs, provides the flexibility to ensure a reasonable end result that does not undermine the Commission's policy objectives.

Apart from the results of quantitative methods, it is crucial to recognize the importance of supporting a strong financial position so that Cheyenne Light remains

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

[20] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 155 (Aug. 11, 2011) (subsequent history omitted).

prepared to respond to unforeseen events that may materialize in the future. While this imperative is reinforced by recent capital market conditions, it extends well beyond the financial markets and includes the challenges facing Cheyenne Light. These considerations indicate that a 10.6% base ROE is reasonable.

IV. OUTLOOK FOR CAPITAL COSTS

Q 26. Do current capital market conditions provide a representative basis on which to evaluate a fair ROE?

A26. No. Current capital market conditions reflect the legacy of the Great Recession, and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties in recent years, investors repeatedly have 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 and investor confidence in the face of heightened economic risk.

Q 27. How do current yields on public utility bonds compare with what investors have experienced in the past?

A27. Despite recent increases, the yields on utility bonds remain near their lowest levels in modern history. Figure No. Cheyenne Light-1, below, compares the January 2014 average yield on long-term, triple-B rated utility bonds of 5.09% with those prevailing since 1968:

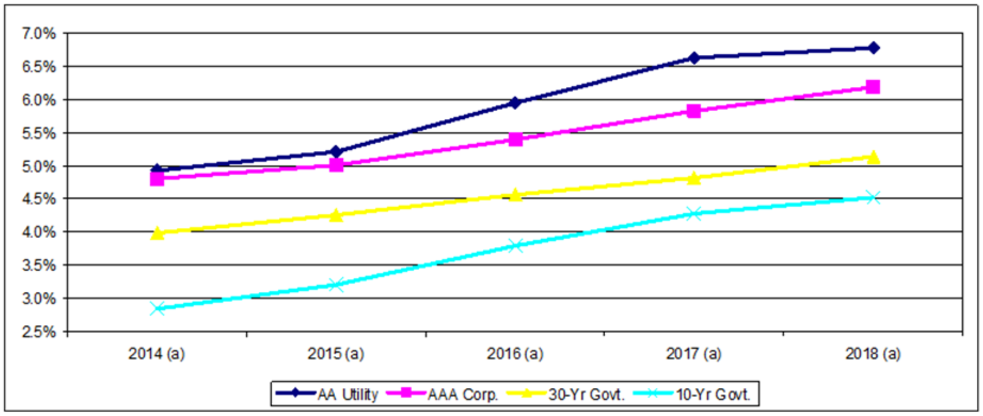
FIGURE NO. CLP-1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

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.

Q 28. Are these very low interest rates expected to continue?

A28. No. Investors do not anticipate that these low interest rates will continue into the future. It is widely anticipated that as the economy continues to stabilize and resume a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Figure No. CLP-2 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE NO. CLP-2
INTEREST RATE TRENDS



(a) Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 22, 2013)
IHS Global Insight, U.S. Economic Outlook at 25 (Nov. 2013)
Energy Information Administration, Annual Energy Outlook 2014, Early Release (Dec. 16, 2013)
Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013)

These forecasting services are highly regarded and widely referenced, with the Commission incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas pipelines. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2014-2018 period than it is currently.

Q 29. Do recent actions of the Federal Reserve support a contention that current low interest rates will continue indefinitely?

A29. No. While the Federal Reserve continues to express support for highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, it has also acted to pare back its $85 billion-a-month bond-buying program.[21] The Federal Reserve's decision to begin tapering its asset purchases was based on improving conditions for employment and the economy. Reductions in the Federal Reserve's bond buying program should ease downward pressure on long-term interest rates, with The Wall Street Journal observing that:

[21] *Press Release,* Board of Governors of the Federal Reserve System (Dec. 18, 2013, Jan. 29, 2014).

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[22]

While the Federal Reserve's tapering announcements have moderated uncertainties over just when, and to what degree, the stimulus program would be modified, investors continue to face ongoing uncertainties over future moves. The International Monetary Fund noted that, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "A smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[23]

These developments highlight concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve continuing to evaluate additional tapering of its bond-buying program, ongoing concerns over political stalemate in Washington, continued economic weakness in the Eurozone, and turmoil in emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q 30. Do the unprecedented low interest rates you have discussed affect the results of the Commission's DCF model?

A30. Yes. The Commission's policy is to eliminate low-end DCF estimates that do not exceed six-month historical average public utility bond yields by approximately 100

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

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

basis points or more.[24] As discussed above, the low interest rates that have characterized recent historical trends are unprecedented and reflect the legacy of the recession and the Federal Reserve's stimulus policies. As illustrated in Figures CLP-1 and CLP-2, these low historical interest rates are anomalous and do not reflect expectations for the future, which is the only relevant consideration when evaluating investors' required return. As a result, adding a margin of approximately 100 basis points to average historical bond yields produces a threshold that is too low to reflect investors' required returns going forward. As we will discuss below, 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, this static test of low-end outliers based on historical public utility bond yields retains low-end DCF estimates that are far below what investors require to accept the risks of an equity investment in Cheyenne Light.

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

Q 31. What do these events imply with respect to the ROE for Cheyenne Light more generally?

A31. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to profound dislocations in the economy and financial markets and ongoing economic and political risks. As a result, historical interest rates do not provide a sound threshold to evaluate capital costs that are expected by investors over the near-term future. This conclusion is supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated earlier, recognized economic forecasting services project that long-

[24] *See, e.g.*, *SoCal Edison*, 131 FERC ¶ 61,020 at P 55.

term capital costs will increase from present levels. To address the reality of current capital markets, our testimony expressly considers near-term forecasts for public utility bond yields in evaluating a reasonable base ROE for Cheyenne Light.

Q 32. Does the ability to seek an increase in the allowed ROE through a future Section 205 filing eliminate the need to consider expectations for higher capital costs?

A32. No. The fact that a utility can request a higher ROE at some future time does not negate the low-interest rate drag on DCF results, or the fact that interest rates are expected to increase significantly from their current exceptionally low levels. Ignoring the widely anticipated increase in interest costs will deny Cheyenne Light the opportunity to earn a fair ROE for three reasons. First, as discussed later in our testimony, economic studies show that risk premiums are higher when interest rates are at very low levels. As a result, applying a constant premium of 100 basis points to utility bond yields that are at (or near) their lowest levels in modern history results in an artificially low and distorted screen for low-end DCF estimates. Because of this, the results of the DCF approach are biased downward and fail to reflect investors' current expectations. A future Section 205 filing will not correct for this current bias or allow Cheyenne Light to earn its opportunity cost of equity going forward.

Second, the purpose of the Commission's evaluation is to establish a just and reasonable ROE over the time when rates are in effect. Given the inherent lag in rate proceedings, a failure to consider near-term expectations for higher capital costs will render any new ROE insufficient by the time it becomes effective. Considering the costs and burdens inherent in any rate filing, it is simply not practical or desirable to promote an outcome of continuous rate filings in an effort to keep pace with ongoing increases in capital costs. Accordingly, we present a wide variety of evidence in this evaluation, including the DCF range, the results of other methods, and ongoing capital market trends that impact shareholders' required rate of return. Interest rate projections are a key indicator that has direct relevance in evaluating a fair ROE from within the zone of reasonableness.

Third, although DCF calculations are made at a point in time, they are intended to be valid over the time when rates will be in effect. Deliberately ignoring expected changes in capital market conditions produces DCF results that will deny investors the opportunity to earn a fair ROE on their capital invested in Cheyenne Light.

V. CAPITAL MARKET ESTIMATES

Q 33. What is the purpose of this section?

A33. This section presents capital market estimates of the cost of equity. First, we address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, we describe DCF, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for a benchmark group of comparable risk firms. Finally, we examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q 34. What role does the ROE play in a utility's rates?

A34. 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.

Q 35. What fundamental economic principle underlies this cost of equity concept?

A35. 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.

Q 36. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A36. 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.

Q 37. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A37. 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.

Q 38. Is this risk-return tradeoff limited to differences between firms?

A38. 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.

Q 39. What does the above discussion imply with respect to estimating the cost of equity?

A39. 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.

Q 40. How did you go about evaluating the cost of equity for Cheyenne Light and determining a reasonable base ROE?

A40. We considered three methodologies used to determine cost of capital, the DCF method, the ECAPM, and the risk premium approach. There is no single quantitative method or approach that is inherently more accurate or reliable. Accordingly, rather than rely on a single analytical tool, our analysis combines the results of these studies to evaluate a reasonable ROE for Cheyenne Light.

B. Development and Selection of a Proxy Group

Q 41. How did you implement these quantitative methods to estimate the cost of common equity for Cheyenne Light?

A41. Application of the DCF, ECAPM, and risk premium 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. Thus, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error.

As a result, the accepted approach to increase confidence in the results is to apply the alternative quantitative methods 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.

Q 42. What specific proxy group did you rely on for your analysis?

A42. 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;
4. Electric utilities that have been assigned a corporate credit rating between "BBB-" and "BBB+" by S&P;
5. Electric utilities with a Value Line Safety Rank of "2" or "3"; and,
6. Electric utilities with a published 5-year earnings per share ("EPS") growth forecast from IBES.[25]

As shown on Exhibit No. CLP-103, the National Group is composed of 27 comparable-risk utilities.

Q 43. What was the basis for the range of S&P credit ratings used to identify the National Group?

A43. 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

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[25] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters. We 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. *See, e.g., Enbridge Pipelines (Southern Lights) LLC*, Answering Testimony of Commission Staff Witness Edward Alvarez III, Docket Nos. IS11-146-000 & IS10-399-003 (consolidated) at p. 16 (Aug. 16, 2011).

"notch" higher or lower than the corporate credit ratings of the utility at issue and within the investment grade ratings scale.[26] While Cheyenne Light does not have an overall corporate or issuer credit rating, the criterion used to identify our risk-comparable proxy group is consistent with the "BBB" rating assigned to its parent, Black Hills Corp.

Q 44. Does this comparison indicate that investors would view the firms in your National Group as risk-comparable to Cheyenne Light?

A44. Yes. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings also are frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity. The Commission has determined that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and concluded, "Credit ratings are a key consideration in developing a proxy group that is risk-comparable."[27] The Commission has also determined that the comparable risk band afforded by its credit rating screen alone is a sufficient test of comparable investment risks.[28]

Q 45. What other risk measures did you examine?

A45. Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Accordingly, our 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.[29] Given that Value Line is perhaps

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

[27] *Potomac-Appalachian Transmission Highline, LLC*, 133 FERC ¶ 61,152 at P 63 (2010).

[28] *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52 n. 70 (2011).

[29] While the Financial Strength Rating and beta were not relied on as a criteria in identifying the National Group, these are both widely referenced as risk indicators.

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

Q 46. How do the overall risks of your proxy group compare with Cheyenne Light?

A46. Risk measures for the National Group are shown on Exhibit No. CLP-103, and summarized in Table No. CLP-1, below, along with comparable data corresponding to Cheyenne Light. Because the Company has no publicly traded common stock, we referenced the Value Line risk measures for its parent, Black Hills Corp.:

[30] The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *Potomac-Appalachian*, 133 FERC ¶ 61,152 at P 63 n. 90.

TABLE NO. CHEYENNE LIGHT-1
COMPARATIVE RISK INDICATORS

		Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
National Group	BBB	2	B++	0.75
Cheyenne Light	BBB	3	B+	0.90

Q 47. What does this comparison indicate regarding investors' assessment of the relative risks associated with the National Group and Cheyenne Light?

A47. As shown above, the "BBB" rating corresponding to the Company is equal to the average corporate credit rating for the National Group. Meanwhile, the average Value Line Financial Strength Rating, Safety Rank, and beta associated with Cheyenne Light all suggests 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 Cheyenne Light are somewhat greater than those of the firms in the National Group. As a result, the cost of equity estimates produced by our analyses provide a conservative basis on which to evaluate a fair ROE for Cheyenne Light.

C. DCF Model

Q 48. How is the DCF model used to estimate the cost of equity?

A48. 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 model assumes the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. Thus, the cash flows that investors expect from a stock are estimated, and given its current market price, we can back into the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q 49. What market valuation process underlies DCF models?

A49. 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) 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.

1. Application of DCF Model

Q 50. What form of the DCF model is customarily used to estimate the cost of equity in rate cases?

A50. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[31]

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

[31] The constant growth DCF model is dependent on a number of 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.

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

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 price appreciation.

Q 51. How is the constant growth form of the DCF model typically used to estimate the cost of common equity?

A51. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q 52. How was the dividend yield for the National Group determined?

A52. For D_1, we used estimates of dividends to be paid by each of these utilities over the next 12 months, obtained from Value Line. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the National Group are presented on page 1 of Exhibit No. CLP-104. As shown there, dividend yields for the firms in the National Group ranged from 2.9% to 5.7%.

Q 53. What is the next step in applying the constant growth DCF model?

A53. The next step is to evaluate long-term growth expectations, or "g", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q 54. What are investors most likely to consider in developing their long-term growth expectations?

A54. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for electric utilities falling significantly. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS"). Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that dividend growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q 55. Did Professor Myron J. Gordon, who originated the DCF approach, recognize the pivotal role that earnings play in forming investors' expectations?

A55. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[32]

Q 56. What are security analysts currently projecting in the way of growth for the firms in the National Group?

A56. In applying the DCF model, we referenced EPS growth projections from IBES and Value Line,[33] which are the two sources of analysts' estimates that have been customarily relied on by the Commission. The earnings growth projections for each of the firms in the National Group reported by IBES and Value Line are displayed on page 2 of Exhibit No. CLP-104.

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[32] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

[33] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters. We 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. *See, e.g., Answering Testimony of Commission Staff Witness Edward Alvarez III,* Docket Nos. IS11-146-000 & IS10-399-003, consolidated at 16 (Aug. 16, 2011).

Q 57. Some argue that analysts' assessments of growth rates are biased. Do you believe these projections are appropriate for estimating investors' required return using the DCF model?

A57. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (*e.g.*, Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[34]

Q 58. Has the Commission recognized that analysts' growth rate estimates are an important and meaningful guide to investors' expectations?

A58. Yes. The Commission has expressed a clear preference for projected growth rates in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities, and has expressly rejected reliance on other sources. For example, the Commission concluded:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[35]

[34] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).
[35] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) ((footnote omitted).

Q 59. Did you include the "sustainable," br+sv growth rate in applying the DCF model?

A59. No. The sustainable growth rate, which is generally calculated by the formula, g = br+sv,[36] is dependent entirely on the strict assumptions underlying constant growth DCF theory, which are never met in practice. Apart from the disparity from these theoretical assumptions and the practical reality faced by investors, there are other significant shortcomings associated with this approach.

First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[37]

Q 60. What cost of common equity estimates were implied for the National Group using the DCF model?

A60. After combining the dividend yields and respective IBES and Value Line EPS growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit No. CLP-104.

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[36] Where: "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

[37] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

2. Evaluation of DCF Results.

Q 61. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate cost of equity estimates that are extreme outliers?

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

Q 62. How did you evaluate DCF estimates at the low end of the range?

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

The practice of eliminating low-end outliers has been affirmed in numerous proceedings.[38] In its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more. . . ."[39]

Q 63. What else should be considered in evaluating DCF estimates at the low end of the range?

A63. As indicated earlier, while corporate bond yields have declined substantially as the financial crisis has abated, it is generally expected that long-term interest rates will

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

[39] *SoCal Edison*, 131 FERC ¶ 61,020 at P 55.

rise as the economy returns to a more normal pattern of growth. As shown in Table No. Cheyenne Light-2 below, the most recent forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.58% over the period 2014-2018:

TABLE NO. CLP-2
IMPLIED BBB UTILITY BOND YIELD

	2014-18
Projected AA Utility Yield	
IHS Global Insight (a)	6.04%
EIA (b)	5.75%
Average	5.89%
Current BBB - AA Yield Spread (c)	0.69%
Implied Triple-B Utility Yield	**6.58%**

(a) IHS Global Insight, U.S. Economic Outlook at 25 (Nov. 2013)
(b) Energy Information Administration, Annual Energy Outlook 2014, Early Release (Dec. 16, 2013)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Aug. 2013 - Jan. 2014

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb on the order of 165 basis points through 2018.[40] In light of the risk-return tradeoff principle and the test of economic logic applied by the Commission, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities.

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

Q 64. What do you conclude with respect to low-end DCF outliers?

A64. As highlighted on page 3 of Exhibit No. CLP-104, we eliminated low-end DCF estimates ranging from –3.3% to 7.4% as outliers. In light of the risk-return tradeoff principle and the test of economic logic applied by the Commission, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q 65. Did you also exclude DCF values at the high end of the range?

A65. Yes. The upper end of the DCF range for the National Group was set by a cost of equity estimate of 25.6%, which was based on an estimated EPS growth rate of 21.5%. The Commission has repeatedly found cost of equity estimates of 17.7% or greater are extreme, and has also expressed concern regarding the sustainability of growth rates of 13.3% or more. Accordingly, this 25.6% DCF estimate was properly eliminated on the basis of the underlying growth rate.

Q 66. Is there a basis to exclude other DCF estimates at the high end of the range?

A66. No. After excluding the 17.3% high-end value for Otter Tail Corporation, the upper end of the DCF range for the National Group was set by a cost of equity estimate of 15.9% for Black Hills Corp. This 15.9% high-end DCF estimate falls far below the 17.7% threshold established by the Commission. Similarly, the 13.0% growth rate underlying this cost of equity estimate is also 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.

Moreover, the 15.9% value at the upper end of the DCF range is not an "extreme outlier" when compared with the ROE ranges approved by the Commission in the past.[41] While this cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.5% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return. Accordingly, this high-end cost of equity estimate is properly included.

Q 67. What DCF results are implied after excluding illogical low and high-end outliers?

A67. As shown on page 3 of Exhibit No. CLP-104, excluding illogical values resulted in an adjusted range of reasonableness for the National Group of 7.5% to 15.9%, with a midpoint of 11.7%, and median and average values of 9.8%.

D. Risk Premium Approach

Q 68. Briefly describe the risk premium method.

A68. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

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[41] For example, the upper-end of the DCF range approved by the Commission for Tallgrass Transmission, LLC and Prairie Wind Transmission, LLC was 16.9%. *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 at P 78 (2008). The upper end of the DCF range approved by the Commission for Northern Pass Transmission LLC was 16.4%. *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 53 (2011) and Exhibit No. NPT-603.

Q 69. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A69. 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 Cheyenne Light.

Q 70. How did you implement the risk premium approach?

A70. We based our estimates of equity risk premiums for utilities on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. 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. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q 71. Is it circular to consider risk premiums based on authorized returns in assessing a fair ROE for Cheyenne Light?

A71. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches. 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.

Q 72. Has the Commission staff previously recognized the merits of this risk premium approach?

A72. Yes. In a 1992 study, FERC Staff observed that a risk premium approach based on previously authorized ROEs "provides a powerful tool to the Financial Analysis Branch to help it formulate its recommendations on electric utilities' cost of common equity."[42] The Staff noted that:

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

This is exactly the approach we are recommending in this proceeding.

Q 73. How did you calculate the equity risk premiums based on allowed ROEs?

A73. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. CLP-105, the average yield on public utility bonds is subtracted from the average state-authorized ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2013.[43] As shown on page 3 of Exhibit No. CLP-105, over this period, these equity risk premiums for electric utilities averaged 3.53%, and the yield on public utility bonds averaged 8.69%.

Q 74. Is there any capital market relationship that must be considered when implementing the risk premium method?

A74. 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

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

[43] Our analysis encompasses the entire period for which published data is available.

rates.[44] 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. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. 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.

Q 75. Has this inverse relationship been documented in the financial research?

A75. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[45] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[46]

The Commission Staff noted in a study of risk premiums based on allowed ROEs that, "the lower the bond cost the higher the risk premium,"[47] and other regulators

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[44] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Vol. 14 No. 1 (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Vol. 21 No. 2 (Summer 1992).

[45] *Id.*

[46] Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

[47] *Risk Premium Study*, FERC Office of Electric Power Regulation, Division of Electric Power Investigation, Financial Analysis Branch, at 6 (Aug. 4, 1992).

have also recognized that the cost of equity does not move in tandem with interest rates.[48]

Q 76. What are the implications of this relationship under current capital market conditions?

A76. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q 77. What cost of equity is implied by the risk premium method using ROEs authorized by state regulators?

A77. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. CLP-105, the equity risk premium for electric utilities increased approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. CLP-105, with an average six-month historical yield on public utility bonds at January 2014 of 4.83%, this implied a current equity risk premium of 5.17% for electric utilities. Adding this equity risk premium to the average six-month historical yield on triple-B utility bonds implies a current cost of equity of approximately 10.4%.

Q 78. How else did you implement the risk premium approach?

A78. We also 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.

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[48] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf.

Q 79. What cost of equity is implied by the risk premium approach based on ROEs approved by the Commission?

A79. As shown on page 1 of Exhibit No. CLP-106, adding an equity risk premium corresponding to current interest rate levels to the average yield on triple-B utility bonds for the six-months ending January 2014 of 5.22% implies a current cost of equity for electric utilities of approximately 10.6%. In addition, because the Commission routinely references 10-year Treasury bond yields in the context of updating ROE findings, we developed implied equity risk premiums based on this series of government bond yields. Applying the risk premium approach using 10-year Treasury bond yields produces a current cost of equity of approximately 10.7%.

E. Empirical Capital Asset Pricing Model

Q 80. Please describe the ECAPM.

A80. The ECAPM is a variant of the traditional CAPM, which is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the ECAPM 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 ECAPM 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 largely have been rejected by the Commission in the past, our ECAPM analysis specifically incorporated forward-looking expectations that are consistent with the assumptions of this approach.

Q 81. Why is the ECAPM approach an appropriate component of evaluating the cost of equity for Cheyenne Light?

A81. The CAPM approach, which forms the foundation of the ECAPM, 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. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere,[49] the ECAPM provides important insight into investors' required rate of return for utility stocks.

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[49] *See*, *e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," *Financial Practice and Education* (1998).

Q 82. How does the ECAPM approach differ from traditional applications of the CAPM?

A82. Myriad 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 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 finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[50]

As discussed in *New Regulatory Finance*, empirical evidence suggests that the expected return on a security is more accurately 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, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

[50] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

Q 83. How did you apply the empirical version of the CAPM to estimate the cost of common equity?

A83. Application of the ECAPM to the National Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. CLP-107. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend-paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 405 individual firms, current estimates imply an average growth rate over the next five years of 10.1%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.4%. Subtracting a 3.8% risk-free rate based on the six-month average yield on 30-year Treasury bonds at January 2014 produced a market equity risk premium of 8.6%.

Q 84. What was the source of the beta values you used to apply the ECAPM?

A84. We relied on the beta values reported by Value Line, which in our 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.[51]

The fact that investors rely on Value Line betas in evaluating expected returns for utility common stocks provides strong support for this approach.

Q 85. What else should be considered in applying the ECAPM?

A85. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[52]

Because financial research indicates that the ECAPM 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 ECAPM, 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 ECAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[53] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of 6.0% for a company in the first decile (market capitalization less than $254.6 million), to a reduction of 37 basis points for firms in the tenth decile (market

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

[52] Morningstar, *Ibbotson SBBI 2013 Valuation Yearbook* at p. 85 (2013).

[53] *Id.* at Table C-1.

capitalization between $17.6 billion and $626.6 billion). Accordingly, our ECAPM 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.

Q 86. What is the implied ROE for the National Group using the ECAPM approach?

A86. As shown on page 1 of Exhibit No. CLP-107, a forward-looking application of the ECAPM approach resulted in an ROE range of 9.8% to 12.1%, a midpoint of 10.9%, and median and average values of 10.8%. After adjusting for the impact of firm size, the ECAPM approach implied an ROE range of 9.5% to 13.8% for the National Group, with a midpoint of 11.6%, a median of 11.9%, and an average of 11.8%.

F. Flotation Costs

Q 87. What other considerations are relevant in setting the return on equity for a utility?

A87. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q 88. Is there an established mechanism for a utility to recognize equity issuance costs?

A88. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q 89. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A89. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[54]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[55]

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[54] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 323 (2006).

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 4.0% implies a flotation cost adjustment on the order of 14 to 40 basis points. While we did not make an explicit adjustment to the results of our alternative methods to include an adjustment for flotation costs, this is a legitimate consideration that supports the reasonableness of our recommended base ROE for Cheyenne Light in this case.[56]

VI. OTHER ROE BENCHMARKS

Q 90. What is the purpose of this section of your testimony?

A90. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE for Cheyenne Light. Specifically, we tested our recommended ROE for Cheyenne Light based on a risk premium approach using ROEs approved by the Commission for natural gas pipelines, applications of the traditional CAPM, and reference to expected rates of return for electric utilities. Further, the utility quantitative analyses were corroborated against DCF results for a group of extremely low risk non-utility firms.

While our recommended base ROE range and point estimates were not based on the results of these alternative benchmarks, they provide useful guidance in determining whether a proposed ROE is just and reasonable, and in evaluating a point estimate from within the zone of reasonableness. As explained earlier, no single approach provides a fail-safe means to estimate investors' required ROE and it is

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[55] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth at Exhibit GJE-11.1 (Jul. 2, 2004). Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[56] FERC Staff has previously recommended, and the Commission has approved, a flotation cost allowance in establishing the base ROE for an electric transmission utility. *See Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Co.*, 115 FERC ¶ 63,043 at PP 96, 104 (2006), *affirmed in relevant part*, Opinion No. 501, 123 FERC ¶ 61,047 at PP 57, 62-65 (2008), *on reh'g*, Opinion No. 501-A, 144 FERC ¶ 61,132 (2013).

important to consider the results of alternative methods. These additional benchmarks provide additional guidance that is relevant in corroborating the end-result of the primary methods discussed previously.

A. Gas Pipeline ROEs

Q 91. What other benchmark is useful in evaluating a fair ROE for Cheyenne Light?

A91. We have also referenced ROE determinations for natural gas pipelines as an additional means of benchmarking a fair ROE for Cheyenne Light. The Commission has vacillated somewhat on comparing electric utilities to natural gas pipelines when determining ROE. For example, in *Williston Basin*, FERC Staff proposed expanding the proxy group used to estimate the cost of equity for gas pipelines to include utilities with electric utility operations, noting that investors "see a linkage between the risk profile of different types of utilities," and concluding that:

> [G]as pipelines and transmission facilities for electricity have characteristics in common in that both transmit a product with time end weather sensitive demand profiles over rights-of-way that are capital intensive and relatively inflexible. Expanding the gas pipeline proxy group to include publicly-owned companies engaged in other regulated lines of energy-related business will, in my opinion, increase the level of confidence in the reasonableness of the results of my DCF analysis...[57]

Staff's arguments ultimately were persuasive, as the Commission subsequently adopted a proxy group of natural gas pipeline companies that also included firms with substantial electric utility operations.

At the same time, the Commission previously has 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*, the Commission stated that it was not appropriate to consider returns in the

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[57] *Williston Basis Interstate Pipeline Co.*, Docket No. RP00-107-000, Prepared Direct and Answering Testimony of Commission Staff Witness George M Shriver, III at p. 17 (Jun. 7, 2000).

natural gas industry when evaluating electric utilities because "the electric industry is just beginning a significant new phase of its restructuring."[58] Thirteen years have passed since this statement was made, however, and the electric industry and its restructuring have matured. Thus, the Commission's ROE determinations for natural gas pipelines can provide another benchmark that is useful in evaluating a fair ROE for Cheyenne Light.

Q 92. How did you use the information contained in ROE determinations for natural gas pipelines to develop an ROE benchmark for electric utilities?

A92. We 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. Our analysis then examined the historical ROE differential between the natural gas pipeline and electric utility industries, and then applied it to the current allowed ROE for natural gas pipelines to infer a corresponding ROE for electric utilities. As a result, this approach relies directly on the Commission's own determination as to the impact of relative industry risks and current returns.

Allowed ROEs approved by the Commission for natural gas pipelines for the years 2006 through 2013 are presented on pages 4 and 5 of Exhibit No. CLP-108. The average annual ROE, the corresponding average bond yields, and implied risk premiums are summarized on page 3 of Exhibit No. CLP-108. 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. What current cost of equity is implied for an electric utility based on these allowed ROEs?

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[58] *Southern California Edison*, Opinion No. 445, 92 FERC ¶ at 61,261.

Q 93. What current cost of equity is implied for an electric utility based on these allowed ROEs?

A93. As shown on page 1 of Exhibit No. CLP-8, adding an equity risk premium corresponding to current interest rate levels to the average yield on triple-B utility bonds for the six-months ending January 2014 of 5.22% implies a current cost of equity for natural gas pipelines of approximately 12.56%. As shown in the lower portion of page 3 of Exhibit No. NMP-8, the average ROE for natural gas pipelines has exceeded the ROE approved by the Commission for electric utilities by 2.02% between 2006 and 2013. Subtracting this spread from the 12.56% current risk premium estimate for natural gas pipelines results in a current implied ROE for an electric utility of approximately 10.5%, if one were to assume that the risk spread between utilities and pipelines should remain constant. Applying this same approach using 10-year Treasury bond yields produces a current cost of equity of approximately 10.7%.

B. Capital Asset Pricing Model

Q 94. What cost of equity estimates were indicated by the traditional CAPM?

A94. Our application of the traditional CAPM approach was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit No. CLP-109, applying the forward-looking CAPM approach to the firms in the National Group results in a theoretical cost of equity range of 9.0% to 12.0%, or 8.6% to 13.7% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[59]

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[59] The midpoint, median, and average CAPM results based on historical bond yields were 10.5%, 10.3%, and 10.3%, respectively, or 11.2%, 11.4%, and 11.3%, respectively, after adjusting for firm size.

C. Projected Bond Yields

Q 95. Is it appropriate to consider anticipated capital market changes in applying the risk premium, ECAPM, and CAPM approaches?

A95. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, we also applied the risk premium, ECAPM, and CAPM methods based on projections for utility bond yields published by IHS Global Insight, and EIA.

Q 96. What risk premium cost of equity estimates were produced after incorporating forecasted bond yields?

A96. As shown on page 2 of Exhibit No. CLP-105, incorporating a forecasted yield for 2014-2018 and adjusting for changes in interest rates since the study period implied an equity risk premium based on state-authorized ROEs of 4.59% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2014-2018 of 6.58% resulted in an implied cost of equity of approximately 11.2%.

As shown on page 2 of Exhibit No. CLP-106, applying the risk premium approach based on the Commission's allowed ROEs for electric utilities and incorporating average forecasted yields for 2014-2018 implied a cost of equity of approximately 10.8%. Finally, once adjusted for the impact of higher projected bond yields, the risk premium method based on allowed ROEs for natural gas pipelines implied a cost of equity for an electric utility of approximately 10.9% (Exhibit No. CLP-8, page 2).

Q 97. Did you also apply the ECAPM and CAPM using forecasted bond yields?

A97. Yes. As shown on page 2 of Exhibit No. CLP-107, applying the ECAPM using a forecasted Treasury bond yield for 2014-2018 implied an ROE range of 10.0% to 12.1% for the National Group, or 9.7% to 13.8% after adjusting for the impact of relative size.[60]

As shown on page 2 of Exhibit No. CLP-109, incorporating a forecasted Treasury bond yield for 2014-2018 implied a CAPM range of 9.2% to 12.0% for the National Group, or 8.9% to 13.7% after adjusting for the impact of relative size.[61]

D. Expected Earnings Approach

Q 98. What other benchmarks did you develop to evaluate the ROE for Cheyenne Light?

A98. We 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.

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[60] The midpoint of the unadjusted estimates was 11.1%, while the median and average were 10.9%. The midpoint, median, and average values of the adjusted estimates were 11.7%, 12.0%, and 11.9%, respectively.

[61] The midpoint of the unadjusted CAPM results based on projected bond yields was 10.6%, with a median of 10.4% and an average of 10.5%. For the adjusted estimates, the midpoint was 11.3%, with a median of 11.6% and an average of 11.4%.

Q 99. What economic premise underlies the expected earnings approach?

A99. The simple, but fundamental concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital.

Q 100. How is the comparison of opportunity costs typically implemented?

A100. 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. Our application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Moreover, regulators do not set the returns that investors earn in the capital markets—they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q 101. Has the expected earnings approach been recognized as a valid ROE benchmark?

A101. Yes. While this method predominated before the DCF model became fashionable with academic experts, we continue to encounter it around the country.[62] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[63] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[64] as well as sound regulatory economics. We routinely have used the comparable earnings approach, and it has been referenced widely in regulatory decision-making.[65]

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[62] For example, the Virginia State Corporation Commission is required by statute (Code of Virginia § 56-585.1(A)(2)(a) (2013) to consider the earned returns on book value of electric utilities in its region. In orders issued on November 30, 2011 and July 15, 2010 in Docket Nos. PUE-2011-00037 and PUE-2009-00030, the VSCC established the allowed ROE for Appalachian Power Company based solely on the earned returns on book value for a peer group of other electric utilities. Another example is the Idaho Public Utilities Commission, which continues to confirm the relevance of return on book equity evidence.

[63] Parcell, David C., "The Cost of Capital—a Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at 115-116 (2010).

[64] *Id.* at 116.

[65] For example, a NARUC survey reported that 19 regulatory jurisdictions cited the comparable earnings test as a primary method favored in determining the allowed rate of return. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In our experience, while a few commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

Q 102. What rates of return on equity are indicated for electric utilities based on the expected earnings approach?

A102. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.4% over its 2016-2018 forecast horizon.[66] 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. CLP-110. In *Southern California Edison*, the Commission correctly recognized that if the rate of return were based on end-of-year book values, such as those reported by Value Line, it would understate actual returns because of growth in common equity over the year.[67] Accordingly, consistent with the Commission's findings and the theory underlying this approach, an adjustment was incorporated to compute an average rate of return.[68] As shown on Exhibit No. CLP-110, Value Line's projections for the National Group resulted in an ROE range of 8.1% to 13.4% after eliminating outliers.[69]

E. Extremely Low-Risk Non-Utility DCF Model

Q 103. What other proxy group did you consider in evaluating a fair ROE for Cheyenne Light?

A103. Consistent with underlying economic and regulatory standards, we also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. We refer to this group as the "Non-Utility Group."

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[66] The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).

[67] *Southern California Edison,* Opinion No. 445, 92 FERC ¶ at 61,263 n. 38.

[68] Use of an average return in developing the rate of return is well supported. *See*, *e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports*, at 305-306 (2006) (discussing the need to adjust Value Line's end-of-year data, consistent with the Commission's prior findings).

[69] The midpoint, median, and average values were 10.8%, 9.4%, and 9.7%, respectively.

Q 104. Do utilities have to compete with non-regulated firms for capital?

A104. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there is a wide range of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.[70] 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.

Q 105. Is it consistent with *Bluefield* and *Hope* to consider required returns for non-utility companies?

A105. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties."[71] It does not restrict consideration to other utilities. Similarly, *Hope* states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[72]

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[70] 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.

[71] *Bluefield*, 262 U.S. 679.

[72] *Hope*, 320 U.S. 591.

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

In the early applications of the comparable earnings approach, utilities explicitly were eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q 106. Does consideration of the results for the Non-Utility Group make the estimation of the cost of equity using the DCF model more reliable?

A106. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. 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.

Q 107. What criteria did you apply to develop the Non-Utility Group?

A107. Our comparable risk proxy group was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.60 or less; and (5) have investment grade credit ratings from S&P.

Q 108. How do the overall risks of this Non-Utility Group compare to your proxy group of utilities?

A108. Table No. CLP-3 compares the Non-Utility Group with the National Group and Cheyenne Light across four indicators of investment risk:

TABLE NO. CHEYENNE LIGHT-3
COMPARISON OF RISK INDICATORS

		Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A	1	A+	0.59
National Group	BBB	2	B++	0.75
Cheyenne Light	BBB	3	B+	0.90

Taken together, the average credit ratings, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group clearly 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 are greater than those of the firms in the Non-Utility Group.

The eight companies that make up the Non-Utility Group are representative of the very pinnacle of corporate America. These firms, which include household names such as General Mills, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q 109. What were the results of your DCF analysis for the Non-Utility Group?

A109. We applied the DCF model to the Non-Utility Group in exactly the same manner described earlier for the National Group. The results of our DCF analysis for the Non-Utility Group are presented on Exhibit No. CLP-111. As shown on page 3 of Exhibit No. CLP-111, our DCF analysis for the Non-Utility Group resulted in an ROE range of 9.6% to 13.1%, with a midpoint of 11.3%, a median of 11.0%, and an average of 11.1% As discussed above, reference to 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.

Q 110. How can you reconcile these DCF results for the Non-Utility Group against the significantly lower estimates produced for your proxy group of utilities?

A110. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As we documented earlier, the risks that investors associate with the group of non-utility firms—as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and beta -- are lower than the risks investors associate with the National Group. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Cheyenne Light. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector. In fact, considering the prominence of the nine non-utility companies, the diversification afforded by considering multiple industries, and the scrutiny that analysts' afford to these paragons of American industry, the divergence between the DCF estimates for the group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result.

Q 111. Please summarize the results of your alternative ROE benchmarks.

A111. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. CLP-102. The results of these alternative benchmarks reinforce the results of our primary methods and confirm our conclusion that a base ROE of 10.6% for Cheyenne Light is a conservative estimate of investors' required ROE.

F. FERC DCF Model

Q 112. Have you also applied the Commission's DCF approach to the companies in your proxy group?

A112. Yes. While we believe the primary methods described in our testimony provide a superior guide to investors' expectations under current capital market conditions, we have applied the Commission's DCF approach for completeness.

Q 113. How did you calculate the dividend yield component of the DCF model?

A113. Following Commission policy, average low and high indicated dividend yields were calculated for each electric utility during the six months from August 2013 through January 2014. As indicated on Exhibit No. CLP-112, these six-month average low and high historical dividend yields were also increased by one-half of the low and high growth rates discussed subsequently (1 + 0.5*g*) to convert them to adjusted dividend yields.

Q 114. What growth rates are used in the Commission's one-step DCF method for electric utilities?

A114. The one-step DCF method for electric utilities adopted by the Commission employs two growth rates for each firm. The first growth rate is a "sustainable" growth rate calculated by the following formula:

$$g = \mathrm{br} + \mathrm{sv}$$

where: b = expected retention ratio;
r = expected earned rate of return;
s = percent of common equity expected to be issued annually as new common stock;
v = equity accretion ratio.

The second growth rate is the IBES consensus 5-year earnings growth forecast. These two growth rates are combined with the adjusted dividend yields to develop a cost of equity range for each company.

Q 115. How did you calculate the sustainable growth rate?

A115. For each electric utility, the expected retention ratio (b) was calculated based on projected dividends and earnings per share from Value Line for 2013, 2014, and its 2016-2018 forecast horizon. Consistent with the Commission's DCF method, each firm's expected earned rate of return (r) was based on Value Line's end-of-year forecasts.[73] In *Southern California Edison*, the Commission correctly recognized that if the rate of return, or "r" component of the br + sv growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.[74] Accordingly, consistent

[73] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 at P 19 (2008).
[74] *Id.* at P 20 (citing *Southern California Edison*, 92 FERC at 61,263).

with the Commission's findings and the theory underlying this approach to estimating investors' growth expectations, an adjustment was incorporated to compute an average rate of return.[75] Finally, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding over Value Line's forecast horizon, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. The calculation of the sustainable growth rate for each electric utility in the National Proxy Group is shown on Exhibit No. CLP-113.

Q 116. What are investment analysts' projected growth rates for the proxy companies?

A116. The five-year IBES earnings growth forecasts for each electric utility in the proxy group are shown in column (d) on Exhibit No. CLP-112.

Q 117. What were the results of applying the Commission's one-step DCF approach to the proxy group?

A117. As shown on Exhibit No. CLP-112, application of the Commission's DCF model to the National Proxy Group resulted in current cost of equity estimates ranging from -3.0% to 12.0%.

Q 118. What were the results of the Commission's DCF approach after eliminating low-end outliers?

A118. As shown on page 1 of Exhibit No. CLP-112, eliminating low-end DCF estimates that failed to exceed the thresholds based on projected yields for triple-B rated utilities resulted in an adjusted DCF zone of reasonableness of 6.9% to 12.0%. The midpoint of this range is 9.5%, while the median and average are 9.0%.

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[75] Use of an average return in developing the sustainable growth rate is well supported. *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-306, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's findings in *Southern California Edison*. The Commission affirmed the need for this adjustment to "r" in *Bangor Hydro-Elec.* , 122 FERC ¶ 61,265.

Q 119. What other observations do you have regarding the results of the Commission's DCF approach?

A119. As indicated on page 1 of Exhibit No. CLP-112, all but six of the low-end DCF estimates for the National Group were equal to or below the expected yield on public utility bonds. This result suggests that the Commission's DCF approach is currently exhibiting a downward bias, which undermines its ability to accurately reflect investors' true expectations. This provides further support for the use of the primary methods discussed in our testimony, and the need to reference alternative approaches and checks of reasonableness in establishing a fair ROE for CLP.

Q 120. What DCF results are implied if low-end estimates are eliminated based on historical bond yields?

A120. As shown on page 2 of Exhibit No. CLP-112, excluding illogical low-end values based on the Commission's threshold of approximately 100 basis points over historical utility bond yields resulted in an adjusted range of reasonableness for the National Group of 6.4% to 12.0%. The midpoint, median, and average of this range are 9.2%, 8.5% and 8.3%, respectively.

Q 121. Does the 8.5% median value resulting from this DCF analysis meet established regulatory standards?

A121. No. A value of 8.5% is far too low to meet the Supreme Court standards or achieve the established policy goals of promoting investment in FERC-jurisdictional electric utility infrastructure – nor would it be sufficient to maintain CLP's financial integrity. In contrast to the Commission's long-standing support of investment in wholesale utility infrastructure, as noted above, a 8.5% ROE would represent one of the lowest ROEs in the country, well below average returns authorized for other utilities. Adopting an inadequate ROE would undermine CLP's ability to attract and retain capital and could lead investors to view the regulatory framework as unstable, an outcome that would have a long-term, chilling effect on investors' willingness to support future expansion of electric transmission and related infrastructure. The inevitable result of such developments would be an increase in the cost of capital to CLP and other electric utilities. It is only rational for potential investors to consider the regulatory treatment afforded to CLP in evaluating whether or not to commit new capital, and at what cost.

Q 122. Does this conclude your testimony?

A122. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cheyenne Light, Fuel and Power	Docket No. EL14-___-000

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

I, William E. Avera, being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information, and belief.

William E. Avera

Subscribed and sworn to before me, the undersigned notary public, the 3rd day of MARCH, 2014.

Notary Public

My Commission expires on 1/10/15.

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cheyenne Light, Fuel and Power	Docket No. EL14-___-000

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

I, Adrien M. McKenzie, being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information, and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, the undersigned notary public, the 3rd day of March, 2014.

Notary Public

My Commission expires on 09/24/2016.

JENNIFER M LYNCH
NOTARY PUBLIC
STATE OF TEXAS
MY COMM. EXP. 9/24/16

QUALIFICATIONS OF WILLIAM E. AVERA AND ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes our background and experience and contains the details of our qualifications.

Q. DR. AVERA, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC")

Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

Q. MR. MCKENZIE, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. 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. In 1984, I joined FINCAP, Inc. as an Associate. Since that time, 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 previously prepared prefiled testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.

WILLIAM E. AVERA

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fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., Economics, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in almost 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to

Organic Livestock Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

"Economic Perspectives on Texas Water Resources," with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources,* Mary K. Sahs, ed. State Bar of Texas (2012).

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

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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

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. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits in the commercial explosives and chemical industries; development of explanatory models in connection with prudency issues surrounding nuclear generating facilities; and the analysis of avoided cost pricing for cogenerated power.

SUMMARY OF RESULTS

PRIMARY METHODS

DCF	**Range**	**Midpoint**	**Median**	**Average**
IBES / Value Line EPS Growth	7.5% -- 15.9%	11.7%	9.8%	9.8%
Risk Premium				
State ROE (a)	10.1% -- 10.6%	10.4%	10.4%	10.4%
FERC ROE (a)		10.6%	10.6%	10.6%
Empirical CAPM				
Unadjusted	9.8% -- 12.1%	10.9%	10.8%	10.8%
Size Adjusted	9.5% -- 13.8%	11.6%	11.9%	11.8%
Summary - All Methods				
Average		**11.1%**	**10.7%**	**10.7%**
Median		**10.9%**	**10.6%**	**10.6%**

(a) Point estimate value.

CHECKS OF REASONABLENESS

	Range	Midpoint	Median	Average
Risk Premium - FERC Gas Pipelines (a)		10.5%	10.5%	10.5%
CAPM - Historical Bond Yield				
Unadjusted	9.0% -- 12.0%	10.5%	10.3%	10.3%
Size Adjusted	8.6% -- 13.7%	11.2%	11.4%	11.3%
Risk Premium - Projected Bond Yields				
State ROE (a)		11.2%	11.2%	11.2%
FERC ROE (a)	10.8% -- 11.2%	10.8%	10.8%	10.8%
FERC Gas Pipelines (a)		10.9%	10.9%	10.9%
Empirical CAPM - Projected Bond Yields				
Unadjusted	10.0% -- 12.1%	11.1%	10.9%	10.9%
Size Adjusted	9.7% -- 13.8%	11.7%	12.0%	11.9%
CAPM - Projected Bond Yield				
Unadjusted	9.2% -- 12.0%	10.6%	10.4%	10.5%
Size Adjusted	8.9% -- 13.7%	11.3%	11.6%	11.4%
Expected Earnings				
Industry (a, b)		10.4%	10.4%	10.4%
Proxy Group	8.1% -- 13.4%	10.8%	9.4%	9.7%
Non-Utility DCF	9.6% -- 13.1%	11.3%	11.0%	11.1%
Summary - All Methods				
Average		**10.9%**	**10.8%**	**10.8%**
Median		**10.9%**	**10.9%**	**10.9%**

(a) Point estimate value.
(b) Average for Value Line Electric Utility industry group.

RISK MEASURES

			(a)		(b)				(b)
			S&P		**Value Line**				
			Credit		**Safety**	**Financial**			**Market**
	Company	**SYM**	**Rating**		**Rank**	**Strength**		**Beta**	**Cap**
1	ALLETE	ALE	BBB+	8	2	A	3	0.75	$1,960
2	Ameren Corp.	AEE	BBB+	8	3	B++	4	0.80	$8,743
3	American Elec Pwr	AEP	BBB	9	3	B++	4	0.70	$22,550
4	Avista Corp.	AVA	BBB	9	2	A	3	0.75	$1,678
5	Black Hills Corp.	BKH	BBB	9	3	B+	5	0.90	$2,360
6	CMS Energy Corp.	CMS	BBB	9	3	B+	5	0.70	$7,057
7	DTE Energy Co.	DTE	BBB+	8	2	B++	4	0.80	$11,612
8	Duke Energy Corp.	DUK	BBB+	8	2	A	3	0.65	$47,916
9	Edison International	EIX	BBB-	10	2	B++	4	0.75	$14,707
10	El Paso Electric	EE	BBB	9	2	B++	4	0.65	$1,421
11	Empire District Elec	EDE	BBB	9	2	B++	4	0.70	$962
12	Entergy Corp.	ETR	BBB	9	3	B++	4	0.70	$10,791
13	Exelon Corp.	EXC	BBB	9	3	B++	4	0.75	$23,162
14	Great Plains Energy	GXP	BBB	9	3	B+	5	0.85	$3,760
15	Hawaiian Elec.	HE	BBB-	10	2	B++	4	0.80	$2,589
16	IDACORP, Inc.	IDA	BBB	9	2	B++	4	0.75	$2,626
17	NorthWestern Corp.	NWE	BBB	9	3	B+	5	0.70	$1,666
18	Otter Tail Corp.	OTTR	BBB	9	3	B+	5	0.95	$1,042
19	Pepco Holdings	POM	BBB+	8	3	B	6	0.75	$4,722
20	PG&E Corp.	PCG	BBB	9	3	B+	5	0.60	$17,975
21	PNM Resources	PNM	BBB	9	3	B	6	0.95	$1,915
22	Portland General Elec.	POR	BBB	9	2	B++	4	0.75	$2,321
23	PPL Corp.	PPL	BBB	9	3	B++	4	0.65	$18,718
24	SCANA Corp.	SCG	BBB+	8	2	B++	4	0.70	$6,452
25	Sempra Energy	SRE	BBB+	8	2	A	3	0.75	$22,053
26	UIL Holdings	UIL	BBB	9	2	B++	4	0.80	$1,925
27	Westar Energy	WR	BBB	9	2	B++	4	0.75	$4,188
			BBB	9	**2**	**B++**	4	**0.75**	**$9,143**

(a) Corporate credit rating from www.standardandpoors.com (retrieved Feb. 12, 2014).
(b) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	ALLETE	$ 49.51	$ 1.96	4.0%
2	Ameren Corp.	$ 36.21	$ 1.60	4.4%
3	American Elec Pwr	$ 46.83	$ 2.02	4.3%
4	Avista Corp.	$ 28.20	$ 1.28	4.5%
5	Black Hills Corp.	$ 53.06	$ 1.56	2.9%
6	CMS Energy Corp.	$ 26.70	$ 1.08	4.0%
7	DTE Energy Co.	$ 66.16	$ 2.69	4.1%
8	Duke Energy Corp.	$ 68.59	$ 3.15	4.6%
9	Edison International	$ 46.45	$ 1.45	3.1%
10	El Paso Electric	$ 35.35	$ 1.11	3.1%
11	Empire District Elec	$ 22.66	$ 1.03	4.5%
12	Entergy Corp.	$ 61.77	$ 3.32	5.4%
13	Exelon Corp.	$ 27.50	$ 1.24	4.5%
14	Great Plains Energy	$ 24.31	$ 0.94	3.9%
15	Hawaiian Elec.	$ 26.00	$ 1.24	4.8%
16	IDACORP, Inc.	$ 52.15	$ 1.72	3.3%
17	NorthWestern Corp.	$ 43.72	$ 1.56	3.6%
18	Otter Tail Corp.	$ 28.77	$ 1.19	4.1%
19	Pepco Holdings	$ 18.90	$ 1.08	5.7%
20	PG&E Corp.	$ 40.61	$ 1.82	4.5%
21	PNM Resources	$ 24.24	$ 0.74	3.1%
22	Portland General Elec.	$ 29.84	$ 1.12	3.8%
23	PPL Corp.	$ 29.89	$ 1.49	5.0%
24	SCANA Corp.	$ 46.62	$ 2.08	4.5%
25	Sempra Energy	$ 90.44	$ 2.64	2.9%
26	UIL Holdings	$ 38.19	$ 1.73	4.5%
27	Westar Energy	$ 32.45	$ 1.39	4.3%
	Average			**4.1%**

(a) Average of closing prices for 30 trading days ended Jan. 31, 2014.
(b) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).

GROWTH RATES

		Earnings Growth	
		(a)	(b)
	Company	**IBES**	**V Line**
1	ALLETE	6.0%	6.0%
2	Ameren Corp.	2.0%	-0.5%
3	American Elec Pwr	4.2%	5.5%
4	Avista Corp.	5.0%	6.5%
5	Black Hills Corp.	4.0%	13.0%
6	CMS Energy Corp.	6.1%	5.5%
7	DTE Energy Co.	4.9%	5.0%
8	Duke Energy Corp.	3.3%	4.0%
9	Edison International	-1.0%	1.5%
10	El Paso Electric	3.7%	1.5%
11	Empire District Elec	3.0%	5.0%
12	Entergy Corp.	-8.6%	-3.5%
13	Exelon Corp.	-7.2%	-5.5%
14	Great Plains Energy	7.0%	6.5%
15	Hawaiian Elec.	2.4%	3.5%
16	IDACORP, Inc.	4.0%	2.0%
17	NorthWestern Corp.	7.0%	4.5%
18	Otter Tail Corp.	6.0%	21.5%
19	Pepco Holdings	4.2%	6.0%
20	PG&E Corp.	-1.8%	2.5%
21	PNM Resources	5.9%	12.0%
22	Portland General Elec.	6.7%	3.5%
23	PPL Corp.	-2.4%	0.0%
24	SCANA Corp.	4.8%	4.5%
25	Sempra Energy	5.6%	4.5%
26	UIL Holdings	7.1%	4.0%
27	Westar Energy	2.9%	6.0%

(a) www.finance.yahoo.com (retrieved Feb. 4, 2014).
(b) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).

COST OF EQUITY ESTIMATES

	Company	(a) IBES	(a) V Line	Low		High	Avg.
1	ALLETE	10.0%	10.0%	10.0%	--	10.0%	10.0%
2	Ameren Corp.	6.4%	3.9%	3.9%	--	6.4%	--
3	American Elec Pwr	8.5%	9.8%	8.5%	--	9.8%	9.2%
4	Avista Corp.	9.5%	11.0%	9.5%	--	11.0%	10.3%
5	Black Hills Corp.	6.9%	15.9%	6.9%	--	15.9%	--
6	CMS Energy Corp.	10.1%	9.5%	9.5%	--	10.1%	9.8%
7	DTE Energy Co.	9.0%	9.1%	9.0%	--	9.1%	9.0%
8	Duke Energy Corp.	7.9%	8.6%	7.9%	--	8.6%	8.2%
9	Edison International	2.2%	4.6%	2.2%	--	4.6%	--
10	El Paso Electric	6.8%	4.6%	4.6%	--	6.8%	--
11	Empire District Elec	7.5%	9.5%	7.5%	--	9.5%	8.5%
12	Entergy Corp.	-3.3%	1.9%	-3.3%	--	1.9%	--
13	Exelon Corp.	-2.7%	-1.0%	-2.7%	--	-1.0%	--
14	Great Plains Energy	10.9%	10.4%	10.4%	--	10.9%	10.6%
15	Hawaiian Elec.	7.2%	8.3%	7.2%	--	8.3%	--
16	IDACORP, Inc.	7.3%	5.3%	5.3%	--	7.3%	--
17	NorthWestern Corp.	10.6%	8.1%	8.1%	--	10.6%	9.3%
18	Otter Tail Corp.	10.1%	25.6%	10.1%	--	25.6%	--
19	Pepco Holdings	9.9%	11.7%	9.9%	--	11.7%	10.8%
20	PG&E Corp.	2.7%	7.0%	2.7%	--	7.0%	--
21	PNM Resources	8.9%	15.1%	8.9%	--	15.1%	12.0%
22	Portland General Elec.	10.5%	7.3%	7.3%	--	10.5%	--
23	PPL Corp.	2.6%	5.0%	2.6%	--	5.0%	--
24	SCANA Corp.	9.2%	9.0%	9.0%	--	9.2%	9.1%
25	Sempra Energy	8.5%	7.4%	7.4%	--	8.5%	--
26	UIL Holdings	11.6%	8.5%	8.5%	--	11.6%	10.1%
27	Westar Energy	7.2%	10.3%	7.2%	--	10.3%	--
	Range of Reasonableness			**-3.3%**	**--**	**25.6%**	
	Adjusted Range of Reasonableness (a)			**7.5%**	**--**	**15.9%**	
	Midpoint				**11.7%**		
	Median						**9.8%**
	Average						**9.8%**

(a) Excludes highlighted figures.

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield - Historical	4.83%
	Change in Bond Yield	-3.86%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.64%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**5.17%**

Implied Cost of Equity

BBB Utility Bond Yield - Historical	5.22%
Adjusted Equity Risk Premium	5.17%
Risk Premium Cost of Equity	**10.39%**

(a) Exhibit No. CLP-105, page 3.
(b) Six-month average yield for Aug. 2013 - Jan. 2014 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) Exhibit No. CLP-105, page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Projected Average Utility Bond Yield 2014-2018	6.19%
	Change in Bond Yield	-2.50%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.06%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**4.59%**

Implied Cost of Equity

(b)	Projected BBB Utility Bond Yield 2014-2018	6.58%
	Adjusted Equity Risk Premium	4.59%
	Risk Premium Cost of Equity	**11.17%**

(a) Exhibit No. CLP-105, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (Nov. 2013); Energy Information Administration, Annual Energy Outlook 2014, Early Release (Dec. 16, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. CLP-105, page 4.

IMPLIED RISK PREMIUM

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
Average	12.21%	8.69%	3.53%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates;*UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

RISK PREMIUM - STATE ROE

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.918651654
R Square	0.843920861
Adjusted R Square	0.839813516
Standard Error	0.00513785
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005423795	0.005423795	205.4662334	6.57062E-17
Residual	38	0.001003105	2.63975E-05		
Total	39	0.0064269			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072131874	0.002698047	26.73484383	3.01556E-26	0.066669963	0.077593786	0.066669963	0.077593786
X Variable 1	-0.424559652	0.02961887	-14.33409339	6.57062E-17	-0.484519922	-0.364599382	-0.484519922	-0.364599382

HISTORICAL BOND YIELDS

		Utility Bonds	10-Yr Treasury Bonds
	Current Equity Risk Premium		
(a)	Avg. Yield Over Study Period	6.50%	3.33%
(b)	Average Bond Yield - Historical	5.22%	2.78%
	Change in Bond Yield	-1.28%	-0.55%
(c)	Risk Premium/Interest Rate Relationship	-0.8597	-0.8479
	Adjustment to Average Risk Premium	1.10%	0.47%
(a)	Average Risk Premium over Study Period	4.25%	7.42%
	Adjusted Risk Premium	**5.36%**	**7.89%**
	Implied Cost of Equity		
(d)	Average Bond Yield - Historical	5.22%	2.78%
	Adjusted Equity Risk Premium	5.36%	7.89%
	Risk Premium Cost of Equity	**10.58%**	**10.67%**

(a) See Exhibit No. CLP-106, p. 3.
(b) Average of monthly yields from Aug. 2013 - Jan. 2014 based on data from from Moody's Investors Service, www.credittrends.com and the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(c) See Exhibit No. CLP-106, p. 5.
(d) See (b), above. Historical utility bond yield reflects average yield for triple-B rating category.

PROJECTED BOND YIELDS

		Utility Bonds	10-Yr Treasury Bonds
	Current Equity Risk Premium		
(a)	Avg. Yield Over Study Period	6.50%	3.33%
(b)	Bond Yield - Projected 2014-2018	6.58%	3.68%
	Change in Bond Yield	0.08%	0.34%
(c)	Risk Premium/Interest Rate Relationship	-0.8597	-0.8479
	Adjustment to Average Risk Premium	-0.07%	-0.29%
(a)	Average Risk Premium over Study Period	4.25%	7.42%
	Adjusted Risk Premium	**4.19%**	**7.13%**
	Implied Cost of Equity		
(d)	Bond Yield - Projected 2014-2018	6.58%	3.68%
	Adjusted Equity Risk Premium	4.19%	7.13%
	Risk Premium Cost of Equity	**10.77%**	**10.81%**

(a) See Exhibit No. CLP-106, p. 3.
(b) Based on data from , , Energy Information Administration, Annual Energy Outlook 2014, Early Release (Dec. 16, 2013), Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013), Moody's Investors Service at www.credittrends.com, and Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(c) See Exhibit No. CLP-106, p. 5.
(d) See (b), above. Projected utility bond yield reflects average for triple-B rating category.

IMPLIED RISK PREMIUM

				(a)		(b)	
				BBB Utility		**10-Year Treasury**	
			Base	**Bond**	**Risk**	**Bond**	**Risk**
Date	**Utility**	**Docket No.**	**ROE**	**Yield**	**Premium**	**Yield**	**Premium**
Apr-06	Baltimore Gas & Elec.	ER05-515	10.80%	6.22%	4.58%	4.62%	6.18%
Apr-06	Baltimore Gas & Elec.	ER05-515	11.30%	6.22%	5.08%	4.62%	6.68%
Aug-06	Westar Energy Inc.	ER05-925	10.80%	6.51%	4.29%	4.98%	5.82%
Oct-06	Bangor Hydro-Elec. Co.	ER04-157	11.14%	6.46%	4.68%	4.94%	6.20%
Apr-07	San Diego Gas & Elec.	ER07-284	11.35%	6.12%	5.24%	4.65%	6.70%
Jul-07	Idaho Power Co.	ER06-787	10.70%	6.28%	4.42%	4.80%	5.90%
Jul-07	Wisconsin Elec. Pwr. Co.	ER06-1320	11.00%	6.28%	4.72%	4.80%	6.20%
Oct-07	Commonwealth Edison Co.	ER07-583	11.00%	6.43%	4.57%	4.76%	6.24%
Nov-07	Duquesne Light Co.	EL06-109	10.90%	6.44%	4.46%	4.66%	6.24%
Nov-07	Pepco Holdings, Inc.	ER08-10	10.80%	6.44%	4.36%	4.66%	6.14%
Feb-08	Atlantic Path 15	ER08-374	10.65%	6.42%	4.23%	4.13%	6.52%
Mar-08	Westar Energy Inc.	ER08-396	10.80%	6.46%	4.34%	3.96%	6.84%
Mar-08	Startrans IO, LLC	ER08-413	10.65%	6.46%	4.19%	3.96%	6.69%
Apr-08	NSTAR Elec. Co.	ER07-549	10.90%	6.54%	4.36%	3.82%	7.08%
Apr-08	Southwestern Public Service	EL05-19	9.33%	6.54%	2.79%	3.82%	5.51%
Apr-08	Trans-Allegheny	ER07-562	11.20%	6.54%	4.66%	3.82%	7.38%
Apr-08	Virginia Elec. & Power Co.	ER08-92	10.90%	6.54%	4.36%	3.82%	7.08%
Jul-08	Arizona Public Service Co.	ER07-1142	10.75%	6.80%	3.95%	3.82%	6.93%
Jul-08	So. Cal Edison (c)	ER08-375	9.54%	6.80%	2.74%	3.82%	5.72%
Aug-08	Virginia Elec. & Power Co.	ER08-1207	10.90%	6.86%	4.04%	3.85%	7.06%
Aug-08	Pepco Holdings, Inc.	ER08-686	11.30%	6.86%	4.44%	3.85%	7.46%
Aug-08	New England Pwr. Co.	ER07-694	11.14%	6.86%	4.28%	3.85%	7.30%
Sep-08	Public Service Elec. & Gas	ER08-1233	11.18%	6.94%	4.24%	3.88%	7.31%
Oct-08	Pepco Holdings, Inc.	ER08-1423	10.80%	7.23%	3.57%	3.90%	6.90%
Oct-08	Central Maine Power Co.	EL08-74	11.14%	7.23%	3.91%	3.90%	7.24%
Oct-08	Duquesne Light Co.	ER08-1402	10.90%	7.23%	3.67%	3.90%	7.00%
Nov-08	Northeast Utils Service Co.	ER08-1548	11.14%	7.60%	3.54%	3.84%	7.30%
Nov-08	Central Maine Power Co.	EL08-77	11.14%	7.60%	3.54%	3.84%	7.30%
Dec-08	NSTAR Elec. Co.	ER09-14	11.14%	7.80%	3.34%	3.56%	7.58%
Dec-08	Tallgrass / Prairie Wind	ER09-35/36	10.80%	7.80%	3.00%	3.56%	7.24%
Feb-09	Black Hills Power Co.	ER08-1584	10.80%	8.08%	2.72%	3.14%	7.66%
Mar-09	AEP - SPP Zone	ER07-1069	10.70%	8.22%	2.48%	3.00%	7.71%
Mar-09	Pioneer Transmission	ER09-75	10.54%	8.22%	2.32%	3.00%	7.55%
Mar-09	ITC Great Plains	ER09-548	10.66%	8.22%	2.44%	3.00%	7.67%
Mar-09	Public Service Elec. & Gas	ER09-249	11.18%	8.22%	2.96%	3.00%	8.19%
Apr-09	Green Power Express	ER09-681	10.78%	8.13%	2.65%	2.85%	7.93%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.10%	7.93%	3.17%	2.81%	8.29%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.14%	7.93%	3.21%	2.81%	8.33%
May-09	PPL Elec. Utilities Corp.	ER08-1457	11.18%	7.93%	3.25%	2.81%	8.37%
May-09	Baltimore Gas & Elec.	ER09-745	11.30%	7.93%	3.37%	2.81%	8.49%
May-09	Niagara Mohawk Pwr. Co.	ER08-552	11.00%	7.93%	3.07%	2.81%	8.19%

IMPLIED RISK PREMIUM

				(a)		(b)	
				BBB Utility		**10-Year Treasury**	
			Base	**Bond**	**Risk**	**Bond**	**Risk**
Date	**Utility**	**Docket No.**	**ROE**	**Yield**	**Premium**	**Yield**	**Premium**
May-09	Oklahoma Gas & Elec.	ER08-281	10.60%	7.93%	2.67%	2.81%	7.79%
Jun-09	Kentucky Utilities Co.	ER08-1588	11.00%	7.79%	3.21%	3.03%	7.98%
Aug-09	Westar Energy Inc.	ER07-1344	10.80%	7.39%	3.41%	3.32%	7.48%
Aug-09	So. Cal Edison (d)	ER09-187	10.04%	7.39%	2.65%	3.32%	6.72%
Oct-09	Xcel Energy	ER08-313	10.77%	6.76%	4.01%	3.49%	7.28%
Nov-09	National Grid Generation LLC	ER09-628	10.75%	6.50%	4.25%	3.51%	7.24%
Nov-09	Westar Energy Inc.	ER09-1762	10.80%	6.50%	4.30%	3.51%	7.29%
May-10	AEP - PJM Zone	ER08-1329	10.99%	6.21%	4.79%	3.67%	7.32%
Sep-10	So. Cal Edison (e)	ER10-160	10.33%	5.93%	4.40%	3.14%	7.19%
Oct-10	AEP Transco	ER10-355	10.99%	5.84%	5.16%	2.92%	8.07%
Oct-10	KCPL	ER10-230	10.60%	5.84%	4.77%	2.92%	7.68%
Dec-10	So. Cal Edison	ER11-1952	10.30%	5.76%	4.54%	2.83%	7.48%
Feb-11	Northern Pass Transmission	ER11-2377	10.40%	5.87%	4.53%	3.04%	7.37%
May-11	Ameren	EL10-80	12.38%	5.98%	6.40%	3.38%	9.00%
May-11	Atlantic Grid Operations	EL11-13	10.09%	5.98%	4.11%	3.38%	6.71%
Jun-11	Xcel Energy	ER10-1377	10.40%	5.92%	4.48%	3.34%	7.07%
Jun-11	PJM & PSE&G	ER11-3352	11.18%	5.92%	5.26%	3.34%	7.85%
Jun-11	South Carolina Elec. & Gas	ER10-516	10.55%	5.92%	4.63%	3.34%	7.22%
Oct-11	Duke Energy Carolinas	ER11-2895	10.20%	5.45%	4.75%	2.60%	7.60%
Oct-11	RITELine	ER11-4069	9.93%	5.45%	4.48%	2.60%	7.33%
Nov-11	PATH	ER08-386	10.40%	5.31%	5.09%	2.41%	7.99%
Dec-11	PJM & PSE&G	ER12-296	11.18%	5.21%	5.97%	2.24%	8.94%
May-12	Public Service Colorado	ER11-2853	10.10%	5.06%	5.04%	1.99%	8.11%
May-12	Public Service Colorado	ER11-2853	10.40%	5.06%	5.34%	1.99%	8.41%
Jun-12	DATC Midwest Holdings	ER12-1593	12.38%	5.03%	7.35%	1.99%	10.39%
Mar-13	Duke Energy Ohio	ER12-91	10.88%	4.61%	6.27%	1.83%	9.05%
May-13	Puget Sound Energy	ER12-778	9.80%	4.64%	5.16%	1.88%	7.92%
May-13	PacifiCorp	ER11-3643	9.80%	4.64%	5.16%	1.88%	7.92%
May-13	Entergy Arkansas	ER11-2560	10.20%	4.64%	5.56%	1.88%	8.32%
May-13	Transource Missouri	ER12-1593	9.80%	4.64%	5.16%	1.88%	7.92%
Jun-13	ITC Holdings	ER12-2681	12.38%	4.72%	7.66%	1.97%	10.41%
Aug-13	Maine Public Service Co.	ER12-1650	9.75%	4.91%	4.85%	2.21%	7.54%
Nov-13	So. Cal Edison	ER11-3697	9.30%	5.22%	4.09%	2.63%	6.67%
	Average			**6.50%**	**4.25%**	**3.33%**	**7.42%**

(a) Moody's Investors Service, www.credittrends.com.
(b) Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(c) Order issued April 15, 2010, with ROE applied for March 1, 2008 through December 31, 2008.
(d) Order issued April 19, 2012, with ROE applied for January 1, 2009 through May 31, 2010.
(e) Order issued April 19, 2012, with ROE applied for June 1, 2010 through December 31, 2010.

REGRESSION RESULTS

SUMMARY OUTPUT -- BBB UTILITY BONDS

Regression Statistics	
Multiple R	0.848244762
R Square	0.719519177
Adjusted R Square	0.71562361
Standard Error	0.005704257
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006009936	0.006009936	184.7020416	1.46386E-21
Residual	72	0.002342775	3.25385E-05		
Total	73	0.008352712			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.098433976	0.004166253	23.62649811	1.20177E-35	0.090128707	0.106739245	0.090128707	0.106739245
X Variable 1	-0.859662404	0.063254596	-13.59051293	1.46386E-21	-0.985758058	-0.733566751	-0.985758058	-0.733566751

SUMMARY OUTPUT -- 10-YEAR TREASURY BONDS

Regression Statistics	
Multiple R	0.781598521
R Square	0.610896249
Adjusted R Square	0.60549203
Standard Error	0.005752426
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00374056	0.00374056	113.0406216	2.07718E-16
Residual	72	0.002382509	3.30904E-05		
Total	73	0.00612307			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.102489752	0.002740315	37.400723	6.52008E-49	0.097027037	0.107952466	0.097027037	0.107952466
X Variable 1	-0.847866617	0.07974625	-10.63205632	2.07718E-16	-1.006837761	-0.688895473	-1.006837761	-0.688895473

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$1,960	1.70%	12.5%
2	Ameren Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	11.1%	$8,743	0.76%	11.9%
3	American Elec Pwr	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$22,550	-0.37%	10.1%
4	Avista Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$1,678	1.72%	12.5%
5	Black Hills Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.90	75%	5.8%	8.0%	11.8%	$2,360	1.70%	13.5%
6	CMS Energy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$7,057	0.92%	11.4%
7	DTE Energy Co.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	11.1%	$11,612	0.76%	11.9%
8	Duke Energy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	10.1%	$47,916	-0.37%	9.8%
9	Edison International	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$14,707	0.76%	11.5%
10	El Paso Electric	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	10.1%	$1,421	1.72%	11.9%
11	Empire District Elec	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$962	1.73%	12.2%
12	Entergy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$10,791	0.76%	11.2%
13	Exelon Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$23,162	-0.37%	10.4%
14	Great Plains Energy	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.85	75%	5.5%	7.6%	11.4%	$3,760	1.14%	12.6%
15	Hawaiian Elec.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	11.1%	$2,589	1.70%	12.8%
16	IDACORP, Inc.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$2,626	1.70%	12.5%
17	NorthWestern Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$1,666	1.72%	12.2%
18	Otter Tail Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.95	75%	6.1%	8.3%	12.1%	$1,042	1.73%	13.8%
19	Pepco Holdings	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$4,722	0.92%	11.7%
20	PG&E Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.60	75%	3.9%	6.0%	9.8%	$17,975	-0.37%	9.5%
21	PNM Resources	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.95	75%	6.1%	8.3%	12.1%	$1,915	1.70%	13.8%
22	Portland General Elec.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$2,321	1.70%	12.5%
23	PPL Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	10.1%	$18,718	-0.37%	9.8%
24	SCANA Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	10.5%	$6,452	0.92%	11.4%
25	Sempra Energy	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$22,053	-0.37%	10.4%
26	UIL Holdings	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	11.1%	$1,925	1.70%	12.8%
27	Westar Energy	2.3%	10.1%	12.4%	3.8%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	10.8%	$4,188	1.14%	11.9%
	Range of Reasonableness												**9.8% -- 12.1%**			**9.5% -- 13.8%**
	Midpoint (h)												**10.9%**			**11.6%**
	Median												**10.8%**			**11.9%**
	Average												**10.8%**			**11.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jan. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jan. 13, 2014).
(c) Six-month average yield on 30-year Treasury bonds for Aug. 2013 - Jan. 2014 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) See Exhibit No. CLP-103.
(f) www.valueline.com (retrieved Jan. 17, 2014).
(g) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).
(h) Average of low and high values.

ECAPM - PROJECTED BOND YIELD

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)			2014-18	Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	ALLETE	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$1,960	1.70%	12.6%
2	Ameren Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.80	75%	4.7%	6.7%	11.2%	$8,743	0.76%	12.0%
3	American Elec Pwr	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.70	75%	4.1%	6.1%	10.6%	$22,550	-0.37%	10.3%
4	Avista Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$1,678	1.72%	12.6%
5	Black Hills Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.90	75%	5.3%	7.3%	11.8%	$2,360	1.70%	13.5%
6	CMS Energy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.70	75%	4.1%	6.1%	10.6%	$7,057	0.92%	11.5%
7	DTE Energy Co.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.80	75%	4.7%	6.7%	11.2%	$11,612	0.76%	12.0%
8	Duke Energy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.65	75%	3.9%	5.8%	10.3%	$47,916	-0.37%	10.0%
9	Edison International	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$14,707	0.76%	11.7%
10	El Paso Electric	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.65	75%	3.9%	5.8%	10.3%	$1,421	1.72%	12.0%
11	Empire District Elec	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.70	75%	4.1%	6.1%	10.6%	$962	1.73%	12.4%
12	Entergy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.70	75%	4.1%	6.1%	10.6%	$10,791	0.76%	11.4%
13	Exelon Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$23,162	-0.37%	10.5%
14	Great Plains Energy	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.85	75%	5.0%	7.0%	11.5%	$3,760	1.14%	12.7%
15	Hawaiian Elec.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.80	75%	4.7%	6.7%	11.2%	$2,589	1.70%	12.9%
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19	Pepco Holdings	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$4,722	0.92%	11.8%
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21	PNM Resources	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.95	75%	5.6%	7.6%	12.1%	$1,915	1.70%	13.8%
22	Portland General Elec.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$2,321	1.70%	12.6%
23	PPL Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.65	75%	3.9%	5.8%	10.3%	$18,718	-0.37%	10.0%
24	SCANA Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.70	75%	4.1%	6.1%	10.6%	$6,452	0.92%	11.5%
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26	UIL Holdings	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.80	75%	4.7%	6.7%	11.2%	$1,925	1.70%	12.9%
27	Westar Energy	2.3%	10.1%	12.4%	4.5%	7.9%	25%	2.0%	0.75	75%	4.4%	6.4%	10.9%	$4,188	1.14%	12.1%
	Range of Reasonableness												**10.0% -- 12.1%**			**9.7% -- 13.8%**
	Midpoint (h)												**11.1%**			**11.7%**
	Median												**10.9%**			**12.0%**
	Average												**10.9%**			**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jan. 8, 2014).

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jan. 13, 2014).

(c) Average yield on 30-year Treasury bonds for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (Nov. 2013); & .

(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).

(e) See Exhibit No. CLP-103.

(f) www.valueline.com (retrieved Jan. 17, 2014).

(g) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013)

(h) Average of low and high values.

HISTORICAL BOND YIELDS

	Utility Bonds	10-Yr Treasury Bonds
Current Equity Risk Premium		
(a) Avg. Yield Over Study Period	6.04%	3.31%
(b) Average Bond Yield - Historical	5.22%	2.78%
Change in Bond Yield	-0.82%	-0.53%
(c) Risk Premium/Interest Rate Relationship	-0.7244	-0.8179
Adjustment to Average Risk Premium	0.59%	0.44%
(a) Average Risk Premium over Study Period	6.74%	9.47%
Adjusted Risk Premium	**7.34%**	**9.91%**
Implied Cost of Equity - Gas Pipelines		
(d) Average Bond Yield - Historical	5.22%	2.78%
Adjusted Equity Risk Premium	7.34%	9.91%
Risk Premium Cost of Equity	**12.56%**	**12.69%**
Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.02%**	**2.02%**
Implied Electric ROE	**10.54%**	**10.67%**

(a) See Exhibit No. CLP-108, p. 3.
(b) Average of monthly yields from Aug. 2013 - Jan. 2014 based on data from from Moody's Investors Service, www.credittrends.com and the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(c) See Exhibit No. CLP-108, p. 6.
(d) See (b), above. Historical utility bond yield reflects average for triple-B rating category.

PROJECTED BOND YIELDS

		Utility Bonds	10-Yr Treasury Bonds
Current Equity Risk Premium			
(a)	Avg. Yield Over Study Period	6.04%	3.31%
(b)	Bond Yield - Projected 2014-2018	6.58%	3.68%
	Change in Bond Yield	0.54%	0.36%
(c)	Risk Premium/Interest Rate Relationship	-0.7244	-0.8179
	Adjustment to Average Risk Premium	-0.39%	-0.30%
(a)	Average Risk Premium over Study Period	6.74%	9.47%
	Adjusted Risk Premium	**6.35%**	**9.17%**
Implied Cost of Equity			
(d)	Bond Yield - Projected 2014-2018	6.58%	3.68%
	Adjusted Equity Risk Premium	6.35%	9.17%
	Risk Premium Cost of Equity	**12.93%**	**12.85%**
Less: Average Spread / Gas Pipeline - Electric Utility ROE		**2.02%**	**2.02%**
Implied Electric ROE		**10.92%**	**10.83%**

(a) See Exhibit No. CLP-108, p. 3.

(b) Based on data from , , Energy Information Administration, Annual Energy Outlook 2014, Early Release (Dec. 16, 2013), Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013), Moody's Investors Service at www.credittrends.com, and Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.

(c) See Exhibit No. CLP-108, p. 6.

(d) See (b), above. Projected utility bond yield reflects average for triple-B rating category.

IMPLIED RISK PREMIUM

Year	(a) Average Pipeline ROE	BBB Utility (b) Bond Yield	BBB Utility Risk Premium	10-Year Treasury (c) Bond Yield	10-Year Treasury Risk Premium
2006	12.86%	6.32%	6.54%	4.79%	8.07%
2007	13.07%	6.33%	6.74%	4.63%	8.44%
2008	12.79%	7.25%	5.55%	3.67%	9.12%
2009	13.18%	7.06%	6.12%	3.26%	9.92%
2010	12.61%	5.98%	6.63%	3.21%	9.40%
2011	13.31%	5.57%	7.74%	2.79%	10.52%
2012	12.65%	4.86%	7.79%	1.80%	10.84%
2013	11.79%	4.98%	6.81%	2.35%	9.44%
		6.04%	6.74%	3.31%	9.47%

Year	Average Pipeline ROE	(d) Average Electric Base ROE	Spread
2006	12.86%	11.01%	1.85%
2007	13.07%	10.96%	2.11%
2008	12.79%	10.82%	1.98%
2009	13.18%	10.84%	2.34%
2010	12.61%	10.64%	1.97%
2011	13.31%	10.67%	2.64%
2012	12.65%	10.96%	1.69%
2013	11.79%	10.24%	1.55%
			2.02%

(a) Exhibit No. CLP-108, pp. 2-3.
(b) Moody's Investors Service, www.credittrends.com.
(c) Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(d) Exhibit No. CLP-106, pp. 3-4.

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Feb-06	RP06-63	Guardian Pipeline LLC.	14.00%
Mar-06	CP05-372	Midwestern Gas Transmission Co.	13.00%
Mar-06	RP04-274	Kern River Gas Transmission Co.	9.34%
May-06	CP02-378	Cameron Interstate Pipeline, LLC	14.00%
Jun-06	CP04-411	Crown Landing LLC; Texas Eastern Transmission, LP	12.75%
Jun-06	CP05-83	Port Arthur Pipeline, L.P.	14.00%
Jun-06	CP05-130	Dominion Cove Point LNG	13.00%
Jun-06	CP05-360	Creole Trail LNG, L.P.	14.00%
Jul-06	CP06-71	Carolina Gas Transmission Corp.; SCG Pipeline, Inc.	12.70%
Jul-06	CP06-5	Empire State Pipeline	12.50%
Sep-06	CP06-354	Rockies Express Pipeline LLC	13.00%
Sep-06	CP06-167	Questar Overthrust Pipeline Co.	11.75%
Oct-06	RP04-274	Kern River Gas Transmission Co.	11.20%
Oct-06	CP06-61	North Baja Pipeline, LLC	14.00%
Dec-06	CP06-5	Empire Pipeline, Inc.	12.50%
Dec-06	CP98-150	Millennium Pipeline Co.	14.00%
Feb-07	CP06-403	Northern Natural Gas Co.	13.42%
Mar-07	CP06-448	Kinder Morgan Louisiana Pipeline LLC	14.00%
Apr-07	CP07-25	Questar Pipeline Company	11.75%
Apr-07	CP06-407	Missouri Interstate Gas	11.20%
Apr-07	CP06-89	WTG Hugoton, LP and Northern Natural Gas Co.	11.20%
Apr-07	CP06-471	Elba Express Co.	14.00%
May-07	CP07-44	Southeast Supply Header, LLC	13.50%
Jun-07	CP06-115	Texas Eastern Transmission LP	12.75%
Jun-07	CP00-6	Gulfstream Natural Gas Supply, L.L.C.	14.00%
Jun-07	CP07-14	Wyoming Interstate Co., Ltd.	12.50%
Jul-07	CP06-454	Kinder Morgan Illinois Pipeline LLC	13.00%
Jul-07	CP07-76	Sonora Pipeline, LLC	14.00%
Sep-07	CP07-32	Gulf South Pipeline LP	12.25%
Sep-07	CP05-91	Calhoun LNG/Point Comfort Pipeline, LP	14.00%
Oct-07	RP07-38	Eastern Shore Natural Gas Co.	13.60%
Dec-07	CP07-8	Guardian Pipeline, L.L.C.	14.00%
Apr-08	CP07-398	Gulf Crossing Pipeline LLC	13.50%
May-08	CP07-208	Rockies Express Pipeline LLC	13.00%
May-08	CP07-417	Texas Gas Transmission. LLC	11.50%

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Jul-08	CP08-65	Midcontinent Express Pipeline LLC	13.00%
Jul-08	CP08-17	Cimarron River Pipeline LLC	11.20%
Jul-08	CP08-5	Southern Natural Gas Co.	12.00%
Aug-08	CP08-65	Tennessee Gas Pipeline Co.	11.50%
Aug-08	CP08-398	White River Hub, LLC	13.00%
Sep-08	CP06-365	Bradwood Landing LLC/NorthernStar Energy LLC	14.00%
Sep-08	CP08-152	North Baja Pipeline LLC	14.00%
Nov-08	RP08-632	MarkWest Pioneer, L.L.C.	14.00%
Jan-09	CP07-62	AES Sparrows Point LNG/Mid-Atlantic Express L.L.C.	14.00%
Jan-09	RP08-350	Southern Star Central Pipeline, Inc.	11.25%
Jan-09	RP04-274	Kern River Gas Transmission Co.	11.55%
Feb-09	CP09-3	T.W. Phillips Pipeline Corp.	14.00%
Jun-09	CP08-429	Kern River Gas Transmission Co.	13.25%
Sep-09	CP09-54	Ruby Pipeline, L.L.C.	14.00%
Nov-09	CP09-17	Florida Gas Transmission Co.	13.00%
Nov-09	CP09-68	Texas Eastern Transmission, LP	12.75%
Dec-09	CP09-433	Fayetteville Express Pipeline LLC	14.00%
Dec-09	CP07-442	Pacific Connector Gas Pipeline, LP	14.00%
Apr-10	CP09-161	Bison Pipeline LLC	14.00%
Apr-10	CP09-460	ETC Tiger Pipeline	14.00%
May-10	CP09-444	Tennessee Gas Pipeline Co.	11.50%
Sep-10	CP10-14	Kern River Transmission Co.	11.55%
Nov-10	CP10-468	Northern Border Pipeline Co.	12.00%
Jan-11	CP10-194	Central New York Oil & Gas Co.	13.50%
Feb-11	RP08-306	Portland Natural Gas Transmission System	12.99%
Apr-11	CP11-19	Trunkline Gas Co., LLC	12.56%
Jul-11	CP09-54	Ruby Pipeline L.L.C.	14.00%
Nov-11	CP10-480	Central New York Oil & Gas Co.	13.50%
Jan-12	CP11-46	Kern River Gas Transmission Co.	11.55%
Feb-12	CP11-508	Texas Eastern Transmission, LP	12.75%
May-12	CP11-56	Texas Eastern Transmission, LP	12.75%
May-12	CP12-31	Southern LNG, L.L.C.	12.50%
Jun-12	CP12-4	Southern Natural Gas Co.-High Point Gas Trans.	12.99%
Jun-12	CP11-543	ANR Pipeline Co.-TC Offshore LLC	12.99%
Sep-12	CP13-21	Alliance Pipeline L.P.	12.99%
Mar-13	CP12-494	Gas Transmission Northwest	12.20%
Mar-13	RP10-729	Portland Natural Gas Transmission System	11.59%
May-13	CP12-490	Tennessee Gas Pipeline Co.	11.59%

REGRESSION RESULTS

SUMMARY OUTPUT -- BBB UTILITY BONDS

Regression Statistics	
Multiple R	0.844037338
R Square	0.712399027
Adjusted R Square	0.664465532
Standard Error	0.004365541
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000283244	0.000283244	14.86223821	0.008409442
Residual	6	0.000114348	1.90579E-05		
Total	7	0.000397591			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.111176559	0.011455938	9.704710618	6.86983E-05	0.083144869	0.139208249	0.083144869	0.139208249
X Variable 1	-0.724382695	0.187899644	-3.855157352	0.008409442	-1.184156897	-0.264608492	-1.184156897	-0.264608492

SUMMARY OUTPUT -- 10-YEAR TREASURY BONDS

Regression Statistics	
Multiple R	0.891457863
R Square	0.794697121
Adjusted R Square	0.760479975
Standard Error	0.004661038
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000504572	0.000504572	23.2251138	0.002942342
Residual	6	0.000130352	2.17253E-05		
Total	7	0.000634924			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.121796841	0.005858074	20.79127832	8.05934E-07	0.107462641	0.136131041	0.107462641	0.136131041
X Variable 1	-0.817931544	0.169721957	-4.819244111	0.002942342	-1.233226517	-0.402636571	-1.233226517	-0.402636571

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	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$1,960	1.70%	12.0%
2	Ameren Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.80	10.7%	$8,743	0.76%	11.4%
3	American Elec Pwr	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$22,550	-0.37%	9.5%
4	Avista Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$1,678	1.72%	12.0%
5	Black Hills Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.90	11.5%	$2,360	1.70%	13.2%
6	CMS Energy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$7,057	0.92%	10.7%
7	DTE Energy Co.	2.3%	10.1%	12.4%	3.8%	8.6%	0.80	10.7%	$11,612	0.76%	11.4%
8	Duke Energy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.65	9.4%	$47,916	-0.37%	9.0%
9	Edison International	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$14,707	0.76%	11.0%
10	El Paso Electric	2.3%	10.1%	12.4%	3.8%	8.6%	0.65	9.4%	$1,421	1.72%	11.1%
11	Empire District Elec	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$962	1.73%	11.6%
12	Entergy Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$10,791	0.76%	10.6%
13	Exelon Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$23,162	-0.37%	9.9%
14	Great Plains Energy	2.3%	10.1%	12.4%	3.8%	8.6%	0.85	11.1%	$3,760	1.14%	12.3%
15	Hawaiian Elec.	2.3%	10.1%	12.4%	3.8%	8.6%	0.80	10.7%	$2,589	1.70%	12.4%
16	IDACORP, Inc.	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$2,626	1.70%	12.0%
17	NorthWestern Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$1,666	1.72%	11.5%
18	Otter Tail Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.95	12.0%	$1,042	1.73%	13.7%
19	Pepco Holdings	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$4,722	0.92%	11.2%
20	PG&E Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.60	9.0%	$17,975	-0.37%	8.6%
21	PNM Resources	2.3%	10.1%	12.4%	3.8%	8.6%	0.95	12.0%	$1,915	1.70%	13.7%
22	Portland General Elec.	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$2,321	1.70%	12.0%
23	PPL Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.65	9.4%	$18,718	-0.37%	9.0%
24	SCANA Corp.	2.3%	10.1%	12.4%	3.8%	8.6%	0.70	9.8%	$6,452	0.92%	10.7%
25	Sempra Energy	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$22,053	-0.37%	9.9%
26	UIL Holdings	2.3%	10.1%	12.4%	3.8%	8.6%	0.80	10.7%	$1,925	1.70%	12.4%
27	Westar Energy	2.3%	10.1%	12.4%	3.8%	8.6%	0.75	10.3%	$4,188	1.14%	11.4%
	Range of Reasonableness							**9.0% -- 12.0%**			**8.6% -- 13.7%**
	Midpoint							**10.5%**			**11.2%**
	Median							**10.3%**			**11.4%**
	Average							**10.3%**			**11.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jan. 8, 2014).

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jan. 13, 2014).

(c) Six-month average yield on 30-year Treasury bonds for Aug. 2013 - Jan. 2014 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.

(d) See Exhibit No. CLP-103.

(e) www.valueline.com (retrieved Jan. 17, 2014).

(f) Morningstar, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

NATIONAL GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)			2014-18						
		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	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$1,960	1.70%	12.1%
2	Ameren Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.80	10.8%	$8,743	0.76%	11.6%
3	American Elec Pwr	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$22,550	-0.37%	9.7%
4	Avista Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$1,678	1.72%	12.1%
5	Black Hills Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.90	11.6%	$2,360	1.70%	13.3%
6	CMS Energy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$7,057	0.92%	11.0%
7	DTE Energy Co.	2.3%	10.1%	12.4%	4.5%	7.9%	0.80	10.8%	$11,612	0.76%	11.6%
8	Duke Energy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.65	9.6%	$47,916	-0.37%	9.3%
9	Edison International	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$14,707	0.76%	11.2%
10	El Paso Electric	2.3%	10.1%	12.4%	4.5%	7.9%	0.65	9.6%	$1,421	1.72%	11.4%
11	Empire District Elec	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$962	1.73%	11.8%
12	Entergy Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$10,791	0.76%	10.8%
13	Exelon Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$23,162	-0.37%	10.1%
14	Great Plains Energy	2.3%	10.1%	12.4%	4.5%	7.9%	0.85	11.2%	$3,760	1.14%	12.4%
15	Hawaiian Elec.	2.3%	10.1%	12.4%	4.5%	7.9%	0.80	10.8%	$2,589	1.70%	12.5%
16	IDACORP, Inc.	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$2,626	1.70%	12.1%
17	NorthWestern Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$1,666	1.72%	11.8%
18	Otter Tail Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.95	12.0%	$1,042	1.73%	13.7%
19	Pepco Holdings	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$4,722	0.92%	11.3%
20	PG&E Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.60	9.2%	$17,975	-0.37%	8.9%
21	PNM Resources	2.3%	10.1%	12.4%	4.5%	7.9%	0.95	12.0%	$1,915	1.70%	13.7%
22	Portland General Elec.	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$2,321	1.70%	12.1%
23	PPL Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.65	9.6%	$18,718	-0.37%	9.3%
24	SCANA Corp.	2.3%	10.1%	12.4%	4.5%	7.9%	0.70	10.0%	$6,452	0.92%	11.0%
25	Sempra Energy	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$22,053	-0.37%	10.1%
26	UIL Holdings	2.3%	10.1%	12.4%	4.5%	7.9%	0.80	10.8%	$1,925	1.70%	12.5%
27	Westar Energy	2.3%	10.1%	12.4%	4.5%	7.9%	0.75	10.4%	$4,188	1.14%	11.6%
	Range of Reasonableness							**9.2% -- 12.0%**			**8.9% -- 13.7%**
	Midpoint							**10.6%**			**11.3%**
	Median							**10.4%**			**11.6%**
	Average							**10.5%**			**11.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jan. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jan. 13, 2014).
(c) Average projected 30-year Treasury bond yield for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (Nov. 2013); & .
(d) See Exhibit No. CLP-103.
(e) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).
(f) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

EXPECTED EARNINGS APPROACH **Exhibit No. CLP-110**

NATIONAL GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0403	9.4%
2	Ameren Corp.	8.5%	1.0138	8.6%
3	American Elec Pwr	10.5%	1.0222	10.7%
4	Avista Corp.	9.0%	1.0237	9.2%
5	Black Hills Corp.	10.0%	1.0229	10.2%
6	CMS Energy Corp.	13.0%	1.0331	13.4%
7	DTE Energy Co.	9.5%	1.0320	9.8%
8	Duke Energy Corp.	8.0%	1.0117	8.1%
9	Edison International	11.0%	1.0271	11.3%
10	El Paso Electric	10.0%	1.0245	10.2%
11	Empire District Elec	8.5%	1.0234	8.7%
12	Entergy Corp.	9.5%	1.0149	9.6%
13	Exelon Corp.	8.0%	1.0158	8.1%
14	Great Plains Energy	8.0%	1.0169	8.1%
15	Hawaiian Elec.	8.5%	1.0504	8.9%
16	IDACORP, Inc.	8.5%	1.0195	8.7%
17	NorthWestern Corp.	9.5%	1.0269	9.8%
18	Otter Tail Corp.	11.5%	1.0297	11.8%
19	Pepco Holdings	8.0%	1.0202	8.2%
20	PG&E Corp.	8.5%	1.0246	8.7%
21	PNM Resources	9.0%	1.0185	9.2%
22	Portland General Elec.	8.5%	1.0343	8.8%
23	PPL Corp.	10.5%	1.0393	10.9%
24	SCANA Corp.	9.5%	1.0446	9.9%
25	Sempra Energy	11.0%	1.0239	11.3%
26	UIL Holdings	9.0%	1.0265	9.2%
27	Westar Energy	9.5%	1.0322	9.8%
	Range of Reasonableness			**8.1% -- 13.4%**
	Midpoint			**10.8%**
	Median			**9.4%**
	Average			**9.7%**

(a) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).

(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. CLP-113.

(c) (a) x (b).

DIVIDEND YIELD

			(a)	(b)	
	Company	**Industry Group**	**Price**	**Dividends**	**Yield**
1	Church & Dwight	Household Products	$ 65.87	$ 1.12	1.7%
2	Colgate-Palmolive	Household Products	$ 64.52	$ 1.45	2.2%
3	Gen'l Mills	Food Processing	$ 49.33	$ 1.52	3.1%
4	Kellogg	Food Processing	$ 60.68	$ 1.84	3.0%
5	Kimberly-Clark	Household Products	$ 104.75	$ 3.24	3.1%
6	McCormick & Co.	Food Processing	$ 68.79	$ 1.51	2.2%
7	McDonald's Corp.	Restaurant	$ 95.70	$ 3.24	3.4%
8	Wal-Mart Stores	Retail Store	$ 77.76	$ 2.00	2.6%
	Average				**2.7%**

(a) Average of closing prices for 30 trading days ended Jan. 23, 2014.
(b) The Value Line Investment Survey, Summary & Index (Jan. 24, 2014).

GROWTH RATES

		(a)	(b)
		Earnings Growth	
	Company	**IBES**	**V Line**
1	Church & Dwight	11.4%	10.5%
2	Colgate-Palmolive	9.3%	10.0%
3	Gen'l Mills	7.7%	6.5%
4	Kellogg	6.7%	7.5%
5	Kimberly-Clark	7.7%	9.5%
6	McCormick & Co.	8.2%	8.5%
7	McDonald's Corp.	8.1%	8.0%
8	Wal-Mart Stores	8.6%	7.5%

(a) www.finance.yahoo.com (retrieved Jan. 24, 2014).
(b) The Value Line Investment Survey (Nov. 1, Nov. 29 & Dec. 27, 2013, Jan. 24, 2014).

COST OF EQUITY ESTIMATES

	Company	IBES	V Line	Low		High	Avg.
1	Church & Dwight	12.2%	13.1%	12.2%	--	13.1%	12.6%
2	Colgate-Palmolive	12.2%	11.5%	11.5%	--	12.2%	11.9%
3	Gen'l Mills	9.6%	10.8%	9.6%	--	10.8%	10.2%
4	Kellogg	10.5%	9.7%	9.7%	--	10.5%	10.1%
5	Kimberly-Clark	12.6%	10.7%	10.7%	--	12.6%	11.7%
6	McCormick & Co.	10.7%	10.4%	10.4%	--	10.7%	10.6%
7	McDonald's Corp.	11.4%	11.5%	11.4%	--	11.5%	11.4%
8	Wal-Mart Stores	10.1%	11.2%	10.1%	--	11.2%	10.6%
	Range of Reasonableness			**9.6%**	**--**	**13.1%**	
	Midpoint				**11.3%**		
	Median						**11.0%**
	Average						**11.1%**

PROJECTED BOND YIELD

		(a)		(b)		(c)	(d)		(e)				
		6 Mo. Div. Yield		Adjusted Div. Yield		Growth Rates		S&P	Low-End	Cost of Equity			
	Company	Low	High	Low	High	br + sv	IBES	Credit Rating	Threshold	Low		High	Avg.
1	ALLETE	3.7%	4.0%	3.8%	4.1%	3.7%	6.0%	BBB+	7.6%	7.5%	--	10.1%	--
2	Ameren Corp.	4.4%	4.7%	4.4%	4.8%	2.3%	2.0%	BBB+	7.6%	6.4%	--	7.1%	--
3	American Elec Pwr	4.2%	4.5%	4.3%	4.6%	4.2%	4.2%	BBB	7.6%	8.5%	--	8.8%	8.7%
4	Avista Corp.	4.3%	4.6%	4.4%	4.7%	3.3%	5.0%	BBB	7.6%	7.7%	--	9.7%	8.7%
5	Black Hills Corp.	2.8%	3.1%	2.9%	3.2%	4.3%	4.0%	BBB	7.6%	6.9%	--	7.5%	--
6	CMS Energy Corp.	3.7%	3.9%	3.8%	4.0%	5.5%	6.1%	BBB	7.6%	9.3%	--	10.1%	9.7%
7	DTE Energy Co.	3.8%	4.0%	3.9%	4.1%	4.1%	4.9%	BBB+	7.6%	8.0%	--	9.0%	8.5%
8	Duke Energy Corp.	4.4%	4.7%	4.4%	4.8%	2.2%	3.3%	BBB+	7.6%	6.6%	--	8.1%	--
9	Edison International	2.8%	3.1%	2.8%	3.2%	6.6%	-1.0%	BBB-	7.6%	1.8%	--	9.8%	--
10	El Paso Electric	2.9%	3.2%	3.0%	3.3%	5.5%	3.7%	BBB	7.6%	6.7%	--	8.8%	--
11	Empire District Elec	4.4%	4.7%	4.5%	4.8%	2.7%	3.0%	BBB	7.6%	7.2%	--	7.8%	--
12	Entergy Corp.	5.0%	5.4%	4.8%	5.5%	3.2%	-8.6%	BBB	7.6%	-3.8%	--	8.7%	--
13	Exelon Corp.	4.1%	4.5%	4.0%	4.6%	3.2%	-7.2%	BBB	7.6%	-3.2%	--	7.8%	--
14	Great Plains Energy	3.7%	4.0%	3.8%	4.1%	3.3%	7.0%	BBB	7.6%	7.1%	--	11.1%	--
15	Hawaiian Elec.	4.7%	5.0%	4.8%	5.1%	3.4%	2.4%	BBB-	7.6%	7.2%	--	8.5%	--
16	IDACORP, Inc.	3.1%	3.3%	3.2%	3.4%	4.4%	4.0%	BBB	7.6%	7.2%	--	7.8%	--
17	NorthWestern Corp.	3.4%	3.6%	3.5%	3.7%	4.2%	7.0%	BBB	7.6%	7.7%	--	10.7%	9.2%
18	Otter Tail Corp.	1.2%	1.4%	1.2%	1.4%	4.2%	6.0%	BBB	7.6%	5.4%	--	7.4%	--
19	Pepco Holdings	5.5%	5.9%	5.5%	6.0%	1.3%	4.2%	BBB+	7.6%	6.8%	--	10.2%	--
20	PG&E Corp.	4.2%	4.5%	4.2%	4.5%	2.2%	-1.8%	BBB	7.6%	2.4%	--	6.7%	--
21	PNM Resources	2.7%	3.0%	2.8%	3.1%	3.9%	5.9%	BBB	7.6%	6.7%	--	9.0%	--
22	Portland General Elec.	3.6%	3.9%	3.7%	4.0%	3.1%	6.7%	BBB	7.6%	6.8%	--	10.7%	--
23	PPL Corp.	4.7%	5.0%	4.6%	5.1%	5.3%	-2.4%	BBB	7.6%	2.2%	--	10.4%	--
24	SCANA Corp.	4.2%	4.4%	4.3%	4.5%	5.3%	4.8%	BBB+	7.6%	9.1%	--	9.8%	9.5%
25	Sempra Energy	2.8%	3.0%	2.9%	3.1%	4.7%	5.6%	BBB+	7.6%	7.6%	--	8.7%	--
26	UIL Holdings	4.4%	4.7%	4.5%	4.9%	2.4%	7.1%	BBB	7.6%	6.9%	--	12.0%	--
27	Westar Energy	4.2%	4.4%	4.3%	4.5%	4.2%	2.9%	BBB	7.6%	7.2%	--	8.7%	--
	Range of Reasonableness									**-3.8%**	--	**12.0%**	
	Adjusted Range of Reasonableness (f)									**6.9%**	--	**12.0%**	
	Midpoint									**9.5%**			
	Median												**9.0%**
	Average												**9.0%**

(a) Six-month average dividend yield for Aug. - Jan. 2014.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. CLP-113.
(d) www.finance.yahoo.com (retrieved Feb. 4, 2014).
(e) 100 basis points over average projected triple-B bond yield for 2014-2017 of 6.58%.
(f) Excludes highlighted values.

HISTORICAL BOND YIELD 5.7%

		(a)		(b)		(c)	(d)		(e)				
		6 Mo. Div. Yield		Adjusted Div. Yield		Growth Rates		S&P	Low-End	Cost of Equity			
	Company	Low	High	Low	High	br + sv	IBES	Credit Rating	Threshold	Low		High	Avg.
1	ALLETE	3.7%	4.0%	3.8%	4.1%	3.7%	6.0%	BBB+	6.2%	7.5%	--	10.1%	8.8%
2	Ameren Corp.	4.4%	4.7%	4.4%	4.8%	2.3%	2.0%	BBB+	6.2%	6.4%	--	7.1%	6.8%
3	American Elec Pwr	4.2%	4.5%	4.3%	4.6%	4.2%	4.2%	BBB	6.2%	8.5%	--	8.8%	8.7%
4	Avista Corp.	4.3%	4.6%	4.4%	4.7%	3.3%	5.0%	BBB	6.2%	7.7%	--	9.7%	8.7%
5	Black Hills Corp.	2.8%	3.1%	2.9%	3.2%	4.3%	4.0%	BBB	6.2%	6.9%	--	7.5%	7.2%
6	CMS Energy Corp.	3.7%	3.9%	3.8%	4.0%	5.5%	6.1%	BBB	6.2%	9.3%	--	10.1%	9.7%
7	DTE Energy Co.	3.8%	4.0%	3.9%	4.1%	4.1%	4.9%	BBB+	6.2%	8.0%	--	9.0%	8.5%
8	Duke Energy Corp.	4.4%	4.7%	4.4%	4.8%	2.2%	3.3%	BBB+	6.2%	6.6%	--	8.1%	7.4%
9	Edison International	2.8%	3.1%	2.8%	3.2%	6.6%	-1.0%	BBB-	6.2%	1.8%	--	9.8%	--
10	El Paso Electric	2.9%	3.2%	3.0%	3.3%	5.5%	3.7%	BBB	6.2%	6.7%	--	8.8%	7.8%
11	Empire District Elec	4.4%	4.7%	4.5%	4.8%	2.7%	3.0%	BBB	6.2%	7.2%	--	7.8%	7.5%
12	Entergy Corp.	5.0%	5.4%	4.8%	5.5%	3.2%	-8.6%	BBB	6.2%	-3.8%	--	8.7%	--
13	Exelon Corp.	4.1%	4.5%	4.0%	4.6%	3.2%	-7.2%	BBB	6.2%	-3.2%	--	7.8%	--
14	Great Plains Energy	3.7%	4.0%	3.8%	4.1%	3.3%	7.0%	BBB	6.2%	7.1%	--	11.1%	9.1%
15	Hawaiian Elec.	4.7%	5.0%	4.8%	5.1%	3.4%	2.4%	BBB-	6.2%	7.2%	--	8.5%	7.9%
16	IDACORP, Inc.	3.1%	3.3%	3.2%	3.4%	4.4%	4.0%	BBB	6.2%	7.2%	--	7.8%	7.5%
17	NorthWestern Corp.	3.4%	3.6%	3.5%	3.7%	4.2%	7.0%	BBB	6.2%	7.7%	--	10.7%	9.2%
18	Otter Tail Corp.	1.2%	1.4%	1.2%	1.4%	4.2%	6.0%	BBB	6.2%	5.4%	--	7.4%	--
19	Pepco Holdings	5.5%	5.9%	5.5%	6.0%	1.3%	4.2%	BBB+	6.2%	6.8%	--	10.2%	8.5%
20	PG&E Corp.	4.2%	4.5%	4.2%	4.5%	2.2%	-1.8%	BBB	6.2%	2.4%	--	6.7%	--
21	PNM Resources	2.7%	3.0%	2.8%	3.1%	3.9%	5.9%	BBB	6.2%	6.7%	--	9.0%	7.9%
22	Portland General Elec.	3.6%	3.9%	3.7%	4.0%	3.1%	6.7%	BBB	6.2%	6.8%	--	10.7%	8.8%
23	PPL Corp.	4.7%	5.0%	4.6%	5.1%	5.3%	-2.4%	BBB	6.2%	2.2%	--	10.4%	--
24	SCANA Corp.	4.2%	4.4%	4.3%	4.5%	5.3%	4.8%	BBB+	6.2%	9.1%	--	9.8%	9.5%
25	Sempra Energy	2.8%	3.0%	2.9%	3.1%	4.7%	5.6%	BBB+	6.2%	7.6%	--	8.7%	8.2%
26	UIL Holdings	4.4%	4.7%	4.5%	4.9%	2.4%	7.1%	BBB	6.2%	6.9%	--	12.0%	9.5%
27	Westar Energy	4.2%	4.4%	4.3%	4.5%	4.2%	2.9%	BBB	6.2%	7.2%	--	8.7%	8.0%
	Range of Reasonableness									**-3.8%**	--	**12.0%**	
	Adjusted Range of Reasonableness (f)									**6.4%**	--	**12.0%**	
	Midpoint										**9.2%**		
	Median												**8.5%**
	Average												**8.3%**

(a) Six-month average dividend yield for Aug. - Jan. 2014.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. CLP-113.
(d) www.finance.yahoo.com (retrieved Feb. 4, 2014).
(e) 100 basis points over 6-mo. average historical triple-B bond yield of 5.22%.
(f) Excludes highlighted values.

BR + SV GROWTH RATE

		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
		2013				2014				2017						Adjustment		Avg	Avg
	Company	**EPS**	**DPS**	**b**	**r**	**EPS**	**DPS**	**b**	**r**	**EPS**	**DPS**	**b**	**r**	**Avg b**	**Avg r**	**Factor**	**Adjstd r**	**br**	**br + sv**
1	ALLETE	$2.60	$1.90	26.9%	8.0%	$2.75	$1.96	28.7%	7.5%	$3.50	$2.20	37.1%	9.0%	30.9%	8.2%	1.0403	8.5%	2.6%	**3.7%**
2	Ameren Corp.	$2.00	$1.60	20.0%	7.5%	$2.25	$1.60	28.9%	8.0%	$2.50	$1.70	32.0%	8.5%	27.0%	8.0%	1.0138	8.1%	2.2%	**2.3%**
3	American Elec Pwr	$3.10	$1.95	37.1%	9.5%	$3.30	$2.02	38.8%	10.0%	$4.00	$2.30	42.5%	10.5%	39.5%	10.0%	1.0222	10.2%	4.0%	**4.2%**
4	Avista Corp.	$1.80	$1.22	32.2%	8.5%	$1.85	$1.28	30.8%	8.0%	$2.25	$1.40	37.8%	9.0%	33.6%	8.5%	1.0237	8.7%	2.9%	**3.3%**
5	Black Hills Corp.	$2.75	$1.52	44.7%	9.5%	$2.60	$1.56	40.0%	8.5%	$3.25	$1.80	44.6%	10.0%	43.1%	9.3%	1.0229	9.5%	4.1%	**4.3%**
6	CMS Energy Corp.	$1.65	$1.02	38.2%	13.0%	$1.75	$1.08	38.3%	13.0%	$2.00	$1.30	35.0%	13.0%	37.2%	13.0%	1.0331	13.4%	5.0%	**5.5%**
7	DTE Energy Co.	$4.05	$2.59	36.0%	9.0%	$4.25	$2.73	35.8%	9.0%	$5.00	$3.15	37.0%	9.5%	36.3%	9.2%	1.0320	9.5%	3.4%	**4.1%**
8	Duke Energy Corp.	$4.05	$3.09	23.7%	7.0%	$4.50	$3.15	30.0%	7.5%	$5.00	$3.35	33.0%	8.0%	28.9%	7.5%	1.0117	7.6%	2.2%	**2.2%**
9	Edison International	$3.35	$1.36	59.4%	11.5%	$3.50	$1.46	58.3%	11.0%	$4.00	$1.80	55.0%	11.0%	57.6%	11.2%	1.0271	11.5%	6.6%	**6.6%**
10	El Paso Electric	$2.30	$1.05	54.3%	10.5%	$2.40	$1.11	53.8%	10.5%	$2.50	$1.30	48.0%	10.0%	52.0%	10.3%	1.0245	10.6%	5.5%	**5.5%**
11	Empire District Elec	$1.40	$1.01	27.9%	8.0%	$1.45	$1.03	29.0%	8.0%	$1.70	$1.15	32.4%	8.5%	29.7%	8.2%	1.0234	8.4%	2.5%	**2.7%**
12	Entergy Corp.	$4.75	$3.32	30.1%	9.0%	$4.95	$3.32	32.9%	9.0%	$5.50	$3.40	38.2%	9.5%	33.7%	9.2%	1.0149	9.3%	3.1%	**3.2%**
13	Exelon Corp.	$2.25	$1.46	35.1%	9.0%	$2.05	$1.24	39.5%	7.5%	$2.25	$1.30	42.2%	8.0%	38.9%	8.2%	1.0158	8.3%	3.2%	**3.2%**
14	Great Plains Energy	$1.55	$0.88	43.2%	7.0%	$1.65	$0.94	43.0%	7.5%	$2.00	$1.10	45.0%	8.0%	43.8%	7.5%	1.0169	7.6%	3.3%	**3.3%**
15	Hawaiian Elec.	$1.60	$1.24	22.5%	9.5%	$1.60	$1.24	22.5%	9.0%	$1.75	$1.30	25.7%	8.5%	23.6%	9.0%	1.0504	9.5%	2.2%	**3.4%**
16	IDACORP, Inc.	$3.50	$1.57	55.1%	9.5%	$3.45	$1.76	49.0%	9.0%	$3.60	$2.20	38.9%	8.5%	47.7%	9.0%	1.0195	9.2%	4.4%	**4.4%**
17	NorthWestern Corp.	$2.60	$1.52	41.5%	9.5%	$2.70	$1.56	42.2%	9.5%	$3.00	$1.80	40.0%	9.5%	41.3%	9.5%	1.0269	9.8%	4.0%	**4.2%**
18	Otter Tail Corp.	$1.45	$1.19	17.9%	10.0%	$1.55	$1.19	23.2%	10.0%	$2.00	$1.30	35.0%	11.5%	25.4%	10.5%	1.0297	10.8%	2.7%	**4.2%**
19	Pepco Holdings	$1.10	$1.08	1.8%	6.0%	$1.25	$1.12	10.4%	6.5%	$1.70	$1.16	31.8%	8.0%	14.7%	6.8%	1.0202	7.0%	1.0%	**1.3%**
20	PG&E Corp.	$2.00	$1.82	9.0%	6.0%	$2.40	$1.82	24.2%	7.5%	$3.00	$2.10	30.0%	8.5%	21.1%	7.3%	1.0246	7.5%	1.6%	**2.2%**
21	PNM Resources	$1.40	$0.66	52.9%	6.5%	$1.50	$0.74	50.7%	7.0%	$2.15	$1.08	49.8%	9.0%	51.1%	7.5%	1.0185	7.6%	3.9%	**3.9%**
22	Portland General Elec.	$1.65	$1.10	33.3%	7.0%	$1.85	$1.12	39.5%	7.0%	$2.25	$1.25	44.4%	8.5%	39.1%	7.5%	1.0343	7.8%	3.0%	**3.1%**
23	PPL Corp.	$2.40	$1.47	38.8%	13.0%	$2.20	$1.50	31.8%	10.5%	$2.50	$1.60	36.0%	10.5%	35.5%	11.3%	1.0393	11.8%	4.2%	**5.3%**
24	SCANA Corp.	$3.40	$2.03	40.3%	10.0%	$3.55	$2.08	41.4%	10.0%	$4.00	$2.25	43.8%	9.5%	41.8%	9.8%	1.0446	10.3%	4.3%	**5.3%**
25	Sempra Energy	$4.15	$2.52	39.3%	9.5%	$4.55	$2.64	42.0%	10.0%	$5.50	$3.00	45.5%	11.0%	42.2%	10.2%	1.0239	10.4%	4.4%	**4.7%**
26	UIL Holdings	$2.20	$1.73	21.4%	9.5%	$2.25	$1.73	23.1%	9.0%	$2.55	$1.73	32.2%	9.0%	25.5%	9.2%	1.0265	9.4%	2.4%	**2.4%**
27	Westar Energy	$2.25	$1.36	39.6%	9.5%	$2.35	$1.40	40.4%	9.0%	$2.75	$1.52	44.7%	9.5%	41.6%	9.3%	1.0322	9.6%	4.0%	**4.2%**

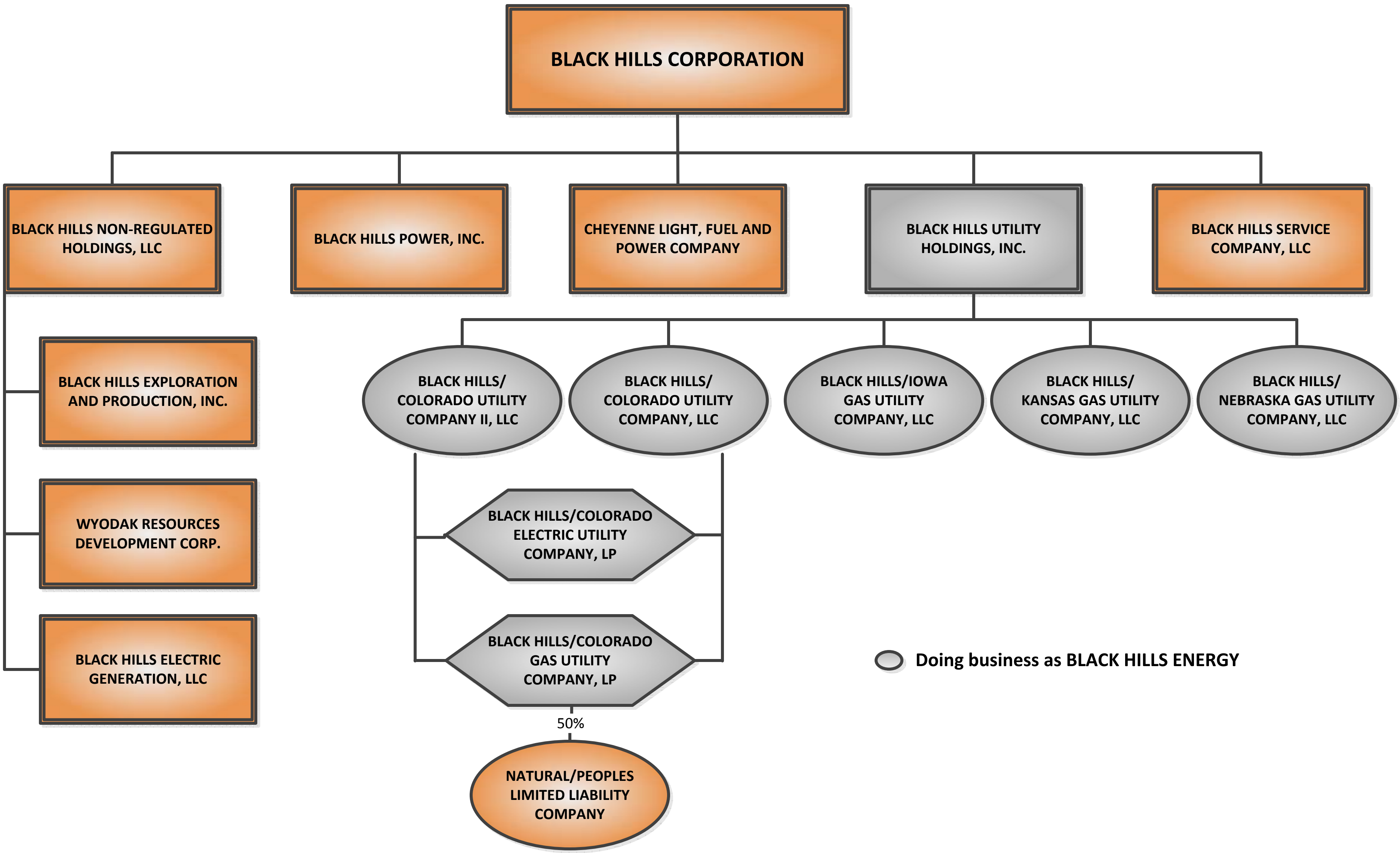
NATIONAL PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		2012			2017			Chg	2017 Price			2017		No. Shares			"sv" Factor		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	BVPS	M/B	2012	2017	Growth	s	v	sv
1	ALLETE	56.3%	$2,135	$1,202	58.0%	$3,100	$1,798	8.4%	$55.00	$40.00	$47.50	$37.50	1.267	39.4	48.0	4.03%	0.0510	0.2105	1.07%
2	Ameren Corp.	49.4%	$13,384	$6,612	55.0%	$13,800	$7,590	2.8%	$40.00	$25.00	$32.50	$30.00	1.083	242.6	255.0	1.00%	0.0109	0.0769	0.08%
3	American Elec Pwr	49.4%	$30,823	$15,227	54.0%	$35,200	$19,008	4.5%	$60.00	$40.00	$50.00	$38.50	1.299	485.7	496.0	0.42%	0.0055	0.2300	0.13%
4	Avista Corp.	49.2%	$2,561	$1,260	51.5%	$3,100	$1,597	4.8%	$35.00	$25.00	$30.00	$24.50	1.224	59.8	64.5	1.52%	0.0186	0.1833	0.34%
5	Black Hills Corp.	56.8%	$2,171	$1,233	42.5%	$3,650	$1,551	4.7%	$50.00	$35.00	$42.50	$34.00	1.250	44.2	45.5	0.58%	0.0072	0.2000	0.14%
6	CMS Energy Corp.	31.6%	$10,101	$3,192	38.0%	$11,700	$4,446	6.9%	$35.00	$20.00	$27.50	$16.25	1.692	264.1	274.0	0.74%	0.0125	0.4091	0.51%
7	DTE Energy Co.	51.2%	$14,387	$7,366	51.0%	$19,900	$10,149	6.6%	$80.00	$60.00	$70.00	$53.25	1.315	172.4	190.0	1.97%	0.0259	0.2393	0.62%
8	Duke Energy Corp.	52.9%	$77,307	$40,895	49.0%	$93,800	$45,962	2.4%	$75.00	$55.00	$65.00	$64.75	1.004	704.0	710.0	0.17%	0.0017	0.0038	0.00%
9	Edison International	46.2%	$20,422	$9,435	45.0%	$27,500	$12,375	5.6%	$60.00	$45.00	$52.50	$38.00	1.382	325.8	325.8	0.00%	-	0.2762	0.00%
10	El Paso Electric	45.2%	$1,825	$825	43.0%	$2,450	$1,054	5.0%	$45.00	$30.00	$37.50	$26.25	1.429	40.1	40.0	-0.05%	(0.0008)	0.3000	-0.02%
11	Empire District Elec	50.9%	$1,409	$717	49.0%	$1,850	$907	4.8%	$25.00	$18.00	$21.50	$19.50	1.103	42.5	46.5	1.82%	0.0201	0.0930	0.19%
12	Entergy Corp.	42.9%	$21,432	$9,194	42.0%	$25,400	$10,668	3.0%	$85.00	$60.00	$72.50	$59.75	1.213	177.8	178.5	0.08%	0.0009	0.1759	0.02%
13	Exelon Corp.	53.5%	$40,057	$21,430	54.0%	$46,500	$25,110	3.2%	$35.00	$25.00	$30.00	$29.00	1.034	855.0	865.0	0.23%	0.0024	0.0333	0.01%
14	Great Plains Energy	54.4%	$6,136	$3,338	52.0%	$7,600	$3,952	3.4%	$30.00	$18.00	$24.00	$25.25	0.950	153.5	156.0	0.32%	0.0030	(0.0521)	-0.02%
15	Hawaiian Elec.	53.1%	$3,001	$1,594	51.0%	$5,175	$2,639	10.6%	$30.00	$20.00	$25.00	$20.75	1.205	97.9	128.0	5.50%	0.0663	0.1700	1.13%
16	IDACORP, Inc.	54.5%	$3,225	$1,758	51.0%	$4,190	$2,137	4.0%	$55.00	$40.00	$47.50	$41.75	1.138	50.2	51.2	0.41%	0.0047	0.1211	0.06%
17	NorthWestern Corp.	46.2%	$2,021	$934	52.0%	$2,350	$1,222	5.5%	$45.00	$30.00	$37.50	$31.50	1.190	37.2	39.0	0.94%	0.0112	0.1600	0.18%
18	Otter Tail Corp.	54.4%	$959	$522	54.0%	$1,300	$702	6.1%	$35.00	$25.00	$30.00	$17.50	1.714	36.2	40.0	2.03%	0.0349	0.4167	1.45%
19	Pepco Holdings	52.7%	$8,432	$4,444	50.0%	$10,880	$5,440	4.1%	$30.00	$19.00	$24.50	$21.50	1.140	230.0	255.0	2.08%	0.0237	0.1224	0.29%
20	PG&E Corp.	50.4%	$25,956	$13,082	48.5%	$34,500	$16,733	5.0%	$55.00	$35.00	$45.00	$35.00	1.286	430.7	480.0	2.19%	0.0282	0.2222	0.63%
21	PNM Resources	48.7%	$3,278	$1,596	49.0%	$3,920	$1,921	3.8%	$30.00	$20.00	$25.00	$23.85	1.048	79.7	80.0	0.09%	0.0009	0.0460	0.00%
22	Portland General Elec.	52.9%	$3,264	$1,727	51.5%	$4,725	$2,433	7.1%	$30.00	$25.00	$27.50	$27.00	1.019	75.6	89.5	3.44%	0.0351	0.0182	0.06%
23	PPL Corp.	35.9%	$29,205	$10,485	44.5%	$34,900	$15,531	8.2%	$40.00	$25.00	$32.50	$23.25	1.398	581.9	670.0	2.86%	0.0400	0.2846	1.14%
24	SCANA Corp.	45.6%	$9,103	$4,151	47.0%	$13,800	$6,486	9.3%	$60.00	$45.00	$52.50	$41.00	1.280	132.0	157.0	3.53%	0.0452	0.2190	0.99%
25	Sempra Energy	46.7%	$22,002	$10,275	45.0%	$29,000	$13,050	4.9%	$90.00	$65.00	$77.50	$52.25	1.483	242.4	250.0	0.62%	0.0092	0.3258	0.30%
26	UIL Holdings	41.1%	$2,717	$1,117	45.5%	$3,200	$1,456	5.5%	$45.00	$35.00	$40.00	$28.45	1.406	50.9	51.0	0.05%	0.0007	0.2888	0.02%
27	Westar Energy	48.8%	$5,938	$2,898	50.0%	$8,000	$4,000	6.7%	$40.00	$30.00	$35.00	$29.65	1.180	126.5	135.0	1.31%	0.0155	0.1529	0.24%

(a) The Value Line Investment Survey (Nov. 22 & Dec. 20, 2013, Jan. 31, 2014).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2013, 2014, and 2017.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2013, 2014, and 2017 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

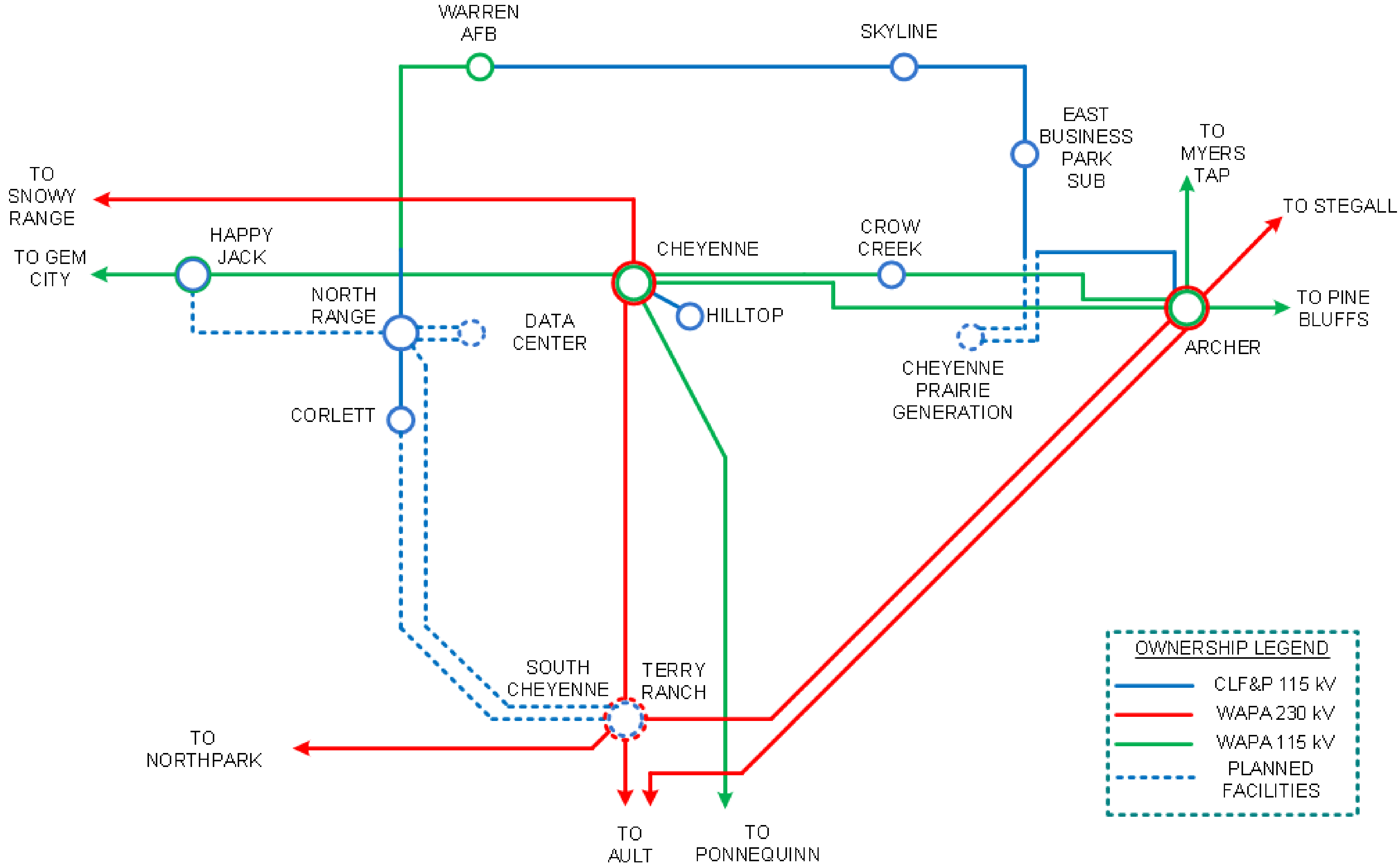
Attachment A

BLACK HILLS CORPORATION ORGANIZATIONAL CHART

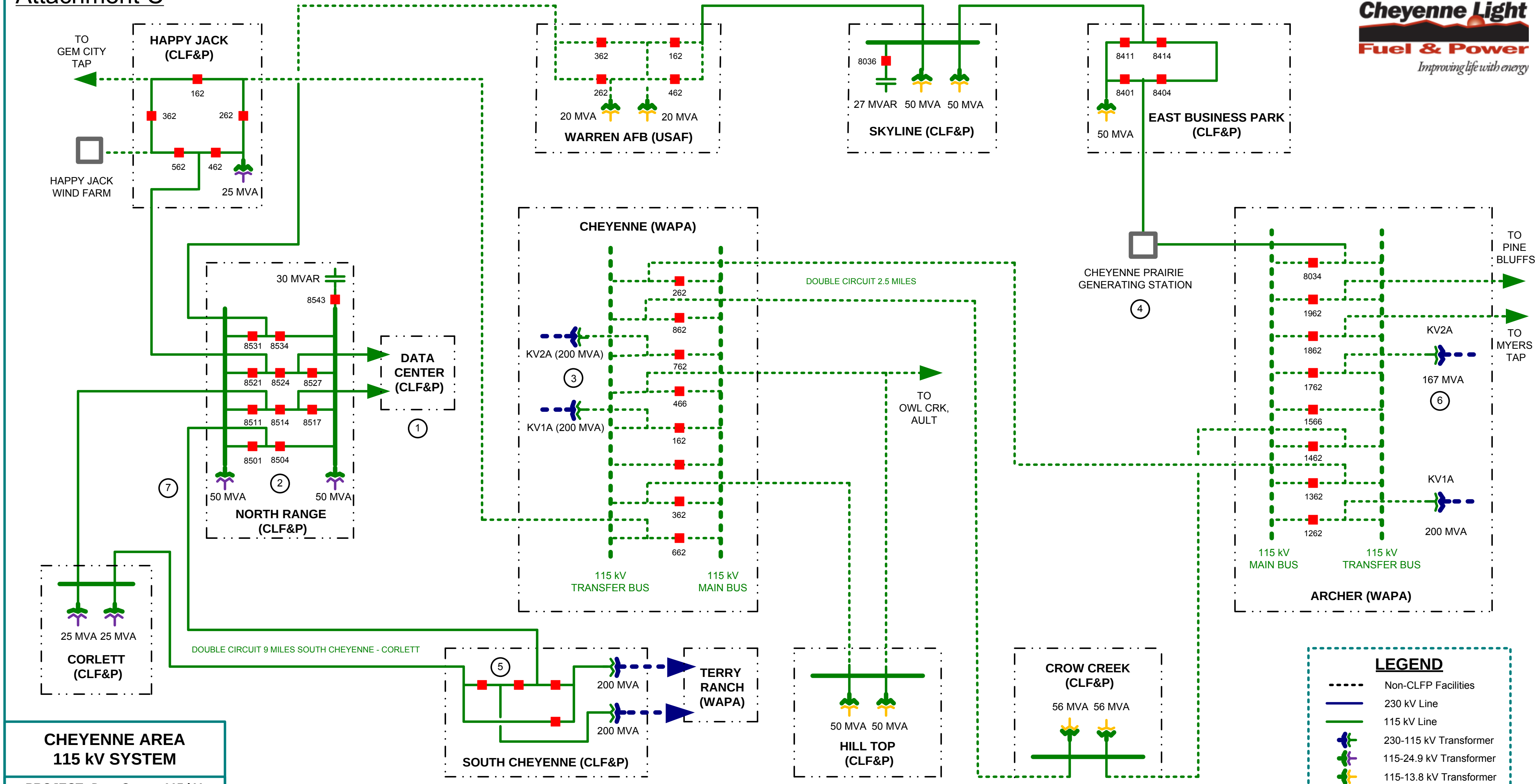


Attachment B

2013-2017 CLFP Transmission Plan



Attachment C



CHEYENNE AREA 115 kV SYSTEM

PROJECT: ***Data Center 115 kV Substation & 115 kV Upgrades***

Project Diagram: TP-PD-2004b

DATE	APPROVED BY
Created 03/04/2013	Wes Wingen
Revision 02/12/2014	Wes Wingen

1. New Data Center 115 kV Substation, including 2 x 115-24.9 kV 50 MVA Distribution Transformers with space for a third.
2. Convert North Range 115 kV Substation to Breaker and a Half, including two dedicated 115 kV Tie Lines to Data Center Substation.
3. WAPA adds KV2A 230-115 kV 200 MVA Transformer at Cheyenne. Planned in service date March 2014 (BKR 762). Owl Creek 115 kV line move BKR 466.
4. Cheyenne Prairie Generating Station. Latest planned commercial operation late 2014.
5. Add second 230-115 kV 200 MVA Transformer at Terry Ranch with new South Cheyenne-North Range double circuit 115 kV.
6. WAPA replaces KV2A 230-115 kV 167 MVA Transformer at Archer with a 200 MVA unit. Planned in service date 2016.
7. 2.3 miles of the legacy 636 ACSR Grosbeak utilized in the South Cheyenne – North Range circuit.

ATTACHMENT D

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Balancing Authority. This service can be provided only by the operator of the Balancing Authority in which the transmission facilities used for transmission service are located. A portion of Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider and the remainder the Balancing Authority operator, or indirectly by the Transmission Provider making arrangements with the Balancing Authority operator. The Transmission Customer must purchase this service from the Transmission Provider and the Balancing Authority operator. The Transmission Provider's charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Transmission Provider obtains the Balancing Authority operator's portion of this service for the Transmission Customer, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority operator.

Charges for Scheduling, System Control and Dispatch Service

Term of Reservation	Cheyenne Light Scheduling Area
Annual	$2.77/kW/Year
Monthly	$0.230/kW/Month
Weekly	$0.05/kW/Week
Daily Off Peak	$0.008/kW/Day
Daily On Peak	$0.009/kW/Day
Hourly Off Peak	$0.32 /MWh
Hourly On Peak	$0.55 /MWh

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a ~~Control Area~~Balancing Authority. This service can be provided only by the operator of the ~~Control Area~~Balancing Authority in which the transmission facilities used for transmission service are located. A portion of Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider ~~(if~~and the ~~Transmission Provider~~remainder ~~is~~ the ~~Control Area~~Balancing Authority operator~~)~~, or indirectly by the Transmission Provider making arrangements with the ~~Control Area~~Balancing Authority operator ~~that performs this service for the Transmission Provider's Transmission System.~~. The Transmission Customer must purchase this service from the Transmission Provider ~~or~~and the ~~Control Area~~Balancing Authority operator. The Transmission Provider's charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below ~~and shall in no event exceed:~~

~~Term of Reservation~~	~~Rate Cap~~
~~Monthly~~	~~**To be determined**~~
~~Weekly~~	~~**To be determined**~~
~~Daily~~	~~**To be determined**~~
~~Hourly~~	~~**To be determined**~~

. To the extent the Transmission Provider obtains the ~~Control Area~~Balancing Authority ~~operator performs~~ operator's portion of this service for the Transmission ~~Provider~~Customer, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Control Area~~Balancing Authority operator.

Charges for Scheduling, System Control and Dispatch Service

Term of Reservation	Cheyenne Light Scheduling Area
Annual	$2.77/kW/Year
Monthly	$0.230/kW/Month
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Daily Off Peak	$0.008/kW/Day
Daily On Peak	$0.009/kW/Day
Hourly Off Peak	$0.32 /MWh
Hourly On Peak	$0.55 /MWh

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SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the Balancing Authority operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Balancing Authority operator) or indirectly by the Transmission Provider making arrangements with the Balancing Authority operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Balancing Authority operator. The charges for such service will be based on the rates set forth below:

Term of Reservation	Rate Cap
Monthly	**To be determined**
Weekly	**To be determined**
Daily	**To be determined**
Hourly	**To be determined**

To the extent the Balancing Authority operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Balancing Authority operator.

SCHEDULE 2

Reactive Supply and Voltage Control from

Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the ~~control area~~Balancing Authority operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the ~~Control Area~~Balancing Authority operator) or indirectly by the Transmission Provider making arrangements with the ~~Control Area~~Balancing Authority operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the ~~Control Area~~Balancing Authority operator. The charges for such service will be based on the rates set forth below~~ and shall in no event exceed~~:

Term of Reservation	Rate Cap
Monthly	**To be determined**
Weekly	**To be determined**
Daily	**To be determined**
Hourly	**To be determined**

To the extent the ~~Control Area~~Balancing Authority operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the ~~Control Area~~Balancing Authority operator.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or Balancing Authority Operator that performs this function for the Transmission Provider). WAPA-RMR is the Balancing Authority Operator for the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Balancing Authority. The Transmission Customer must either purchase this service directly from the Balancing Authority Operator, or indirectly from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. Since the Balancing Authority operator performs this service for the Transmission Provider, charges to the

Transmission Customer will reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority Operator.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or ~~the Control Area operator~~Balancing Authority Operator that performs this function for the Transmission Provider). WAPA-RMR is the ~~Control Area~~ Balancing Authority Operator for the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its ~~Control Area~~Balancing Authority. The Transmission Customer must either purchase this service directly from the ~~Control Area~~Balancing Authority Operator, or indirectly from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission ~~customer~~Customer has made alternative comparable arrangements.

~~The amount of and charges for Regulation and Frequency Response Service are set forth below.~~ ~~To the extent~~Since the ~~Control Area~~Balancing Authority operator performs this service for the Transmission Provider, charges to the Transmission Customer ~~are to~~will reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Control Area~~Balancing Authority ~~operator~~Operator.

~~Term of Reservation~~	~~Rate Cap~~
~~Monthly~~	~~To be determined~~
~~Weekly~~	~~To be determined~~
~~Daily~~	~~To be determined~~
~~Hourly~~	~~To be determined~~

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Balancing Authority over a single hour. WAPA-RMR is the Balancing Authority Operator for the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Balancing Authority. The Transmission Customer must either purchase this service directly from the Balancing Authority Operator, or indirectly from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Balancing Authority Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority operator.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a ~~Control Area~~Balancing Authority over a single hour. ~~The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area.~~WAPA-RMR is the Balancing Authority Operator for the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Balancing Authority. The Transmission Customer must either purchase this service directly from the Balancing Authority Operator, or indirectly from the Transmission Provider or make alternative comparable arrangements to satisfy its ~~Regulation and Frequency Response~~Energy Imbalance Service obligation. ~~The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation.~~ To the extent the ~~Control Area~~Balancing Authority ~~o~~Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Control Area~~Balancing Authority operator. ~~The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.~~

~~The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW)~~

~~of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.~~

~~For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.~~

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point

Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

Term of Reservation	**Charge**
Annual ($/kW/Year)	$ 34.70
Monthly ($/kW/Month)	2.89
Weekly ($/kW/Week)	0.67
Daily - Off Peak ($/kW/Day)	0.095
Daily - On-Peak ($/kW/Day)	0.111
Hourly - Off-Peak ($/MWH)	3.96
Hourly - On-Peak ($/MWH)	6.95

Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the hourly charge identified in this Schedule 7. On-Peak Hours are the hours between 7:00 a.m. and 11:00 p.m., Mountain Prevailing Time, Monday through Saturday, and Off-Peak Hours are all other hours.

Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point

Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

~~1) **Yearly delivery**: one-twelfth of the demand charge of $**[To Be Determined]** of Reserved Capacity per year.~~

~~2) **Monthly delivery**: $**[To Be Determined]** of Reserved Capacity per month.~~

~~3) **Weekly delivery**: $**[To Be Determined]** of Reserved Capacity per week.~~

~~4) **Daily on-peak delivery**: $**[To Be Determined]** of Reserved Capacity per day.~~

~~5) **Daily off-peak delivery: [To Be Determined]** of Reserved Capacity per day.~~

~~The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.~~

~~5)~~

Term of Reservation	**Charge**
Annual ($/kW/Year)	$ 34.70
Monthly ($/kW/Month)	2.89
Weekly ($/kW/Week)	0.67
Daily - Off Peak ($/kW/Day)	0.095
Daily - On-Peak ($/kW/Day)	0.111
Hourly - Off-Peak ($/MWH)	3.96
Hourly - On-Peak ($/MWH)	6.95

Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an ~~affiliate's~~Affiliate's use)

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must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from ~~p~~Point(s) of ~~receipt~~ Receipt to ~~point~~Point(s) of ~~delivery~~Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

~~6) Capacity and energy losses occur when a Transmission Provider delivers electricity across its transmission facilities for a Transmission Customer. A Transmission Customer may elect to (1) supply the capacity and/or energy necessary to compensate the Transmission Provider for such losses, (2) receive an amount of electricity at delivery points that is reduced by the amount of losses incurred by the Transmission Provider, or (3) have the Transmission Provider supply the capacity and/or energy necessary to compensate for such losses. If losses are supplied by the Transmission Provider, the applicable charges for energy relating to such service are as follows: The basic charge for energy losses generated and provided by the Company shall be computed as the product of (a) the relevant energy loss factor as listed in the table in section 15.7 times (b) the energy scheduled by the Customer times (c) an energy loss rate of $**[To Be Determined]**.~~

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the hourly charge identified in this Schedule 7. On-Peak Hours are the hours between 7:00 a.m. and 11:00 p.m., Mountain Prevailing Time, Monday through Saturday, and Off-Peak Hours are all other hours.

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Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the

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Tariff.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

Term of Reservation	Charge
Annual ($/kW/Year)	$ 34.70
Monthly ($/kW/Month)	2.89
Weekly ($/kW/Week)	0.67
Daily - Off Peak ($/kW/Day)	0.095
Daily - On-Peak ($/kW/Day)	0.111
Hourly - Off-Peak ($/MWh)	3.96
Hourly - On-Peak ($/MWh)	6.95

Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate’s use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the hourly charge identified in this Schedule 8. On-Peak Hours are the hours between 7:00 a.m. and 11:00 p.m., Mountain Prevailing Time, Monday through Saturday, and Off-Peak Hours are all other hours.

Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the

Tariff.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

~~1) **Monthly delivery**: $**[To Be Determined]** of Reserved Capacity per month.~~

~~2) **Weekly delivery**: $**[To Be Determined]** of Reserved Capacity per week.~~

~~3) **Daily on-peak delivery:** $**[To Be Determined]** of Reserved Capacity per day.~~

~~4) **Daily off-peak delivery**: $**[To Be Determined]** of Reserved Capacity per day.~~

~~The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.~~

~~4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $**[To Be Determined]**. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.~~

~~5)~~

Term of Reservation	**Charge**
Annual ($/kW/Year)	$ 34.70
Monthly ($/kW/Month)	2.89
Weekly ($/kW/Week)	0.67
Daily - Off Peak ($/kW/Day)	0.095
Daily - On-Peak ($/kW/Day)	0.111
Hourly - Off-Peak ($/MWh)	3.96
Hourly - On-Peak ($/MWh)	6.95

Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an ~~affiliate's~~Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from ~~point~~Point(s) of ~~receipt~~ Receipt to ~~point~~Point(s) of ~~delivery~~Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System ~~except when transmission service is provided for a verifiable contingency or emergency~~.

~~6) Capacity and energy losses occur when a Transmission Provider delivers electricity across its transmission facilities for a Transmission Customer. A Transmission Customer may elect to (1) supply the capacity and/or energy necessary to compensate the Transmission Provider for such losses, (2) receive an amount of electricity at delivery points that is reduced by the amount of losses incurred by the Transmission Provider, or (3) have the Transmission Provider supply the capacity and/or energy necessary to compensate for such losses. If losses are supplied by the Transmission Provider, the applicable charges for energy relating to such service are as follows:~~

~~The basic charge for energy losses generated and provided by the Company shall be computed as the product of (a) the relevant energy loss factor as listed in the table in section 15.7 times (b) the energy scheduled by the Customer times (c) an energy loss rate of $~~~~**[To Be Determined]**~~.

Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this

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service is reserved and in no event shall exceed the hourly charge identified in this Schedule 8. On-Peak Hours are the hours between 7:00 a.m. and 11:00 p.m., Mountain Prevailing Time, Monday through Saturday, and Off-Peak Hours are all other hours.

Resales: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

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Attachment E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cheyenne Light, Fuel and Power Company	**Docket No. ER14-____-000**

ATTESTATION PURSUANT TO 18 C.F.R. § 35.13(d)(6)

I, Ivan Vancas, the Vice President--Operations Services of Cheyenne Light, Fuel and Power Company, do hereby attest that, to the best of my knowledge, information, and belief, the cost of service materials and supporting data submitted as part of this filing, which purport to reflect the books of Cheyenne Light, Fuel and Power Company, are true, accurate, and current representations of the company's books, budgets, or other documents.

Ivan Vancas

____
Ivan Vancas

Subscribed and sworn before me at county of Pennington, state of South Dakota this 28th day of February, 2014.

Kenna J Hagan

____
Notary Public

My commission expires on: 10-26-16

KENNA J. HAGAN
NOTARY
PUBLIC
STATE OF SOUTH DAKOTA

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Cheyenne Light, Fuel and Power	Docket No. EL14-___-000

INDEX OF EXHIBITS

Exhibit No.	Description
CLP-1	Direct Testimony of Alan C. Heintz
CLP-2	Summary of Testimony Experience of Alan C. Heintz
CLP-3	Period I Statement AA – Balance Sheets
CLP-4	Period I Statement AB – Income Statement
CLP-5	Period I Statement AC – Statement of Retained Earnings
CLP-6	Period I Statement AD – Utility Plant in Service
CLP-7	Period I Statement AE – Accumulated Depreciation
CLP-8	Period I Statement AF – Specified Deferred Credits
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CLP-10	Period I Statement AH – Operation and Maintenance Expenses
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CLP-30	Period I Statement BC – Reliability Data
CLP-31	Period I Statement BD – Allocation Energy and Supporting Data
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CLP-70	Period II Statement BF – Exclusive-Use Commitments of Major Power Supply Facilities
CLP-71	Period II Statement BG – Proposed and Present Revenues
CLP-72	Period II Statement BH – Present Revenues
CLP-73	Period II Statement BI – Fuel Cost Adjustment Factors
CLP-74	Period II Statement BJ – Summary Data Tables
CLP-75	Period II Statement BK – Cost of Service Study
CLP-76	Period II Statement BL – Rate Design
CLP-77	Period II Statement BM - Construction Program Statement
CLP-100	Prepared Direct Testimony and Exhibits of William E. Avera, Ph.D. and Adrien M. Mckenzie
CLP-101	Qualifications of William E. Avera and Adrien M. McKenzie
CLP-102	Summary of Results
CLP-103	Risk Measures – National Group
CLP-104	DCF Model – National Group

CLP-105	Risk Premium – State ROE
CLP-106	Risk Premium – FERC ROE
CLP-107	Empirical Capital Asset Pricing Model
CLP-108	Risk Premium – Gas Pipeline ROE
CLP-109	Capital Asset Pricing Model
CLP-110	Expected Earnings Approach
CLP-111	DCF Model – Non-Utility Group
CLP-112	FERC DCF Model – National Group
CLP-113	BR+SV Growth Rate – National Group

CHEYENNE LIGHT, FUEL AND POWER COMPANY
BALANCE SHEET -- ASSETS
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-3
PERIOD I
STATEMENT AA

Title of Account	2011	2012
UTILITY PLANT		
Utility Plant	416,300,956	441,400,625
Construction Work in Progress	11,684,553	24,088,060
TOTAL Utility Plant	427,985,509	465,488,685
(Less) Accum. Prov. for Depr. Amort. Depl.	98,080,166	105,095,539
Net Utility Plant	329,905,343	360,393,146
TOTAL Other Property and Investments	329,905,343	360,393,146
CURRENT AND ACCRUED ASSETS		
Cash	364,901	631,456
Accounts Receivable	28,488,160	13,441,893
Inventories	7,595,771	6,912,218
Prepayments	941,006	992,634
Other	5,326,314	5,092,541
TOTAL Current and Accrued Assets	42,716,152	27,070,742
DEFERRED DEBITS		
Unamortized Debt Exp	1,309,468	1,237,352
Other Regulatory Assets	24,578,254	25,779,396
Other	7,730,468	8,313,494
TOTAL Deferred Debits	33,618,190	35,330,242
TOTAL Assets and Other Debits	$ 406,239,685	$ 422,794,130

Note: Ties to 2012 FERC Form 1, pages 110-113.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
BALANCE SHEET -- LIABILITIES
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-3
PERIOD I
STATEMENT AA

Title of Account	2011	2012
CAPITALIZATION		
Common Shareholder Equity	$ 177,090,274	$ 175,965,410
Preferred Securities	0	0
Long-term Debt	127,000,000	127,000,000
TOTAL Proprietary Capital & Long-Term Debt	304,090,274	302,965,410
OTHER NONCURRENT LIABILITIES		
Capital Leases		
Accumulated Provision for Damages and Injuries	51,203	56,465
Accumulated Provision for Pensions and Benefits	0	93,691
Other Noncurrent Liabilities	0	0
Asset Retirement Obligations	217,529	226,825
TOTAL Other Noncurrent Liabilities	268,732	376,981
CURRENT LIABILITIES		
Short term Debt		
Current Debt Maturities		
Accounts Payable	16,489,413	29,060,605
Customer Deposits	1,632,651	1,813,142
Accrued Dividends, Intereest and Taxes	2,738,142	4,175,525
Accrued Misellaneous & Other	3,493,127	3,228,635
TOTAL Current & Accrued Liabilities	24,353,333	38,277,907
DEFERRED CREDITS		
Deferred Income Taxes & ITC	70,244,712	75,494,153
Other Regulatory Liabilities	3,538,393	3,436,462
Customer Advances for Construction	3,744,241	2,243,217
Accrued Other		
TOTAL Deferred Credits	77,527,346	81,173,832
TOTAL Liab and Other Credits	$ 406,239,685	$ 422,794,130

Note: Ties to 2012 FERC Form 1, pages 110-113.

CHEYENNE LIGHT, FUEL AND POWER COMPANY	Exh. No. CLP-4
INCOME STATEMENT	PERIOD I
Calendar Years 2011 & 2012	STATEMENT AB
Units: $000s	

Title of Account	2011	2012
UTILITY OPERATING INCOME		
Operating Revenues	$ 165,610,893	$ 159,493,259
Operating Expenses		
Operating & Maintenance Expense	119,985,091	113,083,622
Depreciation & Amortization Expense	11,447,784	11,932,967
Regulatory Debits (net)		
Taxes Other Than Income	2,978,020	3,751,900
Income Taxes -- Federal and Other	(3,369,695)	2,886,726
Provision for Deferred Income Taxes	11,539,611	4,805,042
Other	(45,206)	(43,384)
TOTAL Utility Operating Expenses	142,535,605	136,416,873
Net Utility Operating Income	23,075,288	23,076,386
Other Income		
Other Income	792,579	612,112
Other Income Deductions	158,258	162,305
Taxes on Other Income	5,717	1,953
TOTAL Other Income -- Net	628,604	447,854
Earnings before Interest & Preferred	23,703,892	23,524,240
Interest Charges		
Interest Expense	7,827,350	7,714,119
(Less) Allowance for Borrowed Funds Used During Construction	(88,892)	(121,743)
Net Interest Charges	7,916,242	7,835,862
Earnings before Preferred & Extraordinary Items	15,787,650	15,688,378
Preferred Dividends and Extradordinary Items	0	0
Net Income	$ 15,787,650	$ 15,688,378

Note: Ties to 2012 FERC Form 1, pages 114-117.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
STATEMENT OF RETAINED EARNINGS
Calendar Years 2011 & 2012
Units: $000s

Exh. No. CLP-5
PERIOD I
STATEMENT AC

Item	2011	2012
Unappropriated Balance - Beginning of Year	$ 39,184,033	$ 40,471,683
Equity Earnings of Subsidiary Company		(16,813,242)
Balance Transferred from Income	15,787,650	15,688,378
Transfers from Account 216.1	(14,500,000)	
Unappropriated Balance - End of Year	$ 40,471,683	$ 39,346,819
Appropriated Retained Earnings		
Change in Accounting Method for Unbilled Revenue		
Total Retained Earnings	$ 40,471,683	$ 39,346,819

Note: Ties to 2012 FERC Form I, pg 118 & 119

CHEYENNE LIGHT, FUEL AND POWER COMPANY
UTILITY PLANT IN SERVICE
December 2011 through December 2012
Units: $000s

Exh. No. CLP-6
PERIOD I
STATEMENT AD

UTILITY PLANT IN SERVICE

Month/Yr	Production	Transmission	Distribution	General	Intangible	Electric Common	Total
Dec-11	$ 182,716,932	$ 5,867,274	$ 129,799,426	$ 3,010,785	$ 168,500	$ 5,120,996	$ 326,683,913
Jan-12	182,768,073	5,867,277	130,155,228	3,059,829	168,500	5,123,032	327,141,939
Feb-12	182,768,073	5,867,075	130,990,996	3,099,668	168,500	5,123,032	328,017,344
Mar-12	182,871,222	5,857,776	131,714,485	3,272,701	168,500	4,780,771	328,665,455
Apr-12	182,901,625	5,867,767	133,949,292	2,915,878	168,500	4,805,900	330,608,962
May-12	182,930,265	8,337,411	135,748,180	2,925,870	168,500	4,794,583	334,904,809
Jun-12	183,219,200	8,319,574	138,936,899	2,969,164	168,500	4,817,531	338,430,868
Jul-12	183,174,489	8,257,354	139,400,064	3,000,504	168,500	4,858,156	338,859,067
Aug-12	183,190,891	9,078,377	139,688,793	2,999,768	168,500	4,859,013	339,985,342
Sep-12	184,681,766	9,244,976	140,179,303	3,040,798	168,500	5,127,581	342,442,924
Oct-12	184,099,317	9,244,976	140,511,852	3,040,663	168,500	5,129,836	342,195,144
Nov-12	184,099,317	9,244,976	141,880,516	3,035,173	168,500	5,127,077	343,555,559
Dec-12	184,542,754	10,366,408	142,345,868	3,962,063	168,500	4,954,608	346,340,201
13 Month Average	$ 183,381,840	$ 7,801,632	$ 136,561,608	$ 3,102,528	$ 168,500	$ 4,970,932	$ 335,987,041

	GSU's Booked to Transmission
Dec-11	$ 1,570,095
Jan-12	$ 1,570,095
Feb-12	$ 1,570,095
Mar-12	$ 1,570,095
Apr-12	$ 1,570,095
May-12	$ 1,570,095
Jun-12	$ 1,570,095
Jul-12	$ 1,570,095
Aug-12	$ 1,570,095
Sep-12	$ 1,570,095
Oct-12	$ 1,570,095
Nov-12	$ 1,570,095
Dec-12	$ 1,570,095
13 Month Average	$ 1,570,095

Note: (1) December 2011 & 2012 electric numbers tie to Form I, pages 204/205, rows 5 & 46, and pages 206/207, rows 58, 75, 99 & 104. The total number also ties to pages 200/201, row 3.
(2) The remaining months are pulled from the company's internal financial records.
(3) The "13 Month Average" amounts go forward to:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study
(4) The "13 Month Average" GSU amounts go forward to:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
ACCUMULATED DEPRECIATION
December 2011 through December 2012
Units: $000s

Exh. No. CLP-7
PERIOD I
STATEMENT AE

ACCUMULATED DEPRECIATION

Month/Yr	Intangible	Production	Transmission	Distribution	General	Electric Common	Total
Dec-11	$ 169,610	$ 16,175,531	$ 1,920,195	$ 42,925,499	$ 912,804	$ 2,724,318	$ 64,827,957
Jan-12	169,616	16,576,161	1,931,356	43,230,443	937,977	2,759,488	65,605,041
Feb-12	169,605	16,975,166	1,942,328	43,427,275	963,314	2,794,367	66,272,055
Mar-12	168,326	17,244,129	1,938,678	43,924,494	960,979	2,440,644	66,677,250
Apr-12	168,330	17,641,611	1,949,735	44,123,115	986,373	2,474,423	67,343,587
May-12	168,196	18,024,232	1,961,593	44,183,555	1,022,205	2,533,509	67,893,290
Jun-12	168,225	18,424,091	1,977,738	43,908,667	1,044,902	2,567,509	68,091,132
Jul-12	168,266	18,825,445	1,990,956	44,221,720	1,061,987	2,601,728	68,870,102
Aug-12	168,203	19,200,209	2,005,237	44,355,972	1,078,521	2,649,975	69,458,117
Sep-12	168,167	19,592,880	1,969,967	44,533,347	1,094,718	2,685,011	70,044,090
Oct-12	168,214	19,446,316	1,985,806	44,739,504	1,112,247	2,709,843	70,161,930
Nov-12	168,189	19,840,425	2,000,785	44,952,944	1,124,621	2,730,959	70,817,923
Dec-12	168,207	$ 20,239,680	$ 2,887,027	$ 44,361,624	$ 1,343,243	$ 2,647,185	71,646,966
13 Month Average	$ 168,550	$ 18,323,529	$ 2,035,492	$ 44,068,320	$ 1,049,530	$ 2,639,920	$ 68,285,342

Note: (1) December 2011 & 2012 electric numbers tie to Form I, pages 200/201, row 33, and page 219, rows 20 through 29.
(2) The remaining months are pulled from the company's internal financial records.
(3) The "13 Month Average" category amounts go forward to:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SPECIFIED DEFERRED CREDITS
Calendar Years 2011 and 2012

EOY AVERAGES

Units: $000s

Specified Deferred Credits	Total	Production	Transmission	Distribution	General & Intangible
#254 Deferred Tax Excess FAS 109 & Unamort. ITC	$ 236,473	$ 131,661	$ 5,624	$ 99,188	
#255 Acc. Deferred Investment Tax Credit	208,495	113,796	4,841	84,742	2,030
Allocation % for acct #411.4 activity		54.6%	2.3%	40.6%	1.0%
Amount Charged to #411.4	36,343	19,836	844	14,772	354
#282-283 Acc. Deferred Income Tax					
NPLT	(37,658,288)	(23,494,902)	(825,297)	(13,338,089)	
Pension (W&S)	126,837	56,708	2,912	67,217	
Other (see workpaper AF WP2)	(11,657,289)	(11,493,463)	-	(163,826)	
Total ADIT	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	-
Total Deferred Credits	$ (48,980,246)	$ (34,817,861)	$ (817,544)	$ (13,349,956)	$ 2,030

Specified Deferred Credits	Account #254 FAS109	Account #255 ADIT Credit	Account #282 ADIT	Account #283 ADIT	Total
12/31/2011 (Form I, pg 266, 274, 276, 278)	$ 250,656	$ 226,666	$ (46,022,113)	$ (9,316,619)	
12/31/2012 (Form 1, pg 267, 275, 277, 278)	222,290	190,323	(53,242,200)	(9,133,819)	
BOY/EOY Average	$ 236,473	$ 208,495	$ (49,632,156)	$ (9,225,219)	$(58,648,881)

Note: (1) The amounts in the following rows:
#254 Deferred Tax Excess FAS 109 & Unamortized ITC
#255 Amount Charged to #411.4
Total ADIT flow forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY	PERIOD I
SPECIFIED DEFERRED CREDITS	Workpaper #1 for Statement AF
Calendar Years 2011 and 2012	
Units: $000s	

(I) ACCOUNT 254 Deferred Tax Excess FAS 109 & Unamortized ITC

#254 Deferred Tax Excess FAS 109 & Unamortized ITC Account		Balance 12/31/2011	Balance 12/31/2012	Average
254300	ITC			$ -
254300	FAS109	$ 250,656	$ 222,290	236,473
		$ 250,656	$ 222,290	
Total 254				$ 236,473

(I) ACCOUNT 255 (INVESTMENT TAX CREDITS):

Description	Balance 12/31/2011	Balance 12/31/2012	Average
10% Electric Utility	$ 226,666	$ 190,323	$ 208,495
		-	-
			-
			-
			-
			-
			-
			-
			-
			-
Total	$ 226,666	$ 190,323	$ 208,495
Amount Charged to Account #411.4		$ 36,343	

Note: (1) Year-end 2011 & 2012 Account 254 Deferred Tax Excess FAS 109 & Unamortized ITC numbers tie to FERC Form I, page 278, rows 7 and 9.

(2) Year-end 2012 & 2013 Account 255 (Investment Tax Credits) tie to FERC Form I, pages 266 and 267, row 8.

(3) The "Totals" row amounts from this worksheet go forward to: Statement AF-Specified Deferred Credits

	BALANCE 12/31/2011	BALANCE 12/31/2012	Average	Gas	Common Plant Related	Common Labor Related	Electric Allocated W&S	Electric Allocated NPLT	Electric Production	Electric Trans	Electric Distribution
			-								
ELECTRIC											
481A Adjustment - Unit of Property	(1,502,511)	(1,502,511)	(1,502,511)					(1,502,511)			
Acquisition Costs	(40,001)	(40,001)	(40,001)					(40,001)			
Amortization	(3,368,515)	(4,457,904)	(3,913,209)						(3,913,209)		
Capitalized Interest	1,573,613	1,573,613	1,573,613						1,573,613		
Contributions In Aid Of Const-Elec	557,189	908,669	732,929					732,929			
Cost Of Removal-Elect	(848,418)	(870,395)	(859,406)					(859,406)			
Depreciation	(22,442,984)	(24,351,699)	(23,397,342)					(23,397,342)			
Facts And Circumstances-Elect	(673,862)	(1,272,147)	(973,004)					(973,004)			
Repair Allowance	(1,074,875)	(1,074,875)	(1,074,875)					(1,074,875)			
Sec 162 Ordinary & Necessary Busin	(130,521)	(130,521)	(130,521)						(130,521)		
Sec 481(A)-Tolling	(773,079)	(773,079)	(773,079)					(773,079)			
Section 174 Develop & Engineer Cos	(6,387,318)	(6,387,318)	(6,387,318)						(6,387,318)		
Unit of Property	(976,672)	(2,474,845)	(1,725,758)					(1,725,758)			
UTP - Property Balance Deferred	-	(370,697)	(185,349)						(185,349)		
FIN 48 Adjustment	-	408,388	204,194					204,194			
GAS											
Contributions In Aid Of Const-Gas	428,019	729,497	578,758	578,758							
Cost Of Removal-Gas	(207,182)	(233,840)	(220,511)	(220,511)							
Depreciation - Gas	(8,438,569)	(10,337,926)	(9,388,248)	(9,388,248)							
Facts And Circumstances-Gas	(78,509)	(263,852)	(171,180)	(171,180)							
COMMON											
Book/Tax Gain Difference	(562,986)	(1,350,258)	(956,622)		(956,622)						
Cost Of Removal -- Common	(2,275)	(2,893)	(2,584)		(2,584)						
Depreciation - Other	(1,072,658)	(967,606)	(1,020,132)		(1,020,132)						
								-			
TOTAL DEFERRED TAX LIABILITY (ACCT 282)	(46,022,113)	(53,242,200)	(49,632,156)	(9,201,181)	(1,979,338)	-	-	(29,408,854)	(9,042,784)	-	-
(12/31/2011 & 2012 Balance agrees to Form I, pg 274/2	(46,022,113)	(53,242,200)	Check Figure								
Electric											
Equity Afudc	(3,941,172)	(3,972,350)	(1,986,175)					(1,986,175)			
Equity Afudc Adjustment	11,347	15,557	(1,962,807)					(1,962,807)			
Deferred Costs	(353,009)	(338,999)	(163,826)								(163,826)
Deferred Energy	(3,626,598)	(4,548,348)	(2,450,679)						(2,450,679)		
Reg Energy Efficient Asset	-	(225,611)	(1,926,104)					(1,926,104)			
Deferred Rate Case	-	(4,658)	(2,329)					(2,329)			
Common											
Oci Derivative -- Interest Rate Swap	(1,296,525)	-	(648,262)		(648,262)						
Performance Plan Bonus	1,843	2,130	1,987			1,987					
Results Compensation/Bonus/Etc	128,025	173,387	150,706			150,706					
Reaquired Bond Loss	(166,421)	(151,539)	(158,980)		(158,980)						
Prepaid Expenses	(74,109)	(83,383)	(78,746)		(78,746)						
Derivatives Oci Noncurrent Assets	1,292,355	1,254,835	1,273,595		1,273,595						
Derivatives Oci Noncurrent Liabili	(1,292,358)	(1,254,838)	(1,273,598)		(1,273,598)						
TOTAL DEF.TAX LIABILITY (ACCT 283000/283110)	(9,316,619)	(9,133,819)	(9,225,219)	-	(885,991)	152,693	-	(5,877,416)	(2,450,679)	-	(163,826)
(12/31/2011 & 2012 Balance agrees to Form I, pg 276/2	(9,316,619)	(9,133,818)									
TOTALS	$ (55,338,733)	$ (62,376,018)	$ (58,857,375)	$ (9,201,181)	$ (2,865,329)	$ 152,693	$ -	$ (35,286,270)	$ (11,493,463)	$ -	$ (163,826)
Common Allocator					82.78%	83.07%					
Electric Portion			(49,188,740)		(2,372,018)	126,837	$ -	$ (35,286,270)	$ (11,493,463)	$ -	$ (163,826)
Gas Portion			(9,668,635)								

Note: (1) Year-end 2011 & 2012 Total Account 282 Deferred Tax Liability amounts tie to FERC Form I, pages 274 & 275, row 9.
(2) Year-end 2011 & 2012 Total Account 283 Deferred Tax Liability amounts tie to FERC Form I, pages 276 & 277, row 19.
(3) The "Totals" row amounts from this worksheet go forward to: Statement AF-Specified Deferred Credits

CHEYENNE LIGHT, FUEL AND POWER COMPANY
SPECIFIED PLANT ACCOUNTS AND DEFERRED DEBITS
December 2011 through December 2012
Units: $s

Exh. No. CLP-9
PERIOD I
STATEMENT AG

Property Held for Future Use -- Account 105

	Balance 12/31/2011	Balance 12/31/2012	Average Balance
Production	-	-	-
Transmission	-		-
Distribution	10,914		10,914
General	-		-
Common	-	-	-
Total	10,914	-	5,457

Account 182.3 -- Regulatory Assets	13 Month Ave. Balance
Other Reg. Assets FAS 109	$ 3,930,117

Accumulated Deferred Income Taxes -- Account 190 Electric

	Allocator	Production	Transmission	Distribution	Total Ave. Balance
Direct	Direct	112,307		-	112,307
Benefit Related	W&S	1,428,609	70,027	1,693,351	3,195,322
Miscellaneous	NPLT	888,366	31,205	504,327	1,423,898
Subtotal		2,429,282	101,232	2,197,677	4,731,527

Note: (1) Year-end 2011 & 2012 Total Account 105 Property Held for Future Use amounts tie to FERC Form I, page 214, row 47.

(2) Thirteen month average balance of Account 182.3-Other Regulatory Assets FAS 109 comes from workpaper Statement AG_WP1.

(3) Accumulated Deferred Income Taxes -- Account 190 amounts come from workpaper Statement AG_WP2. The Total Average Balance ties to the amount on workpaper Statement AG_WP1.

(3) The Average Balance numbers for each of the categories on this Statement AG go forward to the following worksheets:

Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
SPECIFIED DEFERRED DEBITS Statement AG Workpaper #1
Calendar Years 2011 & 2012
Units: $s

Unit	Acct	Year	Period			Balance
50502		2011	12		$	5,816,711
50502		2012	12			7,427,042
				Average	$	6,621,877

Regulatory Tax Asset - FAS 109

Unit	Acct	Year	Period		Balance
50502	182390	2011	12	$	3,929,824
50502	182390	2012	1		3,929,473
50502	182390	2012	2		3,929,122
50502	182390	2012	3		3,928,771
50502	182390	2012	4		3,928,421
50502	182390	2012	5		3,928,070
50502	182390	2012	6		3,927,719
50502	182390	2012	7		3,927,368
50502	182390	2012	8		3,927,017
50502	182390	2012	9		3,926,666
50502	182390	2012	10		3,926,316
50502	182390	2012	11		3,925,965
50502	182390	2012	12		3,956,793
				$	3,930,117

Note: (1) Year-end 2011 & 2012 balances in Account 190-Accumulated Deferred Income Taxes tie to FERC Form I, page 234, row 18, columns b & c.

(2) Year-end 2011 & 2012 balances in Account 182.3-Regulatory Deferred Income Taxes-FAS 109 tie to FERC Form I, page 232, row 27, columns b & f.

(3) The Average Balance amounts for Account 190-Accumulated Deferre Income Taxes tie to Statement AG, Total Average Balance of Account 190.

(4) The Average Balance amounts for Account 182-310-Regulatory Deferred Income Taxes-FAS 109 move forward to Statement AG.

CHEYENNE LIGHT, FUEL AND POWER COMPANY — PERIOD I
DEFERRED TAX ASSET ACCOUNTS — Statement AG Workpaper #2
Calendar Years 2011 & 2012
Units: $s

	FINAL BALANCE 12/31/2011	Per 10K END BAL 12/31/2012	Average	Gas	Common Plant Related	Common Labor	Allocated W&S	Allocated NPLT	Distribution	Production
ELECTRIC			$ -					$ -		
Line Extension	169,806	(113,766)	28,020					28,020	-	
Investment Tax Credit	79,334	66,673	73,004						-	73,004
FAS 109-ITC	42,712	35,895	39,304						-	39,304
Other	158,588	4,815	81,702					81,702		
			-						-	
GAS			-						-	
Line Extention Dep	660,338	498,386	579,362	579,362						
Deferred Costs	96,912	427,901	262,407	262,407						
Investment Tax Credit	83,377	77,746	80,562	80,562						
FAS 109-ITC	44,891	41,859	43,375	43,375						
									-	
COMMON										
Other										
Pension	647,758	316,214	481,986			481,986				
Retiree Healthcare	2,308,946	2,489,454	2,399,200			2,399,200				
Vacation	83,718	57,769	70,744			70,744				
Net Operating Loss Carryforward	(2,829,473)	-	(1,414,737)		(1,414,737)					
Disability Liability	171,884	168,985	170,435		170,435					
Bad Debt Reserve	963,926	950,087	957,007		957,007					
FAS 109	66,970	52,550	59,760		59,760					
FAS 109 Retiree Healthcare (190)	2,000,769	-	1,000,385		1,000,385					-
FAS 109 retiree Healthcare (190)	-	755,262	377,631		377,631					
Reg Pension	735,910	-	367,955			367,955				
Reg Pension	-	1,007,189	503,595			503,595				
Reacquired Bond Gain	330,708	303,149	316,929		316,929					
Investment Tax Credit - Other	339	210	275		275					
Employee Group Insurance	22,303	19,763	21,033			21,033				
ARO FASB 143 Asset	22,775	26,029	24,402		24,402					
Rollover Adjustments	(41,400)		(20,700)		(20,700)					
Workmans Compensation	(4,381)	8,763	2,191			2,191				
R & D Credit Carryover		187,301	93,651		93,651					
UTP - Accrued Interest B/S Inactive		39,975	19,988		19,988					
UTP - Accrued Interest B/S Expense		4,928	2,464		2,464					
	$ 5,816,710	$ 7,427,137	$ 6,621,924	$ 965,705	$ 1,587,487	$ 3,846,703	$ -	$ 109,722	$ -	$ 112,307
Common Allocator					82.78%	83.07%				
Electric Portion			4,731,527		1,314,177	3,195,322	$ -	$ 109,722	$ -	$ 112,307
Gas Portion			1,890,396	965,705	273,310	651,381				

Note: (1) Year-end 2011 & 2012 balances in Account 190-Accumulated Deferred Income Taxes tie to FERC Form I, page 234, row 18, columns b & c.

(2) The categorized total amounts for the average Account 190-Accumulated Deferred Income Taxes move forward to Statement AG.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

Operation and Maintenance Expenses	Total Year
Production	$ 66,401,461
Transmission	11,750,217
Distribution	2,573,114
Customer Accounts	1,103,729
Customer Service	601,067
Sales Expenses	538
Administrative and General	6,741,442
Total	$ 89,171,568

Note: (1) The source for these totals are the following Schedule AH pages.
(2) The totals for each of the categories on this Statement AH go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

FERC Account		Demand	Energy	Total
	Production			
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering			
501	Fuel			
502	Steam Expenses			
503	Steam from Other Sources			
504	Steam Transferred - Credit			
505	Electric Expenses			
506	Miscellaneous Steam Power Expenses			
507	Rents			
	Total Operation	-	-	-
Maintenance				
510	Maintenance Supervision and Engineering			
511	Maintenance of Structures			
512	Maintenance of Boiler Plant			
513	Maintenance of Electric Plant			
514	Maintenance of Miscellaneous Steam Plant			
	Total Maintenance	-	-	-
	Total Power Production Expenses - Steam Plant	-	-	-
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	-	-	-
518	Fuel	-	-	-
519	Coolants and Water	-	-	-
520	Steam Expenses	-	-	-
521	Steam from Other Sources	-	-	-
522	Steam Transferred - Credit	-	-	-
523	Electric Expenses	-	-	-
524	Miscellaneous Steam Power Expenses	-	-	-
525	Rents	-	-	-
	Total Operation			-
Maintenance				
528	Maintenance Supervision and Engineering	-	-	-
529	Maintenance of Structures	-	-	-
530	Maintenance of Reactor Plant Equipment	-	-	-
531	Maintenance of Electric Plant	-	-	-
532	Maintenance of Miscellaneous Steam Plant	-	-	-
	Total Maintenance			-
	Total Power Production Expenses - Nuclear Plant			-

Note: (1) Totals for FERC accounts 500 - 532 tie to FERC Form 1, page 320, rows 4 through 41, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

		Demand	Energy	Total
	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	-	-	-
536	Water for Power	-	-	-
537	Hydraulic Expenses	-	-	-
538	Electric Expenses	-	-	-
539	Misc. Hydraulic Power Gen. Expenses	-	-	-
540	Rents	-	-	-
	Total Operation			-
Maintenance				
541	Maintenance Supervision and Engineering	-	-	-
542	Maintenance of Structures	-	-	-
543	Maint. of Reservoirs, Dams & Waterways	-	-	-
544	Maintenance of Electric Plant	-	-	-
545	Maintenance of Misc. Hydroelectric Plant	-	-	-
	Total Maintenance			-
	Total Power Production Expenses -- Hydroelectric			-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering			
547	Fuel			
548	Generation Expenses			
549	Miscellaneous Other Power Gen. Expenses			
550	Rents			
	Total Operation	-	-	-
Maintenance				
551	Maintenance Supervision and Engineering			
552	Maintenance of Structures			
553	Maintenance of Generation & Electric Plant			
554	Maintenance of Misc. Other Power Gen.			
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Other Power	-	-	-
	Other Power Supply Expenses			
Operation				
555	Purchased Power			
556	System Control and Load Dispatching			
557	Other Expenses			
	Total Operation	-	-	-
	Total Power Production Expenses	$ -	$ -	$ 66,401,461

Note: (1) Totals for FERC accounts 535 - 545 tie to FERC Form 1, page 320, rows 44 through 59, column b.
(2) Totals for FERC accounts 546 - 557 tie to FERC Form 1, page 321, rows 62 through 80, column b.
(3) Note that Account 557 reflects a retail fuel deferral.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

	Transmission Expenses	
Operation		
560	Operation Supervision and Engineering	$ 107,908
561	Load Dispatching (561.1 through 561.4)	101,791
561	Reliability & Studies (561.5 through 561.8)	166,984
562	Station Expenses	
563	Overhead Line Expenses	
564	Underground Line Expenses	
565	Transmission of Electricity of Others	11,384,117
566	Miscellaneous Transmission Expenses	(10,583)
567	Rents	
	Total Operation	11,750,217
Maintenance		
568	Maintenance Supervision and Engineering	
569	Maintenance of Structures	
570	Maintenance of Station Equipment	
571	Maintenance of Overhead Lines	
572	Maintenance of Underground Lines	
573	Maintenance of Miscellaneous Transm. Plant	
	Total Maintenance	-
	Total Transmission Expenses	11,750,217
	Distribution Expenses	
Operation		
580	Operation Supervision and Engineering	
581	Load Dispatching	
582	Station Expenses	
583	Overhead Line Expenses	
584	Underground Line Expenses	
585	Street Lighting and Signal System Expenses	
586	Meter Expenses	
587	Customer Installation Expenses	
588	Miscellaneous Distribution Expenses	
589	Rents	
	Total Operation	-
Maintenance		
590	Maintenance Supervision and Engineering	
591	Maintenance of Structures	
592	Maintenance of Station Equipment	
593	Maintenance of Overhead Lines	
594	Maintenance of Underground Lines	
595	Maintenance of Line Transformers	
596	Maintenance of Street Lighting and Signal Systems	
597	Maintenance of Meters	
598	Maintenance of Miscellaneous Distribution Plant	
	Total Maintenance	-
	Total Distribution Expenses	$ 2,573,114

Note: (1) Totals for FERC accounts 560 - 573 tie to FERC Form 1, page 321, rows 83 through 112, column b.
(2) Totals for FERC accounts 580 - 598 tie to FERC Form 1, page 322, rows 134 through 156, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

		Customer Accounts Expenses	
Operation			
	901	Supervision	
	902	Meter Reading Expenses	
	903	Customer Records and Collection Expenses	
	904	Uncollectible Accounts	
	905	Miscellaneous Customer Accounts Expenses	
		Total Customer Accounts Expenses	1,103,729
		Customer Service and Information Expenses	
Operation			
	907	Supervision	
	908	Customer Assistance Expenses	
	909	Informational and Instructional Expenses	
	910	Miscellaneous Customer Service and Information Expenses	
		Total Customer Service and Information Expenses	601,067
		Sales Expenses	
Operation			
	911	Supervision	
	912	Demonstrating and Selling Expenses	
	913	Advertising Expenses	
	916	Miscellaneous Sales Expenses	
		Total Sales Expenses	538
		Administrative and General Expenses	
Operation			
	920	Administrative and General Salaries	3,854,195
	921	Office Supplies and Expenses	763,248
	922	Administrative Expenses Transferred - Credit	(10,117)
	923	Outside Services Employed	748,362
	924	Property Insurance	159,333
	925	Injuries and Damages	387,284
	926	Employee Pensions and Benefits	48,713
	927	Franchise Requirements	
	928	Regulatory Commission Expenses	24,833
	929	Duplicate Charges - Credit	
	930.1	General Advertising Expenses (See Next Page)	187,184
	930.2	Miscellaneous General Expenses (See Next Page)	192,137
	931	Rents	120,765
		Total Operation	6,475,937
Maintenance			
	935	Maintenance of General Plant	265,505
		Total Administrative and General Expenses	$ 6,741,442

Fuel Expenses

	Steam Generation Acct. 501	Nuclear Generation Acct. 518	Other Generation Acct. 547	Purchased Power Acct. 555	Total
January					
February					
March					
April					
May					
June	NOT USED FOR TRANSMISSION COST OF SERVICE				
July					
August					
September					
October					
November					
December					
Total	-	-		-	-

Note: (1) Totals for FERC accounts 901 - 905 tie to FERC Form 1, page 322, rows 159 through 164, column b.
(2) Totals for FERC accounts 907 - 935 tie to FERC Form 1, page 323, rows 167 through 197, column b.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OPERATION AND MAINTENANCE EXPENSES
Calendar Year 2012
Units: $s

Exh. No. CLP-10
PERIOD I
STATEMENT AH

Details of Accounts 930.1 and 930.2

Account 930.1	
General Advertising	$ 187,184
Total Account 930.1	187,184
Account 930.2	
Industry Association Dues	46,040
Publishing and Distribution Information to Stockholders	3,514
Other Miscellaneous Expense	16,001
Director Fees and Expenses	96,405
Travel	5,039
Supplies	1,416
GAAP to FERC (Acct 930299)	23,722
Total Account 930.2	$ 192,137

(v) 928.000 REGULATORY COMMISSION EXPENSES, DETAIL:

Description	FERC	non-FERC	Total
Jurisdictional Assessment		$ 6,180	$ 6,180
Expenses incurred by the Company in connection with formal cases before regulatory commissions.		16,444	$ 16,444
Professional Services and Other Expenses (Other than Officers or Employees)			$ -
Employee related expenses			$ -
Totals	$ -	$ 22,624	$ 22,624

Note: (1) These detailed amounts for accounts 930.1, 930.2 and 928 come from the Company's books and records.
Further details of accounts 930.1, 930.2 and 928 are contained in the workpapers.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WAGES AND SALARIES
Calendar Year 2012
Units: $s

Exh. No. CLP-11
PERIOD I
Statement AI

Electric Utility Wages and Salaries

Included in Operation and Maintenance Expenses

	Total
Production	$ 1,821,980
Transmission	93,563
Regional Market	
Distribution	920,161
Customer Accounts	748,550
Customer Service	490,908
Sales Expenses	
Administrative and General	2,963,212
Total Wages and Salaries Included in O&M Expenses	$ 7,038,374
Wages & Salaries Excluding A&G	$ 4,075,162

Note: (1) Total wages and salaries by category come from FERC Form I, page 354, rows 20-28, column b.

(2) The totals for each of the categories on this Statement AI go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Function	Depreciable Plant Base Form 1, pg 337-337.1	Depreciation Expense Annual Form 1, pg 336
Production Plant	$ 184,321	$ 4,762,036
Transmisson Plant	7,994	163,458
Distribution Plant	143,339	3,855,356
General, Common & Intangible Plant	13,866	807,467
Total Depr Amortization Expense	$ 349,520	9,588,317
Limited Term Amortization (Acct. 404)		
Total Depreciation & Amortiztion Expense		$ 9,588,317

Note: (1) Annual depreciation expense come from FERC Form 1, page 336, rows 1 - 12, columns b & d.
(2) Depreciable plant base ties to FERC Form 1, pages 337-337.1, subtotals in column b.
(3) The annual depreciation expense totals, by category, go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Account	Description		Annual Rate
	Steam Production Plant		
310		$ -	
311		8,540	2.77%
312		95,207	2.77%
314		71,004	2.39%
315		9,468	2.50%
316		102	5.72%
317			
	Sub-total	184,321	
	Other Production Plant		
340		-	
341		-	
342		-	
343		-	
344		-	
345		-	
346		-	
347		-	
	Sub-total	-	
	Total Production Plant	184,321	
	Transmission Plant		
350		-	
352		732	2.15%
353		4,270	1.92%
354		364	2.98%
355		1,541	2.29%
356		1,087	2.35%
357			
358			
359			
	Total Transmission Plant	$ 7,994	

Note: (1) Depreciable plant base by FERC account comes from FERC Form 1, page 337, column b.
(2) Annual depreciation rate by FERC account comes from FERC Form 1, page 337, column e.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
DEPRECIATION AND AMORTIZATION EXPENSES
Calendar Year 2012
Units: $000s

Exh. No. CLP-12
PERIOD I
STATEMENT AJ

Account	Description	Depr Plant Base	Annual Rate
	Distribution Plant		
360		-	
361		658	2.54%
362		14,578	2.65%
364		20,174	2.79%
365		19,531	2.80%
366		6,743	2.69%
367		37,108	2.69%
368		19,169	2.77%
369		14,590	2.64%
370		880	4.01%
372		2,012	3.82%
373		7,896	2.80%
	Total Distribution Plant	143,339	
	General Plant		
389		-	
390		3,012	2.79%
391.1		1,911	3.72%
391.2		4,093	9.00%
392		189	4.98%
393		2,040	4.98%
394		62	4.98%
395		643	9.00%
396		1,866	4.98%
397		50	4.98%
398		-	
399.1		-	
	Total General Plant	13,866	
	Total Depreciable Plant	349,520	

Note: (1) Depreciable plant base by FERC account comes from FERC Form 1, pages 337-337.1, column b.
(2) Annual depreciation rate by FERC account comes from FERC Form 1, pages 337-337.1, column e.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
TAXES OTHER THAN INCOME TAXES
Calendar Year 2012
Units: $s

Exh. No. CLP-13
PERIOD I
STATEMENT AK

		Annual Total
Revenue taxes		
Real estate and property taxes (incl. Ad volorem)		1,194,583
Payroll taxes (incl. "Insurance contributions")		6,856
Business		
Franchise		1,083,117
Miscellaneous taxes (incl. Reg. Commission)		269,470
	$	2,554,026
Income		2,594,767
Total per FM 1	$	5,148,793

Note: (1) Taxes other than income come from FERC Form 1, page 263, column i.
(2) The *total* Taxes Other Than Income amount goes forward to:
Statement BJ-Summary Data Tables
The Taxes Other Than Income *category amounts* go forward to:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WORKING CAPITAL
December 2011 through December 2012
Units: $s

Exh. No. CLP-14
PERIOD I
STATEMENT AL

SUMMARY

	Average
Fuel Inventories (non-nuc.)	N/A
Materials & Supplies -- Transmission	-
Property Insurance	$ 123,836
Other Prepayments	759,124
Total	882,960

Materials and Supplies

	Production	Transmission	Distribution	Construction & Other	Total
Dec-11	2,332,965		47,470	3,103,882	5,484,317
Dec-12	2,371,719		53,889	3,161,601	5,587,209
Beg/End Avg.	2,352,342	-	50,680	3,132,742	5,535,763

Prepayments and Insurance

	Property Insurance	Other		Total
		Prepayments	Direct - Prod. & Dist.	
13 Mo. Avg.	$ 123,836	$ 95,837	$ 663,287	$ 882,960

Note: (1) Materials and Supplies come from FERC Form 1, page 227, columns b & c.
(2) The Prepayments amounts come from Statement AL_WP1.
(3) The average Working Capital category amounts go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WORKING CAPITAL
December 2011 through December 2012
Units: $s

PERIOD I
Workpaper for Statement AL

Prepayments

Period I	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	13 Mo. Ave
Insurance														
														-
165002 Prepaid Insurance	$ 184,822	$ 163,868	$ 142,914	$ 121,961	$ 101,007	$ 80,053	$ 59,099	$ 55,416	$ 34,260	$ 13,104	$ 240,003	$ 217,787	$ 195,571	$ 123,836
														-
														-
														-
Total Insurance Prepayments	184,822	163,868	142,914	121,961	101,007	80,053	59,099	55,416	34,260	13,104	240,003	217,787	195,571	123,836
Other Prepayments														
														-
165004 Prepaid Maintenance	12,448	11,316	10,185	9,053	7,921	6,790	5,658	4,527	3,395	2,263	1,132	10,692	9,801	7,322
165012 Prepaid Other	40,967	40,967	80,627	76,661	72,695	68,729	64,763	60,797	56,831	52,865	48,899	44,933	40,967	57,746
165013 Prepaid Transmission Deposits	-	-	-	-	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	30,769
														-
														-
														-
Total Other Prepayments	53,415	52,283	90,812	85,714	80,616	125,519	120,421	115,324	110,226	105,128	100,031	105,625	100,768	95,837
Electric Production Prepayments														
														-
165013 Prepaid Coal	702,769	660,388	387,178	660,388	705,662	683,806	696,295	685,367	718,152	657,265	672,877	696,295	696,295	663,287
														-
														-
														-
														-
														-
														-
														-
														-
Total Electric Production Prepayments	702,769	660,388	387,178	660,388	705,662	683,806	696,295	685,367	718,152	657,265	672,877	696,295	696,295	663,287
Total Prepayments	$ 941,006	$ 876,539	$ 620,904	$ 868,063	$ 887,285	$ 889,378	$ 875,815	$ 856,107	$ 862,638	$ 775,497	$ 1,012,911	$ 1,019,707	$ 992,634	$ 882,960

Note: (1) Beginning and ending Prepayments balances tie to FERC Form 1, page 111, row 57, columns b (ending balance) & d (beginning balance).

CWIP IS NOT INCLUDED IN RATE BASE

CHEYENNE LIGHT, FUEL AND POWER COMPANY | Exh. No. CLP-16
NOTES PAYABLE | PERIOD I
December 2011 through December 2012 | Statement AN
Units: $000s

	Electric
December '11	$ -
January '12	-
February	-
March	-
April	-
May	-
June	-
July	-
August	-
September	-
October	-
November	-
December '12	-
Total	-
13 Mo. Avg.	$ -

Note: (1) Monthly balances in Notes Payable come from the companies books and records.
(2) The average Notes Payable balance goes forward to the following worksheet:
Statement BJ-Summary Data Tables

CHEYENNE LIGHT, FUEL AND POWER COMPANY
RATE FOR ALLOWANCE FOR FUNDS
USED DURING CONSTRUCTION
Calendar Year 2012
Units: $s

Exh. No. CLP-17
PERIOD I
STATEMENT AO

Note: The Company used 7.986% AFUDC rate in 2012. This rate was within the FERC guidelines. The calculation of the AFUDC is shown below.

Input Values

S = Average Short-Term Debt for year 2011	=	$ 884,278
RS = Short-Term Debt Interest Rate	=	5.38%
D = Long-Term Debt, Year End 2011	=	$ 127,000,000
RD = Long-Term Debt Interest Rate	=	6.15%
P = Preferred Stock, Year End 2011	=	$ -
RP = Preferred Stock Cost Rate	=	0.00%
C = Common Equity, Year End 2011	=	$ 177,090,274
RC = Commony Equity Cost Rate (Authorized per PSCN)	=	9.60%
W = Average CWIP plus Nuclear Fuel In Process	=	$ 14,213,633

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction
= (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))

AI =	2.743%	6.00%
AI=	6.000%	

AE = Rate for Allowance for Other Funds used during Construction
= (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))

AE =	5.243%	2.37%
AE=	2.37%	

Gross Nominal Rate =	7.986%
Effective annual Rate (Semi-Annual Compounding	8.146%
Effective Monthly Rate (Semi-Annual Compounding)	0.655%

Notes: (1) AFUDC notes and numbers come from the company's books and records.
(2) This is a standalone worksheet; these numbers flow to no other statements.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
FEDERAL INCOME TAX DEDUCTIONS -- INTEREST
Calendar Year 2012
Units: $000s

Exh. No. CLP-18
PERIOD I
STATEMENT AP

Long Term Interest Expense	Rate Base	Weighted LTD Rate (%)	Long Term Interest
Transmission	$ 5,050,281	2.539%	$ 128,234
All Other	213,718,290	2.539%	5,426,607
Total	$ 218,768,571		$ 5,554,840

Acct. 431 -- Other Interest Expense	
Other Interest Expense	$ 109,183
Total	$ 109,183

Account 432 (see Stmt AB)	$ 121,743

Note: (1) Long Term Interest Expense - Rate Base amounts come from Statement BK.
(2) Long Term Interest Expense - Weighted LTD Rates come from Statement AV.
(3) Total Account 431 - Other Interest Expense ties to FERC Form 1, page 117, row 68, column c. Detailed amounts come from company's books & records.
(4) Account 432 - Allowance for Borrowed Funds Used During Construction amounts come from FERC Form 1, page 117, row 69, column c.
(5) The totals from this statement go forward to the following worksheet:
Statement BJ-Summary Data Tables

CHEYENNE LIGHT, FUEL AND POWER COMPANY | Exh. No. CLP-19
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST | PERIOD I
Calendar Year 2012 | STATEMENT AQ
Units: $000s

Additions to Income Before Taxes

Contributions in Aid in Construction	$	1,004	NPLT
Nondeductible and Deferred Taxes		(2,355)	NPLT
Employee Benefits		-	W&S
Other		34	NPLT
Allowance for Funds Used During Construction		(38)	NPLT
Total Additions to Income Before Taxes	$	(1,355)	

Allocators		
Production		-
Distribution		-
NPLT		(1,355)
W&S		-
Total	$	(1,355)

Deductions from Income Before Taxes

Cost of Removal		64	NPLT
Employee Benefits		-	W&S
Line Extension Deposits		1,501	NPLT
Deferred Revenue		2,594	NPLT
Tax Depreciation in Excess of Book Depreciation		17,244	NPLT
Other		250	NPLT
NOL Carry forward		-	NPLT
Total Reductions to Income Before Taxes	$	21,653	

Allocators		
Production		-
Distribution/Retail		-
Transmission		-
NPLT		21,653
W&S		-
Total	$	21,653

Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2 for details on the source for these amounts.

(2) The total "Allocators" by category go forward to the following worksheet:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY — PERIOD I
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST — Workpaper #1 to Statement AQ
Calendar Year 2012
Units: $000s

Federal Income Tax Deductions
- Other Than Interest

		Total	Statement BK Allocator	WP#2 Ref #
Additions to Income Before Taxes				
Contributions in Aid in Construction	$	1,004	NPLT	1
Nondeductible and deferred taxes		(2,355)	NPLT	2
Employee Benefits		-	W&S	3
Other		34	NPLT	4
Allowance for Funds Used During Construction		(38)	NPLT	12
Total Additions to Income Before Taxes		(1,355)		
Reductions to Income Before Taxes				
Cost of Removal		-	NPLT	5
Employee Benefits		64	W&S	6
Line Extension Deposits		-	NPLT	7
Deferred Revenue		1,501	NPLT	8
Tax Depreciation in Excess of Book Depreciation		2,594	NPLT	9
Other		17,244	NPLT	10
NOL Carry forward		250	NPLT	11
Total Reductions to Income Before Taxes		21,653		
Federal Income Tax Deductions - Other Than Interest		(23,008)	Ties to 2012 CP	

Reconciliation to FERC Form 1 pg 261			
Total federal income tax deductions (above)		23,008	Does not tie to FERC Form 1 because AQ WP 1 and 2 are electric only and the FERC Form is for all products.
Additional deductions per FF1 Pg 261		23,008	
FERC Form 1 Page 261			
Net income per books (line 1)		15,689	
Federal income taxes (line 12)		7,661	
Pre-tax income		23,350	
Net taxable income (line 27)		-	
Additional deductions per FERC Form 1	$	(23,350)	

Notes:

(1) Source for the numbers on this worksheet is Statement AQ_WP2. Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2 for details on the source for these amounts.

(2) The total "Additions to Income Before Taxes" and "Reductions to Income Before Taxes" amounts go forward to the following worksheet:
Statement AQ-Federal Income Tax Deductions Other Than Interest

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST Workpaper #2 to Statement AQ
Calendar Year 2012
Units: $s

	Ref #	ELECTRIC 12 MONTHS ENDING DEC 12
increase to income = positive		
PERMANENT & FLOW-THRU ITEMS		
Equity AFUDC Perm	12	$ (38,432)
SUBTOTAL PERM ITEMS & FLOW-THRU		(38,432)
NORMALIZED ITEMS		
Net Operating Loss	2	(2,354,562)
Reg Energy Efficient Asset	10	(249,824)
Deferred Energy	8	(2,633,574)
Deferred Costs	8	40,030
Deferred Rate Case	4	33,850
Line Extension Deposits	7	(1,501,025)
Contributions in Aid of Const-Elec	1	1,004,229
Cost of Removal-Elec	5	(63,712)
Depreciation	9	(16,717,391)
Facts and Circumstances-Elect	9	(482,139)
Unity of Property	9	(44,495)
SUBTOTAL NORMALIZED		(22,968,613)
TOTAL ADJUSTMENTS		$ (23,007,045)

Notes:
(1) Source for these numbers is the company's books and records.
Please refer to the workpapers for Statement AQ_WP1 and AQ_WP2
for details on the source for these amounts.
(2) These amounts are summarized, and move forward, to the following worksheet:
Statement AQ-Federal Income Tax Deductions Other Than Interest

CHEYENNE LIGHT, FUEL AND POWER COMPANY
INCOME TAX ADJUSTMENTS -- ACCOUNT 410.1
Calendar Year 2012
Units: $000s

Exh. No. CLP-20
PERIOD I
STATEMENT AR

		Allocator/Assignment				
	TOTAL	NPLT	W&S	DISTRIBUTION	PRODUCTION	TRANSMISSION
FERC Account 190 - Accumulated Deferred						
Income Taxes						
Line Extension Deposits	(749,148)	(749,148)				
NOL Carryforward	1,661,437	1,661,437				
	912,289	912,289	-	-	-	-
FERC Account 282 - Accumulated Deferred						
Amortization	(1,089,389)				(1,089,389)	
Cost of Removal-Elec	(22,299)	(22,299)				
Depreciation	(5,851,087)	(5,851,087)				
Facts and Circumstances-Elec	(645,934)	(645,934)				
Unity of Property	(1,498,173)	(1,498,173)				
UTP - Property Balance Deferred	(370,697)				(370,697)	
	(9,477,579)	(8,017,493)	-	-	(1,460,086)	-
FERC Account 283 - Accumulated Deferred						
Income Taxes - Other Property						
Income Taxes - Other Property						
Deferred Energy	(1,159,637)	(1,159,637)				
Reg Energy Efficient Asset	(225,611)	(225,611)				
Deferred Rate Case	(16,506)	(16,506)				
	(1,401,754)	(1,401,754)	-	-	-	-
Totals	$ (9,967,044)	$ (8,506,958)	$ -	$ -	$ (1,460,086)	$ -

Notes:

(1) Source for the numbers on this worksheet is the company's books and records. Please refer to the workpapers for Statement AR and AR_WP1 for details on the source for these amounts.

(2) The "Allocator/Assignment" totals by category go forward to the following worksheet: Statement BK-Cost of Service Study

(3) Note that there are no amounts in account #411.1

CHEYENNE LIGHT, FUEL AND POWER COMPANY PERIOD I
FEDERAL TAX ADJUSTMENTS Workpaper to Statement AR
Calendar Year 2012
Units: $000s

Reconciliation of FERC Form 1 page 115

Per FERC Form 1 page 115 line 17 (electric only)	$	15,192,613
Prior period adjustments including IRS audit & misc		(5,225,569)
		9,967,044
Statement AR		
Account 190		912,289
Account 282		(9,477,579)
Account 283		(1,401,754)
	$	(9,967,044)

Note: (1) Source for the numbers on this worksheet is the company's books and records. Please refer to the workpapers for Statement AR and AR_WP1 for details on the source for these amounts.

(2) The three "Statement AR" amounts, by account, come directly from that statement.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
ADDITIONAL STATE INCOME TAX DEDUCTIONS
Calendar Year 2012
Units: $000s

Exh. No. CLP-21
PERIOD I
STATEMENT AS

There were no additional state tax deductions for 2012

Deductions from Book Income to Determine Taxable Income:

	Amount
Total	$ -

Additions to Book Income to Determine Taxable Income:

	Amount
Total	$ -

Source: Corporate Records

CHEYENNE LIGHT, FUEL AND POWER COMPANY
STATE TAX ADJUSTMENTS
Calendar Year 2012

Exh. No. CLP-22
PERIOD I
STATEMENT AT

There were no additional state tax adjustments

CHEYENNE LIGHT, FUEL AND POWER COMPANY
REVENUE CREDITS
Calendar Year 2012
Units: $s

Exh. No. CLP-23
PERIOD I
STATEMENT AU

FERC Account	Description	12 mos of 2012 Revenue Credits Amount
456	Short-term Firm & Non-Firm Transmission of Electricity - Thrid Party Transactions	$ -
	Other Revenue Credits	-
447	Sales for Resale - Transmission Component of Offsystem Sales	-
	Total Transmission Revenue Credits	$ -

Note: (1) Source for the numbers on this worksheet is Statement AU_WP1.
(2) The "Total Transmission Revenue Credits" go forward to the following worksheet: Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
REVENUE CREDITS
Calendar Year 2012
Units: $s

PERIOD I
Workpaper for Statement AU

El PASO	AcctGL	ClsDescription					
	456175			456175 Total	456170	456170 Total	Grand Total
CustShortName	Third Party Firm Transmission	Third Party Long-Term Transmission	TSA Long Term Transmission		Non Firm Transmission		
N/A							
Grand Total							

Pole Attachment Fees		
Total		-
		-

Note: (1) Source for the numbers on this worksheet is a query of the company's books and records.
(2) The three totals (Pole Attachment Fees; 456170; 447010) move forward to the following worksheet:
Statement AU-Revenue Credits

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CAPITAL STRUCTURE
Year End 2012
Units: $000s

Exh. No. CLP-24
PERIOD I
STATEMENT AV

Component	Amount	Share (%)	Cost Rate (%)	Weighted Cost (%)
Long-Term Debt	$ 127,000,000	41.9%	6.06%	2.54%
Preferred Securities	-	-	-	-
Common Equity	175,965,410	58.1%	10.60%	6.16%
Total	$ 302,965,410	100.0%		8.70%

Note: (1) All source numbers (except ROE) on this Statement AV come from the workpapers for this statement.

(2) The capital structure and ROE come from, and are supported by, Company records.

(3) The Total Weighted Cost of Capital moves forward to the following worksheet:
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
WEIGHTED COST OF CAPITAL December 31, 2012

PERIOD I
Workpaper #1 to Statement AV

Line No.	Rate	Description	Amount Outstanding	Unamortized Discount	Unamortized Premium	Unamortized Debt Exp.	Net Proceeds	Interest Expense	Annual Amortization Discount (Premium)	Annual Amortization Debt Expense	Annual Cost	Embedded Cost %	Cumulative Cost %
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			BALANCE					ANNUAL REQUIREMENT					
							(b)+(c)+(d)+(e)	(rate*(b))			(g)+(h)+(I)	(j)/(f)	
1		**General and Refunding Mortgage Bonds**											
2													
3		First Mortgage Bonds	110,000,000			766,349	110,766,349	7,337,000		35,893	7,372,893	6.66	6.66
4		Industrial Development Bonds (due 2021)	7,000,000			289,936	7,289,936	155,400		0	155,400	2.13	6.38
5		Industrial Development Bonds (due 2027)	10,000,000			181,068	10,181,068	221,480		0	221,480	2.18	6.04
6											0		6.04
7											0		6.04
8													
9	**2.44%**	Revolving Credit Facility (2)	0	0	0	0	0	0	0	0	0		6.04
10													
11		Note Payable to Assoc Companies (Acct 233)	5,284,237				5,284,237	98,649			98,649	1.87	5.88
12											0		5.88
13											0		5.88
14											0		5.88
15													
16											0		5.88
17											0		5.88
18													
19		**Total Long-Term Debts**	127,000,000	0	0	0	127,000,000	0	0	0	0	0.00	0.00
20													
21						0	ST Debt			0	ST Debt		
22						0	Preferred			0	Preferred		
23						1,237,353	#181			35,893	#181		
24		**Footnotes**				#REF!	#189			#REF!	#189		
25						0	#257			0	#257		
26		(1) Floating Rate Debt - Interest is calculated monthly				**#REF!**	**Total**			**#REF!**	**Total**		
27													
28		(2) Revolving credit facility which allows borrowing up to $600,000,000. Variable rate interest on amount outstanding											
29													
30		(3) Converted Series 2006B ($13M) to variable demand notes wherein NPC is the sole holder of the bonds and recevies all interest payments. Consrquently, there is no interest expense asociated with these issues and the debt remains outstanding											
31													
32		(4) Tendered and repurchased											
33													

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CORPORATE STRUCTURE -- COMMON EQUITY
Year End 2012
Units: $000s

PERIOD I
Workpaper #2 for Statement AV

Line No.	(a) Description	(b) Total Common Stock Equity
1	Total Proprietary Capital	$175,965,410
2	(less) Preferred Stock	0
3	(less) Accumulated Other Comprehensive Income (Acct. 291)	0
4	(less) Unappropriated Undistributed Subsidiary Earnings (Acct. 216.1)	0
5	Common Equity (line 1 - line 2 - line 3 - line 4)	$ 175,965,410

Notes:

(1) These capital amounts come from FERC Form 1, page 112, column c, lines 16, 3, 15, & 12 (in the order the amounts appear above).

(2) The *total* Common Equity goes forward to the following worksheet:
Statement AV-Capital Structure

Cost of Short-Term Debt

Short term debt is not considered in the cost of service.

CHEYENNE LIGHT, FUEL AND POWER COMPANY
OTHER RECENT AND PENDING RATE CHANGES
December 2011 through December 2012

Exh. No. CLP-26
PERIOD I
STATEMENT AX

None

CHEYENNE LIGHT, FUEL AND POWER COMPANY	Exh. No. CLP-27
INCOME AND REVENUE TAX DATA	PERIOD I
Calendar Year 2012	STATEMENT AY

A	Federal Income Tax Rate	35.0000%
B	Nominal State Income Tax Rate	
		0.0000%
	Composite SIT	0.0000%

C Deductibility of State Income Taxes:

All state income and franchise taxes are deductible for Federal income tax purposes.

D Revenue Tax Rate (Not Included in Transmission Revenue Requirement)

Rate Names

Not Necessary if not to be filed.

Sum	0.0000%

Note: The mill assessment is included in account #928. There is no expense related to the remaining taxes. The utility merely acts as a tax collector.

E	Proportion of Federal Income Tax Deductible For State Income (weighed, if more than one state)	0.0000%

Note: (1) All source numbers on this Statement AY come from the company's books and records.

(2) These Income & Revenue Tax Percentages go forward to the following worksheets:
Statement BJ-Summary Data Tables
Statement BK-Cost of Service Study

CHEYENNE LIGHT, FUEL AND POWER COMPANY
CUSTOMER RATE GROUPS -- FERC JURISDICTION
Calendar Year 2012

Exh. No. CLP-28
PERIOD I
STATEMENT BA

OATT Transmission Service

Network Customers
Retail Load

Long-Term Firm Transmission Service
None

Short-Term Firm & Non-Firm Transmission Service
None

CHEYENNE LIGHT, FUEL AND POWER COMPANY
TRANSMISSION SYSTEM LOAD
Calendar Year 2012
Units: MW

Exh. No. CLP-29
PERIOD I
STATEMENT BB

System Peak	1/11	2/6	3/2	4/24	5/21	6/25	7/20	8/8	9/10	10/24	11/26	12/10
Hour	18	20	19	14	13	16	16	17	16	19	18	1/18
Total Native Load	**166**	**160**	**155**	**144**	**146**	**184**	**187**	**182**	**162**	**153**	**164**	**174**
Network Load (For Others)												
L-T Firm Contracts (P-P & Other)												
Total Transmission System Load (MW)	**166**	**160**	**155**	**144**	**146**	**184**	**187**	**182**	**162**	**153**	**164**	**174**

12 Coincident Peak ("CP") Average: **165**

Note: (1) Monthly peak load amounts tie to FERC Form 1, page 400, column b.
Details of that load come from the company's books and records.
(2) The "12 Coincident Peak Average" goes forward to the following worksheet: Statement BL
(3) Measured Load Coincident to Peak
(4) Contract Demand

Not Applicable

Not Applicable

None

None

NOT NEEDED

Not Applicable

Units: $000s

Statement	Description	Function/ Sub-Function		13-Month Average
AD	Cost of Plant	Production	$	183,381,840
		Transmission		7,801,632
		Distribution		136,561,608
		General/Intangible		8,241,960
		Common		
			$	335,987,041
AE	Accumulated Depreciation and Amortization	Production	$	18,323,529
		Transmission		2,035,492
		Distribution		44,068,320
		General/Intangible		3,858,000
		Common		
			$	68,285,342
AF	Specified Deferred Credits			
	Account 255	Production	$	113,796
		Transmission		4,841
		Distribution		84,742
		Total	$	203,380
	Account 281			-
	Account 282/283	Production	$	(34,931,657)
		Transmission		(822,385)
		Distribution		(13,434,698)
		Total	$	(49,188,740)

Statement	Description	Function/ Sub-Function		Beg of Yr/End of Yr Average
AG	Specified Plant Accts and Deferred Debits			
	Account 105	Production	$	-
		Transmission		-
		Distribution		11
		General		-
		Total	$	11
	Account 182	Total	$	3,930
	Account 190	Production	$	2,429
		Transmission		101
		Distribution		2,198
		Total	$	4,728
				Annual Amount
AH	Operating & Maintenance Expenses	Production	$	66,401
		Transmission		11,750
		Distribution		2,573
		General		6,741
		Total	$	87,466
AI	Wages & Salaries	Production	$	1,822
		Transmission		94
		Distribution		-
		General		920
		Common		-
		Total	$	2,836
AJ	Depreciation & Amortization Expense	Production	$	4,762,036
		Transmission		163,458
		Distribution		3,855,356
		General		807,467
		Total	$	9,588,317

Units: $000s

Statement	Description	Function/ Sub-Function		Annual Amount
AK	Taxes Other Than Income	Total	$	2,554
				13-Month Average
AL	Working Capital	Fuel Supplies		
		M & S -- Transmission		-
		Prepayments		883
		Total	$	883
AM	Construction Work In Process			
		Production	$	-
		Transmission		-
		Distribution		-
		General		-
		Total	$	-
AN	Notes Payable		$	-

Statement	Description	Function/ Sub-Function		Year-to-Date
AP	Fed Income Tax Deductions-Interest			
	Account 431	Other Interest	$	109,183
	Account 432	Total	$	121,743
	Long Term Interest Exp	Transmission	$	128,234
		All Other		5,426,607
		Total	$	5,554,840
AQ	Income Tax Deductions-Other Than Interest			
	Additions to Book Income		$	(1,355)
	Deductions from Book Income		$	21,653
AR	Income Tax Deductions			
	Acct 410.1 - Provision for Deferred Income Taxes - Debit			
		Account 281		
		Account 282		(9,477,579)
		Account 283		(1,401,754)
		Account 190		912,289
		Summary Account 410.1	$	(9,967,044)
	Acct 411.1 - Provision for Deferred Income Taxes - Credit			
		Account 281	$	-
		Account 282		-
		Account 283		-
		Account 190		-
		Summary Account 411.1	$	-

Units: $000s

Statement	Description					
AS	Additional State Income Tax Deductions	No additional state income tax deductions.				
AT	State Tax Adjustments	No state income tax deductions.				
AV	Rate of Return					
	Cost of Capital		NPC	Percent Of Total	Cost	Weighted Cost
		Long -Term Debt	$ 127,000,000	41.9000%	6.06%	2.54%
		Preferred Stock	-	-	-	-
		Common Equity	175,965,410	58.1000%	10.60%	6.16%
		Total	$ 302,965,410	100.00%		8.70%
AW	Cost of Short-Term Debt	Not Included in the Capital Structure for return purposes, therefoe, not considered in COS.				
AY	Income & Revenue Tax Rate Data	Nominal Federal Income Tax Rate				35.00%
		Nomital State Income Tax Rate				
		Total				0.00%

CHEYENNE LIGHT, FUEL AND POWER COMPANY
COST OF SERVICE STUDY
Calendar Year 2012
Units: $000s

TRANSMISSION REVENUE REQUIREMENT

Exh. No. CLP-37
PERIOD I
STATEMENT BK
Schedule 1
Page 1 of 1

Summary of Results

Line	Description	Source	Total Electric	Production	Transmission	Distribution	All Other
	Rate Base						
1	Gross Plant in Service	Sch 2 ; Page 1	$ 335,987,041	$ 187,066,770	$ 7,990,862	$ 140,929,408	$ 327,996,178
2	Depreciation Reserve	Sch 2 ; Page 1	(68,285,342)	(20,048,417)	(2,124,069)	(46,112,855)	(66,161,272)
3	Net Utility Plant		267,701,699	167,018,353	5,866,793	94,816,553	261,834,906
4	Accumulated Deferred Income Taxes	Sch 3 ; Page 1	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
5	Other Subtractive Adjustments	Sch 3 ; Page 1	-	-	-	-	-
6	Materials & Supplies	Sch 3 ; Page 2	-	-	-	-	-
7	Prepaids and Other	Sch 3 ; Page 2	759	53	2	703	757
8	Cash Working Capital	Sch 3 ; Page 2	9,711	8,678	52	980	9,658
9	Acct. 190 and Other Additive Adjustments	Sch 3 ; Page 2	245,142	136,278	5,819	103,045	239,323
10	Total Rate Base		218,768,571	132,231,705	5,050,281	81,486,584	213,718,290
	Operating Expenses						
12	Total O&M Expense	Sch 4 ; Page 1	77,686	69,422	419	7,843	77,267
13	Total Depreciation Expense	Sch 4 ; Page 2	9,588,317	5,123,050	181,997	4,283,271	9,406,320
14	Total Other Taxes	Sch 4 ; Page 3	2,554	818	35	1,701	2,519
15	Subtotal - O&M & Other		9,668,557	5,193,290	182,451	4,292,814	9,486,106
16	Net Federal Income Taxes	Sch 5 ; Page 1	(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
17	Net State Income Taxes	Sch 5 ; Page 3	-	-	-	-	-
18	Total Operating Expense		1,521,905	$ (871,794)	61,523	$ 2,332,173	1,460,381
19	Return on Rate Base	l. 10 * l. 33	$ 19,027,922	$ 11,501,170	$ 439,260	$ 7,087,491	$ 18,588,661
20	Total Cost of Service -- Before Exclusions		$ 20,549,826	$ 10,629,376	$ 500,784	$ 9,419,665	$ 20,049,043
21	Inclusion Ratio						
22	Total Transmission Plant	Sch 2; Page 1			$ 7,801,632		
23	Excluded Transmission Plant (GSUs)	Statement AD			$ 1,570,095		
24	Adjusted Transmission Plant	l. 22 - l. 23			$ 6,231,537		
25	Inclusion Ratio	l. 24 / l. 22			79.87%		
26	Adjusted Cost of Service	l. 25 * l. 20			400,000		
27	Less Revenue Credits	Statement AU			$ -		
28	Pro Forma Adjustment	l. 27 * % rate increase			$ -		
29	Net cost of Service (Excluding Schedule 1)	l. 26 - l. 27 - l. 28			$ 400,000		
30	Schedule 1 Gross Revenue Requirement	Sch 4; Page 1; l. 13			$ 102		
31	Less Revenue Credits (Company Records)						
32	Schedule 1 Net Revenue Requirement	l. 30 - l. 31			$ 102		
33	Rate of Return on Rate Base	Statement AV	8.70%	8.70%	8.70%	8.70%	8.70%

Units: $000s

Electric Plant in Service - Statement AD

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production Plant		183,381,840	183,381,840			183,381,840
2	Transmission Plant		7,801,632		7,801,632		-
3	Distribution Plant		136,561,608			136,561,608	136,561,608
4	Gross P, T, D Plant		327,745,081	183,381,840	7,801,632	136,561,608	319,943,448
5	Total General and Electric Common Plant		8,073,460				
6	Total Intangible Plant		168,500				
7	Total General, Electric Commmon & Intangible		8,241,960		-		
8	Gen. & Intang. Functionalized	W&S	8,241,960	3,684,930	189,230	4,367,800	8,052,730
9	Gross Electric Plant in Service (l.4 + l.8)		335,987,041	187,066,770	7,990,862	140,929,408	327,996,178

Depreciation Reserve - Statement AE

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
11	Production Plant		18,323,529	18,323,529			18,323,529
12	Transmission Plant		2,035,492		2,035,492		-
13	Distribution Plant		44,068,320			44,068,320	44,068,320
14	Gross P, T, D Plant		64,427,341	18,323,529	2,035,492	44,068,320	62,391,849
15	Total General, Electric Commmon & Intangible	W&S	3,858,000	1,724,888	88,577	2,044,535	3,769,423
16	Total Depreciation Reserve (l. 14 + l. 15)		68,285,342	20,048,417	2,124,069	46,112,855	66,161,272

Units: $000s

Net Electric Plant

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production Plant		165,058,311	165,058,311	-	-	165,058,311
2	Transmission Plant		5,766,140		5,766,140		-
3	Distribution Plant		92,493,288	-	-	92,493,288	92,493,288
4	Net P, T, D Plant		263,317,739	165,058,311	5,766,140	92,493,288	257,551,599
5	General & Intangible Net Plant		4,383,960	1,960,042	100,653	2,323,265	4,283,307
6	Net Electric Plant in Service (l. 4 + l. 5)		267,701,699	167,018,353	5,866,793	94,816,553	261,834,906

Units: $000s

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Subtractive Adjustments -- Statement AF						
1	Accum. Deferred ITC -- Acct. 255		-	-	-	-	-
2	Accum. Deferred Inc.Taxes (Acct. 281)		-	-	-	-	-
3	Accum. Deferred Inc.Taxes (Acct. 282 & 283)	NPLT	(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
4	Subtotal Accum. Deferred Taxes (l. 1 through l. 3)		(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)
5	Other Subtractive Adjustments		-	-	-	-	-
6	Total Subtractive Adjustments (l. 4 + l. 5)		(49,188,740)	(34,931,657)	(822,385)	(13,434,698)	(48,366,355)

Units: $000s

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Additive Adjustments -- Statement AG						
						-	-
1	Accum. Deferred Inc. Taxes (Acct. 190)	NPLT	4,728	2,429	101	2,198	4,627
	Land Held for Future Use (Acct. 105)						
2	Production	Direct	-	-			-
3	Transmission	Direct	-		-		-
4	Distribution	Direct	11			11	11
5	General Functionalized	W&S	-	-	-	-	-
6	Total Land for Future Use		11	-	-	11	11
	CWIP Land						
7	Transmission						
8	Other						
9	Total CWIP Land		-	-	-	-	-
	Other Additive Adjustments (FAS 109)						
10	FAS 109 (acct 182.3) (Statement AG)	NPLT	3,930	2,188	93	1,648	3,837
11	less FAS 109 (acct 254.02) (Statement AF)	NPLT	236,473	131,661	5,624	99,188	230,849
12	Total Other Additive Adjust.		240,403	133,849	5,718	100,837	234,686
13	Total Additive Adjustments (l. 1 + l. 6 + l. 9 + l. 12)		245,142	136,278	5,819	103,045	239,323

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Working Capital						
14	Materials and Supplies (Beg/End Yr Avg) --Transmission Only		-		-		-
15	Prepayments	Statement AL					
16	Property Insurance	GPLT	-	-	-	-	-
17	Other Prepayments	Direct	663			663	663
18	Other Prepayments	GPLT	96	53	2	40	94
19	Total Prepayments		759	53	2	703	757
	Cash Working Capital (Auto Calculation)						
20	(One eighth O&M less fuel and PP)	(auto calculation)	9,711	8,678	52	980	9,658
21	Total Working Capital (l.14 + l.19 + l.20)		10,470	8,731	55	1,684	10,415

Units: $000s

Expenses Statement AH

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Production O&M						
	Energy Related Production O&M						
1	Fuel		-	-			-
2	Purchased Power		-	-			-
3	Other		-	-			-
4	Gas Steam Energy Related		-				
5	Total Energy Related		-	-	-	-	-
	Demand Related Production O&M						
6	Purchased Power		-	-			-
7	Other Demand Related		-	-			-
8	Fixed Fuel (Storage & Maintenance)		-				
9	Gas Steam Demand Related		-				
10	Total Demand Related		-	-	-	-	-
11	Total Production O&M		66,401	66,401	-	-	66,401
	Transmission O&M						
12	Total		11,750		11,750		-
13	Less Acct 561.1 thru 561.4 -- Schedule 1 Ancillary		(102)		(102)		
14	Less Acct. 565 (Tx by Others)		(11,384)		(11,384)		-
15	Transmission O&M (adjusted)		264		264		-
	Distribution O&M						
16	Distribution O&M		2,573			2,573	2,573
17	Customer Accounting		1,104			1,104	1,104
18	Customer Service & Information		601			601	601
19	Sales		1			1	1
	Administrative & General						
20	Property Insurance	GPLT	159	89	4	67	156
21	Regulatory Commission Expense	Direct	25		-	23	25
22	Other Labor Related	W&S	6,557	2,932	151	3,475	6,407
23	Total Admin & General		6,741	3,020	154	3,564	6,587
24	Total O&M Expense (l. 11 + l.15 through 19 + l. 23)		77,686	69,422	419	7,843	77,267

Units: $000s

Depreciation Expense Statement BJ

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
1	Production		4,762,036	4,762,036			4,762,036
2	Transmission		163,458		163,458		-
3	Distribution		3,855,356			3,855,356	3,855,356
4	General & Intangible	W&S	807,467	361,014	18,539	427,915	788,928
5	Total Depreciation Expense (l. 1 thru l. 4)		9,588,317	5,123,050	181,997	4,283,271	9,406,320

Units: $000s

Other Taxes and Miscellaneous Expenses

Statement AK

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Taxes Other than Income						
1	Revenue Taxes	GPLT	-	-	-	-	-
2	Real Estate and Property Taxes	GPLT	1,195	665	28	501	1,166
3	Payroll Taxes	W&S	7	3	0	4	7
4	Franchise Taxes	Direct	1,083			1,083	1,083
5	Business Tax	GPLT	-	-	-	-	-
6	Miscellaneous Taxes	GPLT	269	150	6	113	263
7	Total Taxes Other than Income (l. 1 through l. 4)		2,554	818	35	1,701	2,519

Units: $000s

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Federal Income Tax						
	Federal Income Tax Deductions						
1	Interest Expense (Auto - Synchronized)	Statement AV	5,554,840	3,357,548	128,234	2,069,058	5,426,607
	Other Deductions	Statement AQ					
2	Plant Related	NPLT	21,653	13,509	475	7,669	21,178
3	Labor Related	W&S	0	0	0	0	-
4	Production	Direct	0	0			-
5	Transmission	Direct	0		0		-
6	Retail/Distribution	Direct	0			0	0
7	Total Other Deductions		21,653	13,509	475	7,669	21,178
8	Total Deductions (l. 1 + l. 7)		5,576,493	3,371,057	128,708	2,076,728	5,447,785
	Federal Income Tax Additions	Statement AQ					
7	Plant Related	NPLT	(1,355)	(845)	(30)	(480)	(1,325)
8	Labor Related	W&S	0	0	0	0	-
9	Production	Direct	0	0			-
10	Transmission	Direct	0		0		-
11	Retail/Distribution	Direct	0			0	0
12	Total Additions		(1,355)	(845)	(30)	(480)	(1,325)
13	Net Deductions and Additions (l. 8 - l. 12)		5,577,848	3,371,903	128,738	2,077,208	5,449,110
	Federal Income Tax Adjustments	Statement AR					
	Fed. Prov. Deferred Inc. Tax (410.1)						
12	Plant Related	NPLT	(8,506,958)	(5,307,468)	(186,433)	(3,013,057)	(8,320,525)
13	Labor Related	W&S	0	0	0	0	-
	Production	Direct	(1,460,086)	(1,460,086)			(1,460,086)
	Transmission	Direct	0		0		
14	Retail/Distribution	Direct	0			0	0
15	Total Fed. Def. Inc. Tax		(9,967,044)	(6,767,554)	(186,433)	(3,013,057)	(9,780,611)

Units: $000s

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	Investment Tax Credits						
	Amortized Investment Tax Credit						
1	Production	Statement AF	19,836	19,836			19,836
2	Transmission	Statement AF	844		844		-
3	Distribution	Statement AF	14,772			14,772	14,772
4	General & Intangible	W&S	354	158	8	188	346
5	Total Investment Tax Credit		35,805	19,994	852	14,959	34,953
	Preliminary Summary -- Adjustments						
6	Total Fed. Def. Inc. Tax (410.1)	Sch 5; Page 1	(9,967,044)	(6,767,554)	(186,433)	(3,013,057)	(9,780,611)
7	Total Amortized ITC		(35,805)	(19,994)	(852)	(14,959)	(34,953)
8	Total Federal Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
	Federal Tax Computation						
9	Return on Rate Base	Sch 1; Page 1	19,027,922	11,501,170	439,260	7,087,491	18,588,661
10	Net Deductions and Additions		(5,577,848)	(3,371,903)	(128,738)	(2,077,208)	(5,449,110)
11	Total Federal Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
12	Base for FIT Calculation		3,447,224	1,341,719	123,237	1,982,268	3,323,987
	FIT Factor (= FIT Rate/(1-FIT Rate)		53.846%	53.846%	53.846%	53.846%	53.846%
13	Preliminary Fed. Income Tax (Payable)		1,856,197	722,464	66,358	1,067,375	1,789,839
14	Total Fed. Income Tax Adjustments		(10,002,849)	(6,787,548)	(187,285)	(3,028,016)	(9,815,564)
15	Net Federal Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)

Units: $000s

d On Return (Continued)

Line	Description	Allocator	Total Electric	Production	Transmission	Distribution	All Other
	State Income Tax						
	State Income Tax Adjustments						
1							
2							
3	Total State Inc. Tax Adjustments		-	-	-	-	-
	SIT Calculation						
4	Return on Rate Base		19,027,922	11,501,170	439,260	7,087,491	18,588,661
5	Net Deductions and Additions		5,577,848	(3,371,903)	(128,738)	(2,077,208)	5,706,586
6	Proportion of FIT Deductible for State Inc.		0.00%	0.00%	0.00%	0.00%	0.00%
7	Net Federal Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
8	Total State Inc. Tax Adjustments		0	0	0	0	0
9	Base for SIT Calculation		16,459,118	2,064,183	189,595	3,049,643	16,269,523
	SIT Factor (= SIT Rate/(1-SIT Rate)		0.00%	0.00%	0.00%	0.00%	0.00%
10	Preliminary State Income Tax (Payable)		0	0	0	0	-
11	Total State Income Tax Adjustments		0	0	0	0	0
12	Net State Income Tax		0	0	0	0	0
	Cost of Service Computation						
13	Total Op. Exp. Excl. Inc. & Rev. Taxes		9,668,557	5,193,290	182,451	4,292,814	9,486,106
14	Return on Rate Base		19,027,922	11,501,170	439,260	7,087,491	18,588,661
15	Net Fed Income Tax Allowable		(8,146,652)	(6,065,084)	(120,927)	(1,960,641)	(8,025,725)
16	Net State Income Tax Allowable		0	0	0	0	0
17	Cost of Service Ex. Rev. Taxes		20,549,826	10,629,376	500,784	9,419,665	20,049,043
18	Revenue Tax Factor		1	1	1	1	1
19	Total Cost of Service		20,549,826	10,629,376	500,784	9,419,665	20,049,043

FUNCTIONALIZATION FACTORS SUMMARY

	Factors	Reference		Production	Transmission	Distribution	Source
1	Gross Plant, Including GP&I	GPLT	100.000%	55.677%	2.378%	41.945%	Sch 2, page 1
2	Net Plant, Including GP&I	NPLT	100.000%	62.390%	2.192%	35.419%	Sch. 2, page 2
3	Salaries & Wages, Excl. A&G	W&S	100.000%	44.709%	2.296%	52.995%	Statement AI

CHEYENNE LIGHT, FUEL AND POWER COMPANY
RATE DESIGN
Calendar Year 2012
Units: $s

Exh. No. CLP-38
PERIOD I
STATEMENT BL

	Transmission Rate		Schedule 1	
ATRR	$	399,999,940	$	101,791
12CP (KW)		164,750		164,750
Monthly Rate	$	202.33	$	0.051
	Per KW		Per MW	

Not Applicable

	DESCRIPTION	JUNE 2014	JUNE 2015
	ELECTRIC PLANT AT ORIGINAL COST:		
x	Plant in Service	$424,254,373	$584,878,152
x	Less accumulated depreciation (enter negative)	($61,935,555)	($79,586,881)
	Net plant in service	$362,318,818	$505,291,272
x	Construction work in progress	$143,775,855	$21,415,757
	Property Under Capital Leases		
	Completed Construction not Classified		-
x	Plant Acquisition Adjustments	$4,942,723	$4,942,723
	Plant Held For Future Use		
	Total	$511,037,395	$531,649,751
x	OTHER PROPERTY AND INVESTMENTS	$11,798,459	$13,634,607
	CURRENT ASSETS:		
x	Cash and Prepayments	($313,309)	($313,309)
x	Deferred Current Assets	$189,947	$189,947
x	Net Receivables	20,020,489	21,091,353
x	Fuel Stock	793,865	842,162
x	Materials and supplies	6,211,638	7,131,639
x	Prepayments	228,052	228,052
x	Accrued Utility Revenues	$9,430,855	$5,556,680
xx	Total	$36,561,537	$34,726,523
	DEFERRED ASSETS	$27,514,673	$28,863,028
	TOTAL ASSETS	$586,912,065	$608,873,910

Source: Company Records

Cheyenne Light Fuel and Power
BALANCE SHEET
June 31, 2015

Exhibit No. CLP-40
Period II
Statement AA

	DESCRIPTION		JUNE 2014		JUNE 2015
	CAPITALIZATION:				
	Common Stock				
	Other Paid in Captial	$	136,618,590	$	136,618,590
	Retained earnings		65,939,000		84,869,062
	Accumulated Other Comprehensive Income				
		$	202,557,590	$	221,487,652
	Cumulative preferred stock				
	Long - term debt & other non-current liabilities		$127,000,000		$202,000,000
	Total Capitalization		$329,557,590		$423,487,652
	CURRENT LIABILITIES:				
x	Notes Payables		$114,731,570		$16,748,795
x	Accounts Payable		$16,996,361		$16,907,326
x	Accrued interest & taxes		(1,781,470)		8,149,778
x	Tax Collections Payable		5,122,503		5,169,503
x	Miscellaneous Current & Accrued Liabilities		1,968,834		1,992,834
			$137,037,799		$48,968,237
	DEFERRED CREDITS AND OTHER LIABILITIES:				
	Accumulated deferred investment tax credits				
	Customers' advances for construction				
	Accumulated deferred taxes on income - electric only		59,364,371		59,615,167
	Obligation under Capital Lease				
	Other		60,952,305		76,802,854
			$120,316,676		$136,418,021
	TOTAL CAPITALIZATION AND LIABILITIES		$586,912,065		$608,873,910
Source:	Company Records		27329907.92		18,767,076.15
	Tie out to budget		$614,241,973		$627,640,985.96

Cheyenne Light Fuel and Power
INCOME STATEMENT
Fiscal Years

Exhibit No. CLP-41
Period II
STATEMENT AB

		DESCRIPTION	JUNE 2014	JUNE 2015
1		UTILITY OPERATING INCOME		
2	x	OPERATING REVENUES	$ 175,379,957	$ 194,976,536
3				
4		OPERATING EXPENSES AND TAXES		
5	x	Operation Expense	114,996,263	123,835,581
6	x	Maintenance Expense	4,954,966	5,808,642
7	x	Depreciation Expense	13,141,586	17,638,074
8		Amort. & Depl. Of Utility Plant		0
9		Amort. Of Utility Plant Acq. Adj.		
10		Amort. of Property Losses, Unrecove. Plant and Reg. Study Costs		
11	x	Taxes Other Than Income	4,092,186	4,640,571
12		Income Taxes - Federal	(1,948,838)	14,145,542
13		Income Taxes - Other	(377,605)	-
14		Provision for Deferred Income Taxes	20,555,061	54,217
15		(Less) Provision for Deferred Income Taxes - Credits	(8,435,804)	0
16		Investment Tax Credit Adj.	(25,090)	0
17		(Less) Gains from Disp. Of Utility Plant		
18		(Less) Gains from Disposition of Allowances		
19		TOTAL OPERATING EXPENSE	$ 146,952,725	$ 166,122,626
20		TOTAL UTILITY OPERATING INCOME	$ 28,427,232	$ 28,853,910
21				
22		OTHER INCOME		
23		NONUTILITY OPERATING INCOME		
24		Revenues From Merchandising, Jobbing & Contract Work		$ -
25		(Less) Costs and Exp. of Merchandizing, etc.		-
26		Revenues from Nonutility Operations		
27		(Less) Expenses of Nonutility Operations	(58,411)	(58,411)
28		Nonoperating Rental Income		
29		Equity in Earnings of Subsidiary Companies		
30		Interest and Dividend Income	251,517	75,481
31		Allowance for Funds Used During Construction	-	-
32		Miscellaneous Nonoperating Income	13,149	-
33		Gain on Disposition of Property		
34		TOTAL OTHER INCOME	206,255	17,070
35				
36		TOTAL OTHER INCOME DEDUCTIONS		
37				
38		TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS		
39		Taxes Other than Income Taxes		$ -
40		Income Taxes - Federal	(12,446)	(12,446)
41		Income Taxes Other		-
42		Provision for Deferred Income Taxes		
43		(Less) Prov. for Def. Income Taxes Credit		
44		TOTAL TAXES ON OTHER INCOME AND DEDUCTIONS	$ (12,446)	$ (12,446)
45		NET OTHER INCOME AND DEDUCTIONS	$ 218,701	$ 29,516
46				
47		INTEREST CHARGES		
48		Interest on Long-Term Debt	$ 7,633,350	$ 8,619,364
49		Amortization of Debt Discount and Expense	164,529	294,905
50		Amortization of Loss on Reacquired Debt	21,259	
51		Loss on Reacquired Capital Stock	59,593	
52		(Less) Amort of Premium on Debt - Credit		
53		(Less) Amortization of Gain on Reacquired Debt - Credit		
54		Interest on Debt to Assoc. Companies	7,815	7,815
55		Other Interest Expense	2,269,611	1,554,612
56		(Less) Allowance for Borrowed Funds Used During Construction	(339,461)	(523,333)
57		NET INTEREST CHARGES	9,816,696	9,953,363
58				
59		NET INCOME	$ 18,829,237	$ 18,930,063

Soruce: Company Records

Cheyenne Light Fuel and Power
STATEMENT OF RETAINED EARNINGS
June 30 2015 Forecast

Exhibit No. CLP-42
Period II
Statement AC

(a)	(b)
UNAPPROPRIATED RETAINED EARNINGS	
Balance at beginning of period	$65,939,000
Balance Transferred from Income	$18,930,063
Unrealized Loss on Investment	
Dividends Declared - Preferred Stock	
Dividends Declared - Common Stock	
Transfers from Unappropriated Undistributed Subsidiary Earnings	
Balance at End of Year	$84,869,062
Appropriated Retained Earnings	
Total Retained Earnings	$84,869,062
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS	
Balance Beginning of Year	NA
Equity in Earnings for Year	NA
Less Dividends Received	NA
Balance at end of period	NA

Source: Company Records

Cheyenne Light Fuel and Power
UTILITY PLANT IN SERVICE
June 30 2015 Forecast

Exhibit No. CLP-43
Period II
Statement AD

UTILITY PLANT IN SERVICE

Month/Yr	Production	Transmission Service at Issue	Distribution	General/Intan.	Other Utility	Total	
6	187,462,693	33,976,698	155,249,564	10,460,459	7,990,379	395,139,793	
7	187,462,693	33,976,698	155,865,888	10,540,594	8,043,987	395,889,861	
8	187,462,693	33,976,698	156,482,212	10,620,730	8,097,596	396,639,929	
9	187,462,693	33,976,698	157,098,536	10,700,865	8,151,204	397,389,996	
10	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
11	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
12	303,557,195	33,976,698	157,098,536	10,700,865	8,151,204	513,484,498	
1	303,557,195	33,976,698	157,798,536	10,700,865	8,151,204	514,184,498	
2	303,557,195	36,379,691	158,498,536	10,700,865	8,151,204	517,287,491	
3	303,557,195	47,752,426	168,069,536	10,700,865	8,151,204	538,231,227	
4	307,709,034	47,752,426	168,769,536	10,700,865	8,151,204	543,083,065	
5	307,919,033	47,752,426	169,469,536	10,700,865	8,151,204	543,993,064	
6	308,020,807	47,752,426	170,169,536	10,700,865	8,151,204	544,794,839	
13 Month Average	268,834,063	38,400,229	160,674,387	10,663,879	8,126,462	486,699,020	
Beg/End Average	247,741,750	40,864,562	162,709,550	162,709,550	10,580,662	8,070,792	632,676,866

Note: GSU Transformers are recorded in Production

Source: Company Records

Cheyenne Light Fuel and Power
ACCUMULATED DEPRECIATION
June 30 2015 Forecast

Exhibit No. CLP-44
Period II
Statement AE

ACCUMULATED DEPRECIATION

Month/Yr	Production	Transmission Service at Issue	Distribution	General/Intan.	Other Utility	Total
6	24,520,071	3,228,415	47,966,071	4,608,834	4,682,116	85,005,507
7	24,959,046	3,297,218	48,328,460	4,651,884	4,735,608	85,972,215
8	25,398,021	3,366,021	48,692,281	4,695,261	4,789,457	86,941,041
9	25,836,996	3,434,823	49,057,535	4,738,965	4,843,663	87,911,983
10	26,580,711	3,503,626	49,422,789	4,782,670	4,897,868	89,187,664
11	27,324,426	3,572,429	49,788,043	4,826,374	4,952,074	90,463,346
12	28,068,141	3,641,232	50,153,297	4,870,079	5,006,279	91,739,028
1	28,811,857	3,710,035	50,520,179	4,913,783	5,060,485	93,016,338
2	29,555,572	3,783,704	50,888,688	4,957,487	5,114,690	94,300,141
3	30,299,287	3,880,402	51,279,450	5,001,192	5,168,896	95,629,226
4	31,053,174	3,977,101	51,671,839	5,044,896	5,223,101	96,970,111
5	31,807,576	4,073,800	52,065,855	5,088,601	5,277,307	98,313,138
6	32,562,227	4,170,498	52,461,500	5,132,305	5,331,512	99,658,042
13 Month Average	28,213,623	3,664,562	50,176,614	4,870,179	5,006,389	91,931,368
Beg/End Average	28,541,149	3,699,457	50,213,786	4,870,569	5,006,814	92,331,774

Note: GSU Transformers are recorded in Production.
Note: Accumulated Amortization for Intangible Plant appears in Other Production on Page 219 of the Form No. 1, it is moved to Intangible Plant on this Statement.
Source: Company Records

ACCUMULATED DEFERRED INVESTMENT TAX CREDIT -- ACCOUNT 255

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	78,227	13,082	46,754	3,103	2,365	143,532
End	62,021	10,372	37,068	2,460	1,875	113,796
Average	70,124	11,727	41,911	2,782	2,120	128,664

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 281

Year	Production	Transmission	Distribution	General	Common	Total
Beginning		-	-	-	-	-
End		-	-	-	-	-
Average		-	-	-	-	-

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 282

Year	Production	Electric Only Transmission	Distribution	General	Common	Total
Beginning	31,589,952	4,740,293	14,506,745	760,628	409,620	52,007,238
End	31,742,289	4,763,153	14,576,701	764,296	411,595	52,258,034
Average	31,666,120	4,751,723	14,541,723	762,462	410,608	52,132,636

FAS 109 Only (ACCOUNT 254)

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	-	-	-	-	-	195,271
End	-	-	-	-	-	195,271
Average		-			-	195,271

ACCUMULATED DEFERRED INCOME TAX -- ACCELERATED AMORTIZATION -- ACCOUNT 283
Deferred Energy Only & DSM Programs

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	2,202,410	-	1,011,391	53,030	28,558	3,295,390
End	2,202,410	-	1,011,391	53,030	28,558	3,295,390
Average	2,202,410	-	1,011,391	53,030	28,558	3,295,390

Other Acct 283

Year	Production	Transmission	Distribution	General	Common	Total
Beginning	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743
End	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743
Average	2,485,757	342,391	1,141,510	59,852	32,232	4,061,743

Total Acct. 283

Beginning	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133
End	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133
Average	4,688,167	342,391	2,152,901	112,882	60,790	7,357,133

Source:
Company Records

Property Held for Future Use -- Account 105 (Transmission Only)

	Balance 06/30/2014	Balance 06/30/2015	Average Balance
Transmission	-	-	-
General	-	-	-
Common	-	-	-
Total	-	-	-

Source: Company's Records

Account 182.3 -- Regulatory Assets

	Balance 06/30/2014	Balance 06/30/2015	Average Balance
Def. PRB FAS 109	3,988,499	4,018,499	4,003,499
Other Reg. Assets	-	-	-
Total	3,988,499	4,018,499	4,003,499

Accumulated Deferred Income Taxes -- Account 190

	Allocator	Production	Transmission	Distribution	Total Ave Balance
State Jurisdictional					
Direct	Direct	-	-	-	-
Benefit Related	W&S	753,193	178,621	345,881	1,277,695
Miscellaneous	NPLT	3,168,812	463,730	1,455,182	5,087,724
Subtotal		3,922,004	642,351	1,801,064	6,365,419
FERC Jurisdictional					
Plant Related		-		-	-
FAS 109		-		-	-
Subtotal		-	-	-	-
Grand Total		3,922,004	642,351	1,801,064	6,365,419

Source: Company's Records

Cheyenne Light Fuel and Power
SPECIFIED PLANT ACCOUNTS AND DEFERRED DEBITS — Period II
June 30 2015 Forecast — Statement AG Workpaper 1

Accumulated Deferred Income Taxes -- Account 190

	06/30/2014	06/30/2015	Average Balance	Allocated W&S	Allocated NPLT
State Jurisdictional					
Pension FAS 158	66,066	66,066	66,066	66,066	
Line Extension Deposits	1,908,958	4,181,858	3,045,408		3,045,408
State Inc Tax	-	-	-		-
Bad Deb Reserve	662,567	662,567	662,567		662,567
Retiree Health Plan	1,211,629	1,211,629	1,211,629	1,211,629	
Other	1,379,749	1,379,749	1,379,749		1,379,749
Subtotal	5,228,969	7,501,869	6,365,419	1,277,695	5,087,724
FERC Jurisdictional					
Plant Related	-	-	-		
FAS 109	-	-	-		
Subtotal	-	-	-		
Grand Total	5,228,969	7,501,869	6,365,419		

	06/30/2014	06/30/2015	Allocation to electric *
State Jurisdictional			
Pension FAS 158	125,600	125,600	52.6%
Line Extension Deposits	1,908,958	4,181,858	100.0%
State Inc Tax	-	-	0.0%
Bad Deb Reserve	839,755	839,755	78.9%
Retiree Health Plan	2,303,478	2,303,478	52.6%
Other	1,921,656	1,921,656	71.8%
Subtotal	7,099,447	9,372,347	

* Used the same allocator as in the state rate case.

Source: Company's Records

Regulatory Tax Asset - FAS 109

Unit	Acct	Year	Period	Balance
50502	182390	2013	12	$ 3,988,499
50502	182390	2012	1	3,929,473
50502	182390	2012	2	3,929,122
50502	182390	2012	3	3,928,771
50502	182390	2012	4	3,928,421
50502	182390	2012	5	3,928,070
50502	182390	2012	6	3,927,719
50502	182390	2012	7	3,927,368
50502	182390	2012	8	3,927,017
50502	182390	2012	9	3,926,666
50502	182390	2012	10	3,926,316
50502	182390	2012	11	3,925,965
50502	182390	2012	12	3,956,793
				$ 3,930,117

Operation and Maintenance Expenses	Total Year
Production	64,161,809
Transmission	763,596
Distribution	3,295,271
Customer Accounts	830,529
Customer Service	602,130
Sales Expenses	6,745
Administrative and General	10,950,133
Total	80,610,212

Source: Following Tables

FERC Account		Demand	Energy	Total
Production				
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering		-	
501	Fuel		-	8,272,020
502	Steam Expenses		-	4,069,028
503	Steam from Other Sources		-	-
504	Steam Transferred - Credit		-	-
505	Electric Expenses		-	-
506	Miscellaneous Steam Power Expenses		-	-
507	Rents	-	-	-
	Total Operation	-	-	12,341,048
Maintenance				
510	Maintenance Supervision and Engineering			-
511	Maintenance of Structures			-
512	Maintenance of Boiler Plant			3,309,799
513	Maintenance of Electric Plant			-
514	Maintenance of Miscellaneous Steam Plant		-	-
	Total Maintenance	-	-	3,309,799
	Total Power Production Expenses - Steam Plant	-	-	15,650,847
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	-	-	-
518	Fuel	-	-	-
519	Coolants and Water	-	-	-
520	Steam Expenses	-	-	-
521	Steam from Other Sources	-	-	-
522	Steam Transferred - Credit	-	-	-
523	Electric Expenses	-	-	-
524	Miscellaneous Steam Power Expenses	-	-	-
525	Rents	-	-	-
	Total Operation	-	-	-
Maintenance				
528	Maintenance Supervision and Engineering	-	-	-
529	Maintenance of Structures	-	-	-
530	Maintenance of Reactor Plant Equipment	-	-	-
531	Maintenance of Electric Plant	-	-	-
532	Maintenance of Miscellaneous Steam Plant	-	-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses - Nuclear Plant	-	-	-

Source: Company Records

	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	-	-	-
536	Water for Power	-	-	-
537	Hydraulic Expenses	-	-	-
538	Electric Expenses	-	-	-
539	Misc. Hydraulic Power Gen. Expenses	-	-	-
540	Rents	-	-	-
	Total Operation	-	-	-
Maintenance				
541	Maintenance Supervision and Engineering	-	-	-
542	Maintenance of Structures	-	-	-
543	Maint. of Reserviors, Dams & Waterways	-	-	-
544	Maintenance of Electric Plant	-	-	-
545	Maintenance of Misc. Hydroelectric Plant	-	-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Hydroelectric	-	-	-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering		-	-
547	Fuel			2,757,785
548	Generation Expenses		-	-
549	Miscellaneous Other Power Gen. Expenses		-	610,152
550	Rents	-	-	-
	Total Operation	-	-	3,367,937
Maintenance				
551	Maintenance Supervision and Engineering		-	-
552	Maintenance of Structures		-	-
553	Maintenance of Generation & Electric Plant		-	402,601
554	Maintenance of Misc. Other Power Gen.		-	-
	Total Maintenance	-	-	402,601
	Total Power Production Expenses -- Other Power			3,770,538
	Other Power Supply Expenses			
Operation				
555	Purchased Power (p. 326, 327)			44,091,282
556	System Control and Load Dispatching		-	649,142
557	Other Expenses			-
	Total Operation	-	-	44,740,424
	Total Power Production Expenses	-	-	64,161,809

Source: Company Records

	Transmission Expenses	
Operation		
560	Operation Supervision and Engineering	202,810
561	Load Dispatching	545,666
562	Station Expenses	-
563	Overhead Line Expenses	-
564	Underground Line Expenses	-
565	Transmission of Electricity by Others	-
566	Miscellaneous Transmission Expenses	-
567	Rents	-
	Total Operation	748,476
Maintenance		
568	Maintenance Supervision and Engineeering	-
569	Maintenance of Structures	-
570	Maintenance of Station Equipment	-
571	Maintenance of Overhead Lines	-
572	Maintenance of Underground Lines	-
573	Maintenance of Miscellaneous Transm. Plant	15,120
	Total Maintenance	15,120
	Total Transmission Expenses	763,596

Source: Company Records

Distribution Expenses

Operation		
580	Operation Supervision and Engineering	-
581	Load Dispatching	-
582	Station Expenses	-
583	Overhead Line Expenses	-
584	Underground Line Expenses	-
585	Street Lighting and Signal System Expenses	-
586	Meter Expenses	-
587	Customer Installation Expenses	-
588	Miscellaneous Distribution Expenses	2,003,916
589	Rents	-
	Total Operation	2,003,916
Maintenance		
590	Maintenance Supervision and Engineeering	-
591	Maintenance of Structures	-
592	Maintenance of Station Equipment	-
593	Maintenance of Overhead Lines	-
594	Maintenance of Underground Lines	-
595	Maintenance of Line Transformers	-
596	Maintenance of Street Lighting and Signal Systems	-
597	Maintenance of Meters	-
598	Maintenance of Miscellaneous Distribution Plant	1,291,355
	Total Maintenance	1,291,355
	Total Distribution Expenses	3,295,271

Source: Company Records

		Customer Accounts Expenses		
Operation				
	901	Supervision		-
	902	Meter Reading Expenses		372
	903	Customer Records and Collection Expenses		333,532
	904	Uncollectible Accounts		103,886
	905	Miscellaneous Customer Accounts Expenses		392,739
		Total Customer Accounts Expenses		830,529
		Customer Service and Information Expenses		
Operation				
	907	Supervision		-
	908	Customer Assistance Expenses		602,130
	909	Informational and Instructional Expenses		-
	910	Miscellaneous Customer Service and Information Expenses		-
		Total Customer Service and Information Expenses		602,130
		Sales Expenses		
Operation				
	911	Supervision		-
	912	Demonstrating and Selling Expenses		6,745
	913	Advertising Expenses		-
	916	Miscellaneous Sales Expenses		-
		Total Sales Expenses		6,745
		Administrative and General Expenses		
Operation				
	920	Administrative and General Salaries		6,812,918
	921	Office Supplies and Expenses		1,360,974
	922	Administrative Expenses Transferred - Credit	Enter Negative	-
	923	Outside Services Employed		972,239
	924	Property Insurance		270,130
	925	Injuries and Damages		575,059
	926	Employee Pensions and Benefits		25,452
	927	Franchise Requirements		
	928	Regulatory Commission Expenses (See Next Page)		78,900
	929	Duplicate Charges - Credit	Enter Negative	-
	930.1	General Advertising Expenses (See Next Page)		145,109
	930.2	Miscellaneous General Expenses (See Next Page)		247,180
	931	Rents		106,423
		Total Operation		10,594,385
Maintenance				
	935	Maintenance of General Plant		355,748
		Total Administrative and General Expenses		10,950,133

Source: Company Records

Account 930.1	
Customer Communications	58,043
Community Relations	29,022
Communications Marketing	47,886
Management & Administration	-
Hiring - Internet Advertising	10,157
Other Miscellaneous	-
Total Account 930.1	145,108
Account 930.2	
Annual Meeting Costs	-
Shareholder Relations Costs	-
Board of Directors	121,446
Executive Communications	-
Management & Administration	-
Transfer Agent Costs	-
External Financing Costs	-
Load Research	-
Planning Studies	-
Human Resources Benefits	-
Vehicle Program Administration	-
Dues & Membership Fees	70,572
Trees Program	-
Other Miscellaneous	55,162
Total Account 930.2	247,180
Account 928.000 (Regulatory Commission Expenses)	
FERC	-
All Other	-
FERC Transmission Rate Case ($150k ÷ 3 years)	-
Total Account 928	78,900

Source: Company Records

Fuel Expenses

	Steam Generation Acct. 501	Nuclear Generation Acct. 518	Other Generation Acct. 547	Purchased Power Acct. 555	Total
July	674,177		-	4,122,049	4,796,226
August	674,177		-	4,079,348	4,753,524
September	652,123		-	3,960,500	4,612,623
October	674,177		235,427	3,218,904	4,128,507
November	652,123		274,007	3,183,733	4,109,863
December	674,177		298,407	3,541,398	4,513,981
January	731,509		391,666	3,977,604	5,100,779
February	660,718		307,294	3,368,252	4,336,263
March	731,509		541,819	3,864,474	5,137,802
April	707,912		41,667	3,594,078	4,343,657
May	731,509		294,424	3,785,984	4,811,917
June	707,912		373,075	3,394,958	4,475,945
Total	8,272,020	0	2,757,785	44,091,282	55,121,087

Source: Company Records

Electric Utility Wages and Salaries

Included in Operation and Maintenance Expenses

Operation and Maintenance Expenses	Total Year
Production	-
Transmission	252,098
Distribution	1,020,135
Customer Accounts	242,451
Customer Service	286,858
Sales Expenses	1,741
Administrative and General	3,518,845
Total Wages and Salaries Included in O&M Expenses	5,322,128
Wages & Salaries Excluding A&G	1,803,283

Source: Company Records

FERC Account		Demand	Energy	Total
Production				
	Steam Power Generation			
Operation				
500	Operation Supervision and Engineering		0	-
501	Fuel			-
502	Steam Expenses	0	0	962,553
503	Steam from Other Sources	0	0	-
504	Steam Transferred - Credit	0	0	-
505	Electric Expenses	0	0	-
506	Miscellaneous Steam Power Expenses	0	0	-
507	Rents	0	-	-
	Total Operation	-	-	962,553
Maintenance				
510	Maintenance Supervision and Engineering		0	-
511	Maintenance of Structures	0	0	-
512	Maintenance of Boiler Plant		0	962,605
513	Maintenance of Electric Plant		0	-
514	Maintenance of Miscellaneous Steam Plant	0	-	-
	Total Maintenance	-	-	962,605
	Total Power Production Expenses - Steam Plant			1,925,157
	Nuclear Power Generation			
Operation				
517	Operation Supervision and Engineering	0	0	-
518	Fuel	0	0	-
519	Coolants and Water	0	0	-
520	Steam Expenses	0	0	-
521	Steam from Other Sources	0	0	-
522	Steam Transferred - Credit	0	0	-
523	Electric Expenses	0	0	-
524	Miscellaneous Steam Power Expenses	0	0	-
525	Rents	0	0	-
	Total Operation			-
Maintenance				
528	Maintenance Supervision and Engineering	0	0	-
529	Maintenance of Structures	0	0	-
530	Maintenance of Reactor Plant Equipment	0	0	-
531	Maintenance of Electric Plant	0	0	-
532	Maintenance of Miscellaneous Steam Plant	0	0	-
	Total Maintenance			-
	Total Power Production Expenses - Nuclear Plant			-

	Hydroelectric Power Generation			
Operation				
535	Operation Supervision and Engineering	0	0	-
536	Water for Power	0	0	-
537	Hydraulic Expenses	0	0	-
538	Electric Expenses	0	0	-
539	Misc. Hydraulic Power Gen. Expenses	0	0	-
540	Rents	0	0	-
	Total Operation			-
Maintenance				
541	Maintenance Supervision and Engineering	0	0	-
542	Maintenance of Structures	0	0	-
543	Maint. of Reserviors, Dams & Waterways	0	0	-
544	Maintenance of Electric Plant	0	0	-
545	Maintenance of Misc. Hydroelectric Plant	0	0	-
	Total Maintenance			-
	Total Power Production Expenses -- Hydroelectric			-
	Other Power Generation			
Operation				
546	Operation Supervision and Engineering		0	-
547	Fuel		0	-
548	Generation Expenses		0	-
549	Miscellaneous Other Power Gen. Expenses		0	-
550	Rents		0	-
	Total Operation			-
Maintenance				
551	Maintenance Supervision and Engineering		0	-
552	Maintenance of Structures		0	-
553	Maintenance of Generation & Electric Plant		0	-
554	Maintenance of Misc. Other Power Gen.		-	-
	Total Maintenance	-	-	-
	Total Power Production Expenses -- Other Power			-
	Other Power Supply Expenses			
Operation				
555	Purchased Power	0		-
556	System Control and Load Dispatching	0	0	299,257
557	Other Expenses		-	-
	Total Operation	-	-	299,257
	Total Power Production Expenses			-

	Transmission Expenses	
Operation		
560	Operation Supervision and Engineering	82,961
561	Load Dispatching	165,616
562	Station Expenses	
563	Overhead Line Expenses	
564	Underground Line Expenses	
565	Transmission of Electricity of Others	
566	Miscellaneous Transmission Expenses	
567	Rents	
	Total Operation	248,577
Maintenance		
568	Maintenance Supervision and Engineeering	
569	Maintenance of Structures	
570	Maintenance of Station Equipment	
571	Maintenance of Overhead Lines	
572	Maintenance of Underground Lines	
573	Maintenance of Miscellaneous Transm. Plant	3,521
	Total Maintenance	3,521
	Total Transmission Expenses	252,098

	Distribution Expenses	
Operation		
580	Operation Supervision and Engineering	
581	Load Dispatching	
582	Station Expenses	
583	Overhead Line Expenses	
584	Underground Line Expenses	
585	Street Lighting and Signal System Expenses	
586	Meter Expenses	
587	Customer Installation Expenses	
588	Miscellaneous Distribution Expenses	702,901
589	Rents	
	Total Operation	702,901
Maintenance		
590	Maintenance Supervision and Engineeering	
591	Maintenance of Structures	
592	Maintenance of Station Equipment	
593	Maintenance of Overhead Lines	
594	Maintenance of Underground Lines	
595	Maintenance of Line Transformers	
596	Maintenance of Street Lighting and Signal Systems	
597	Maintenance of Meters	
598	Maintenance of Miscellaneous Distribution Plant	317,234
	Total Maintenance	317,234
	Total Distribution Expenses	1,020,135

	Customer Accounts Expenses		
Operation			
901		Supervision	-
902		Meter Reading Expenses	189
903		Customer Records and Collection Expenses	62,645
904		Uncollectible Accounts	-
905		Miscellaneous Customer Accounts Expenses	179,617
	Total Customer Accounts Expenses		242,451
	Customer Service and Information Expenses		
Operation			
907		Supervision	-
908		Customer Assistance Expenses	286,858
909		Informational and Instructional Expenses	-
910		Miscellaneous Customer Service and Information Expenses	-
	Total Customer Service and Information Expenses		286,858
	Sales Expenses		
Operation			
911		Supervision	-
912		Demonstrating and Selling Expenses	1,741
913		Advertising Expenses	-
916		Miscellaneous Sales Expenses	-
	Total Sales Expenses		1,741
	Administrative and General Expenses		
Operation			
920		Administrative and General Salaries	3,518,742
921		Office Supplies and Expenses	
922		Administrative Expenses Transferred - Credit	
923		Outside Services Employed	
924		Property Insurance	
925		Injuries and Damages	
926		Employee Pensions and Benefits	
927		Franchise Requirements	
928		Regulatory Commission Expenses	
929		Duplicate Charges - Credit	
930		General Advertising & Miscellaneous General Expenses (See Next Page)	
931		Rents	
		Total Operation	3,518,742
Maintenance			
935		Maintenance of General Plant	103
	Total Administrative and General Expenses		3,518,845

Cheyenne Light Fuel and Power
DEPRECIATION AND AMORTIZATION EXPENSES
June 30 2015 Forecast

Exhibit No. CLP-49
Period II
Statement AJ

Function	Depreciable Plant Balances (EOY)	Depreciation Rate (Percent)	Depreciation Amount Annual
Production Plant			
Prior to October 1, 2014 (CPGS)	303,557,195	2.81%	2,132,489
Subsequent to October 1, 2014 (CPGS)	308,020,807	2.94%	6,791,859
Transmisson Plant			
Bulk Plant	38,400,229	2.43%	933,126
Direct Assignment		0%	-
Distribution	-	0%	-
Generation Step-Up	-	0%	-
Total Transmission Plant	38,400,229	2.43%	933,126
Distribution Plant			
Bulk Plant	-	0%	
Direct Assignment	-	0%	
Distribution	160,674,387	2.79%	4,482,815
Generation Step-Up	-	0%	
Other Distribution	-	0%	
Total Distribution Plant	160,674,387	2.79%	4,482,815
General Plant			
Distribution	-	0%	-
Power Marketing	-	0%	-
Production	-	0%	-
Retail Services	-	0%	-
Transmission	-	0%	-
Total General Plant	10,663,879	2.25%	239,937.29
Other Utility Plant			
Distribution	-	0%	-
Power Marketing	-	0%	-
Production	-	0%	-
Retail Services	-	0%	-
Transmission	-	0%	-
Total Other Utility Plant	8,126,462	7.98%	648,491.64
Total Depreciation and Amortization Expense	525,885,765		15,228,718

Depreciation rates from Statement J Wyoming State Rate case.

Sources: Company Records

Real Estate and Personal Property	2,025,902
Payroll Taxes	707,530
Gross Receipts Taxes	216501.6
Miscellaneous Taxes	1,817,183
Total Taxes Other than Income:	4,767,117

Source: Company Records

	13 Month Average	Average Beg/End Yr.	End of Year
Fuel Inventories (non-nuc.)	-	-	-
Materials & Supplies	6,202,967	5,955,275	6,415,275
Property Insurance	61,627	25,445	33,194
Other Prepayments	677,346	688,737	643,490
Total	6,941,940	6,669,457	7,091,960

Fuel Inventories

	Coal	Oil	Natural Gas	Other	Total
December					
January					
February					
March					
April					
May					
June					
July					
August					
September					
October					
November					
December					
13 Mo. Avg.	-	-	-	-	-
Beg/End Avg.	-	-	-	-	-

Cheyenne Light Fuel and Power
WORKING CAPITAL
June 30 2015 Forecast

Materials and Supplies

	Production	Transmission	Distribution	General	Total
July	2,638,376	46,460	2,778,437	32,002	5,495,275
August	2,638,376	46,460	2,778,437	32,002	5,495,275
September	2,638,376	46,460	2,778,437	32,002	5,495,275
October	3,558,376	46,460	2,778,437	32,002	6,415,275
November	3,558,376	46,460	2,778,437	32,002	6,415,275
December	3,558,376	46,460	2,778,437	32,002	6,415,275
January	3,558,376	46,460	2,778,437	32,002	6,415,275
February	3,558,376	46,460	2,778,437	32,002	6,415,275
March	3,558,376	46,460	2,778,437	32,002	6,415,275
April	3,558,376	46,460	2,778,437	32,002	6,415,275
May	3,558,376	46,460	2,778,437	32,002	6,415,275
June	3,558,376	46,460	2,778,437	32,002	6,415,275
July	3,558,376	46,460	2,778,437	32,002	6,415,275
13Mo. Avg.	3,346,068	46,460	2,778,437	32,002	6,202,967
Beg/End Avg.	3,098,376	46,460	2,778,437	32,002	5,955,275

Source: Company Records

Prepayments and Insurance

	Property Insurance	Other Prepayments
July	29,536	750,691
August	18,260	778,378
September	6,984	712,394
October	127,921	722,908
November	116,080	751,920
December	104,240	747,063
January	92,399	636,142
February	80,558	670,555
March	68,717	642,489
April	56,876	493,723
May	45,035	628,957
June	33,194	643,490
July	21,354	626,784
13 Mo. Avg.	61,627	677,346
Beg/End Avg.	25,445	688,737

Source: Company Records

Cheyenne Light Fuel and Power
CONSTRUCTION WORK IN PROGRESS
June 30 2015 Forecast

Exhibit No. CLP-52
Period II
Statement AM

Not applicable for this transmission filing

	Steam Production	Nuclear (a) Production	Other Production	Transmission	Total
December	-	0	0	-	-
January		0	0		-
February		0	0		-
March		0	0		-
April		0	0		-
May		0	0		-
June		0	0		-
July		0	0		-
August		0	0		-
September		0	0		-
October		0	0		-
November		0	0		-
December		0	0		-
13 Mo. Avg.	-	0	-	-	-

	Distribution	General	Common
12/31/1999	-	-	0
12/31/2000	-	-	0
Average	-	-	0

Notes:
(a) Excludes Nuclear Fuel

	Total Company	Electric
July	112,893,389	94,830,447
August	113,118,653	95,019,669
September	42,826,841	35,974,547
October	39,786,978	33,421,062
November	47,275,436	39,711,367
December	33,202,952	27,890,480
January	28,121,641	23,622,178
February	23,897,897	20,074,233
March	23,037,252	19,351,291
April	18,051,104	15,162,927
May	17,334,531	14,561,006
June	14,848,021	12,472,338
July	10,831,135	9,098,153
Total	525,225,830	441,189,697
13 Mo. Avg.	40,401,987	33,937,669

Cheyenne Light Fuel and Power
RATE FOR ALLOWANCE FOR FUNDS
USED DURING CONSTRUCTION
June 30 2015 Forecast

Exhibit No. CLP-54
Period II
Statement AO

Company forecasts a 7.722 % AFUDC rate in 2015 . A comparison of the AFUDC rate used during the year with the FERC formula rate derived using forecast through 12/31/15. shows that Company is within FERC guidelines. This calculation of AFUDC is shown below.

Input Values

S = Average Short-Term Debt for year	=	$	-
RS = Short-Term Debt Interest Rate	=		0.00%
D = Long-Term Debt, Year End	=	$	302,000,000
RD = Long-Term Debt Interest Rate	=		5.76%
P = Preferred Stock, Year End	=	$	-
RP = Preferred Stock Cost Rate	=		0.00%
C = Common Equity, Year End	=	$	316,087,378
RC = Commony Equity Cost Rate (Authorized)	=		10.60%
W = Average CWIP plus Nuclear Fuel In Process	=	$	10,225,326

Calculated Values

AI = Rate for Gross Allowance for Borrowed Funds used during Construction
= (RS * (S/W)) + (RD * (D/(D+P+C)) * (1-S/W))
AI = 2.813%

AE = Rate for Allowance for Other Funds used during Construction
= (1-S/W) * (RP * (P/(D+P+C)) + RC * (C/(D+P+C)))
AE = 0.000%

Gross Nominal Rate =	2.813%
Effective annual Rate (Semi-Annual Compounding)	2.833%
Effective Monthly Rate (Semi-Annual Compounding)	0.233%

Soruce: Company Records

Account 432		CWIP Taking AFUDC	AFUDC Expenditure	AFUDC Debt Acct. 432
Electric				
	Production	$ 3,096,964	87,114	87,114
	Transmission	$ 1,690,030	47,539	47,539
	Distribution	$ 12,057,536	339,166	339,166
	General	$ 1,760,260	49,514	49,514
	Subtotal	$ 18,604,789	$ 523,333	$ 523,333
	Other Utility Plant	0	0	0
	Total	$ 18,604,789	$ 523,333	$ 523,333

Source: Company Records

Long Term Interest Expense	Rate Base	Weighted LTD Rate (%)	Long Term Interest
Transmission	31,476,233	2.79%	877,431
All Other	322,931,326	2.79%	9,002,034
Total	354,407,559		9,879,465

Source: Statement BK

Acct. 431 -- Other Interest Expense	
90-Day Notes	
Customer Svc Deposits	$ 174,000
Bank Facility Fees	
Miscellaneous	$ 63,000
Total	$ 237,000

Source: Company Records

Cheyenne Light Fuel and Power
FEDERAL INCOME TAX DEDUCTIONS -- OTHER THAN INTEREST
June 30 2015 Forecast

Pretax Net Income 40,570,738

Additions to Income Before Taxes

Description of Each Item		Total
BAD DEBT RESERVE	$	-
BONUS		-
WORKERS COMP		-
DEFERRED REVENUE		-
DEFERRED COSTS		5,169,916
OTHER		
REG RETIREE HEALTHCARE ASSET		-
FAS 143 (ARO)		-
LINE EXTENSION DEP ELEC		6,494,000
GAIN DEFERRAL		-
FAS 106 RETIREE LIAB		-
ACCR LITIGATION LIAB		-
REG PSC PENSION ASSET		
REG ENGY EFF ASSET		452,592
CONTRIBUTIONS IN AID OF CONST		102,804
DERIVATIVE (AOCI)		
Total Additions to Income	$	12,219,312

Deductions from Income Before Taxes

Description of Each Item		Total
INTEREST EXPENSE	$	-
VACATION		-
PENSION FAS 87		-
COST OF REMOVAL		(342,863)
EQUITY ADUFC		-
ACCELERATED DEPRECIATION ELEC		(2,719,393)
INS RESERVE LIAB		-
LT RATE CASE ASSET		(81,390)
REG RESA RIDER ASSET		-
SEVERANCE		-
REG ACCR FAC ELEC		(241,069)
NET OPERATING LOSS CARRYFORWARD		(8,989,502)
GOODWILL AMORT		-
REG ASSET ARO LIABILITY		-
Total Deductions from Income	$	(12,374,217)

Source: Company Records

Cheyenne Light Fuel and Power
INCOME TAX ADJUSTMENTS - ACCOUNT 410.1
June 30 2015 Forecast

Exhibit No. CLP-57
Period II
Statement AR

Provision for Deferred Income Taxes

	Allocator/Assignment					
	TOTAL	NPLT	W&S	DISTRIBUTION	PRODUCTION	TRANSMISSION
FERC Account 190 - Accumulated Deferred Income Taxes						
Line Extension Deposits	2,272,900	2,272,900				207,168
NOL Carryforward	(3,146,326)	(3,146,326)				(286,778)
	(873,426)	(873,426)	-	-	-	(79,610)
FERC Account 282 - Accumulated Deferred						
Cost Of Removal-Elect	(120,002)	(120,002)				(10,938)
Depreciation	(951,788)	(951,788)				(86,752)
Facts And Circumstances-Elect	(84,374)	(84,374)				(7,690)
Contributions in Aid of Const	35,981	35,981				3,280
	(1,120,182)	(1,120,182)	-	-	-	(102,101)
FERC Account 283 - Accumulated Deferred Income Taxes - Other Property						
Deferred Costs	1,809,471	1,809,471				164,927
Reg Energy Efficient Asset	158,407	158,407				14,438
Deferred Rate Case	(28,487)	(28,487)				(2,596)
	1,939,391	1,939,391	-	-	-	176,769
Total	(54,217)	(54,217)	-	-	-	(4,942)

Notes:
(1) The "Allocator/Assignment" totals by category go forward to the following worksheet:
Statement BK-Cost of Service Study
(2) Note that there are no amounts in account #411.1

Source: Company Records

Cheyenne Light Fuel and Power
ADDITIONAL STATE INCOME TAX DEDUCTIONS
June 30 2015 Forecast

Exhibit No. CLP-58
Period II
Statement AS

None for Cheyenne Light Fuel & Power

Deductions from Book Income to Determine Taxable Income:

	Amount
State Tax Depreciation	
Other (Specify)	
Other (Specify)	
Other (Specify)	
Total	0

Additions to Book Income to Determine Taxable Income:

	Amount
Book Depreciation	
Other (Specify)	
Other (Specify)	
Other (Specify)	
Total	0

Source:

None

Source: Company Records

Cheyenne Light Fuel and Power
REVENUE CREDITS
June 30 2015 Forecast

Exhibit No. CLP-60
Period II
Statement AU

FERC Account	Description	Total Company Amount	Ancillary Service Schedule 2	Revenue Credits SF, OS, NF Service
454	Transmission Only			
456	Transmission For Others	$ 819,836	$ 783,836	$ -
447	Sales for Resale (transmission)			
	Total	$ 819,836	$ 783,836	$ -

Source: Company Records

Cheyenne Light Fuel and Power
CAPITAL STRUCTURE
June 30 2015 Forecast

Exhibit No. CLP-61
Period II
Statement AV

	Component	Form No. 1	End of Year Amounts Amount	Share (%)	Cost Rate (%)		Weighted Cost (%)
1	Long-Term Debt	see Note #3	194,000,000	46.0%	6.060%	Note #2	2.79%
2	Preferred Stock	p. 112 3 c		0.0%	0.000%		0.00%
3	Common Equity	see Note #1	185,310,192	54.0%	10.600%		5.72%
4	Total		379,310,192	100.0%			8.51%

Note #1:

5	Proforma Adjustment to Ec	p. 112, 16 d	42,428,938
6	Adjusted Equity		227,739,130
7			
8	Total		421,739,130

Note #1
Adjustment to reflect future retained earnings and equity infusion

Source: Company Records

Cost of Short-Term Debt

Short term debt is not considered in the cost of service, since it is not included in the capital structure

Rate Orders Acted Upon During, or After, Period II

None.

Cheyenne Light Fuel and Power	Exhibit No. CLP-64
INCOME AND REVENUE TAX DATA	Period II
June 30 2015 Forecast	Statement AY

A	Federal Income Tax Rate	35.0000%
B	Nominal State Income Tax Rate	
	Wyoming	0.0000%
C	Deductibility of State Income Taxes:	
	(Provide Statement)	
D	Revenue Tax Rate	
	Description of Each Tax Rate	
		0.0000%
	Sum	0.0000%
E	Proportion of Federal Income Tax Deductible For State Income (weighed, if more than one state)	0.0000%

Source: Company Records

OATT Transmission Service

Long-Term Firm Point-to-Point Customers

Black Hills Power

Short-Term Firm Point-to-Point Customers

None

Network Customers

Cheyenne Light Fuel and Power

Other Long-Term Firm Service

None
None
None
None

Non-Firm Transmission Service

None

Cheyenne Light Fuel and Power
ALLOCATION DEMAND AND CAPABILITY DATA
June 30 2015 Forecast

Exhibit No. CLP-66
Period II
Statement BB

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	**12cp**
Native Retail Load	p. 401	199	190	180	170	179	189	195	186	185	187	180	208	**187**
Other Transmission Service Loads :														
Black Hills Power Point to Point		10	10	10	10	10	10	10	10	10	10	10	10	10
Other														
None														
None														
Total Transmission System Load		209	200	190	180	189	199	205	196	195	197	190	218	197

Not applicable for this transmission filing

Not applicable for this transmission filing

Not applicable for this transmission filing

Not applicable for this transmission filing

Cheyenne Light Fuel and Power
PROPOSED AND PRESENT REVENUES
June 30 2015 Forecast

Exhibit No. CLP-71
Period II
Statement BG & BH

Long-Term Firm Point-to-Point Customers	Average MW	Proposed Rate	Present Rate	Proposed Revenue	Present Revenue	Increase	% Increase
Black Hills Power	10	2.89	NA	$ 347,029		NA	NA

Short-Term Firm Point-to-Point Customers	(1) Annual Transmisison Charges At Present Rate	(2) Proposed Rate ($/kW/Month)	(3) Present Rate ($/kW/Month)	(4) % Increase (2)/(3)	(5) Annual $ Increase (1)x(4)
	NA	2.89	NA	NA	NA

Network Customers	Average Customer Peaks	Average Total Peaks	Proposed Schedule H	Present Schedule H	Proposed Revenues	Present Revenues	$ Increase
Third Party Network	NA	NA	2.89	NA	NA	NA	NA

(1) Applicable to Firm Point-to-Point Transmission Service only.

See Statement BG

Not applicable for this transmission filing

Cheyenne Light Fuel and Power
SUMMARY DATA TABLES
June 30 2015 Forecast

Exhibit No. CLP-74
STATEMENT BJ
Period II

Statement	Description	Function/ Sub-Function	Beginning/Ending Average
AD	Cost of Plant	Production	247,741,750
		Transmission	40,864,562
		Distribution	162,709,550
		General	10,580,662
		Common	-
AE	Accumulated Depreciation and Amortizati	Production	28,541,149
		Transmission	3,699,457
		Distribution	50,213,786
		General	4,870,569
		Common	-
AF	Specified Deferred Credits		
	Account 255	Total	70,124
	Account 281	Total	-
	Account 282	Total	52,132,636
	Account 283	Total	7,357,133

Statement	Description	Function/ Sub-Function	Beg of Yr/End of Yr Average
AG	Specified Plant Accts and Deferred Debits		
	Account 105	Total	
	Account 182	Total	4,003,499
	Account 190	Total	6,365,419
			Annual Amount
AH	Operating & Maintenance Expenses	Production	64,161,809
		Transmission	763,596
		Distribution	3,295,271
		General	10,950,133
		Total	79,170,809
AI	Wages & Salaries	Production	-
		Transmission	252,098
		Distribution	1,020,135
		General	3,518,845
		Common	-
		Total	4,791,078
AJ	Depreciation & Amortization Expense	Production	-
		Transmission	933,126
		Distribution	4,482,815
		General	239,937
		Total	5,655,878

Statement	Description	Function/ Sub-Function	Annual Amount
AK	Taxes Other Than Income		
	Real Estate & Personal Property		2,025,902
	Payroll Taxes		707,530
	Other		-
	Total		2,733,432
			13-Month Average
AL	Working Capital	Fuel Supplies	-
		Materials & Suppl	6,202,967
		Prepayments	677,346
		Total	6,880,313
AM	Construction Work In Process		
		Production	-
		Transmission	-
		Distribution	-
		General	-
		Total	-
AN	Notes Payable		33,937,669

Statement	Description	Function/ Sub-Function	Year-to-Date
AP	Fed Income Tax Deductions-Interest		
	Account 431	Other Interest	237,000
	Account 432	Total	523,333
	Long Term Interest Exp	Transmission	877,431
		All Other	9,002,034
		Total	9,879,465
AQ	Income Tax Deductions-Other Than Interest		
	Additions to Book Income		12,219,312
	Deductions from Book Income		(12,374,217)
AR	Income Tax Deductions		
	Acct 410.1 - Provision for Deferred Income Taxes - Debit		
	Account 281		-
	Account 282	Total	(1,120,182)
	Account 283	Total	1,939,391
	Account 190	Total	(873,426)
	Summary Account 410.1	Total	(54,217)
	Acct 411.1 - Provision for Deferred Income Taxes - Credit		
	Account 281	Total	-
	Account 282	Total	-
	Account 283	Total	-
	Account 190	Total	-
	Summary Account 411.1	Total	-

Statement	Description	
AS	Additional State Income Tax Deductions	No additional state income tax deductions.
AT	State Tax Adjustments	No state income tax deductions.
AV	Rate of Return	

Cost of Capital	Amount	Percent Of Total	Cost	Weighted Cost
Long -Term Debt	194,000,000	46.0000%	6.06%	2.79%
Preferred Stock	-	0.0000%	0.00%	0.00%
Common Equity	185,310,192	54.0000%	10.60%	5.72%
Total	379,310,192	100.00%		8.51%

Statement	Description		
AW	Cost of Short-Term Debt	Not Included in the Capital Structure for return purposes, therefoe, not considered in COS.	
AY	Income & Revenue Tax Rate Data	Nominal Federal Income Tax Rate	35.00%
		Nomital State Income Tax Rate Colorado	0.00%
		Revenue Tax Rate	0.00%

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Summary of Results

Line	Description	Source	Total Electric	Transmission At Issue	All Other
	Rate Base				
1	Gross Plant in Service	Sch 2 ; Page 1	486,699,020	41,027,108	445,671,911
2	Depreciation Reserve	Sch 2 ; Page 1	(91,931,368)	(5,045,300)	(86,886,067)
3	Net Utility Plant		394,767,652	35,981,808	358,785,844
4	Accumulated Deferred Taxes	Sch 3 ; Page 1	(56,765,883)	(5,473,399)	(51,292,484)
5	Other Subtractive Adjustments	Sch 3 ; Page 1	-	-	-
6	Materials & Supplies	Sch 2 ; Page 2	6,170,965	46,460	6,124,505
7	Fuel Inventory	Sch 2 ; Page 2	-	-	-
8	Prepaids and Other	Sch 2 ; Page 2	738,973	62,293	676,680
9	Cash Working Capital	Sch 2 ; Page 2	3,130,432	216,720	2,913,713
10	Acct. 190 and Other Additive Adjust.	Sch 3 ; Page 2	6,365,419	642,351	5,723,068
11	Total Rate Base		354,407,559	31,476,233	322,931,326
	Operating Expenses				
12	Total O&M Expense		80,164,546	1,733,759	78,430,787
13	Total Depreciation Expense		15,228,718	1,057,327	14,171,391
14	Total Other Taxes		4,550,615	422,872	4,127,744
16	Subtotal - O&M & Other		99,943,880	3,213,958	96,729,921
17	Net Federal Income Taxes		10,756,565	954,941	9,801,625
18	Net State Income Taxes		-	-	-
19	Total Operating Expense		110,700,445	4,168,899	106,531,546
20	Return on Rate Base		$ 30,165,754	$ 2,679,131	$ 27,486,623
21	Total Cost of Service		140,866,199	6,848,030	134,018,169
22	Revenue Credits (Statement AU; allocated on TP)		$ 783,836	$ -	
23	Net Cost of Service			6,848,030	
24	Current Revenue Requirement			$ -	
25	Revenue Increase			$ 6,848,030	
26	Allowed Rate of Return (after tax; Statement AV)		8.51%	8.51%	8.51%
27	Schedule 1 Service: Scheduling, System Control and Dispatch Service Annual Revenue Requirement -- Schedule 4, Page 1			$ 545,666	

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Electric Plant in Service

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
1	Production Plant		268,834,063		268,834,063
2	Transmission Plant At Issue		38,400,229	38,400,229	-
3	Distribution Plant		160,674,387		160674386.7
4	Gross Electric P, T, D Plant		467,908,679	38,400,229	429,508,449
6	General & Intangible Plant Functionalized	W&S	18,790,341	2,626,879	16,163,462
7	Gross Electric Plant in Service		486,699,020	41,027,108	445,671,911
				14%	

Depreciation Reserve

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
1	Production Plant		28,213,623		28,213,623
2	Transmission Plant At Issue		3,664,562	3,664,562	-
4	Distribution Plant		50,176,614		50,176,614
5	Gross Electric P, T, D Plant		82,054,799	3,664,562	78,390,238
6	Gen. Plant Depr. Resv. Functionalized	W&S	9,876,568	1,380,739	8,495,830
7	Total Depreciation Reserve (l. 5 + l. 6)		91,931,368	5,045,300	86,886,067

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Net Electric Plant

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
1	Production Plant		240,620,439		240,620,439
2	Transmission Plant At Issue		34,735,668	34,735,668	-
3	Transmission Plant Excluded				-
4	Distribution Plant		110,497,772	-	110,497,772
5	Net P, T, D Plant		385,853,879	34,735,668	351,118,212
6	General & Intangible Net Plant		8,913,773	1,246,140	7,667,632
7	Net Electric Plant in Service		394,767,652	35,981,808	358,785,844

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Subtractive Adjustments				
1	Accum. Deferred ITC -- Acct. 255		128,664	11,727	116,937
2	ADIT (Acct. 281)	NPLT	-	-	-
3	ADIT (Acct. 282)	NPLT	52,132,636	4,751,723	47,380,913
4	ADIT (Acct. 283) (Plant)	NPLT	4,061,743	342,391	3,719,352
5	ADIT (Acct. 282 $ 283 Common)	DA	442,840	367,557	75,283
6	Subtotal Accum. Deferred Taxes		56,765,883	5,473,399	51,292,484
	Other Subtractive Adjustments				
7		NPLT	-	-	-
8	Total Subtractive Adjustments		56,765,883	5,473,399	51,292,484

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Additive Adjustments				
	Accum. Deferred Inc. Taxes (Acct. 190)				
1	Functionalized (wp AG)	W&S / NPLT	6,365,419	642,351	5,723,068
2	Subtotal Acct. 190		6,365,419	642,351	5,723,068
	Land Held for Future Use (Acct. 105)				
3	Transmission	TP	-	-	
4	General Functionalized	W&S	-	-	-
5	Total Land for Future Use		-	-	-
6	Total Additive Adjustments (l.2 + l. 5)		6,365,419	642,351	5,723,068

Accumulated Deferred Income Taxes, Other Rate Base Adjustments and Working Capital (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Working Capital				
	Materials and Supplies				
	Fuel Supplies				
1	Fossil	Direct	-		
2	Nuclear		-		
3	Other		-		
4	Total Fuel Stocks		-	-	-
	Materials and Supplies				
5	Production	DA	3,346,068		3,346,068
6	Transmission	TP	46,460	46,460	-
7	Distribution	DA	2,778,437		2,778,437
8	Total Plant Materials & Supplies		6,170,965	46,460	6,124,505
	Prepayments				
9	Property Insurance	GPLT	61,627	5,195	56,432
10	Other Prepayments	GPLT	677,346	57,098	620,248
11	Total Prepayments		738,973	62,293	676,680
	Cash Working Capital (Auto Calculation)				
12	(One eighth O&M less fuel and PP)	(auto calculation)	3,130,432	216,720	2,913,713
13	Total Working Capital		10,040,371	325,473	9,714,898

O&M Expenses

Line	Description	Allocator	Total Electric	Transmission At Issue	Other
	Production O&M				
	Energy Related Production O&M				
1	Fuel		11,029,805		11,029,805
2	Purchased Power		44,091,282		44,091,282
3	Other				-
4	Gas Steam Energy Related		9,040,722		9,040,722
5	Total Energy Related		64,161,809	-	64,161,809
	Demand Related Production O&M				
6	Purchased Power				-
7	Other Demand Related		-		-
8	Fixed Fuel (Storage & Maintenance)		-		-
9	Gas Steam Demand Related		-		
10	Total Demand Related		-	-	-
11	Total Production O&M		64,161,809	-	64,161,809
	Transmission O&M				-
12	Total	TP	763,596	763,596	-
12a	Less Acct 561	TP	(545,666)	(545,666)	-
13	Less Acct. 565 (Tx by Others)	TP	-	-	-
14	Transmission O&M (adjusted)		217,930	217,930	-
	Distribution O&M				
15	Distribution O&M		3,295,271		3,295,271
16	Customer Accounting		830,529		830,529
17	Customer Service & Information		602,130		602,130
18	Sales		6,745		6,745
	Administrative & General				
19	Property Insurance	GPLT	270,130	22,771	247,359
20a	Less FERC Annual Fees	TP	-	-	-
20	Less EPRI/Reg.Commission Expense	W&S	100,000	-	100,000
21	A&G Excluding Property Insurance	W&S	10,680,003	1,493,058	9,186,945
22	Total Admin & General		11,050,133	1,515,829	9,534,304
23	Total O&M Expense		80,164,546	1,733,759	78,430,787

Depreciation Expense

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
1	Production		8,924,348		8,924,348
2	Transmission	TP	933,126	933,126	-
3	Distribution		4,482,815		4,482,815
4	General & Intangible	W&S	888,429	124,202	764,227
5	Total Depreciation Expense		15,228,718	1,057,327	14,171,391

Other Taxes and Miscellaneous Expenses

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	Taxes Other than Income				
1	Real Estate and Property Taxes	GPLT	2,025,902	170,777	1,855,125
2	Payroll Taxes	W&S	707,530	98,912	608,618
3	Gross Receipts Taxes	NA	0		
4	Miscellaneous Taxes	GPLT	1,817,183	153,182	1,664,000
5	Total Taxes Other than Income		4,550,615	422,872	4,127,744

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

Income Tax Based On Return

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	Federal Income Tax				
	Federal Income Tax Deductions				
	Interest Expense (Automatic - Synchronized)		9,879,465	877,431	9,002,034
	Other Deductions				
	Total Deductions	NPLT	12,374,217	1,127,870	11,246,347
	Total Other Deductions		12,374,217	1,127,870	11,246,347
	Total Deductions		22,253,682	2,005,302	20,248,380
	Federal Income Tax Additions				
	Total Additions	NPLT	12,219,312	1,113,751	11,105,561
	Total Additions		12,219,312	1,113,751	11,105,561
	Net Deductions and Additions		10,034,370	891,551	9,142,820
	Federal Income Tax Adjustments				
	Fed. Prov. Deferred Inc. Tax (410.1)				
	Acct. 281	NPLT	-	-	-
	Acct. 282	NPLT	(1,120,182)	(102,101)	(1,018,081)
	Acct. 283	NPLT	1,939,391	176,769	1,762,622
	Acct. 190	NPLT	(873,426)	(79,610)	(793,816)
	Total Fed. Def. Inc. Tax		(54,217)	(4,942)	-49,275
	Fed. Prov. Deferred Inc. Tax (411.1)				
	Acct. 281	NPLT	-	-	-
	Acct. 282	NPLT	-	-	-
	Acct. 283	NPLT	-	-	-
	Acct. 190	NPLT	-	-	-
	Total Fed. Def. Inc. Tax		-	-	-
	Investment Tax Credits				
	Amortized Investment Tax Credit				
	Total Fed. Def. Inc. Tax		0	0	0
	Preliminary Summary -- Adjustments				
	Total Fed. Def. Inc. Tax (410.1)		(54,217)	(4,942)	(49,275)
	Total Fed. Def. Inc. Tax (411.1)		-	-	-
	Total Amortized ITC		-	-	-
	Total Federal Tax Adjustments		(54,217)	(4,942)	(49,275)
	Federal Tax Computation				
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Deductions and Additions		(10,034,370)	(891,551)	(9,142,820)
	Total Federal Tax Adjustments		(54,217)	(4,942)	(49,275)
	Base for FIT Calculation		20,077,167	1,782,639	18,294,528
	FIT Factor (= FIT Rate/(1-FIT Rate)		0.53846	0.53846	0.53846
	Preliminary Fed. Income Tax (Payable)		10,810,782	959,882	9,850,900
	Total Fed. Income Tax Adjustments		(54,217)	(4,942)	(49,275)
	Net Federal Income Tax		10,756,565	954,941	9,801,625

Income Tax Based On Return (Continued)

Line	Description	Allocator	Total Electric	Transmission At Issue	All Other
	State Income Tax				
	State Income Tax Adjustments				
	Total State Inc. Tax Adjustments		-	-	-
	SIT Calculation				
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Deductions and Additions		(10,034,370)	(891,551)	(9,142,820)
	Proportion of FIT Deductible for State Inc.		0%	0%	0%
	Net Federal Income Tax Allowable		10,756,565	954,941	9,801,625
	Total State Inc. Tax Adjustments		-	-	-
	Base for SIT Calculation		30,887,949	2,742,521	28,145,428
	SIT Factor (= SIT Rate/(1-SIT Rate)		-	-	-
	Preliminary State Income Tax (Payable)		-	-	-
	Total State Income Tax Adjustments		-	-	-
	Net State Income Tax		-	-	-
	Cost of Service Computation				
	Total Op. Exp. Excl. Inc. & Rev. Taxes		99,943,880	3,213,958	96,729,921
	Return on Rate Base		30,165,754	2,679,131	27,486,623
	Net Fed Income Tax Allowable		10,756,565	954,941	9,801,625
	Net State Income Tax Allowable		-	-	-
	Cost of Service Ex. Rev. Taxes		140,866,199	6,848,030	134,018,169
	Revenue Tax Factor		1.00	1.00	1.00
	Total Cost of Service		140,866,199	6,848,030	134,018,169
	Proposed Revenues		-	6,848,030	
	Excess Revenues				
	Composite Tax Rate				
	Excess Tax				
	Excess Return				
	Total Return Earned		30,165,754	2,679,131	27,486,623

TRANSMISSION REVENUE REQUIREMENT

13 MONTH AVERAGE BALANCES

FUNCTIONALIZATION FACTORS SUMMARY (Wages & Salaries Adjusted by TP allocator)

Factors	Source		Transmission At Issue	All Other
Gross Plant, Including GP&I (GPLT)	Sch 2, page 1	1.00000	0.08430	0.91570
Net Plant, Including GP&I (NPLT)	Sch 2, page 2	1.00000	0.09115	0.90885
Salaries & Wages, Excl. A&G (W&S)	Statement AI	1.00000	0.13980	0.86020
			1.00000	