BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF THE EMPIRE DISTRICT ELECTRIC COMPANY, A KANSAS CORPORATION, FOR ANADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	))))))	CAUSE NO. PUD 201600468

REPORT OF THE ADMINISTRATIVE LAW JUDGE ON THE FULL EVIDENTIARY HEARING

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I. HEARING DATES, LOCATIONS AND APPEARANCES OF LEGAL COUNSEL

On May 10-12, 2017, Administrative Law Judge ("ALJ") Ben Jackson conducted a full evidentiary hearing on the application of Empire District Electric Company for a general rate order. The hearing occurred in Courtroom B and Courtroom 301, Jim Thorpe Building, 2101 North Lincoln Boulevard, Oklahoma City Oklahoma. At the hearing, the following attorneys entered appearances: Jack P. Fite for Empire District Electric Company ("EDE"); Deputy Attorney General Dara M. Derryberry and Assistant Attorney General Jared B. Haines for Oklahoma Attorney General Mike Hunter ("AG"); Thomas P. Schroedter for the Oklahoma Industrial Energy Consumers ("OIEC"); and Natasha M. Scott, Deputy General Counsel and Assistant General Counsels Olivia Waldkoetter and Patrick M. Ahern for the Commission's Public Utility Division ("PUD").

II. SUMMARY

The EDE application is a rate base, rate of return ratemaking for EDE, which operates an electricity transmission and distribution system serving ten towns in Ottawa, Delaware and Craig Counties, with a total of 4,689 customers. Current rates and charges were set by settlement under Order No. 592623 (Exhibit No. 136) issued on January 4, 2012. EDE started the current ratemaking in 2016 with a request for a $3.8 million dollar increase, which EDE later dropped to $2.6 million dollars. The 2016 test year plus six months for known and measurable changes ended December 31, 2016, but OIEC and the AG want a one-to-two year moratorium on general rates to see if a new test year after EDE's merger with Liberty Utilities will show significant savings to EDE's customers. In the meantime, OIEC and AG propose only giving EDE an environmental compliance rider to compensate EDE for $304 million dollars in environmental compliance equipment, but the rider proposals would not address an additional $365.5 million dollars in new plant additions.

The ALJ recommends going forward with a general rate order, because the Commission needs to address EDE's revenue deficiency as well as customer rate shock concerns seen in the public comments. In addition, the ratepayers will benefit from avoiding the cost of another full rate case within twelve to twenty-four months, as well as carrying charges on that $365.5 million dollars for new plant additions, which are now used and useful to ratepayers. This ratemaking is driven mainly by $669.5 million dollars in capital expenditures, a drop in the return on equity, changes in incentive compensation and payroll, and rate design adjustments. Table 1 compares the positions of the Parties, Intervener and the ALJ.

Table 1

FINAL POSITION COMPARISON

Parties	Empire (P.10 Errata Exhibit filed on 4-20)	PUD (Ex 138)	OIEC Alternate Proposal(Ex140 Revised)	OIEC ECP Rider (see attached)	AG ECP Rider (see attached)	ALJ Recommendation
Revised Pro Forma Rate Base	$43,275,753	$43,275,753	$3,071,159** (Empire proposed Oklahoma increase)	$804,205 (1st year of rider)***	$866,968 (1st year of rider)	$43,275,753
(ROE) ROR	(9.9%) 7.59%	(9.9%) 7.59%				(9.5%) 7.39%
Required Operating Revenue	$3,284,629*	$3,284,630	$2,494,458 (OIEC Adjustments)**			$3,198,078
Revised Pro Forma Operating Income	$1,429,712	$1,540,573				$1,585,774
Return (Deficiency)	($1,854,917)*	($1,744,057)				$1,612,304
Income Tax Gross Up Factor	163.077%	163.076%				163.076%
Revised Pro Forma Revenue (Deficiency)	($3,024,940)	($2,844,138)	$576,701 (Rate increase after OIEC Adjustments)**			$2,629,281

*Slight difference due to Empire rounding.
**Difference largely due to OIEC disallowing $365,500,000 in total company rate base as plant additions not supported in company direct testimony and OIEC advocating for 9.0% ROE.
Difference in riders largely due to OIEC using a 9.0% ROE.

The ALJ rejected OIEC's revenue requirement (Exhibit No. 140), mainly because it omitted the above-described $365.5 million dollars for plant additions. The ALJ generally adopted PUD's position but lowered the return on equity from PUD's 9.9 percent to 9.5 percent based on the AG's expert witness testimony, and also because of the AG's expert witness testimony, the ALJ denied any recovery for long-term incentive compensation, SERP and payroll adjustments. Due to concern over hardship in the Residential Class, the ALJ rejected EDE's request to increase the regular customer charge from $12.59 dollars to $20.59 and the total electric residential customer charge from $12.50 to $25.00 per month. In any event, the ALJ also amortized the $238,000 dollars rate case expense over three years without interest. As a result, the ALJ's proposed revenue requirement increase totalled $2,629,281 dollars. To allocate costs fairly, the ALJ allocated costs equally to all customer classes, and the ALJ recommends a mitigation plan. PUD sponsored their mitigation plan, and EDE asked for two changes to it, namely a three year step, with year one at fifty percent of the revenue requirement and EDE also asked for carrying charges presented in testimony. The ALJ adopted EDE's two suggestions. The result for the first year is recovery of $1,314,641 dollars plus carrying charges. Additionally, the ALJ accepted EDE's proposal to re-base the Southwest Power Pool Transmision Tariff Schedule by shifting $377,214 dollars to base rates.

III. JURISDICTION AND NOTICE

The Applicant is EDE, an integrated electric utility and a wholly owned subsidiary of Liberty Utilities, Inc. ("LU Central"). EDE, a Kansas corporation, is authorized to do business in Oklahoma and provides transmission and distribution services in northeastern Oklahoma. EDE seeks increases in rates and charges because of an alleged revenue deficiency since issuance of Order No. 592623, the current general rate order issued on January 4, 2012. EDE's current application seeks rate relief under Okla. Const. art. IX, §§ 18 & 19 and 17 O.S. 2011 §152. In that regard, the Commission has jurisdiction of the subject matter and persons. Notice was given as required by law and Commission rules. After a full evidentiary hearing and based on the evidence discussed below, the Commission has jurisdiction to issue a final order in this cause.

IV. SERVICE TERRITORY AND CUSTOMER BASE

EDE is an investor-owned utility providing electric, natural gas (through its wholly owned subsidiary Empire District Gas Company), and water service, with approximately 218,000 customers located in Missouri, Kansas, Oklahoma and Arkansas. EDE also has a subsidiary which provides fiber optic service. Organized in Topeka, Kansas on October 16, 1909, EDE is a Kansas corporation currently headquartered in Joplin, Missouri. Although established in 1909, EDE traces its history to the late nineteenth century as the mining industry grew in what is today EDE's service area. As mining companies were created, electric motors began to replace mules and steam powered engines in several of the mines. EDE was established to address the needs of those mines. Today, EDE has 1,200 miles of transmission and 1,300 megawatts of owned capacity to serve approximately 165,000 electricity customers. The current application concerns only electric transmission and distribution in Oklahoma, because EDE has no generation in Oklahoma. At the hearing on the merits, no one had a map of the EDE system.

As a result, the ALJ asked for maps to be submitted as late filed exhibits, which are shown below as Figure 1 and Figure 2 in Appendix B. Figure 1 is an EDE website map depicting EDE's four State service area. As seen on Figure 1, approximately eighty-five percent of the EDE system lies in Missouri, with the rest located in the abutting corners of Kansas, Oklahoma, and Arkansas. Oklahoma has around three percent of the total customer base. Based on cost of service studies, the Oklahoma jurisdiction allocation factors vary between 2.7349 percent and 3.1268 percent. Figure 2 is an EDE map of the Oklahoma portion of the EDE system. EDE only operates in Ottawa, Delaware and Craig Counties, and Figure 2 shows the ten towns served, namely, Cardin, Picher, Commerce, North Miami, Welch, Blue Jacket, Quapaw, Narcissa, Fairland and Wyandotte. Picher no longer has permanent residents because of the EPA buyout of local homes during EPA's Tar Creek Superfund cleanup.

EDE's customer base consists of 4,689 customers. Table 2[1] compares consumption by customer class between 2010 and 2016 test years.

Table 2
Comparison of 2010 and 2016 Test Years

Test Year	2010*	2016**
Total Oklahoma Customers	4,741	4,685
Oklahoma Jurisdiction	2.848%	2.767%
Residential Customers	3,816	3,780
Actual Residential Sales	55,611,117 kWh	47,279,918 kWh
Commercial Customers	825	802
Actual Annual Commercial Sales	11,999,058 kWh	12,284,848 kWh
Industrial Customers	13	12
Actual Annual Industrial Sales	38,066,216 kWh	27,584,081 kWh
Number of Public Authority Customers (Street and Highway Lighting)	87	91

***PUD 201100082 Kelly S. Walters Direct Testimony Page 3, Lines 16-18.**
****PUD 201600468 Brad P. Beecher Direct Testimony Page 4, Lines 1-3.**

V. EDE's RATE INCREASE REQUEST

EDE's last general rate case occurred in 2011 in Cause No. PUD 201100082, which used calendar year 2010 for the test year and resulted in a settlement finalized by Order No.592623, issued on January 4, 2012. That order granted a general rate increase of $633,436 or 4.1 percent, with a return on equity of 10.19 percent and overall rate of return of 8.27 percent. The current

[1] The 2016 data in Table 2 comes from the corporate overview in Cause No. PUD 201100082, Direct Testimony of Kelley S. Walters p. 3, lines 16-18, and the corporate overview in Cause No. PUD 201600468, Direct Testimony of Brad P. Beecher, p.4, lines 1-3.

application initially asked for $3.8 million dollars per year but now seeks a $2.6 million dollars per year with an overall rate of return of 7.59 percent and a return on equity of 9.9 percent.

VI. PROCEDURAL HISTORY

In the 2012 rate order, the Commission approved the Southwest Power Pool Transmission Tariff schedule rider ("SPPTC"). As outlined in that order, "the SPPTC will be reviewed for the purposes of extension, modification or termination during the next EDE base rate case, which will be filed no later than 42 months following the implementation of the SPPTC." As such, EDE was required to file a base rate case on or before July 5, 2015. In order to comply, EDE filed an application on January 12, 2015, requesting to amend the provision of the SPPTC order by removing the requirement to file a base rate case within 42 months. (*See* Cause No. PUD 201500012, Order No. 639419). In Cause No. PUD 201500012 EDE stated that it was making significant investments in its generation fleet, and due to the timing of the investments associated with the various projects, it would likely require the filing of two base rate cases, one in 2015 and another base rate case to be filed in the third quarter of 2016. In an effort to avoid the significant costs associated with litigating two rate cases within a short period, EDE requested the amendment to the SPPTC tariff. In Cause No. PUD 201500012, PUD witness Mr. Geoffrey M. Rush testified that EDE had completed improvements in its Asbury Plant and was in the process of converting the Riverton 12 Plant into a combined cycle unit by mid-2016. Mr. Rush further stated that it was PUD's opinion that back-to-back rate cases would not only be burdensome to EDE and its customers, but would not serve the public interest. (*See* Order No. 639419, pages 2 and 3 for testimony summary).

As outlined in the Commission's Findings of Fact and Conclusions of Law in Cause No. PUD 201500012, Order No 639419:

> "THE COMMISSION FURTHER FINDS that it would not be in the public interest to have multiple rate cases and therefore the requested amendment to the Southwest Power Pool Transmission Tariff set forth in the testimony of Mr. Owens, and attached hereto as Attachment "A," is granted."

After receiving the Commission's approval to delay a base rate case, EDE filed an application on October 21, 2015, seeking a change in its rates and charges pursuant to the Commission's reciprocity rules, as defined in OAC 165:5-70-60. (Cause No. PUD 201500379). However, once the proposed rates were approved in Missouri and submitted to the Commission, both the AG and the OIEC objected to the increase in base rates under the reciprocity rule. The AG and

OIEC stated that if EDE wants an increase in its Oklahoma base rates, another rate case should be filed with Oklahoma specific information. EDE agreed to work with the parties and on November 2, 2016, EDE filed a Motion to Dismiss Cause No. PUD 201500379, so that a case could be filed using the Commission's Minimum Filing Requirements containing Oklahoma specific information. The Commission issued an Order granting the motion to dismiss (Order No. 659346). The dismissal was granted without prejudice to refilling another base rate case.

With respect to the current application, EDE filed its Notice of Intent on November 2, 2016. The Notice of Intent signified EDE's intention to file a general rate case to review the rates and charges for electricity service to its customers in Oklahoma.

On November 8, 2016, Deputy Attorney General Dara M. Derryberry and Assistant Attorney General Jared B. Haines filed an Entry of Appearance on behalf of the Attorney General of Oklahoma Mike Hunter.

On December 21, 2016, EDE filed its Application and basic filing package, which included accounting schedules and the direct testimony of witnesses Brad P. Beecher, Bryan S. Owens, Blake A. Martens, Aaron J. Doll, Bethany Q. King, Jeffery P. Lee, Thomas J. Sullivan, Dr. James H. Vander Weide, Mark Quan, and Dr. H. Edwin Overcast.

On December 22, 2016, Thomas P. Schroedter filed an Entry of Appearance on behalf of OIEC. On the same day, Assistant Attorney General Vilard Mullaliu filed his Entry of Appearance on behalf of the AG.

On December 29, 2016, EDE filed a Motion to Establish Procedural Schedule and a Motion for Protective Order. The Commission issued a Notice of Hearing for each motion to be heard before the ALJ on January 5, 2017. At that hearing, the Motion to Establish Procedural Schedule was continued until January 19, 2017, while the Motion for Protective Order was accepted by the ALJ with an amendment supported by the parties.

PUD of the Commission filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements on January 12, 2017.

The Motion for Protective Order came before the Commission on its signing agenda on January 18, 2017. The Commission entered its Order Granting Motion for Protective Order, Order No. 659,980, on that date. On January 19, 2017, the Motion for Procedural Schedule was continued for a week until January 26, 2017. On January 26, 2017, the motion was continued for another week until February 2, 2017. Before the hearing on February 2, 2017, the parties and

ALJ agreed to continue the hearing on the Motion for Procedural Schedule to February 16, 2017. The Motion for Procedural Schedule was then continued until February 23, 2017.

On February 16, 2017, EDE filed a Motion to Determine Notice. The Commission executed a Notice of Hearing for the motion to be heard before the ALJ on February 23, 2017.

At the hearing before the ALJ on February 23, 2017, the parties submitted an agreed procedural schedule and customer notice.

The Motion to Determine Notice and Motion to Establish Procedural Schedule came before the Commission on its signing agenda on March 2, 2017. At the signing agenda, the Commission approved an Order Granting Motion to Determine Notice, Order No. 661,607, and its Order Granting Motion to Establish Procedural Schedule, Order No. 661,610.

On March 13, 2017, several witnesses filed responsive testimony. David J. Garrett and Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. Elbert D. Thomas, Geoffrey M. Rush, Kathy Champion, Kiran Patel, McKlein Aguirre, Robert C. Thompson, and Tonya Hinex-Ford filed testimony on behalf of PUD. PUD also filed its Accounting Exhibit on the same day.

On March 20, 2017, the AG filed the Notice of Withdrawal as Counsel of Vilard Mullaliu.

Several witnesses filed rate design testimony on March 22, 2017. Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. Kathy Champion and Jeremy K. Schwartz filed testimony on behalf of PUD.

Public comments were filed on March 31, 2017.

On April 3, 2017, several witnesses filed rebuttal testimony. Christopher D. Krygier, Timothy S. Lyons, Blake A. Mertens, H. Edwin Overcast, Robert W. Sager, Thomas J. Sullivan, and Dr. James H. Vander Weide filed testimony on behalf of EDE. David J. Garrett and Mark E. Garrett filed testimony on behalf of OIEC. Edwin C. Farrar filed testimony on behalf of the AG. David Melvin and Jeremy K. Schwartz filed testimony on behalf of PUD.

Two of EDE's witnesses also filed testimony adopting the testimony of prior witnesses on April 3, 2017. Timothy S. Lyons adopted the direct testimony of Bryan S. Owens, and David Swain adopted the direct testimony of Brad P. Beecher.

Public comments were filed on April 3, 2017, and on April 7, 2017.

OIEC filed its Motion to Dismiss or, in the Alternative, Motion to Strike on April 10, 2017. On the same day, the Commission executed a Notice of Hearing for the motion to be heard before the ALJ on April 21, 2017.

On April 17, 2017, Geoffrey M. Rush filed surrebuttal testimony on behalf of PUD. OIEC, PUD, and the AG each filed a surrebuttal issues list on the same day.

Public comments were filed on April 19, 2017.

On April 20, 2017, the parties filed summaries of testimony. EDE filed the Summary of the Direct Testimony of Aaron J. Doll, the Summary of the Direct Testimony of Bethany Q. King, the Summary of the Rebuttal Testimony of Christopher D. Krygier, the Summary of the Direct Testimony of Jeffery P. Lee, the Summary of the Direct Testimony of Bryan S. Owens Adopted by Mr. Timothy Lyons and Rebuttal Testimony, the Summary of Direct and Rebuttal Testimonies of Blake A. Mertens, the Summary of the Direct and Rebuttal Testimonies of Dr. H. Edwin Overcast, the Summary of the Direct Testimony of Mark Quan, the Summary of the Rebuttal Testimony of Robert W. Sager, the Summary of the Direct Testimony of David Swain, and the Summary of the Direct and Rebuttal Testimonies of Dr. James H. Vander Weide.

PUD filed the Summary Testimony of McKlein Aguirre, the Rate Design Summary Testimony of Kathy Champion, the Summary Testimony of Tonya Hinex-Ford, the Summary Testimony of David Melvin, the Summary Testimony of Kiran Patel, the Testimony Summary of Geoffrey M. Rush, the Cost of Service Summary Testimony of Jeremy K. Schwartz, the Summary Testimony of Elbert Thomas, and the Summary Testimony of Robert C. Thompson. The AG filed Summary of Responsive Testimony of Edwin C. Farrar, the Summary of Rate Design Testimony of Edwin C. Farrar, and the Summary of Rebuttal Testimony of Edwin C. Farrar. OIEC filed the Testimony Summary of David J. Garrett and the Testimony Summary of Mark E. Garrett.

EDE also filed *errata* accounting schedules and a Response to OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike on April 20, 2017.

The parties appeared at pretrial conference on April 21, 2017. At the pretrial conference, PUD, the AG, and OIEC jointly moved that the hearing on the merits be continued from April 24, 2017, to May 10, 2017, in light of EDE's errata filings the previous day. EDE did not oppose the motion. The ALJ agreed. The ALJ also announced that OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike could be advanced to a hearing *en banc* before the Commission rather than being heard by the ALJ.

Public comments were filed on April 21, 24, 25, 27, and 28, 2017. Public comments were also filed on May 1, 2017.

Both the continuance of the hearing on the merits and the advance of OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike came before the Commission at its signing agenda on May 2, 2017. The Commission entered its Order Advancing to Commission *en banc* Oklahoma Industrial Energy Consumers' Motion to Dismiss or, in the Alternative, Motion to Strike and Setting Hearing Date, Order No. 663,323, on that date. The hearing on the motion was set for May 4, 2017, and the hearing on the merits was set to begin on May 10, 2017.

Public comments were filed on May 2 and 3, 2017.

The hearing on OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike was heard before the Commission *en banc* on May 4, 2017. The Commission took the matter under advisement.

Public comments were filed on May 5 and 8, 2017.

On May 9, 2017, the Commission considered OIEC's Motion to Dismiss or, in the Alternative, Motion to Strike at its signing agenda. On that day, the Commission entered its Order Denying Motion to Dismiss, Or in the Alternative, Motion to Strike, Order No. 663,516.

The hearing on the merits began on May 10, 2017, and concluded on May 12, 2017. At the close of the evidentiary hearing, the ALJ closed the record and took the matter under advisement.

Public comments were also filed on May 10, 11, 12, 16, 17, 18, and 22, 2017.

VII. RATEMAKING METHOD

The ratemaking method used in this report is the rate base- rate-of-return method, which is the only method that the Commission has ever used for EDE.

VIII. TEST YEAR

EDE selected the test year, which consists of twelve consecutive months ending on June 30, 2016. Under 17 O.S. 2011 §284, the Commission adds six months to the test year for known and measurable changes. Consequently, balances on June 30, 2016, were adjusted for known and measurable changes through December 31, 2016.

IX. LEGAL STANDARDS

EDE's application seeks a general rate order under 17 O.S. 2011 §152, which amended the Oklahoma Constitution's ratemaking scheme starting in 1913. 1913 Ok. Sess. Laws Ch. 93, p. 150 §2, (emerg. eff. March 25, 1913). In that regard, Ok. Const. Art. IX §18 requires rates and charges that are reasonable and just, but the Commission's authority is limited to setting rates, charges, and terms and conditions of service, because Ok. Const. Art. IX, §18 failed to grant the Commission either the power of internal management or control incident to ownership. *Public Service Co. of Ok v. Ok. Corp. Comm.*, 1996 OK 43, 918 P.,2d 733, 739. Under the legislative scheme, the Commission's power is limited to determining whether or not an act by a utility affects public rights and what steps are needed to avoid an effect that is unreasonable, unfair or prejudicial to public rights. *Lone Star Gas Co. v. Ok. Corp. Comm.*, 1934 OK 396, 39 P.2d 547, 553. However, the Commission lacks the power to demand prior approval of construction plans for a new plant, but once the plant is built, the Commission is empowered to ascertain the plant's effect on rates. *Public Service of Okla. v. Ok. Corp. Comm.*, 1983 OK 124, 688 P.2d 1274, 1277. In that regard, the Commission may disallow any improvident cost or unnecessary item, if not used and useful to public service or if a cost is excessive, unwarranted, unreasonable or incurred in bad faith. *PSO*, pp. 1277-1281. To that end, the Commission has a duty to ensure that the utility charges are the lowest reasonable rates. *State v. OG&E*, 1975 OK 40 ¶20, 536 P.2d 887, 891. And the Commission has the power to prevent a utility from passing on to ratepayers unreasonable costs. *Valiant Tel. Co. v. Ok. Corp. Comm.*, 1982 OK 159, 656 P.2d 273, 275.

Avoiding rate shock is a primary ratemaking goal especially for the residential customers since increases in basic needs can cause hardship for customers on low or fixed income. The term "rate shock" sometimes known as "bill shock" refers to a customer's awareness of a large rate increase. *See* Goodman, *The Process of Ratemaking*, vol. II pg. 899 (Public Utilities Reports, Inc. 1998). In public comments in this cause, EDE customers on low and fixed incomes explained hardship from EDE's high proposed rate increases. Along that line, the courts have long recognized that, while an agency may consider value of service, there is a limit to what the traffic will bear and it is necessary to avoid unduly burdensome rate increases. *New England Divisions Case*, 261 U.S. 184, 191 (1923). Historically, the Commission sets rates and charges using the *End Result Doctrine* arising from *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944), where the Court reasoned:

> It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. (*Hope* at 602).

The Court further stated that the ratemaking process involves a balancing of the investor and consumer interests. (*Hope* at 603). Reasonable balancing requires factual findings establishing a balance between the investor's interest in maintaining financial integrity and access to capital markets versus the consumer's interest in being charged non-exploitative rates. *Jersey Central Power & Light v. F.E.R.C* , 810 F.2d 1168, 1172 (D.C., Cir. 1987); *F.P.C. v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944). In establishing the prudent total cost of service for a utility, the *Hope Case* shifts the focus of debate from a valuation of the capital component of service to a balancing of interests test.

X. MAJOR ISSUES

The outcome of this cause depends on the answers to several issues. The first issue is whether to delay general ratemaking to see if the 2017 merger of EDE and LU Central will generate significant savings, which will lower rates. The next issue, which is the central issue in this cause, is what to do about the size of EDE's requested rate increase. Initially, EDE sought a \$3.8 million dollar increase in its revenue requirement, but dropped that number to \$3.02 million dollars at the evidentiary hearing. In its proposed findings, EDE further reduced rate increase request to \$2.6 million dollars, which would still generate a 22.39 percent total rate increase to all customer classes. The ALJ proposes additional adjustments to the revenue requirement lowering the increase to approximately \$2.3 million dollars, translating into a 20.33 percent total rate increase to all customer class. Nevertheless, OIEC in its Exhibit 140 proposes \$576,701 for the increase in the revenue requirement, translating into a six percent total rate increase for all customer classes. Regardless of which increase in revenue requirement is selected, OIEC wants to shift much of the rate increase to the residential customers, based on OIEC's argument about unfair cross-subsidies from disparities in relative rates of return among the customer classes. Consequently, the next three questions are: what should be the increase in the revenue requirement, what is a fair allocation of those costs to the customers classes, and should the Commission phase in rate increases over several years?

XI. SUMMARY OF THE TESTMONY

Appendix A contains the summaries of the witness testimony, all under oath.

XII. PUBLIC COMMENT

During the prehearing conference, the ALJ received comments from Quapaw Nation citizens, who expressed concern about economic hardship to low income and retired persons. During the full evidentiary hearing, no one gave public comment, but the ALJ did receive written comments from civic leaders, small business owners and residential customers.

XIII. PROGRAM FOR LOW INCOME AND FIXED INCOME CUSTOMERS

The Public Comment File in this cause contains written comments from low and fixed income customers who are concerned about whether they can pay their electric bills under EDE's proposed rate increase. The ALJ's report addresses those concerns in several ways. To begin with, the Commission has a constitutional and statutory duty to set the lowest reasonable rates on a non-discriminatory basis. EDE's proposed residential tariff appears in Schedule N of EDE's Basic Filing and provides a discount for the first six-hundred kilowatt hours consumed each month. The ALJ finds that proposal to be reasonable and just. The ALJ further finds that the ALJ's recommendations for changes in the EDE's revenue requirement and rate design also benefit all residential customers. However, the ALJ also notes that public utility services for low income customers are "affordable" only if the sum of all services does not exceed six percent of income. If a low income customer is having trouble paying a bill, the customer should contact PUD's Consumer Service Department, which can mediate a bill dispute as well as advise the customer about federal and state programs for low income customers, e.g., the Oklahoma Low Income Home Energy Assistance Program (LIHEAP) and the Commission's Lifeline Service Program for telephone service.

XIV. ALGONQUIN MERGER AND THE ENVIRONMENTAL COMPLIANCE RIDER PROPOSAL

A threshold question in this ratemaking is whether the Commission should issue a general rate order in view of a change in conditions or knowledge of conditions occurring after the test-year plus six-months, which ended December 31, 2016. On February 9, 2016, EDE announced its merger with Algonquin Power and Utilities Corp. ("APUC") of Oakville, Ontario, Canada. APUC, a North American diversified utility holding company, bought the capital stock of EDE for US$2.4 billion dollars. APUC operates utilities through Algonquin Power Co. and Liberty Utilities Co. ("LU Canada"), which is the holding company for LU Central, which is now the holding company for EDE. In a triangular merger between EDE, Liberty Subsidiary Corp. (Merger Subsidiary), and LU Central, EDE became a wholly-owned subsidiary of LU Central in January, 2017, which is after the ratemaking test period ended.[2] Since completion of the merger in January, 2017, EDE and LU Central have not entered into any affiliate transactions to share personnel or equipment. Also, EDE has not had access to LU Central's bulk purchasing power to buy equipment, materials or supplies. Consequently, it is not known what specific benefits to ratepayers will be generated by the merger. Nevertheless, AG witness Ed Farrar and OIEC witness Mark Garrett both recommended that the Commission should not entertain a full base rate case until a full and complete test year following EDE's acquisition by LU Central could be provided. According to Mr. Farrar, his suggested approach would allow time for any economic efficiency from the LU Central acquisition of EDE to be incorporated in rates. (Farrar Rate Design, p. 3, ll. 13-20); (Garrett Reb., p. 8, ll. 4-6).

Both AG witness Mr. Farrar and OIEC witness Mr. Garrett recommend versions of a compliance rider referred to as the Environmental Compliance Plan Rider ("ECP") or "The Kansas Plan." The two rider proposals come from a 2016 settlement in Kansas (Exhibit No. 132). According to Mr. Farrar, the Commission should limit the new cost born by EDE's customers to the costs incurred for environmental compliance upgrades, similar to what has been approved by the Kansas Corporation Commission ("KCC"). In Kansas, the Commission allowed environmental costs to be passed through a rider. The Commission provided for a future rate case filing, after a specified period of time, following the acquisition of EDE by LU Central. According to Mr. Farrar, this approach had merit because it allowed time for any efficiencies from the acquisition to be included in EDE's permanent rates, and it allowed customers to more gradually adjust to an increase in their rates. (Farrar Resp., p. 6, ll. 4-11). Mr. Garrett provided similar testimony when he stated that the Commission could authorize a rider for EDE's collection of the capital cost of the Asbury and Riverton 12 projects, subject to refund and

[2] The Commission was the last State utility agency to approve the merger, and the Commission approved the merger by Order No. 652551, effective May 12, 2016.

subject to a Commission review for prudence of these investments in EDE's next Oklahoma rate case. At this time, all other cost increases would be rejected under Mr. Garrett's recommendation but could be considered in EDE's next Oklahoma rate filing, which, according to Mr. Garrett, was consistent with the actions of the KCC. (Garrett Resp., p. 11, ll. 4-9).

Table 4 compares the AG and OIEC calculations for first year of an environmental compliance rider.

Table 3

Oklahoma Environmental Compliance Rider Calculation Comparison
Rider to be subject to refund and annual true-up

Party	Total Company*	OIEC (2.75% Oklahoma allocation)	AG (2.7677% Oklahoma allocation)
Plant in Service	$303,933,214	$8,364,242	$8,411,960
Accumulated Depreciation	($13,820,981)	($380,353)	($382,523)
Accumulated Deferred Income Tax	($56,786,408)	($1,562,762)	($1,571,677)
Total	$233,325,825	$6,421,127	$6,457,759
ROR		9.79%	10.6874%
Return		$628,406	$690,167
Depreciation	$6,388,032	$175,799	$176,802
First Year Rider Revenue		$804,205**	$866,968***

*Total Company reflects costs of environmental upgrades to Riverton 12 and Asbury.
**Mark Garrett Responsive Testimony Page 10.
***Ed Farrar Responsive Testimony Page 8.

Basically, the rider proposals continue with current rates, postpone general ratemaking for one-to-two years, use an environmental compliance rider to compensate EDE only for environmental compliance equipments, and fail to consider $365.5 million dollars for new equipment now in service.

The ALJ recommends that the Commission reject both rider proposals. Through its filing and notice, EDE has invoked the Commission's power to review rates, and EDE's current rates do not provide an adequate return. As reflected in Section B, Schedule 1 of EDE's Minimum Filing Requirements, the return on rate base during the test year, under existing rates, was 2.28%. (Section B., Schedule 1, 1.9). The return on equity during the test year under existing rates is a negative 0.71%. (Section B., Schedule 1, l. 11). Therefore, adoption of the "Kansas plan" will not produce a reasonable result. Next, OIEC and the AG ask the Commission to ignore EDE and PUD's testimony about $365.5 million dollars in capital investment that EDE has presented for inclusion in rate base. OIEC and AG contend that EDE failed to prove that the investments were prudent. That contention is contrary to fact as will be shown later in this report under the heading Plant in Service. Be that as it may, OIEC and AG speculate that the potential post-merger savings make delay reasonable, but OIEC and AG did not present any evidence showing that their imagined savings will even offset the carrying charges on the $365.5 million dollars. The ALJ submits that if the Commission does not put the new plant additions in rate base at this time, then the customers will owe finance charges accruing on the investment until the Commission adjusts rate base in the next general rate case.

XV. TRADITIONAL BASE RATE CASE ITEMS

A. Rate Base

1. Plant in Service

In its initial filing in this cause, the Company proposed to include in rate base $73,910,187 of gross Utility Plant in Service as of June 30, 2016. (Section B, Schedule 1, l. 7). The Company's Utility Plant in Service included in rate base was updated to $74,841,078 to reflect Plant in Service recorded to FERC Account 101 and Completed Construction Not Classified recorded to FERC Account 106 as of December 31, 2016. (Errata Schedule TSL-2.01).

OIEC witness, Mark Garrett, recommended a reduction to the proposed total Company rate base of $365.5 million, or an approximately $10,124,350 reduction to the Oklahoma jurisdictional rate base. (Resp. test., p.37, ll. 17-38, as updated by OIEC Hearing Exhibit 140, l. 21). The basis for Mr. Garrett's proposed adjustment was that the Commission had not been provided with sufficient evidence to determine whether the plant additions were prudent and whether the costs associated with the plant additions were just and reasonable. (*Ibid*).

Both EDE witness Mr. Mertens and PUD witness Mr. Melvin, provided testimony regarding plant investments made by the Company since the last base rate case. Mr. Mertens described various investments made by EDE in an effort to improve system reliability. He also provided information regarding each electric plant project since the last rate case, and continuing through six-months after the end of the test year, costing more than $1 million. (Mertens Reb., BAM Attachment 1). PUD witness Mr. Melvin provided testimony regarding PUD's onsite audit, which included discussion with the Directors of Engineering, Substation Engineering and Distribution Engineering who explained the reasons for and benefits of various projects. (Melvin

Reb., p. 7, ll. 11-19, p. 8, ll. 1-2). As outlined by EDE personnel, several projects were the direct result of mandated requirements by the North American Electric Group Reliability Corporation ("NERC"), as well as upgrades to transmission lines required by the Southwest Power Pool. (Melvin Reb., p. 8, ll. 12-19). Mr. Melvin testified that the competitive bid process was used in most situations and a fixed price contract was EDE's preferred method of contracting (Melvin Reb, p. 10, ll. 11-21). Mr. Melvin testified that after PUD's review of the Application, associated testimonies, schedules, data requests and responses, statues and rules, and onsite audits, PUD recommends the Commission accept the adjustments to plant in service requested in the Application, including the six-month post-test year adjustment of $930,891 made by PUD witness Robert C. Thompson, which results in PUD revised pro forma plant in service of $74,841,078. PUD believes the adjustments for "plant additions are prudent and the associated costs are reasonable." (Melvin Reb., rebuttal at pg. 6, ll. 4lines 8-9 and PUD Revised Accounting Exhibit filed May 15, 2017, Section B, Schedule 1, Line 1). Neither Mr. Mertens nor Mr. Melvin was cross-examined regarding the plant additions they supported in testimony.

The ALJ agrees with the standard of review set forth in EDE's response to OIEC's Motion to Dismiss or, In the Alternative Motion to Strike filed April 20, 2017. EDE met the requirements found at OAC 165:70-1-1 *et seq.*, (MFRs) as was acknowledged in a response dated January 12, 2017, by PUD that stated, "Empire's Application Package in this cause is in substantial compliance with the minimum filing requirements…" With respect to the minimum filing requirement, this Commission has stated that "it is intended to define the information required to be filed and made available in connection with a proposed general rate change in order to facilitate an investigation of and hearing on such rates."

While the Company incurred significant capital expenditures to improve the reliability of the system as described in the testimony of EDE witness Mertens, there were also many other plant investments made by EDE as part of ordinary, day-to-day capital expenditures, generally made by an electric utility to keep the system operational. Schedule BAM-1, attached to the Rebuttal testimony of Mr. Mertens, explains the other capital outlays, which were for ordinary maintenance or upgrades.

The Oklahoma Supreme Court has stated that good faith is presumed on the part of public utility managers regarding their judgment about prudent outlays, including outlays for capital. (Emphasis supplied). *Turpen v. Oklahoma Corp. Com'n*, 1988 OK 126, 769 P.2d 1309, 1330.

The Oklahoma Supreme Court has further stated, "that the regulatory agency bears the burden of proving the payments to non-affiliates is unreasonable." (Turpen, *supra* at 1323). As there are no allegations that any of the payments in the $365,500,000 ($10,124,350 Oklahoma jurisdiction) rate base adjustment proposed by OIEC are made to affiliates or are imprudent, the ALJ finds that there is substantial evidence found in Mr. Mertens and Mr. Melvin's testimonies to include the amounts in rate base.

2. Accumulated Depreciation

EDE requested to include, as a reduction to rate base, the June 30, 2016 balances of the Accumulated Depreciation recorded in FERC Account 108 and the Accumulated Amortization of intangible plant recorded in FERC Account 111.

The PUD, AG, and OIEC all recommended an increase of $1,255,668 to accumulated depreciation, resulting in an accumulated depreciation balance of $23,395,442, to reflect the balance as of December 31, 2016. (Section B, Schedule 1, PUD Revised Accounting Exhibit filed May 15, 2017.) EDE agreed with the adjustment. (Lyons, Reb. p. 7, lines 5, 10 and 11).

3. Other Prepayments

EDE calculated a thirteen-month test year average for the prepayment balance. PUD agreed with the Company's use of a thirteen-month average; however, PUD's thirteen-month average was based on thirteen months ending December 31, 2016, versus the Company's period ending June 30, 2016. PUD's thirteen-month post-test year average for the total Company is $9,071,872. Oklahoma's allocation factor is 2.7526% resulting in an Oklahoma jurisdiction prepayment adjustment of $249,709. Therefore, PUD recommends a $22,003 increase to the requested level of prepayments. (Patel Resp., p. 13, ll. 7-14, p. 14, ll. 1-9). No parties contested this adjustment.

4. Materials and Supplies and Fuel Inventories

Materials and supplies have three components, which are 1) materials, 2) transmission and distribution, and 3) clearing accounts. EDE's Oklahoma jurisdictional thirteen-month average materials and supplies balance ending June 30, 2016, was $719,238. PUD used a thirteen-month post-test year average ending December 31, 2016, resulting in a $21,269 increase in materials and supplies. PUD's thirteen-month post-test year average for the total Company is $27,076,201. Based on the Oklahoma allocation factor of 2.7349%, the resulting Oklahoma jurisdictional balance is $740,507. (Patel Resp., p. 11, ll. 17-19, p. 12, ll. 1-10). No party contested this adjustment.

Additionally, EDE used the thirteen-month average test year balance as of June 30, 2016, for the Fuel Inventory balance. As shown in Section B-2, EDE's thirteen-month average balance as of June 30, 2016, was \$28,177,344. Based on the Company's Oklahoma jurisdiction allocation factor of 3.1268%, the Oklahoma jurisdictional Fuel Inventory balance was \$881,049. PUD used a thirteen-month post-test year average balance ending December 31, 2016, resulting in an Oklahoma jurisdictional Fuel Inventory balance of \$815,281, which is a decrease of \$65,768 from the Company's proposed balance. (Patel Resp., p. 12, ll. 11-16, p. 13, ll. 1-7). No party contested this adjustment.

5. Customer Deposits and Customer Advances and Contributions in aid of Construction

EDE's filing calculated a thirteen-month Oklahoma jurisdictional average balance of \$405,888 for Customer Deposits as of June 30, 2016. PUD proposed a thirteen-month average balance of \$418,779 as of December 31, 2016. Because rate base is reduced by the amount of customer deposits, which are considered customer supplied capital, this adjustment results in a \$12,893 reduction to rate base. (Thomas Resp., p. 10, ll. 1-6). No party contested this adjustment.

The Company's filing included a thirteen-month average balance of \$4,531 for Contributions in Aid of Construction as of June 30, 2016. Because the six-month post-test year balance at December 31, 2016, was not materially different, there were no proposed adjustments to the balance of Contributions in Aid of Construction.(Thomas Dir. P.8 ll 2-9).

6. Cash Working Capital

No party proposed an adjustment to EDE's proposed cash working capital of \$130,864.

7. Accumulated Deferred Income Taxes (ADIT)

On April 20, 2017, EDE filed an *Errata,* reflecting a six-month post-test year net ADIT balance of \$10,407,245 for the Oklahoma jurisdiction as of December 31, 2016. As set forth in the OCC Minimum Filing Requirements, OAC 165:70-5-4 (3) (B) (iii), ADIT is a reduction to rate base. (Errata J-3). No party contested the ADIT adjustment proposed by EDE.

B. RATE OF RETURN

1. Capital Structure

All parties agreed that a capital structure containing a debt ratio of 50.32% and a 49.68% common equity ratio was reasonable to use in this proceeding.

2. Cost of Capital

(a) Cost of Debt

The ALJ recommends that EDE's imbedded cost of long-term debt is 5.30% (See EDE's Minimum Filing Requirements Section F. Schedule 4). No party filed testimony or exhibits opposing the use of EDE's proposed cost of long-term debt.

(b) Return on Equity (ROE)

Table 4 below shows the final EOE recommendations.

Table 4

Party	Percent
EDE	9.9
PUD	9.9
AG	9.3 or 9.5
OIEC	9.0
ALJ	9.5

Mr. Geoffrey M. Rush testified on behalf of PUD concerning the cost of capital. Mr. Rush used a Quarterly Approximation DCF model. As in prior rate cases, the three primary inputs in the DCF model *i.e.* stock price, current dividend, and the growth rate, resulted in disagreement regarding the growth rate among the three witnesses that used the DCF model since the stock price and dividends are known inputs based upon recorded data. Mr. Rush's average DCF result of the proxy companies using the Quarterly Approximation DCF model was 7.12%. (Rush Resp., p. 25, ll. 10-12). Mr. Rush also used a Capital Asset Pricing model ("CAPM"). The CAPM model has primarily three terms required to calculate the required return. The three primary terms of the CAPM model are (1) the risk free rate (2) the Beta co-efficient, and (3) market risk premium, which is the required return on the overall market less the risk-free rate. The average CAPM cost of equity for each proxy company in Mr. Rush's analysis was 6.79%. (Rush Resp., p. 34, ll. 7-9). Mr. Rush also performed a comparable earnings analysis, which is an accounting based model that relies on available accounting data, particularly the return earned on book equity. The comparable earnings model involves averaging the earned returns on equity of other utility companies. For the comparable average Mr. Rush used the annual earned return on equity for each of the proxy companies from 2007-2016 which he averaged resulting in a composite average of 9.82%. (Rush Resp., p. 35, ll. 20-21) The average cost of equity resulting from each of the three models used by Mr. Rush was 7.91%. (Rush Resp., p. 36, ll. 2-3). Mr. Rush accepted the Company's proposed cost of debt of 5.30% and the Company's existing capital structure. Mr. Rush's recommended cost of equity was 9.90%, which was the mid-point in what he considered to be a range of reasonableness of 9.65% – 10.15%. (Rush Resp., p. 46, ll. 8-9).

OIEC witness, Mr. David Garrett did not object to EDE's proposed debt ratio of 50.32% or the cost of debt of 5.30%. However, Mr. Garrett did disagree with EDE's cost of equity capital. The result of Mr. Garrett's DCF model was 7.6%. His CAPM model resulted in a cost of equity of 7.4%, with an average of 7.5%. (Garrett Resp., p. 75, l. 9) Mr. Garrett's average market cost of equity was 8.1% (Garrett Resp., p. 77, l. 4). Although not contained in either Mr. Garrett's DCF or CAPM model, he recommended a 9.0% ROE. (Garrett Resp. test., p. 78).

EDE Witness Dr. Vander Weide performed five different equity models, which were the discounted cash flow (9.3%); Ex ante risk premium (10.5%); Ex post risk premium (10.0%); CAPM-historical (9.7%); and the CAPM-DCF based (10.2%) which resulted in an average of 9.9%. Dr. Vander Weide's proxy companies' cost of equity was in the range of 9.3%-10.5% with an average result equaling 9.9% ROE which was his recommendation. (Vander Weide Dir., p. 48, l. 12).

The ALJ recommends 9.5 percent for ROE and adopts the AG's Mr. Farrar's opinion that the Commission should consider reducing the ROE relative to that granted in PSO and OG&E's last rate cases to encourage better reliability with the implication that its ROE would be set at a "normal level" in a future proceeding "once the company had sufficiently improved reliability". (Reb. test., p. 8, ll. 17-20). The ALJ rejects Mr. Farrar's alternative value of 9.3 percent derived from the Kansas settlement. The ALJ cannot determine if that percentage is reasonable without seeing all riders if there are other riders. With respect to OIEC's position, 9.0 percent is unreasonably low. David Garrett contends that most public utility commissions set ROE too high. However, the ALJ finds that Mr. Garrett understates risk especially in his analysis of EDE. The basic problem here is that EDE is a small utility with large capital costs for new equipment but insufficient load growth to pay for it.

C. OPERATING INCOME/EXPENSES

1. EDE Operating Income

In EDE's Basic Filing (Exhibit No. 4), Section H, Schedule 1 provides test year utility operating income and adjustments. Section H, Schedule 2 sets forth adjustments to operating income and Section H, Schedule 3, contains the explanation of adjustments to operating income. (Owens/Lyons, Dir. test., p. 12, ll. 9-11). Section H, Schedule 2 also sets forth the Oklahoma allocator for the various adjustments. EDE made fifty-two adjustments which were mostly uncontested by the other parties in the proceeding.

2. EDE Payroll and Payroll Related Taxes

PUD, AG and OIEC all recommended that EDE's payroll and payroll related taxes be reduced. AG and OIEC propose adjustments to disallow unfilled positions and future pay raises resulting in a proposed Oklahoma jurisdictional reduction of $63,037. (Hearing Exhibit 140, MG 2.5) EDE did not agree with this adjustment, specifically stating that seventeen of the twenty-seven positions had been filled and that the remaining positions provided important support for the Company's operations. (Lyons, Reb., p. 4, ll. 11-14). Mr. Lyons testified during the preceding that at the time the Company made its filing, which was based upon the test year ending June 30, 2016, there were twenty-seven vacant positions. (Tr. May 10, p.m., p. 89, ll. 23-25). Mr. Lyons further testified that since that time, seventeen of those positions have subsequently been filled. Additional clarification was provided regarding the components of the vacant positions and Mr. Lyons indicated there are other positions where people have left, either to other positions within the Company or they have left the Company completely, and those have created vacant positions and do have an impact on the vacant position numbers. (Tr. May 10, p.m., p. 90, ll. 3-9). The ALJ finds that the Commission has discretion about whether to allow recovery for vacant positions even though a vacancy is not a cost incurred during the test year plus six-months, but EDE did not show a compelling reason for recovery for those vacancies. Therefore, the ALJ recommends that the Commission denies recovery for vacancies and future pay raises.

3. Depreciation

Only EDE and OIEC produced depreciation studies in this cause. EDE's current Oklahoma depreciation rates are based on Order 592623 in PUD Cause No 201100082. The depreciation report prepared for EDE for this Cause was based on an analysis of plant activity through December 31, 2014, with recognition given to known and measurable changes since that date. The summary tables in EDE's report are presented using plant-in-service and accumulated reserve balances as of June 30, 2015. (Sullivan Dir., TJS-2, p. 3). For unit property, specifically production plant, EDE witness Mr. Sullivan developed remaining life depreciation expense rates based on the prospective life span (retirement date) of each generating unit. Included was an allowance for interim additions and retirements of individual pieces of property, as well as an adjustment for net salvage (gross salvage less cost of removal). (Sullivan Dir.,TJS-2, p. 3).

For mass property, specifically transmission, distribution, and general plant, the basis for the recommended accrual rates began with the development of appropriate average service lives ("ASL") and Iowa curves for each plant account using the actuarial analysis method. After developing the recommended ASL and Iowa curves, Mr. Sullivan adjusted for net salvage to develop a whole life depreciation rate.

Mr. Sullivan further recommended establishing depreciation reserve amortization for the negative reserve balance and the cost of decommissioning of the Riverton Steam Plants (Units 7 and 8) and Riverton Unit 9, which were retired in June 2015 but have not been fully depreciated. This amortization, totaling $2.3 million annually, should recover the balance of EDE's investment in Riverton Units 7, 8, and 9 over the next five years. (Sullivan Dir., Schedule TJS-2, p. 4). The Oklahoma jurisdictional portion of the amortization of Riverton Units 7, 8 & 9 would be $63,273 annually. (Section H, Schedule 2, Adj. 17.)

As stated previously, OIEC was the only other party to propose specific depreciation rates. PUD used the existing rates in their accounting schedule (Exhibit No. 138), and AG used EDE's existing depreciation rates in their proposed environmental rider found on page 8 of Mr. Farrar's Responsive testimony. During cross examination, Mr. Farrar stated his recommendation for depreciation rates by answering the following question "Is your recommendation for the Commission to stretch out the depreciation rates as long as possible?" "Yes". (Tr. May 11, p. 113, ll. 13-16). Although as stated earlier, Mr. Farrar produced no study to support his recommendation for the Commission to stretch out the depreciation rates as long as possible.

OIEC witness Mr. David Garrett recommended total adjustments to EDE's Oklahoma jurisdictional proposed depreciation rates amounting to a negative $439,856. According to Mr. Garrett, there were several primary factors driving OIEC's depreciation adjustments which include (1) removing proposed terminal net salvage on production plants, removing future, unapproved plant additions from the Company's calculated depreciation rates on the production accounts, and leaving the current life span estimates for the productions units unchanged for a reduction of $229,806; (2) proposing different Iowa curve shapes average lives for various transmission, distribution, and general accounts for a reduction of $154,303; and (3) amortizing the unrecovered costs of Riverton Units 7, 8, and 9 over the estimated remaining life of Riverton 12 for an additional reduction of $55,748. (Garrett Resp., p. 6, ll. 6-12, p. 7, ll. 1-2).

The ALJ will address the amortization period of Riverton Units 7, 8 and 9; EDE's production facilities and EDE's mass property accounts.

4. Riverton Units

Mr. Garrett proposed amortization of the un-depreciated portion of the retired Riverton Units 7, 8 and 9 over forty-two years. According to Mr. Garrett, closing of the units was part of EDE's environmental compliance plan and therefore the remaining life of Riverton Unit 12, which was installed in 2007 converting the unit to combined cycle natural gas, should be the rational for using the 42 year time period. (Garrett Resp., p. 33, ll. 9-17).

Mr. Garrett's recommendation would result in a depreciation and amortization period of 109 years for Riverton Unit 7 (placed in service in 1950); 105 years for Riverton Unit 8 (placed in service in 1954); and 95 years for Riverton Unit 9 (placed in service in 1964). (Sullivan Reb., p. 5, ll. 14-19). Mr. Sullivan further stated in his rebuttal testimony that Mr. Garrett inaccurately implied that the environmental compliance plan was the only driver for the retirement of the old units. (Sullivan Reb., p. 5, ll. 19-20).

The ALJ recommends using EDE's proposed amortization period for the three Riverton Units. It is unreasonable to use depreciation and amortization periods over a century long, as proposed by OIEC witness Garrett, since amortization should correspond to the un-depreciated lives of these assets.

5. Production Units

Mr. Garrett made three adjustments to EDE's proposed depreciation rates for production units which he described on page 19 of his Responsive testimony beginning at line 2 where he stated: "(1) I removed terminal net salvage due to lack of support through the site-specific decommissioning studies; (2) I recalculated the company's proposed production rates without including future unapproved plant additions; and (3) I allocated the depreciable costs over the currently-approved life spans of the company's production units."

The ALJ agrees with EDE not to include any terminal net salvage in the determination of the depreciation rates for the Company's production units as is indicated by their response to OIEC data request 4.2 attached to the Rebuttal Testimony of Mr. Sullivan. As stated in the answer to the data request, all net salvage rates for production accounts are for interim retirements.

The ALJ also recommends rejecting Mr. Garrett's recalculation of asset lives without including future plant additions. Mr. Garrett's adjustment is an example of single-issue accounting because he rejects the capital expenditures made to accomplish the life extension, but he accepts the extra life that is the result of those expenditures. If the capital expenditures made to accomplish the life extension are not included then the extra life should also not be included. The quotation found in Mr. Sullivan's Rebuttal Testimony on page 20 of pages 6-38 through 6-39 of the publication *Accounting for Public Utilities* is instructive on this matter.

Mr. Farrar also rejected the use of future plant additions (Reb. test., p. 12, ll. 1-12) and incorrectly states this Commission has never accepted future plant additions in a depreciation study. Mr. Garrett does acknowledge that this Commission has accepted interim additions in the past (Tr. May 11, p.m., p. 118, ll. 16-17) but states in his opinion the Company had not met its burden of proof. The ALJ recommends that the Commission accept the extra life as the result of the expenditures, as well as the capital expenditures themselves, as proposed by EDE. However, if the capital expenditures are disallowed, the ALJ recommends that the Commission also make a determination that the extra life added by additions should be disallowed.

It can be further determined from the record that Mr. Garrett did not allocate the depreciable costs over the currently approved life spans of the Company's production units as stated in his testimony. It is also clear that he adopted several of Mr. Sullivan's recommendations to change to the currently used life spans. For example, Mr. Garrett used the same retirement date for Iatan 2 that Mr. Sullivan used which was an increase in the retirement date from 2060 to 2070. (Sullivan Reb., p. 7, ll. 15-18). The ALJ recommends rejecting the adjustment to production plant, due to the inconsistencies in Mr. Garrett's testimony.

6. <u>Mass Property Accounts</u>

The ALJ also recommends rejection of Mr. Garrett's adjustment to mass property accounts. Mr. Garrett stated that he obtained the Company's historical plant data to develop the observed life tables for each account. (Garrett Resp., p. 20, ll. 3-5). That was not the case. As clearly set forth in Mr. Sullivan's Rebuttal Testimony, Mr. Garrett only went back to 1960, wherein the entire data set for many of the accounts went as far back as 1900. (Sullivan Reb., p. 22, ll. 12-18).

Mr. Garrett's use of Iowa curves were a comparison of his Iowa curves, based upon the 1960 database and Mr. Sullivan's which included all of the database back to 1900. Further, Mr. Garrett's graphs are further truncated at 50% surviving. In essence, Mr. Garrett made an inaccurate comparison to Mr. Sullivan's proposed Iowa curves. (Sullivan Reb., p. 23, ll. 4-12). Nowhere in Mr. Garrett's testimony did he indicate these differences between his work and that of Mr. Sullivan's.

The ALJ finds that although Mr. Sullivan's depreciation study will further the goal of setting the best long run rates, the ALJ adopts PUD's position and uses the existing depreciation rates, because of the rate shock problem. Consequently, the ALJ finds that depreciation and amortization expenses as of 12/31/16 should be $2,220,738.

7. Annual and Long-term Incentive Compensation

EDE requested 100% recovery of both the short-term incentive compensation and long-term incentive compensation. (Lyons Reb., p. 4, ll. 6-8). During the hearing, Mr. Lyons testified that there were different levels of employee incentive compensation plans. There was an executive officer level, a department head level, and a salary employee level. (Tr. May 10, p.m., p. 33, ll. 2-7). The incentive plan metrics included, but were not limited to, expense control, regulatory performance, completion of projects, financial performance and customer service. (Tr. May 11, p.m., p. 33, ll. 11-13). EDE considered the amount of dollars associated with each of the metrics, including earnings per share, as highly confidential and the information was provided in camera. (Tr. May 10, p.m., ll. 5-15).

PUD witness Mr. Geoffrey Rush recommended that the Commission disallow 50% of short-term compensation and 75% of the long-term compensation. (Resp. test., p. 43, ll.18-20). According to Mr. Rush, the Commission has consistently disallowed 50% of short-term incentive compensation and 75% of long-term incentive compensation. (Resp. test., p. 43, ll. 4-6). Mr. Rush testified that the rationale behind the Commission's decision was that performance measures that result in the payment of long-term incentive compensation were financial goals that benefit shareholders rather than customers and that the same rationale applied to disallowance of 50% of short-term incentive compensation. In this case, 25% of long-term incentive compensation is based on financial performance and 50% of short-term incentive compensation is based on financial performance. (Rush Resp. test., p. 43, ll. 9-13). Mr. Rush's recommendations result in a reduction of $50,778 on the revenue requirement (Sec. H, Sch. 3, PUD revised accounting exhibit filed May 15, 2017).

OIEC witness, Mr. Mark Garrett proposed excluding 100% of the annual incentive compensation plan expense (Garrett Resp. test., p. 17, l. 11). And AG witness Farrar recommended the disallowance of half of short-term incentive compensation expenses (Farrar Reb. test., p. 14, l.12) and 100% of long-term incentive compensation. (Farrar Reb. test., p. 17, ll. 1-4).

The ALJ finds that Mr. Farrar's position correctly reflects the Commission's position in the recent PSO and OG&E general rate orders where the Commission rejected compensation survey/ fair market value arguments in favor of their view of OIEC's "value to the customer" argument. Therefore, the ALJ recommends recovery of fifty percent of short term incentive competition, and no recovery of other incentive compensation. The twenty-five percent drop from PUD's position represents an additional reduction of $8,614 dollars.

8. SERP

PUD, AG and OIEC opposed the recovery of SERP costs in rates. The SERP is part of the overall compensation package and therefore EDE has requested the full recovery of costs, consistent with the rational set forth for annual and incentive compensation. However, the ALJ cannot recommend SERP, because the ALJ disagrees with EDE's rationale for long-term incentive compensation. In total, the ALJ adjustments on SERP, vacancies and future raises would be a reduction of $65,098 dollars.

9. Pension and OPEB Expenses

EDE witness Mr. Jeff Lee testified that the Company was requesting total annual Oklahoma pension expense of $289,356, which represents an increase of $78,505 to the amounts authorized in rates pursuant to Cause No. PUD 201100082. This total includes actuarially determined expense of $240,660 and a five-year tracker amortization of $48,696 for the pension plan. According to Mr. Lee, EDE is requesting total annual Oklahoma OPEB expense of $44,451, which represents a decrease of $32,441 to the amounts currently authorized. This total includes actuarially determined expense of $50,136 and a negative five-year tracker amortization of ($5,685). (Lee Direct, p. 2, ll. 6-16). PUD witness Rush recommended the Commission adopt EDE's requested increase to pension and decrease to OPEB expenses. (Rush Resp., p. 45, ll. 3-5). Neither OIEC nor AG took issue with the recommendation of EDE and PUD. Therefore, the ALJ adopts EDE's position on pension and OPEB expenses.

XVI. REVENUE DEFICIENCY

Based upon the findings and recommendations contained herein, the ALJ recommends that the Commission find:

Empire's Revised Pro Forma Rate Base	$43,275,753
Rate of Return	7.39%
Required Operating Revenue	$3,198,078
Revised Pro Forma Operating Income	$1,585,774
Return Deficiency	($1,612,304)
Income Tax Gross Up Factor	163.076%
Revised Pro Forma Revenue Deficiency	($2,629,281)

XVII. COST-OF-SERVICE

EDE incurs cost to provide service to customers in four retail jurisdictions in Arkansas, Kansas, Missouri and Oklahoma, as well as being subject to the jurisdiction of the FERC. Therefore, a jurisdictional cost-of-service study is necessary to allocate or assign these costs, as measured by the total Company revenue requirement, to the appropriate jurisdiction to determine the cost-of-service for the specific jurisdiction. Once the jurisdictional costs are determined, a class (that is residential, commercial, industrial, and others) cost-of-service allocates or assigns the jurisdictional cost-of-service to the different classes based on the customers' use of EDE's electric system. The result is the fully allocated embedded cost-of-service study that establishes the cost responsibility for each jurisdiction. An embedded class cost-of-service study assigns the retail jurisdictionally allocated total Company cost to the individual retail customer classes to evaluate the cost EDE incurs in providing electric service to each individual retail customer class. The ALJ recommends EDE's cost-of-service study be used for the jurisdictional cost separation, as it was an uncontested issue.

OIEC was the only party to make a recommendation to modify the Company's filed cost-of-service study. Mr. Mark Garrett recommended modifying EDE's cost-of-service study to use a 4 Coincident Peak ("4CP") methodology for allocation of transmission costs rather than EDE's proposed 12 Coincident Peak ("12CP") methodology. (March 22 Resp. test., p. 4, ll. 12-15).

Mr. Garrett further recommended that the class cost-of-service study be modified to use a 4 Coincident Peak average and excess ("4CP AED") methodology for allocation of production costs rather than EDE's proposed 12 Coincident Peak average and excess ("12CP AED") methodology. (March 22 Resp., p. 4, ll. 21-24).

Mr. Garrett testified that although the Commission has consistently authorized the 4CP for production costs for PSO and OG&E, he relied upon more than prior Commission orders. According to Mr. Garrett, because EDE is a dual peaking system, he looked at the peak load for each month and developed a slightly different 4CP. He used two summer months and two winter months to develop the 4CP for EDE. (Tr. May 12, p. 17, ll. 11-18). Mr. Garrett did not agree with Dr. Overcast that the production allocation factor should be developed by taking into consideration the monthly total capacity demand on the system. Mr. Garrett testified that the Commission had always relied upon peak load and did not consider other factors like forced outages and schedule maintenance. In Mr. Garrett's opinion, this approach diluted the peak loads figures. He further testified that in his opinion, FERC allocations were different than retail. (Tr. May 12, p. 73, l. 25, p. 74, ll. 1-22).

Mr. Garrett testified that the use of a 4CP allocation method for transmission is justified by the significant differences in monthly loading which makes, the 12CP methodology inapplicable to the EDE system. (Responsive testimony dated March 22, 2017, p. 9, ll. 8-16).

In response to Mr. Garrett's recommended modifications to the transmission and production allocators, Dr. Overcast testified that since no two utilities are alike, it was necessary to understand the factors causing costs for each individual utility. (Overcast Reb., p. 3, ll. 14-16). Dr. Overcast testified that Mr. Garrett's approach was inconsistent with FERC standards for determining the appropriate peak allocation factor. FERC standards require that the utility consider "the full range of a company's operating realities including, an addition to the system demand, schedule maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments." (Overcast Reb., p. 4, ll. 10-15). Having considered the full demand on capacity Dr. Overcast used the 12 monthly CP loads as part of the AED/12 CP allocation factor to determine excess demand. (Overcast Dir., p. 19, ll. 21-23, p. 20, ll. 1-7 and Overcast Reb., p. 5, ll. 13-18 and p. 6, ll. 1-6).

Dr. Overcast examined the total demand and capacity for EDE, as well as for both PSO and OG&E. According to Dr. Overcast, EDE had seven months of peak loads above 79% of peak load, while both PSO and OG&E have only four months of load above 79%. (Overcast Reb., p. 7, ll. 8-9).

For transmission, the use of 12CP is appropriate given the costs allocated to the Oklahoma retail customers are based on 12CP not 4CP. (Overcast Reb., p. 7, ll. 12-15). As suggested by Mr. Garrett, his proposal allocated lower costs to his client (higher load factor customers) and more costs to low-load factor residential customers despite the fact that the Oklahoma costs are determined on 12CP. (Tr. May 12, p. 76, l. 25 to p. 77, ll. 1-13).

The ALJ finds that use of the 12CP allocation factor for both production and transmission is a more accurate reflection of cost causation. The ALJ also finds that it is better to use more criteria than simply load as recommended by OIEC. As Dr. Overcast testified, system planners use more than customer load when they analyze the need for capacity. (Overcast Reb., p. 4, ll. 20-21). Therefore, the ALJ recommends that the Commission adopt EDE's proposed cost-of-service study including the transmission and production cost allocators.

XVIII. RATE DESIGN

EDE's proposed rate design placed an emphasis on increasing the monthly customer charge and, for those classes with demand charges, an increase to the demand charge. According to Dr. Overcast, EDE's current rates placed far too much reliance on volumetric recovery of fixed costs. Further, the current rate design did not provide EDE a reasonable opportunity to earn its allowed return in the face of events beyond the Company's control, such as weather and conservation. Third, the rates that consist of a customer charge and volumetric charge do not properly assign costs to the cost causer. Dr. Overcast further testified that current rates are not economically efficient, with the result being the inefficient use of resources resulting from incorrect price signals. (Overcast Dir., p. 29, ll. 11-18). Dr. Overcast proposed to raise the customer charge for regular residential (RG) from $12.50 per month to $20.59 per month, and the total electric residential (RH) customer charge from $12.50 to $25.00 per month. (Overcast Dir., Exhibit HEO-3, Schedule 2- Rate Design, Page 1 of 2).

AG witness Farrar recommended that the Commission reject EDE's request to increase the residential customer charge to over $20 per month. (Farrar Rate Design test., p. 6, ll. 18-21).

PUD witness Champion did not agree with the Company in its proposed rate design stating that EDE's proposal will exacerbate, for many customers, the already significant increases proposed by EDE. (Champion Rate design Resp. test., p. 11, ll. 10-11). [3]

Dr. Overcast testified that the residential customer cost, based on the historic actual test year used in the cost study, is $41.19 per customer. Even at a proposed customer charge of $20.59, and assuming that the total kWh charge is available to compensate EDE for customer costs, customers who have average use of less than 222 kWh per month do not even pay the full cost of service. The customer would not make any contribution to the fixed cost for production and transmission which is over $25.63 dollars. This essentially means that the smallest residential customers never pay the full customer costs, which theoretically results in excess customer cost being recovered in the kWh charge from larger users. (Overcast Dir. test., p. 32, ll. 14-23).

As set forth in Table 3 of Dr. Overcast's rebuttal testimony found on pages 19 and 20, the average monthly charge to a residential customer for a rural electric cooperative is $22.32. Northeast Oklahoma Electric Cooperative, Inc., which is located in close proximity to the service territory of EDE, has a monthly charge of $23.00.

The ALJ adopts the Position of PUD and AG on the customer charge. The ALJ finds that EDE's proposed customer charge would exacerbate the rate shock problem.

A. Revenue Allocation

Revenue allocation is problematic, because we start the current ratemaking with the Residential Class at a minus 1.36 RROR (PUD Schwartz, COS Resp. p. 11), while OIEC wants to move it up to 1.0 or at least to .75 (OIEC Mark Garrett, Tr. Testimony of May 12, 2017, p. 79, line 21 through p. 82), which shifts most of the revenue requirement increase to the Residential Class, causing a major rate increase to the Residential Class.

The AG recommended that the Commission make no change to EDE's cost recovery allocation among customer classes at this time. (Farrar Rate Design test., p. 6, ll. 18-20).

PUD witness Schwartz set forth PUD's proposed revenue distribution and relative rate of return on Figure 3 found on page 13 of Mr. Schwartz' cost-of-service Responsive testimony filed May 22, 2016.

[3] The copy of the Testimony received by EDE does not have page numbers. EDE started p. 1 with the Table of Contents.

Dr. Overcast testified that revenue allocation proposed by Mr. Schwartz in his figure 3 represented a reasonable level of allocation among the classes. (Schwartz Reb. test., p. 9, ll. 19-21).

For the ALJ, the problem here is that a large percentage of the cost of providing service to the residential class is fixed, i.e. generation, transmission and distribution, while both the number of residential customers and usage by the class is declining. Nor is this situation likely to change. Empire serves the three Oklahoma counties of Craig, Delaware and Ottawa. Craig County showed a population decline of 2.7 percent from the 2010 census until July 1, 2016, while Delaware County showed over a 5 percent population drop in the same time frame. Ottawa County showed a slight population gain of 131 between the 2010 census and the end of 2015, but the recent trend is a decline from the peak in 2014. Spreading the fixed costs over a declining customer base is a two-fold problem. First, going from the current negative RROR to a positive RROR substantially increases residential rates, which is undesirable as previously explained. Next, if the Commission raises residential rates through rate design, the Commission invites degradation of EDE's winter peak load from customer migrations to propane, which in turn pushes the customer classes further out of balance. The ALJ finds that the best approach is to adopt PUD witness Kathy Champion's suggestion to allocate costs equally to all classes. Table 5 in Appendix B shows what the numbers would look like. The ALJ submits that equal split still produces residential rates that are too high. As a result, the ALJ additionally recommends adoption of some form of mitigation plan discussed below

XIX. MISCELLANEOUS PROPOSALS

A. PUD'S MITIGATION PLAN

PUD witness, Ms. Kathy Champion proposed a mitigation strategy that would implement the rate increase over a four-year period. According to Figure 1 found on page 5 of Ms. Champion's Rate Design Responsive Testimony, 30% of Staff's recommended revenue deficiency would be put in place in year one; an additional 20%, for a total of 50% of the increase, would be implemented in year two; another 25%, for a total of 75% of the increase, would be put in place in year three; and in year four the final 25% of the increase would be placed into effect, for a total of 100%, with the total customer increase being 33%. (Champion Rate Design, Figure 1, p. 6). During cross-examination, Ms. Champion testified that the Staff position was to set a new revenue requirement for each of the years during the four-year period. (Tr. May 12, p. 105, ll.1-14).

Ms. Champion added that there would need to be a true-up. According to Ms. Champion, if one has a specific revenue target per year, then there should be an opportunity to true-up to make sure that is the amount that is achieved in that year. (Tr. May 12, p. 105, ll. 14-22).

EDE's witness Mr. Timothy Lyons stated that the Company believed the proposed mitigation plan could be improved with two changes. First, the plan should recover a larger percentage of the authorized revenue increase in the first year to better balance the objectives of the mitigation plan with the Company's needs to recover its investment in a timely manner. The Company's proposed mitigation plan would implement 50% of the revenue increase in the first year. Then, there would be an additional 25% increase in year two and a final 25% increase in year three. (Lyons Reb., p. 9, ll. 10-17).

The Company also recommended that the mitigation plan should be followed by a multi-year rate plan tied to the Company's cost-of-service. According to Mr. Lyons, this approach would help ensure that ongoing changes in the Company's cost-of-service are reflected in rates on a timely basis, helping to avoid large customer bill impacts in the future. (Lyons Reb., p. 9, ll. 10-21).

Additionally, EDE recommended carrying costs on the uncollected revenues to allow the Company to recover the full amount of any rate increase granted. (Lyons Reb., p. 13, ll. 1-6). Ms. Champion's mitigation plan did not include carrying costs. As stated in EDE witness Mr. Rob Saeger's Rebuttal Testimony, by not allowing for the deferral of, and a carrying charge on, the unrecovered portion of the revenue increase, the proposed approach may result in an indirect disallowance of costs pursuant to Accounting Standards Codification ("ASC") 980-340. (Sager Reb., p. 4, ll. 1-3).

Furthermore, in considering the use of a mitigation plan, the ALJ notes that revenues associated with the SPPTC rider have been removed from determination of the overall requested deficiency. The actual level of transmission expense for the test year is reflected in the case and the Company is recommending rebasing the rider to include the current expense. (Owens/Lyons Dir., p. 6, ll. 4-10). The amount of the SPPTC rider that is being shifted from the rider to base rates is $377,214 (Owens/Lyons Dir., p. 19, l. 1), thus reducing the effective increase in revenue requirement by $377,214.

The ALJ recommends the Commission use EDE's proposed plan, because PUD's proposed mitigation plan does not grant the Company the full amount of the increase and may result in a disallowance of costs.

B. Rate Case Expense

OIEC witness Mr. Mark Garrett recommended that utilities should only be allowed to recover rate case expenses in proportion to the rate increase granted by the Commission compared to the amount of rate increase requested by the utility in its rate application. (Garrett Resp. test., p. 40, ll. 3-6).

Mr. Lyons testified that EDE did not agree with Mr. Garrett and that rate case expense is appropriate and necessary to prepare and litigate a proposed revenue increase. Further, a portion of the rate case expenses are beyond the utilities' reasonable control since a portion of rate case expense is responding to discovery requests, and analysis of the positions taken by interveners. Mr. Lyons further testified that EDE has an incentive to keep rate case expenses as low as possible since such expenses are recovered over a period of years without carrying costs. (Lyons Reb., p. 27, ll. 6-15.).

The Oklahoma Supreme Court for many years has recognized that a utility is allowed to recover rate case expense. As stated by the Oklahoma Supreme Court in *Lone Star Gas Co. v. Corporation Com'n*, 648 P.2d 36 (1982) at p. 41:

> *In Carey v. Corporation Commission*, 168 Okl. 487, 33 P.2d 788 (1934), we recognize that it would be proper for a public utility company to be allowed rate case expense when "the public service company has reasonably and fairly employed necessary outside help in connection with… (the case). Id. at 794.

There is extensive discovery from multiple parties in rate proceedings, which are beyond the control of the utility. Therefore, based upon the Supreme Court ruling quoted above and the evidence in this cause, the ALJ recommends not changing the Commission's historical method of allowing only reasonable rate case expenses, and therefore amortizes $238,000 dollars over three years without interest.

C. Multi-year Rate Plans

Mr. Lyons testified regarding the use of multi-year rate plans. According to Mr. Lyons, EDE believed that a multi-year rate plan would address several issues raised by parties in the current proceeding. Primary benefits of multi-year rate plans include helping to ensure that utility rates reflect ongoing changes in the cost of service; provide for more gradual rate changes caused by increases in plant investments (which is one of the issues in the current proceeding); produce more stable bills for customers and more stable revenues for the utilities; minimize the expense and uncertainty of rate case proceeding; and, provide incentives for the utility to manage its costs. (Lyons Reb., p. 13, ll. 7-16, p. 14, ll. 1-2).

As an example of multi-year rate plan used in Oklahoma, Mr. Lyons cited the Oklahoma Natural Gas Company's Performance Based Rate Change ("PBRC") plan, which adjusts revenues, either increases or decreases, if the earned return on equity for the most recent year falls outside of an established earned return on equity parameter. (Lyons Reb., p. 14, ll. 8-12).

According to Mr. Lyons, the purpose of the discussion of the multi-year rate plan was for the Company to introduce the concept as a possible solution around the changes in rates and the time period between rate cases. (Tr. May 10, p.m., p. 57, ll. 11-19).

The ALJ recommends the Commission encourage the parties to examine alternatives that might reduce time and costs associated with a fully litigated, contested rate proceeding, while at the same time protecting the interest of customers.

D. SYSTEM RELIABILITY

AG witness Farrar and OIEC witness Garrett both relied upon the Oklahoma Corporation Commission Regulated Electric Utilities 2016 Reliability Scorecard ("2016 Reliability Scorecard") to support their allegations that EDE provides poor service. (Garrett Resp., Exh. MG-4 and Farrar Resp., Attachment C). Mr. Garrett relies upon the 2016 Reliability Scorecard to support his recommendation to disallow 100% of short-term annual incentive plan costs from rates that are tied to operational measures such as safety, reliability and customer satisfaction. (Garrett Resp., p. 24, ll. 8-14). Mr. Farrar relies upon the 2016 Reliability Scorecard to support his recommendation "that the Commission factor in Empire's poor quality of service" as support of denying the rate increase except for the environmental compliance rider costs that were adopted by the Kansas Commission. (Farrar Resp., p. 10, ll. 3-8).

As explained in the Rebuttal Testimony of EDE witness Mr. Blake Mertens, in 2010 EDE developed a ten-year plan, referred to as Operation Toughen-Up, to construct system improvements solely to enhance the reliability of the system. (Mertens Reb., p. 1, l. 19, p. 2, ll. 1-2). Mr. Mertens described the various projects designed to improve the reliability of the Oklahoma system, as well as the accompanying dollar amounts expended on the projects. (Mertens Reb., p. 2, ll. 13-20).

According to Mr. Mertens, Oklahoma customers make up less than 3% of EDE's total customer base. However, since the inception of the reliability program, EDE has spent nearly 32% of its expenditures for the benefit of Oklahoma customers. Once the program is complete, EDE expects that approximately 14% of the total expenditures will benefit Oklahoma customers. (Mertens Reb., p. 4, ll. 7-11).

Mr. Mertens also testified that EDE does not distinguish between the States in which it provides electric service, with regards to its maintenance programs. According to Mr. Mertens, in 2008 the Missouri Public Service Commission implemented reliability inspection standards that dictated the frequency and thoroughness of the system inspections and repairs. Since the implementation of that rule, EDE has elected to implement the Missouri standards for inspection and repairs for facilities in all jurisdictions served by EDE. The Missouri rules for system inspections and repairs exceed any Oklahoma requirements for inspections and repairs. Additionally, EDE adheres to the Oklahoma vegetation management rules, which are more restrictive than those established for Missouri. (Mertens Reb., p. 4, ll. 14-22).

Mr. Mertens further testified that in order to install some of the mechanisms to improve reliability, the system was required to be put in a less reliable condition during the construction phase of the upgrades which resulted in SAIDI and SAIFI indices that are worse than what is expected at the conclusion of the overall program. (Mertens Reb., p. 5, ll. 7-13.).

Mr. Mertens testified that as EDE completes the projects described in his testimony, it expects Oklahoma's reliability metrics to improve. (Mertens Reb., p. 6, ll. 11-12).

PUD witness Mr. Jeremy Schwartz recommended the Commission reject the recommendations and/or adjustments proposed by Mr. Farrar and Mr. Garrett as they relate to system reliability. Instead, Mr. Schwartz recommended that the Commission should accept PUD's recommendation for the Company to provide an in-depth analysis of its system reliability plan in its next rate case proceeding. (Schwartz Reb., p. 10, ll. 8-12).

Mr. Schwartz discussed the Commission's rules that require electric utilities to design and maintain a reliability program. Mr. Schwartz further testified that EDE had complied with the requirements of the Commission's rules regarding the design and maintenance of a reliability program. (Schwartz Reb., p. 4, ll. 10-26, p. 5, ll. 1-22).

Mr. Schwartz also testified that during 2015 and 2016, EDE maintained its reliability levels within the Commission requirements. (Schwartz Reb., p. 6, ll. 9-11).

It is also Mr. Schwartz's testimony that adjusting the Company's revenues based on service quality could have a corresponding effect on its reliability, as it would have fewer dollars to devote to increasing its reliability levels. (Schwartz Reb., p. 9, ll. 6-8).

PUD recommends the Commission require EDE provide an in-depth analysis of its system reliability plan in its next base rate case proceeding. Such an analysis would supplement EDE's annual reliability submission to PUD and would include details on how the Company has, and would, continue to improve its reliability results. Upon review of the additional information, if the Commission is not satisfied with the results, it could make adjustments it deems necessary in the cost of service and/or rate of return of the Company at that time. (Schwartz Reb., p. 9, ll. 12-18).

Based upon the evidence in this proceeding, the ALJ does not believe that providing service, which meets or exceeds the requirements of this Commission's reliability rules, can properly be classified as "poor" service. It is clear from the testimony of Mr. Mertens, that EDE has been aware of reliability issues in its Oklahoma service territory and has developed a plan to resolve those issues. However, the ALJ does find merit with the recommendation of PUD for the Company providing a more in-depth analysis of its system reliability plan in its next general rate preceding at which time the status of operation "Toughen-Up" could be reviewed. Therefore, the ALJ recommends that the Commission reject the proposals of both Mr. Garrett and Mr. Farrar regarding system reliability and accept the recommendation of PUD witness Schwartz.

XX. CONCLUSION

All relevant, uncontested items were accepted. The foregoing findings address all capital costs and all operations and maintenance costs, which were in dispute. The ALJ's recommendations on those costs are reasonable and just. The foregoing findings provide a fair, reasonable and just rate of overall return reflecting an appropriate balance between investor and customer interests. The proposed rates recommended by the ALJ constitute the lowest reasonable rates.

Respectfully submitted

Ben Jackson

BEN JACKSON
Administrative Law Judge

6/9/17
Date

XC:
Dana Murphy
J. Todd Hiett
Bob Anthony
Teryl Williams
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APPENDIX "A"

Testimony Summaries

EMPIRE DISTRICT ELECTRIC COMPANY

THOMAS J. SULLIVAN

Direct Testimony

Thomas J. Sullivan, President and owner of Navillus Utility Consulting LLC., testified on behalf of The Empire District Electric Company ("Empire" or "Company").

Mr. Sullivan testified that a complete depreciation study was performed for Empire's plant in service on December 31, 2014, using Missouri information which was attached to his testimony.

Mr. Sullivan also sponsored the Company's proposed amortization of the depreciation reserve deficiency associated with the retirement of Riverton coal-fired generating facilities (Units 7 and 8) and Riverton combustion turbine Unit 9.

Mr. Sullivan's recommended depreciation rates for Empire's production facilities are based on the remaining life formula, and the depreciation rates for all other facilities (mass property accounts) are based on the whole life formula. Mr. Sullivan also recommended that Empire amortize the undepreciated portion of its investment in the recently retired Riverton steam Units 7 and 8 and Riverton combustion turbine Unit 9 and the cost of decommissioning Riverton Units 7, 8, and 9 over a five-year period.

Mr. Sullivan testified that a five-year amortization of the undepreciated portion of Empire's investment in Riverton Units 7 and 8 and the decommissioning costs associated with the Riverton Units 7 and 8 are equal to $2,135,793 annually, and the undepreciated portion of Empire's investment in Riverton Unit 9 and its associated decommissioning costs are equal to $162,898 annually.

Regarding Riverton Units 7 and 8 coal-fired steam generation units, Mr. Sullivan testified that at the time these units were retired by Empire in June 2015, there was a negative reserve of $6.8 million which represents the undepreciated investment in these units. The units have not been depreciated by Empire since their retirement in June 2015. In addition, Empire has received estimates that it will cost $3.9 million to decommission the units. Therefore, there is a total cost of $10.7 million left to be recovered from the Riverton Units 7 and 8.

Mr. Sullivan recommended that these costs be amortized over a five-year period beginning with the effective date of new rates resulting from this case. The $10.7 million remaining cost, when amortized over 5 years, results in an annual amortization of $2,135,793.

According to Mr. Sullivan, Riverton Unit 9 was retired in June 2015. At the time of its retirement, Unit 9 had $758,397 in undepreciated investment. In addition, the same decommissioning study for Riverton Units 7 and 8 includes approximately $56,000 in net decommissioning costs for Riverton Unit 9. Mr. Sullivan recommended that these costs also be amortized over a five-year period beginning with the effective date of new rates resulting from this case. The $814,490 remaining cost, amortized over 5 years, results in an annual amortization of $162,898.

Mr. Sullivan testified that in his opinion, it is always preferable to recover costs from the ratepayers who are receiving the benefits of the facilities. Deferring costs beyond the retirement of the assets can result in an inter-generational subsidy. In other words, current and future ratepayers will pay costs that should have been borne by past ratepayers. However, Empire is entitled to full recovery of these assets, and the 5-year amortization is a reasonable timeframe to recover the investment and yet mitigate the potential inter-generational subsidy.

Further, the use of the remaining life formula for unit assets (such as power plants) should be used instead of the current practice of using the whole life formula. The remaining life formula and the ability to adjust depreciation rates periodically will provide a more reasonable and straightforward basis to recover the cost of these assets over their useful life.

Mr. Sullivan's depreciation rates for production facilities were developed using the life span and unit property approaches underlying Empire's existing rates. According to Mr. Sullivan, the Riverton steam Units 7 and 8; combustion turbine Unit 9, combustion turbines Units 10 and 11; and combined cycle Unit 12, are treated as separate unit properties. Also, Iatan Units 1 and 2 are treated as separate unit properties.

Mr. Sullivan explained why the remaining life formula is preferable. According to Mr. Sullivan, the remaining life formula for unit property accounts provides a much better opportunity to recover the investment in the facility over the asset's useful life and avoids the situation of deferring cost recovery beyond the life of the unit asset, thus resulting in inter-generational subsidy. The basic premise of the whole life method is that one straight-line depreciation rate is used over the entire life of the asset. If the life characteristics of an asset change over the life of that asset, or if additions are made to an asset that have a lifespan less than the whole life of the plant, depreciation rates based on the whole life method tend to have a bias towards under-collecting depreciation expense, especially for unit type properties such as power plants. If this bias is not corrected, the end result is a failure to properly recover the cost of the unit asset over its useful life.

While the whole life formula can be adjusted for reserve deficiencies (or excesses) to essentially mirror the remaining life formula, it is much more straightforward to use the remaining life formula. For new facilities, the remaining life and whole life formulae produce essentially the same answer, as shown in Table 5-1 for the Iatan and Plum Point units. The issues with using whole life rates over the entire life of an asset begin to manifest themselves as units age and the life of the plant is changed (usually due to life extending investments) and as investments are made to the plant throughout its life that have service lives less than the entire life of the facility.

Mr. Sullivan further testified that the retirement dates and resulting lifespan for Asbury 1 had been increased by 5 years, from a 60 year lifespan (in the 2010 Depreciation Study) to a 65 year lifespan. The retirement date and resulting lifespan for Iatan 2 was increased by 10 years, from a 50 year lifespan (in the 2010 Depreciation Study) to a 60 year lifespan. The 60 year lifespan is consistent with the lifespan being used by Kansas City Power & Light Company, the majority owner of the plant.

For the combustion turbine units Energy Center 1 and 2, Riverton 10 and 11, and State Line 1, the retirement dates and lifespans were reduced by 5 years, from 50 years to 45 years. For the FT-8 combustion turbine units Energy Center 3 and 4, the retirement dates and lifespans were reduced by 10 years, from 50 years to 40 years.

Mr. Sullivan developed rates for the mass property accounts by using the whole life formula underlying Empire's existing rates. The mass property accounts include all transmission, distribution, and general plant facilities and equipment.

According to Mr. Sullivan, the primary reason is that this is the methodology historically used in Missouri and it is the basis for Empire's existing depreciation rates. In addition, there are several key distinctions between the mass property accounts and the unit property accounts. Generally speaking, mass assets do not have a unique or distinct identity. In other words, one transformer, meter, or piece of conductor (of given capacities) is not much different from another and, when a unit is retired, it is usually replaced with a very similar unit with similar life characteristics. Further, the service provided by the mass asset group has an indefinite lifespan, even though individual units have a finite life. If a meter at a home breaks or wears out, it is replaced with another meter that provides essentially the same function and the service continues. This is the key distinction between a mass property unit like a meter or transformer and a unit property like a power plant.

Mr. Sullivan further testified that a power plant has a finite life and, as the end of that life approaches, the specific date of retirement becomes more certain. Once that power plant is retired, it is not immediately replaced with a similar unit. Power plants are large facilities that take years to plan and construct. When Empire retired the 38 megawatt Riverton 7 coal-fired steam unit, it did not replace it with another 38 megawatt coal-fired steam unit.

Mr. Sullivan recommended the following:

1. Adopt the remaining life rates shown in Column E of Table 5-1 in Schedule TJS-2 for Empire's production facilities;
2. Adopt the whole life rates shown in Column O of Table 6-1 in Schedule TJS-2 for Empire's mass property accounts; and,
3. Adopt the amortization of the undepreciated plant investment and decommissioning costs associated with the Riverton steam units (Units 7 and 8) and Riverton combustion turbine Unit 9 shown in Table 5-5 of Schedule TJS-2 over a five-year period beginning with the conclusion of this rate case.

<u>Rebuttal Testimony</u>

Mr. Sullivan filed rebuttal testimony to PUD Witness Mr. Thompson, AG Witness Mr. Farrar and OIEC Witness Mr. David Garrett.

Mr. Sullivan disagreed with OIEC witness David Garrett's recommendations to amortize the undepreciated portion of the retired Riverton Units 7, 8, and 9 over 42 years. According to Mr. Sullivan, Mr. Garrett asserts that since "the retirement of Riverton 7, 8, and 9 and the conversion of Riverton 12 were part of the same environmental plan" (Page 33, Lines 14 and 15) and because "future customers, not current customers, who are the primary beneficiaries of the environmental compliance plan" (Page 34, Lines 2 through 3), the amortization period should be equal to the remaining life of the Riverton 12 plant.

Mr. Sullivan testified that there were several flaws with Mr. Garrett's logic. First and foremost, as discussed in his direct testimony, the five-year period he recommend was intended to strike a balance 1) between the fact that the cost of Riverton Units 7, 8 and 9 were not recovered over their useful life because the depreciation rates used were too low, and 2) recovering those costs over a reasonable period of time to mitigate inter-generational subsidies. Second, the Riverton Units 7, 8 and 9 were placed in service in 1950, 1954, and 1964, respectively, and were nearing the end of their useful lives regardless of the environmental compliance plan. Mr. Garrett's recommendation would create a depreciation and amortization period of 109 years for Riverton Unit 7, 105 years for Unit 8, and 95 years for Unit 9. Third, Mr. Garrett's testimony inaccurately implies that the environmental compliance plan was the only driver for the retirement of Riverton Units 7, 8 and 9. Fourth, there are other generating units that were also part of the environmental compliance plan; Mr. Garrett appears to have simply chosen the power plant with the expected retirement date that is directly under the Company's control that is the furthest in the future. For these reasons, the OIEC's recommendation is unreasonable and should not be adopted by the Commission.

According to Mr. Sullivan, the OIEC is essentially proposing the following three adjustments or changes to the depreciation rates he recommended for Empire's production facilities:

1. The OIEC proposes to use the lifespans that OIEC assumes are underlying the Company's existing depreciation rates.
2. The OIEC proposes to include no allowances for cost of removal or salvage to be included in the derivation of the Company's depreciation rates for its production facilities.
3. The OIEC includes no allowance for interim activity (over the remaining life) in the determination of the Company's depreciation rates for its production facilities.

According to Mr. Sullivan, Mr. Garrett appears to imply that the "currently approved lifespans of the production units" should be used in lieu of the lifespans recommended by Mr. Sullivan. Mr. Garrett lists several instances where Mr. Sullivan reduced the lifespans on some units that were reduced relative to the lifespans that were recommended in Mr. Sullivan's 2010 Report.

Mr. Sullivan testified that Mr. Garrett did not accurately portray the lifespan changes recommended in Schedule TJS-2 relative to the 2010 report.

Mr. Garrett's discussions on Page 18 only highlight the changes made to the Company's combined cycle and combustion turbine generating units where Mr. Sullivan generally reduced the lifespans. However, Mr. Garrett fails to mention that Mr. Sullivan recommended increasing the lifespans on Asbury and Iatan 2 (based on aligning the retirement date of Iatan 2 with the expected retirement date used by Kansas City Power & Light Company – the majority owner and operator).

The lifespans proposed by Mr. Garrett are not based on "currently approved lifespans" according to Mr. Sullivan.

The estimated retirement date used by Mr. Garret for Asbury appears to be 2035 which is the same date recommended by Mr. Sullivan. Mr. Sullivan recommended an increase in the retirement date from 2030 to 2035. The estimated retirement date used by Mr. Garrett for Iatan 2 is also the same as the retirement date used by Mr. Sullivan which was an increase in the retirement date from 2060 to 2070.

Mr. Sullivan testified that as indicated in the Company's response to OIEC Data Request 2.1 and 6.1, the current depreciation rates for Empire's production facilities are not based on a lifespan methodology. The current rates are based on a settlement in Missouri Case No. ER-2011-004. The Settlement adopted the depreciation rates proposed by the Missouri PSC Staff which are based on a whole life mass property approach that does not consider the retirement dates of the individual generating units.

Mr. Sullivan testified that contrary to what he says in his direct testimony, Mr. Garrett has actually cherry-picked between the lifespans used in Schedule TJS-2 and those used in Mr. Sullivan's prior study (2010 Report), not the currently approved lifespans as he states. In cases where Mr. Sullivan has increased the lifespans in Schedule TJS-2 relative to the 2010 Report, he uses the longer lifespans in Schedule TJS-2. In cases where Mr. Sullivan had reduced the lifespans in Schedule TJS-2 relative to the 2010 Report, he uses the longer lifespans in the 2010 Report.

The prior question lists the generating units where he uses the longer lifespans in Schedule TJS-2, the following are where he uses the longer lifespans in the prior 2010 Report:

1. Energy Center 1 and 2 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, 2023 and 2026 retirement dates, respectively. In his 2010 Report, he recommended retirement dates of 2028 and 2031. Mr. Garrett uses a retirement date of 2031 for both units.

2. Energy Center 3 and 4 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 40 year life, a 2043 retirement date for both units. In Mr. Sullivan's 2010 Report, he recommended retirement dates of 2053 for both units. Mr. Garrett uses a retirement date of 2053.

3. Riverton 10 and 11 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, a 2033 retirement date for both units. In his 2010 Report, he recommended retirement dates of 2038 for both units. Mr. Garrett uses a retirement date of 2038 for both units.

4. Stateline 1 – In Schedule TJS-2, Mr. Sullivan recommended a lifespan based on a 45 year life, a 2040 retirement date. In his 2010 Report, he recommended a retirement date of 2045. Mr. Garrett uses the 2045 retirement date.

For the other units not mentioned, he made no changes between Schedule TJS-2 in his 2010 Report.

Mr. Sullivan further testified that on Page 18, Lines 9 through 10, Mr. Garrett states that "Mr. Sullivan, however, provided no other analysis, documentation, or support for the proposed lifespan decreases." This statement is misleading on a couple of fronts. First, it fails to indicate that Mr. Sullivan also recommended lifespan increases set forth above. Furthermore, all of the lifespans Mr. Garrett recommended are based on Mr. Sullivan's recommendations from either Schedule TJS-2 or his 2010 Report (and not based on currently approved lifespans as Mr. Garrett asserts, as there are none because the settlement was not based on a lifespan methodology) and Mr. Sullivan essentially provided the same support and/or rationale for both sets of lifespan recommendations. The recommendations in TJS-2 are based on more current expectations; that is the only real difference between the two sets of numbers.

According to Mr. Sullivan, The OIEC is using a zero net salvage allowance. While Mr. Garrett's testimony on Pages 13 through 16 only discusses terminal net salvage, in fact, the OIEC has not included any salvage or cost of removal allowance on interim or final retirements. In his testimony, Mr. Garrett appears to confuse salvage and cost of removal associated with interim retirements (retirements that occur over the life of the asset) and final or terminal cost of removal and salvage associated with the decommissioning of the power plant. However, the OIEC's recommendations are not limited to terminal net salvage but rather reflect no cost of removal or salvage allowances at all.

Mr. Sullivan testified that the OIEC did not accurately characterize the net salvage allowances he used in the development of the depreciation rates he recommended for the Company's production facilities and his responses to their data requests.

On Page 15, Lines 6 through 8, Mr. Garrett asks and answers the following:

"Q. Did Empire provide any other adequate support for its proposed terminal net salvage rates?

A. No. When asked in discovery to provide all justification and support for the proposed net salvage rates, Mr. Sullivan states that the proposed net salvage amounts "represent minimal allowances that we deem reasonable absent specific demolition studies".

In fact, the above question and answer are a complete fabrication achieved by cutting and pasting three different answers to three different data requests regarding two separate and distinct issues.

In Schedule TJS-3, Mr. Sullivan provided copies of his responses to OIEC data requests 2.14, 4.2, and 9.1.

In data request 2.14, the OIEC asked for all decommissioning studies Mr. Sullivan relied upon. In his response, he indicated that the only decommissioning studies relied upon were for Riverton 7, 8 and 9. Mr. Garrett's discussion on Pages 13 through 16 of his direct testimony did not pertain to Riverton 7, 8 and 9, because neither the OIEC nor the Company recommended depreciation rates for Riverton 7, 8 and 9 since these units are retired. Thus, nowhere in Mr. Sullivan's recommended depreciation rates for the Company's production units did he include any allowance for terminal net salvage.

In Mr. Sullivan's response to OIEC data request 4.2, his response clearly stated that the Company did not include any terminal net salvage in our determination of the depreciation rates for the Company's production units. The response clearly states that: "All net salvage rates for production accounts are for interim retirements".

Finally, in Mr. Sullivan's response to OIEC data request 9.1, he indicated what net salvage allowances he used for interim retirements, having previously established through OIEC data request 4.2 that all salvage rates were for interim retirements. The last sentence that is quoted in Mr. Garrett's testimony is taken completely out of context. The last sentence is properly interpreted to mean that the Company used minimal allowances (for interim retirements only), and when taken in the context of the other two data requests, Empire did not use any terminal net salvage unless there were specific demolition studies (as was the case for Riverton 7,8 and 9).

Mr. Sullivan testified that OIEC's recommendation regarding net salvage for the production facilities was not reasonable.

First, Mr. Garrett's testimony does not address the actual net salvage amounts Mr. Sullivan recommended. He is actually discussing a fabrication of a terminal net salvage recommendation that does not exist. The actual net salvage allowances Mr. Sullivan had reflected are minimal allowances that he deemed reasonable for interim cost of removal and salvage. The adjustment for terminal net salvage that Mr. Garrett actually makes relative to Mr. Sullivan's recommendation is to remove minimal allowances for interim activity for which he provides no justification in his testimony. Mr. Garrett provides justification for removing an adjustment that does not exist.

Mr. Sullivan further testified that on Page 17, Lines 3 through 10 of his direct testimony, Mr. Garrett's response to his question again tries to cleverly combine unrelated statements to create the appearance of something that is simply not there. First, the question between Lines 2 and 3 asks: "Is the cost recovery of plant that has not been deemed prudent or "used and useful" appropriate?" Nowhere in Mr. Sullivan's analyses did he advocate the recovery of investment through depreciation expense for plant that is not in service. Yet, Mr. Garrett's response essentially acknowledges that the question creates a premise that is not true because his response to this question actually answers a different question than the question he poses. On Page 17, Lines 6 through 8, Mr. Garrett states: "Mr. Sullivan's proposed depreciation rates for the Company's production accounts mathematically incorporate these unapproved future plant additions." While this statement is also not accurate, nowhere does Mr. Garrett say (because it is patently not true) that Mr.Sullivan recommended that depreciation expense be calculated based on plant that is not yet in service. Yet, his question insinuates this false premise.

According to Mr. Sullivan, the analyses contained in Appendix A of Schedule TJS-2 show the detailed calculation of the depreciation rates he recommended for Empire's production facilities. They do not show the calculation of depreciation expenses. This analysis includes the historical additions and retirements by account for each generating unit property as well as forecasts of future additions and retirements based on this historical experience. The purpose of this analysis is to estimate the amount of plant balance that would be available each of the remaining years such that a true straight line depreciation rate can be determined that will depreciate all the investment in the facility as (and only as) that investment is actually made.

Mr. Sullivan testified that the failure to consider the impact of future interim retirements and additions results in depreciation rates that are low during the early years of the generating units' lifespan and higher during the later years. This happens primarily for the following reasons:

1. Failure to recognize that many of the component assets have an average service life that is less than the entire lifespan of the generating units.

2. Failure to recognize that capital improvements that are made after the initial in-service date of the asset will have service lives that are less than the entire lifespan of the generating units.

3. Failure to recognize that in order for the generating units to achieve the relatively long lifespans historically experienced, significant capital improvements are made to extend the assets' life and/or to bring the units up to current technology and regulations such that the plants can continue to economically provide service. These relatively large capital additions usually have service lives much less than the lifespan of the generating unit.

Mr. Sullivan testified that it is clearly demonstrated in the existing depreciation rates for Empire's steam production units as shown in Schedule TJS-2. The lowest current depreciation rate is 2.10 percent for Iatan II (put in service in 2010) which is Empire's newest steam production unit. Plum Point (2010) is roughly the same age but has a shorter estimated life, so its current depreciation rate is 2.33 percent. Iatan 1 (1980) is the next oldest unit and is significantly older than Iatan 2 and it has a current depreciation rate of 3.12 percent. The Company's oldest steam production unit is Asbury (1970) and it has a depreciation rate of 4.73 percent. Asbury best demonstrates the phenomena Mr.Sullivan discussed above as shown on Page A-6 of the Depreciation Study (Schedule TJS-2).

The net effect is loading most of the depreciation expense near the end of, and even beyond, the useful life of the generating unit. This creates a huge disconnect between the recovery of the cost of the facility and the value received by the customers who most benefit from the facility. This is further exacerbated when one also takes into account that base load generating units tend to be used less and less as they approach the end of their useful life because newer units tend to be more efficient and economical to dispatch, and are therefore utilized more.

Mr. Sullivan testified that his recommended method did not accelerate depreciation expense accrual.

As Schedules TJS-4 and TJS-5 demonstrates, the deprecation accrual rates are stable throughout the entire service life of the asset.

Mr. Sullivan further testified that his recommended method did not result in mathematically collecting depreciation expense on future costs that are not in service and used and useful.

The depreciation rates are applied to the current period actual plant in service balance, the same balance as the depreciation rates developed using the OIEC's approach. There are not any future dollars in the calculation of depreciation expense (depreciation rate times current plant in service balance).

As shown in Section I, Schedule 2 of the Company's revenue requirement model, the depreciation rates are multiplied by plant balances at June 30, 2016, which do not include the interim additions and retirements used in the development of the depreciation rates.

According to Mr. Sullivan, while there is still higher depreciation expense at the end of the asset's life using the approach he is recommending, a more stable depreciation rate results if forecasted interim retirements and additions are included in the determination of the depreciation rate than if they are not included. The approach he is recommending is a reasonable compromise between the OIEC's approach which defers significant amounts of depreciation expense to the later years of (and even beyond) the generating facility's life, and a unit of production approach which would seek to directly match the investment in the facility with the use (i.e. output) of the facility.

The interim retirements and additions he included are only based on historical experience excluding large capital projects. For the newer base load units such as Iatan 2 and Plum Point, there is virtually no way these units are going to be in service in 2070 and 2060, respectively, without large capital improvements (that will have much shorter remaining lives) than what has been reflected in Schedule TJS 2. As such, the depreciation rates for these units will increase significantly if these plants are still in service that far into the future.

Mr. Sullivan testified that if the Commission were to disallow interim retirements and additions, then the plant lives should be shortened. It is not proper to accept the extra life of the plant due to the interim additions while ignoring the cost of those additions. Both need to either be included or both excluded or the depreciation rate will not match the use of the power plant.

As stated on Pages 6-38 through 6-39 of Accounting for Public Utilities:

> "A depreciation study attempts to predict the future. Therefore, these studies endeavor to consider the estimated effects of future events, of which power plant life extension projects are examples. Such projects have two aspects that are linked:
>
> 1) the capital expenditures made to accomplish life extension; and
> 2) the extra life that is the direct result of these expenditures.
>
> Deferral of recording and recovery of depreciation will occur if the link between these two aspects is broken by elimination from the depreciation rate calculations the capital expenditures until they are recorded in plant-in-service, but currently included in the extra life resulting from the expenditures. Because some of the rate calculation components become inconsistent, depreciation rates will initially decrease and will later increase as the expenditures are made and the rates are recalculated. Increasing depreciation rates for power plants are not rational because they do not match the consumption or usage of the underlying asset."

Mr. Sullivan continued his rebuttal by testifying that beginning on Page 16, Line 13 and continuing onto Page 17, Mr. Garrett states that he has never seen depreciation rates for production units calculated the way he had calculated them in Appendix A of Schedule TJS-2. The testimony filed in the Company's last Oklahoma rate case in Cause No. PUD 201100082 included the 2010 Report discussed earlier in this rebuttal testimony. This report uses the same methodology used in Schedule TJS-2.

Prior to starting his own company in 2011, Mr. Sullivan worked for over 30 years for Black & Veatch Corporation. The first depreciation study he worked on for Black & Veatch was in the late 1980's for Black Hills Power and Light Company and it incorporated this same methodology. This methodology was developed coincident with the widespread use of personal computers. The senior experts at Black and Veatch at that time determined that developing a more transparent analysis of unit properties for which a finite retirement date was known was preferable to using what, up until that time, was largely done in a black box program by mainframe computers. While many of those programs have been converted to use on personal computers, they still lack the flexibility and transparency of performing the calculations using a spreadsheet analysis. Thus the methodology used in Appendix A of Schedule TJS-2 has been the standard practice at Black & Veatch since the 1980's.

Mr. Sullivan testified that there were two significant problems with the OIEC's mass property accounts analyses. First, OIEC excluded historical data from their analyses even though the OIEC claims its analyses are based on all the historical data. The result of excluding this data artificially skews the OIEC's results towards longer service lives. Second, the OIEC mischaracterizes the analyses Mr. Sullivan performed by mismatching his recommended Iowa curves to the abbreviated datasets used in their analyses thus leading one to conclude that his results do not match the underlying data used (which includes all the Company's historical data).

On Page 20, Lines 11 and 12, Mr. Garrett states: "I used all of the Company's property data and created an observed life table ("OLT") for each account."

Mr. Sullivan testified that statement was not correct. In fact, Mr. Garrett has truncated the placement and experience bands of the data he presented in his testimony and exhibits. This is most evident by the fact that none of the accounts in Exhibits 2-6 through 2-17 have exposures older than 55 years, yet Empire's continuing property records contain data as far back as 1900.

According to Mr. Sullivan, the following are the accounts which Mr. Garrett identified as material and the full data available for each account:

1. Account 353 – 1900 to the present
2. Account 362 – 1912 to the present
3. Account 364 – 1900 to the present
4. Account 369 – 1926 to the present
5. Account 390 – 1903 to the present

Mr. Garrett's analysis begins with data from 1960 to the present, not "all of the Company's property data". In addition to the accounts listed above, there are several others where Mr. Garrett has used something less than the full set of data available.

Mr. Sullivan testified that the OIEC had mischaracterized the analyses he performed by mismatching Mr. Sullivan's recommended Iowa curves to the abbreviated datasets used in OIEC's analyses.

In Figures 2 through 6 of his testimony, Mr. Garrett claims he is comparing the Company's selected Iowa curve, the OIEC's selected Iowa curve, and the OLT (Observed Life Table) curve, which as Mr. Sullivan indicated earlier he claimed includes all of the Company's property data. First, his analyses did not use all of the Company's property data. Second, the

OIEC graphs are further truncated at 50 percent surviving. Third, the Company analyses Mr. Garrett shows are based on the Iowa curves shown in Mr. Sullivan's Schedule TJS-2 which do include all of the Company's property data. By making these apples and oranges comparisons, Mr. Garrett's figures mislead the reader into believing that his selected curves fit all of the Company's data better than the curves Mr. Sullivan used, when in fact they do not. His curves fit the truncated (1960 to present) data better. Nowhere in his testimony does Mr. Garrett make this critical distinction. In Mr. Sullivan's workpapers, he provided analyses using both the full data sets and also a test against the 1960 to present shortened data set, but his recommended Iowa curves are based on the full data sets available.

Mr. Sullivan prepared curves showing how his selected curves actually fit all the Company data.

These curves are included in Schedule TJS-6. This schedule shows that the curves Mr. Sullivan recommended fit all of the data better than the curves selected by the OIEC.

In response to a question of what was the net effect of the OIEC using the abbreviated data set, Mr. Sullivan testified that there were two impacts that bias the results towards producing longer lives. By Mr. Garrett removing the older plant and focusing on only the top half of the survivor curve (100% to 50% surviving), he has stretched out the curve by removing the tails of the curve and by removing plant that has gone through its full life cycle. Mr. Sullivan stated that it needed to be made clear that the mathematical analyses underlying his analyses and the OIEC's are essentially the same, a least squares or best fit analysis comparing actual data to standardized Iowa curves. The only difference results from using different data band; the full data band versus the truncated data band. The OIEC has not used all of the Company's data as it claims it has used.

In response to AG witness Farrar, Mr. Sullivan testified that on Page 11, beginning at line 2, Mr. Farrar states that Empire's proposed depreciation rates should be rejected because "future additions to plant were included in the filed depreciation study". Mr. Sullivan assumed Mr. Farrar was referring to interim additions which he addressed in his rebuttal testimony.

He disagreed that consideration of the effective interim activity on the calculation of depreciation rates is an "inappropriate rate making policy". If one excludes the expenditures one must also exclude the extra life which is a result of those expenditures. To not do so would certainly be inappropriate rate making policy.

Mr. Sullivan testified that the depreciation rates recommended in Schedule TJS-2 (based on total Company plant in service at June 30, 2015) resulted in a reduction in depreciation expenses of $198,726 for transmission plant, a reduction in depreciation expenses of $3,654,194 for distribution plant, and an increase in depreciation expenses of $68,859 for general plant. The reductions in depreciation expenses for transmission and distribution plant resulted primarily from recommending longer lives than the lives underlying the existing depreciation rates.

According to Mr. Sullivan, the depreciation rates were reviewed by the Missouri Public Service Commission Staff in Docket No. ER-2016-0023. For the mass property accounts, the Missouri Public Service Commission Staff's findings were so close that he did not even bother to rebut them in that case. Further, the Staff's overall recommendation on the mass property accounts was for generally shorter lives than Mr. Sullivan recommended.

Mr. Sullivan concluded by stating the OIEC's testimony and exhibits are based on misrepresentations and unreasonable and inaccurately supported recommendations. The AG's recommendation is contrary to sound depreciation theory. Therefore, neither should be relied upon by the Commission.

DR. JAMES H. VANDER WEIDE

Direct Testimony

Dr. James H. Vander Weide, President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients, testified on behalf of Empire.

Dr. Vander Weide testified that he estimated Empire's cost of equity by applying several standard cost of equity methods to market data for a large proxy group of electric utility companies.

According to Dr. Vander Weide, he applied his cost of equity methods to a large group of comparable risk companies because standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies; and thus, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the principle enunciated by the United States Supreme Court that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk (*see Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 561, 603 (1944)).

Dr. Vander Weide testified that on the basis of his studies, he found that the cost of equity for his proxy companies is in the range 9.3 percent to 10.5 percent, with an average equal to 9.9 percent. This conclusion was based on his application of standard cost of equity estimation techniques, including the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities, and on the evidence he presented in his testimony that the CAPM, as typically applied, significantly underestimates the cost of equity for companies such as his proxy companies with betas significantly less than 1.0.

He recommended that Empire be authorized a rate of return on equity equal to 9.9 percent.

According to Dr. Vander Weide, his recommended 9.9 percent return on equity is conservative because it does not reflect the higher financial risk implicit in the Company's ratemaking capital structure compared to the average financial risk of the proxy companies' market value capital structure. The financial risk of the proxy companies depends on the market values of the debt and equity in the companies' capital structures.

According to Dr. Vander Weide, economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. If investors do not expect to earn a return on their investment in a company or project that is at least as large as the return they expect to receive on other investments of comparable risk, rational investors will not invest in the company or project.

Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have only a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

According to Dr. Vander Weide economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as he noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Dr. Vander Weide testified that investors estimate the expected rate of return in several steps. First, they estimate the amount of their investment in the company. Second, they estimate the timing and amounts of the cash flows they expect to receive from their investment over the life of the investment. Third, they determine the return, or discount rate, that equates the present value of the expected cash receipts from their investment in the company to the current value of their investment in the company.

Dr. Vander Weide further testified that investors generally measure investment risk by estimating the probability, or likelihood, of earning less than the required return on investment. For investments with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Dr. Vander Weide explained that business risk is the underlying risk that investors will earn less than their required return on investment when the investment is financed entirely with equity. Financial risk is the additional risk of earning less than the required return when the investment is financed with both fixed-cost debt and equity.

He further testified that the business risk of investing in electric utility companies such as Empire is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

With regard to regulatory uncertainty, Dr. Vander Weide also testified that investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation. Investors are keenly aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Dr. Vander Weide testified that the risks of investing in electric utilities such as Empire can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in electric utilities are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are largely irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in electric utilities such as Empire are largely asymmetric. That is, there is little opportunity for the utility to earn more than its required return, but a significant chance that the utility will earn less than its required return.

Dr. Vander Weide testified that he used several generally accepted methods for estimating the cost of equity for Empire. These are the Discounted Cash Flow (DCF), the ex ante risk premium, the ex post risk premium, and the capital asset pricing model (CAPM). The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The ex ante risk premium method assumes that an investor's current expectations regarding the equity risk premium can be estimated from data on the DCF expected rate of return on equity compared to the interest rate on long-term bonds. The ex post risk premium method assumes that an investor's current expectations regarding the equity-debt return differential is equal to the historical record of comparable returns on stock and bond investments. The cost of equity under both risk premium methods is then equal to the interest rate on bond investments plus the risk premium. The CAPM assumes that the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

In regard to Dr. Vander Weide's DCF study, Dr. Vander Weide explained that the DCF equation requires estimates of the growth, dividend, and price terms. As his estimate of growth in his DCF model, Dr. Vander Weide used the analysts' estimates of future earnings per share ("EPS") growth reported by I/B/E/S Thomson Reuters. Dr. Vander Weide explained that he used the I/B/E/S growth estimates because his studies indicate that analysts' forecasts are the best estimate of investors' expectation of future long-term growth, and the DCF model requires the growth expectations of investors. Dr. Vander Weide also described his statistical study comparing historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. He noted that researchers at State Street Financial Advisors updated his study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

As his estimate for the price term, Dr. Vander Weide used a simple average of the monthly high and low stock prices for each firm for the three-month period ending October 2016. These high and low stock prices were obtained from Thomson Reuters. Dr. Vander Weide testified that he used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

He further testified that because Empire is seeking to recover its equity flotation costs as an expense over a five-year period, he did not include an allowance for flotation costs in his cost of equity calculations.

He applied the DCF approach to the Value Line electric companies shown in his Schedule JVW-1.

He selected all the companies in Value Line's groups of electric companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have an I/B/E/S long-term growth forecast; and (4) are not the subject of a merger offer that has not been completed. In addition, each of the utilities included in his comparable groups had an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3.

Dr. Vander Weide obtained an average DCF result of 9.3 percent for his proxy company group.

Dr. Vander Weide also employed the risk premium approach to estimate Empire's cost of equity, using two risk premium methods, an ex ante risk premium approach and an ex post risk premium approach. As Dr. Vander Weide explained, the risk premium method is based on the principle that investors expect to earn a return on an equity investment in Empire that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Dr. Vander Weide's ex ante risk premium method is based on studies of the DCF expected return on a proxy group of electric companies compared to the interest rate on Moody's A-rated utility bonds. Dr. Vander Weide performed a regression analysis to determine if there is a relationship between the calculated risk premium and interest rates and uses the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity using the ex ante risk premium method, according to Dr. Vander Weide, one may add the estimated risk premium over the yield on A-rated utility bonds to the forecasted yield to maturity on A-rated utility bonds. He obtained the expected yield to maturity on A-rated utility bonds, 5.8 percent, by averaging the most recent forecast data from Value Line and the U.S. Energy

Information Administration ("EIA"). For his electric utility sample, his analyses produced an estimated risk premium over the yield on A-rated utility bonds equal to 4.7 percent. Adding an estimated risk premium of 4.7 percent to the expected 5.8 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.5 percent using the ex ante risk premium method.

Dr. Vander Weide described in detail his ex post risk premium method for measuring the required risk premium on an equity investment in Empire.

Dr. Vander Weide concluded that his ex post risk premium analyses provide evidence that investors today require an equity return of at least 3.9 to 4.5 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.8 percent. Adding a 3.9 to 4.5 percentage point risk premium to a yield of 5.8 percent on A-rated utility bonds, he obtained an expected return on equity in the range 9.7 percent to 10.3 percent, with a midpoint estimate equal to 10.0 percent.

Dr. Vander Weide stated that the CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

According to Dr. Vander Weide, the CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For his estimate of the risk-free rate, he used the forecasted yield to maturity on 20-year Treasury bonds of 4.45 percent, using forecast data from Value Line and EIA.

For his estimate of the company-specific risk, or beta, he used the average 0.72 Value Line beta for his proxy electric companies and the 0.90 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio.

For his estimate of the expected risk premium on the market portfolio, he used two approaches. First, he estimated the risk premium on the market portfolio using historical risk premium data reported in the 2016 Valuation Handbook for the years 1926 through 2015, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, he estimated the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Dr. Vander Weide concluded that based on his application of several cost of equity methods to his proxy companies, his proxy companies' cost of equity is in the range 9.3 percent to 10.5 percent, with an average result equal to 9.9 percent. Dr. Vander Weide provided the following table:

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT
Discounted Cash Flow	9.3%
Ex Ante Risk Premium	10.5%
Ex Post Risk Premium	10.0%
CAPM-Historical	9.7%
CAPM-DCF Based	10.2%
Average	9.9%

Dr. Vander Weide testified that his cost of equity conclusion reflects the financial risk associated with the average market value capital structure of his proxy companies, which has approximately 64 percent equity.

Empire is recommending that its consolidated capital structure containing approximately 49.68 percent common equity be used for rate making purposes in this proceeding.

According to Dr. Vander Weide, although Empire's recommended capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for rate making purposes in this proceeding, this recommended rate making capital structure embodies greater financial risk than is reflected in his cost of equity estimates from his proxy companies.

Dr. Vander Weide testified that he conservatively recommends an ROE equal to 9.9 percent. This recommendation is conservative in that it does not reflect the higher financial risk implicit in Empire's rate making capital structure compared to the average financial risk of the proxy companies implicit in the values of debt and equity in their market value capital structures.

Rebuttal Testimony

Dr. Vander Weide filed rebuttal testimony to respond to the allowed rate of return on equity and cost of equity recommendations of Mr. David J. Garrett ("OIEC") and Mr. Geoffrey M. Rush ("PUD").

Mr. Garrett recommended an allowed return on equity equal to 9.0 percent, and Mr. Rush recommended an allowed return on equity equal to 9.9 percent. Mr. Garrett estimated a cost of equity equal to 7.5 percent, and Mr. Rush estimated a cost of equity equal to 7.91 percent. According to Dr. Vander Weide, there was nothing in these testimonies that would cause him to change his cost of equity recommendations.

Dr. Vander Weide testified that Mr. Garrett arrived at his recommended 9.0 percent recommended ROE by: (1) estimating that Empire's cost of equity is 7.5 percent; (2) noting that Empire's current allowed ROE is 9.9 percent; and (3) recommending that the Commission gradually reduce Empire's current 9.9 percent allowed return on equity to his 7.5 percent estimate of Empire's cost of equity. In Mr. Garrett's opinion, a reduction of Empire's allowed return on equity from 9.9 percent to 9.0 percent would be a move in the right direction, without increasing Empire's risk.

According to Dr. Vander Weide, Mr. Garrett tested the reasonableness of his recommendations by comparing the average awarded ROE for U.S. electric utilities from 2005 to 2016 to Dr. Damodaran's estimates of the market cost of equity over the same period. The average electric utility awarded ROE over the period 2005 to 2016 was approximately 200 basis points higher than Dr. Damodaran's average estimate of the market cost of equity. Because Mr. Garrett believes that Dr. Damodaran has provided a reasonable estimate of the required market return, Mr. Garrett concludes that: (1) utility commissions, such as the Oklahoma Corporation Commission, have consistently awarded allowed ROEs that exceed utilities' costs of equity by more than 200 basis points; and (2) the Commission should significantly reduce Empire's current 9.9 percent allowed ROE.

Dr. Vander Weide testified that Dr. Damodaran's data simply represents the results of a mechanical application of his market model to market data for the S&P 500. Mr. Garrett fails to acknowledge that public utility commissions generally set a utility's allowed ROE equal to the commission's best estimate of the utility's cost of equity based on the evidence presented in each proceeding. According to Dr. Vander Weide, Mr. Garrett provided no evidence that utility commissions intentionally set a utility's allowed return above the best estimate of the utility's cost of equity. To suggest otherwise is an insult to Commissioners, according to Dr. Vander Weide.

Dr. Vander Weide noted that one of Mr. Garrett's sources in his testimony is the Graham and Harvey annual survey of chief financial officers. In this survey, Graham and Harvey ask the CFO survey participants to provide information on: (1) their companies' internally calculated weighted average costs of capital; and (2) the hurdle rates their companies use to make investment decisions. Graham and Harvey find that the average internally calculated WACC for U.S. companies is in the range 9.3 percent to 9.7 percent, and that the average hurdle rate used to make investment decisions is in the range 13.1 percent to 14.2 percent.

Dr. Vander Weide explained that the "hurdle rate" is the "cut-off" return a company uses as the target rate of return that must be expected to be earned in order to make the investment in the project. For example, a company with a "hurdle rate" of 12 percent, will only accept projects with a return on total invested capital (debt plus equity) greater than 12 percent. He further stated that the company's weighted average cost of capital is the minimum return on total capital that would allow a company to break-even on a project; that is, the project would have a net present value equal to zero. Companies generally set the investment hurdle rate higher than the WACC, in a world of capital constraints, in order to earn a positive net present value on a project.

Dr. Vander Weide further explained the relevance of the Graham and Harvey finding. The data provides a better test of the reasonableness of Mr. Garrett's recommended 9.0 percent ROE and 7.14 percent WACC because they reflect the costs of capital managers actually use to make real-world investment decisions rather than a mechanical application of a formula to market data without any consideration of whether investors actually use this formula in making investment decisions. Thus, in summary, the WACCs and hurdle rates reported by Graham and

Harvey indicate that Mr. Garrett's recommended 9.0 percent allowed ROE and 7.14 percent WACC are far below a reasonable estimate of Empire's cost of equity and weighted average cost of capital. ["The Equity Risk Premium in 2016," John R. Graham and Campbell R. Harvey]

Dr. Vander Weide rebutted Mr. Garrett's 7.5 percent estimate of Empire's cost of equity.

According to Dr. Vander Weide, Mr. Garrett applied the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") to a group of eighteen Value Line electric utilities. Mr. Garrett also applied his cost of equity models to Dr. Vander Weide's larger proxy group, attempting to establish that "cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups." [Garrett at 23] Mr. Garrett's group excludes companies with market capitalizations "considerably higher than Empire's market capitalization."

Dr. Vander Weide testified that both Mr. Garrett and Dr. Vander Weide used the quarterly DCF model. Mr. Garrett obtained a result of 7.6 percent.

Dr. Vander Weide testified that using the analysts' growth forecasts in Mr. Garrett's DCF model produces a result equal to 9.5 percent, not the 7.6 percent reported by Mr. Garrett.

Dr. Vander Weide's quarterly DCF model results differ from Mr. Garrett's primarily because he used analysts' estimates of long-term growth for the growth component of the DCF model, whereas Mr. Garrett used his estimate of long-run growth in Gross Domestic Product ("GDP") for the growth component of his DCF model.

Dr. Vander Weide used analysts' growth rates reported by I/B/E/S Thomson Reuters because his studies indicate that the analysts' growth rates are highly correlated with stock prices. This evidence provides strong support for the conclusion that investors use analysts' growth rates in making stock buy and sell decisions, and thus the analysts' growth rates should be used to estimate the growth component of the DCF model.

Dr. Vander Weide discussed the analysts' estimates of future EPS growth by saying that part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts.

He further testified that I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as an estimate of future firm performance.

Dr. Vander Weide used the I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutions and other investors.

Dr. Vander Weide relies on analysts' projections of future EPS growth rather than historical growth, retention growth, or long-run growth in GDP because there is considerable empirical evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth. The evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth is important according to Dr. Vander Weide because the DCF model requires the growth expectations of investors.

Dr. Vander Weide testified that he had prepared a study in conjunction with Willard T. Carleton, Professor of Finance Emeritus at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in *The Journal of Portfolio Management*.

Dr. Vander Weide summarized the results of the study. First, a correlation analysis was performed to identify the historically oriented growth rates which best described a firm's stock price. Then a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates.

These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. It should be noted that researchers at State Street Financial Advisors updated Dr. Vander Weide's study, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Dr. Vander Weide testified that Mr. Garrett believes that it is inappropriate to use analysts' growth rate forecasts to estimate investors' growth expectations in the DCF model because analysts' growth forecasts generally exceed the projected long-term growth of the economy as a whole; and, in Mr. Garrett's opinion, it would be irrational for investors to believe that companies can grow forever at a rate in excess of the expected growth in the economy.

According to Dr. Vander Weide, Mr. Garrett also considers inflation, real GDP, and the current risk-free rate as additional estimates of long-term GDP growth. However, the 4.1 percent long-term growth estimate that Mr. Garrett uses in his DCF calculation is based entirely on an estimate of nominal GDP growth.

Dr. Vander Weide did not believe it was appropriate for Mr. Garrett to adjust the growth term in his DCF model, without also adjusting the stock price term in his model.

Dr. Vander Weide testified that Mr. Garrett failed to recognize that the DCF model requires the growth expectations of *investors*, not the growth expectations of Mr. Garrett. If investors use analysts' growth rates to value stocks in the marketplace, Mr. Garrett should use analysts' growth rates to estimate the growth component of the DCF model. Mr. Garrett also failed to recognize that companies do not have to grow at the same rate forever for the single-stage DCF Model to be a reasonable approximation of how prices are determined in capital markets.

Dr. Vander Weide further testified that Mr. Garrett's opinion that a company's earnings cannot grow at a rate greater than the rate of growth in the GDP forever does not imply that companies must grow at an expected GDP growth rate in every year. Mr. Garrett's assumption that companies must only grow at the same rate as his estimate of expected GDP growth is completely arbitrary. Further, Mr. Garrett did not examine more than one estimate of nominal long-term GDP growth according to Dr. Vander Weide.

Dr. Vander Weide further testified that he did not believe that long-term GDP growth is the growth estimate investors use when they invest in stocks and, therefore, is not appropriately used as the estimate of growth in the DCF model. He was aware that estimates of nominal long-term GDP growth are available from the Social Security Administration and the Energy Information Administration, for example; and the current nominal long-term GDP estimates from these sources are 4.6 percent and 4.3 percent, approximately 50 basis points and 20 basis points higher than the 4.1 percent estimate used by Mr. Garrett.

Dr. Vander Weide did not agree with Mr. Garrett's CAPM result. Mr. Garrett's estimate of the risk-free rate, his estimate of the risk premium on the market portfolio, and his failure to acknowledge the substantial evidence that the CAPM tends to underestimate the cost of equity for companies such as his proxy companies with betas less than 1.0 were all points of disagreement.

Dr. Vander Weide disagreed with Mr. Garrett's 3.04 percent estimate of the risk-free rate because the analysis presented in his direct testimony indicates that the forecasted yield on long-term Treasury bonds is approximately 4.1 percent. In estimating the forward-looking equity risk premium on equity investments, it is reasonable to use a forecasted interest rate rather than a current interest rate on long-term Treasury securities.

Given the convincing evidence that the CAPM underestimates the cost of equity for companies with betas less than 1.0, Mr. Garrett should have recognized, for this reason alone, that his cost of equity estimates underestimates Empire's cost of equity.

Dr. Vander Weide further testified that Graham and Harvey state that executives report that their firms use actual weighted average costs of capital in the range 9.3 percent to 9.7 percent, and they report that they use investment hurdle rates in the range 13.1 percent to 14.2 percent. Graham and Harvey's reported information on the WACCs and hurdle rates actually used by executives to make investment decisions is more relevant to assessing Empire's cost of equity than the information on executives' views on expected returns.

Because both the weighted average cost of capital and the hurdle rate are weighted averages of the cost of debt and the cost of equity, and the cost of debt is less than the cost of equity, the costs of equity that executives actually use in making real world investment decisions must be significantly higher than the weighted average cost of capital or hurdle rate. Thus, based on this evidence, the market risk premium must be considerably higher than Mr. Garrett's assumed 5.8 percent, and the cost of equity must be considerably higher than Mr. Garrett's calculated 7.4 percent CAPM cost of equity using a 5.8 percent market risk premium.

Dr. Vander Weide also had several concerns with Mr. Garrett's study of the implied market return on the S&P 500. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

With regard to the risk-free rate component of the CAPM, Dr. Vander Weide recommends using a forecasted yield to maturity on Treasury bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Because current interest rates are depressed as a result of the Federal Reserve's efforts to stimulate the economy by keeping interest rates low, current interest rates at this time are a poor indicator of expected future interest rates. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

Dr. Vander Weide concluded that Mr. Garrett's CAPM cost of equity estimate is unreasonably low and significantly less than Empire's true cost of equity.

Dr. Vander Weide also rebutted Mr. Garrett's views regarding: (1) the risk of investing in regulated utilities such as Empire; (2) the appropriate upper bound estimate of Empire's cost of equity; and (3) the relationship between depreciation and the cost of capital.

Dr. Vander Weide discussed the risks of investing in regulated electric utilities in his direct testimony on pages 13 – 19. In his discussion, he noted that the business risks of investing in electric utilities is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Mr. Garrett argues that Dr. Vander Weide's analysis of the business risks of investing in regulated utilities is misleading because the risks he identifies are all "firm-specific risks" that have no "meaningful effect on the cost of equity estimate," and his view that the regulatory process creates additional risks for utilities is completely untrue. Garrett believes that regulation significantly reduces the risk of investing in electric utilities, rather than increasing the risk of investing in electric utilities.

Dr. Vander Weide testified that the business risks he identified cannot be diversified away because they reflect general risks faced by investors in all industries, rather than the specific risks faced only by investors in electric utilities. He discusses these risks in the context of the electric utility industry to emphasize that the risks of investing in electric utilities has increased as a result of the high costs of meeting increasingly stringent environmental regulations, the impact of technological change has on reducing the demand for electricity generated and sold by electric utilities, and the challenge and complexity of identifying appropriate responses to changing economic conditions in the industry. The structure of the electric utility industry is changing dramatically as more customers are able to obtain electricity from sources other than traditional utilities.

Dr. Vander Weide testified that Mr. Garrett estimated that the average market cost of equity is 8.1 percent.

Mr. Garrett arrives at his 8.1 percent estimate of the market cost of equity by examining the results of the IESE survey, the Graham and Harvey survey, Damodaran, and his own study.

Mr. Garrett concludes that the upper bound for a reasonable estimate of Empire's cost of equity is 8.1 percent.

Dr. Vander Weide testified that Mr. Garrett's conclusion is based on sources that do not provide studies of the cost of equity either for utilities or for the market. Market surveys of executive opinions regarding the expected risk premium on the S&P 500, such as the IESE survey and the Graham and Harvey survey, are not designed to establish an appropriate upper bound for the cost of equity for electric utilities. The Graham and Harvey survey, for example, provides evidence that the executives responding to the survey, in fact, do not use the risk premium data they provide in response to the survey when they are committing their companies' funds to capital projects. Rather, the Graham and Harvey survey provides evidence that companies' use hurdle rates in the range 13.1 percent to 14.2 percent. This 13.1 percent to 14.2 percent range includes both debt and equity costs. Mr. Garrett's 8.1 percent estimate of an upper bound for an electric utility's cost of equity is far below the costs equity that are used to establish hurdle rates for real-world investment decisions.

Mr. Garrett's study on the implied market return on the S&P 500 is flawed in several ways. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

Dr. Vander Weide testified that Mr. Garrett claimed that it was best to over-estimate depreciation lives in depreciation studies because such over-estimation does not harm the company and benefits shareholders. Mr. Garrett stated:

> Moreover, since the Company's awarded and earned returns on equity are far above its true cost of equity, the Company's shareholders further benefit from the excess wealth transfer from ratepayers while these costs are in rate base. Thus, the process of depreciation strives for a perfect match between actual and estimated useful life. When these estimates are not exact, however, it is better that useful lives are overestimated rather than underestimated. [Garrett Depreciation Testimony at 7 – 8]

According to Dr. Vander Weide, Mr. Garrett's assertion is based on his faulty conclusion that Empire's cost of equity is 7.5 percent. Dr. Vander Weide noted that he had been involved in regulatory proceedings for many years, and he could not recall any regulatory commission awarding an allowed rate of return on equity as low as Mr. Garrett's recommended 7.5 percent cost of equity. He had not experienced, and did not believe, Mr. Garrett's assertion that regulators have awarded allowed returns on equity above utilities' cost of equity.

Dr. Vander Weide further testified that Mr. Garrett's statement that utilities "routinely propose awarded returns on equity that far exceed their actual costs of equity for the sole benefit of shareholders, as Empire has done in this case" [Garrett Depreciation Testimony at 34 – 35] is specious, self-serving, and contrary to the extensive evidence presented by the Company in this proceeding. Dr. Vander Weide provided evidence in this case on Empire's cost of equity, and Empire has proposed an allowed return on equity that is equal to his cost of equity estimate, which is based on the average result of his application of the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities. Dr. Vander Weide's estimate of Empire's cost of equity is not only equal to Empire's current allowed ROE in Oklahoma, but is also in line with allowed rates of return for electric utilities throughout the country. To the contrary, Mr. Garrett's 7.5 percent estimate of the cost of equity is far lower than any allowed rates of return on equity.

Dr. Vander Weide did not agree with Mr. Garrett's claim that a company's shareholders benefit if depreciable lives are over-estimated. If depreciable lives are over-estimated, shareholders face the considerable risk that they will not recover the full cost of their investment in these assets.

Mr. Rush accepts Empire's requested 9.9 percent ROE, Dr. Vander Weide did not rebut his recommendation to award Empire an allowed ROE equal to 9.9 percent.

Dr. Vander Weide did not agree with the method that Mr. Rush arrived at his 7.91 percent cost of equity estimate.

Mr. Rush arrives at his 7.91 percent cost of equity estimate by applying the DCF, CAPM, and comparable earnings methods to a proxy group of 29 Value Line electric utilities.

Dr. Vander Weide disagreed with Mr. Rush's decisions to: (1) use quarterly dividends from the second quarter of 2016 along with stock prices for the period December 23, 2016, through February 7, 2017; and (2) use of historical dividend growth and fundamental growth along with Value Line's projected earnings growth to estimate the growth component of the DCF model.

Dr. Vander Weide disagreed with Mr. Rush's use of quarterly dividends from the second quarter of 2016 with stock prices from December 23, 2016, through February 7, 2017, inputs because the DCF model is based on the assumption that investors value a stock based on their estimate of the present value of all expected <u>future</u> dividends. Mr. Rush's decision to use dividends from the second quarter 2016 with stock prices from December 23, 2016, through February 7, 2017, violates this basic assumption because Mr. Rush's dividends were paid prior to the observed stock prices. Thus, Mr. Rush's DCF analysis includes a fundamental mismatch of data.

According to Dr. Vander Weide, Mr. Rush estimates the growth component of his DCF analysis from information on his proxy companies': (1) historical dividend growth over the last five years as reported by Value; (2) projected earnings per share growth as reported by Value Line; and (3) fundamental growth. Mr. Rush's final growth estimate is the average of these three growth estimates. Mr. Rush's data for these growth inputs are shown in Exhibit DG-C-6 in his Excel work papers.

The DCF model requires the growth forecasts investors use to value stocks in the marketplace; and Dr. Vander Weide's studies indicate that investors use consensus analysts' earnings per share growth ("EPS") forecasts to value stocks in the marketplace. Mr. Rush should have relied on analysts' earnings per share growth forecasts rather than on historical dividend growth and fundamental growth forecasts.

Dr. Vander Weide further testified that there appeared to be errors in Mr. Rush's growth data. Mr. Rush's work papers indicate that rather than using the Value Line reported historical dividend growth rates for his proxy companies, the formula on his spreadsheet substitutes a zero percent historical growth rate for 18 out of his 29 proxy companies. Mr. Rush reports an average historical growth rate equal to 2.16 percent, whereas the historical average dividend growth rate is 4.93 percent once his formula and data are corrected.

If Mr. Rush had correctly matched dividend and stock price inputs and used the I/B/E/S growth forecasts, he would have obtained a DCF result equal to 9.1 percent. Using the Value Line projected earnings growth forecast as the growth term in his DCF model, Mr. Rush would have obtained a DCF result equal to 9.0 percent.

Dr. Vander Weide testified that because of an error in the formula in his spreadsheet, Mr. Rush reports an annual DCF model result equal to 4.49 percent. However, once errors in the formula that produces this result are corrected, along with the corrections in the growth rates and dividend inputs in the analysis, the annual DCF model result is 9.0 percent.

Regarding the CAPM analysis of Mr. Rush, Dr. Vander Weide testified that for his estimate of the risk-free rate, Mr. Rush uses the 2.90 percent average yield on 30-year Treasury bonds over the period December 15, 2016, through January 30, 2017. For his estimate of the company-specific risk factor or beta, Mr. Rush uses the average 0.71 Value Line beta for his proxy companies. For his estimate of the expected risk premium on the market portfolio, Mr. Rush uses: (1) historical geometric and arithmetic mean risk premium data reported by Ibbotson; (2) the expected risk premiums reported in the Graham and Harvey and the IESE Business School surveys discussed above; and (3) an implied equity risk premium calculation, which is the same as that used by Mr. Garrett. Based on these data, Mr. Rush uses 5.5 percent as his estimate of the risk premium on the market portfolio.

According to Dr. Vander Weide, Mr. Rush should have used a forecasted yield on Treasury bonds because interest rates have been at unusually low levels, and investors are forecasting that interest rates will increase over the period when Empire's rates will be in effect.

Dr. Vander Weide did not agree with Mr. Rush's historical equity risk premium estimates. Mr. Rush used an average of both the geometric and arithmetic mean historical risk premium estimates. The arithmetic mean risk premium is the only risk premium that will make the initial investment grow to the expected value of the investment at the end of the period. For an investment, such as an equity investment in stocks, which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future.

Dr. Vander Weide also disagreed with Mr. Rush's use of total return on long-term government bonds to estimate the difference between stock and bond returns because the CAPM requires an estimate of the risk-free rate, but the total return on long-term government bonds is not risk free because it includes capital gains and losses. A correct estimate of the historical risk premium is 6.9 percent, not the 5.2 percent reported by Mr. Rush.

In regards to Mr. Rush's comparable earnings method, Dr. Vander Weide stated that Mr. Rush calculates the average annual earned return on equity for each of his proxy utilities for the years 2012 through 2016. Mr. Rush reports that the average earned return for his group of proxy utilities over this historical period is 9.82 percent, and he uses 9.82 percent as his comparable earnings estimate of Empire's cost of equity.

Dr. Vander Weide had at least three criticisms of Mr. Rush's comparable earnings method. First, Mr. Rush should have used forecasted returns on equity rather than historical returns on equity to estimate each company's ROE. Mr. Rush himself acknowledges that historical returns on equity "should be considered with caution" because they do "not account for any prospective forward-looking factors." [Rush at 35] Further, the historical reported returns include factors such as one-time write-offs that are not expected to occur in the future. Second, Mr. Rush should have examined forecasted earned returns for comparable-risk industrial companies, as Mr. Rush himself also acknowledges [Rush at 34 – 35]. Third, Mr. Rush failed to recognize that Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, Mr. Rush should have adjusted Value Line's estimates to reflect rates of return on average equity for each year.

BLAKE A. MERTENS

Direct Testimony

Mr. Blake A. Mertens, Vice President Energy Supply and Delivery Operations for Empire, testified on behalf of Empire.

Mr. Mertens testified that the Asbury Power Plant is a 195 MW coal-fired power plant in northern Jasper County, Missouri, near the Missouri–Kansas state line. The Asbury Power Plant commenced commercial operations on July 1, 1970. The Babcock & Wilcox cyclone boiler was designed to be fueled by bituminous coal from the Pittsburg & Midway mine, which was adjacent to the Asbury Power Plant. Superheated steam from the boiler drove a Westinghouse turbine generator set to generate electrical energy.

According to Mr. Mertens, early pollution controls consisted of an electrostatic precipitator to capture particulate emissions. In the early 1990s, the Environmental Protection Agency created the Acid Rain Program, which required Empire to reduce sulfur dioxide emissions and led to a fuel switch from the local bituminous coal to lower sulfur sub-bituminous coal from the Powder River Basin of Wyoming. This required changes to the fuel handling system to accommodate the higher volume of this less energy dense coal and most notably, the construction of a rotary car dumper to unload the trainloads of coal. In 2008, in anticipation of nitrogen oxides emissions reductions to be required by the Clean Air Interstate Rule, Empire installed a selective catalytic reduction ("SCR") system at the Asbury Power Plant. The SCR injects anhydrous ammonia into the flue gas stream, where in the presence of a catalyst, it reacts with nitrogen oxides to eliminate them.

According to Mr. Mertens, the Federal Clean Air Act and state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control requirements. These requirements include maximum emission limits for sulfur dioxide ("SO2"), particulate matter, nitrogen oxides ("NOx"), carbon monoxide ("CO") and hazardous air pollutants, including mercury. To comply with current and pending environmental regulations, Empire needed to implement a compliance plan at its Asbury unit if the unit was to continue in service. The regulations primarily driving Empire's compliance plan are the Mercury and Air Toxics Standards ("MATS") and the Clean Air Interstate Rule ("CAIR") and its subsequent replacement rule.

Mr. Mertens testified that as part of its 2010 Integrated Resource Plan ("IRP") -- a twenty year planning study -- Empire developed seventeen different resource cases for analysis. Among the alternative resource cases analyzed, the study considered cases that included the construction of the Asbury AQCS or the retirement of Asbury in 2015. Capacity expansion modeling was done for all cases. New conventional and renewable resources, as well as demand-side management programs, were considered available for the capacity expansion required to meet Empire's projected future loads. The resources evaluated to replace or supplement the energy produced by Asbury included supercritical coal, simple cycle combustion turbine, combined cycle, nuclear power purchase agreement, distributed generation, integrated gasification combined cycle, wind, biomass and solar thermal.

Each of the seventeen cases analyzed in the 2010 IRP produced an optimized set of supply-side resources resulting in the lowest present value of revenue requirements ("PVRR") for the scenario represented by that case. Each plan was subjected to stochastic analysis and financial modeling over the planning horizon. Each plan was analyzed at all levels of four critical uncertain factors - environmental costs, market and fuel prices, load forecast and capital and transmission costs and interest rates. This analysis generated seventy-two endpoints for each plan, which make up the risk profiles for the plans.

The risk profiles of the cases that utilized the base case assumptions were compared, and the plan with the lowest risk with respect to PVRR was selected by Empire as its Preferred Plan. This Preferred Plan included the installation of the Asbury AQCS in the 2015 timeframe.

Mr. Mertens further testified that the economic analyses conducted before, during and after the preparation of the 2010 IRP, found that the Asbury AQCS project was the low-cost option for Empire. Additionally, this plan kept approximately 189 MW of Empire owned coal-fired capacity in Empire's generation mix, which helps with fuel diversity and fuel price volatility. With the continued operation of Asbury, Empire's owned generation mix is about 33% coal and 63% natural gas.

According to Mr. Mertens, in March 2010, Empire awarded Black & Veatch an engineering assignment to gather information about Empire's Asbury unit and perform studies to select the preferred technology for reducing emissions – specifically sulfur dioxide, particulate matter and mercury – at the plant. Black & Veatch prepared four individual reports as a result of this assignment: