BEFORE THE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE JOINT	]	
APPLICATION OF WESTAR ENERGY, INC.	]	
AND KANSAS GAS AND ELECTRIC	]	KCC Docket No. 18-WSEE-328-RTS
COMPANY FOR APPROVAL TO MAKE	]	
CERTAIN CHANGES IN THEIR CHARGES	]	
FOR ELECTRIC SERVICE	]	

DIRECT TESTIMONY OF

ANDREA C. CRANE

RE: REVENUE REQUIREMENTS

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

June 11, 2018

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 2805 East Oakland Park Boulevard, #401, Ft. Lauderdale, Florida 33306.

Q. By whom are you employed and in what capacity?

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On February 1, 2018, Westar Energy, Inc. and Kansas Gas and Electric Company (collectively "Westar" or "Company") filed an Application with the Kansas Corporation Commission ("KCC" or "Commission") seeking a two-stage base rate increase. In Phase I, which would take effect in September 2018, Westar proposed an increase of $14.13 million. Westar's proposed Phase I base rate increase includes $15.69 million that is currently being collected through the Ad Valorem Property Tax Surcharge. Therefore, the net impact to ratepayers is a proposed decrease of $1.56 million, or approximately -0.08%. Westar also proposed a Phase II increase of $54.2 million, to take effect on February 1, 2019. The Phase II increase was designed to recover the costs associated with the loss of a large wholesale contract with Mid-Kansas Electric Company ("MKEC") and to reflect the expiration of production tax credits ("PTCs") associated with the Central Plains and Flat Ridge 1 Wind Farms. The net effect of the two proposed increases was a net increase in revenue of $52.6 million or approximately 2.6%.

Finally, Westar proposed to provide a credit to ratepayers to reflect the tax savings from January 1, 2018 through the effective date of new rates resulting from the Tax Cut and Jobs Act of 2017 ("TCJA"), which lowered the corporate federal income tax from 35% to 21%. Westar projected a gross tax savings of $48.7 million for this period. The Company proposed to offset a portion of these tax savings with cost of service increases and to refund the net savings to ratepayers through a bill credit within 120 days after an Order is issued in this case.[1]

The Columbia Group, Inc. was engaged by the State of Kansas, Citizens' Utility Ratepayer Board ("CURB") to review the Company's Application and to provide recommendations to the KCC regarding the Company's revenue requirement claims. CURB is also sponsoring the testimony of Stacey Harden on issues relating to the impact of the Non-Unanimous Settlement Agreement ("Merger Stipulation") in KCC Docket No. 18-

1 In KCC Docket No. 18-GIMX-248-GIV, utilities were required to defer tax savings beginning January 1, 2018, but the KCC stated that is would consider requests by utilities to demonstrate that these tax savings should be offset with any revenue deficiency during this period.

KCPE-095-MER ("18-095 Docket). In addition, Ms. Harden addresses several new rate classes proposed by Westar and she also provides some background on the Company's Western Plains Wind Farm. Brian Kalcic, of Excel Consulting, is also submitting testimony on behalf of CURB on rate design and cost allocation issues.

III. INTRODUCTION

Q. Since the filing of the Application, have there been major developments that impact the revenue increase being requested in this case?

A. Yes. On August 25, 2017, Westar and Kansas City Power and Light Company ("KCP&L") filed an Application for approval of a proposed merger in the 18-095 Docket. That Docket was being litigated when Westar filed its Application seeking a rate increase in this case. On March 7, 2018, a Merger Stipulation was executed by Westar, KCP&L, Staff, CURB, and several other parties. As discussed in the testimony of Ms. Harden, the Merger Stipulation resolved several issues that impact the revenue requirement being requested in this rate case. These include the cost of equity, capital structure, merger savings, and transition costs. In addition, the Merger Stipulation provided that the loss of the wholesale MKEC revenue, which the Company proposed to include in the Phase II rate increase, will instead be handled through the Retail Energy Cost Adjustment ("RECA"). While the signatories to the Merger Stipulation agreed to support a Phase II adjustment to address issues relating to the loss of the MKEC wholesale contract and the expiration of the PTCs, the magnitude of the Phase II adjustment on base rates will be much smaller than originally proposed, due to the fact that the largest component will now be addressed elsewhere. Finally, the Merger Stipulation provided that the full amount of the tax savings, from January 1, 2018 through the effective date of new rates, associated with the reduction in the corporate federal income tax rate would be refunded to customers.

Q. How did you approach your review of the Company's Application in this case?

A. Although the Company proposed a Phase I and Phase II increase, its Application did not explicitly separate the Phase I and Phase II adjustments. Therefore, the schedules that were filed with the Application generally reflected the full amount of the proposed net increase of $52.5 million, as shown on Schedule 3-A of the Application. Therefore, I used supporting workpapers provided by the Company in discovery in order to evaluate the Company's revenue requirement for the initial rate change. These workpapers were very similar to the schedules filed in the Application, except they did not reflect the loss of the MKEC wholesale revenues or the expiration of the PTCs associated with Central Plains and Flat Ridge 1 Wind Farms. The Phase II issues are addressed in a separate section of my testimony.

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues impacting Westar's rate increase request are: 1) the impact of the TCJA, which reduced corporate income taxes from 35% to 21% and which will result in excess deferred income taxes being refunded to Kansas customers, 2) the Company's request to include the Western Plains Wind Farm in rate base, 3) the Company's request for new depreciation rates, and 4) the agreement of the signatories in the 18-095 Docket to recommend a cost of equity of 9.3%.

IV. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending June 30, 2017, is an acceptable Test Year to use in this case to evaluate the reasonableness of the Company's claims.

2. The Company has a pro forma cost of equity of 9.30% and an overall cost of capital of 7.02%, as shown in Schedule ACC-2.

4. Westar has Test Year pro forma rate base of $5,369,538,469 as shown in Schedule ACC-3.

5. Westar has pro forma operating income at present rates of $466,856,664 as shown in Schedule ACC-9.

6. The Company has a Test Year, pro forma, revenue surplus of $122,739,935 as shown on Schedule ACC-1. This is in contrast to Westar's claimed deficiency of $14,128,421. When one takes into account the revenues in the Ad Valorem Property Tax Surcharge that are already being recovered from customers and which will be rolled into base rates, the Company has a net revenue surplus of $138,428,042.

7. The Commission should reject Westar's request to include the cost of the Western Plains Wind Farm in base rates. Instead, Kansas retail ratepayers should pay Westar for energy supplied by the Western Plains Wind Farm on a fixed cost, levelized basis, similar to the way that a Purchased Power Agreement ("PPA") is structured.

8. The Commission should deny Westar's request to increase its depreciation rates at this time.

9. The Commission should authorize a Phase II base rate reduction of $1,909,862 (see Schedule ACC-38). In addition, it should authorize Westar to recover the loss in wholesale revenue associated with the MKEC contract through the RECA.

10. The Commission should order Westar to refund to customers $50,027,522 (including interest) related to tax savings from January 1, 2017 through the effective date of new rates.

V. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company utilized the following capital structure and cost of capital in its filing:

	Percent	Cost	Weighted Cost
Common Equity	51.36%	9.85%	5.06%
Long Term Debt	48.20%	4.65%	2.24%
Post-1970 ITCs	0.44%	7.33%	0.04%
Total			7.33%

Q. Is CURB recommending any adjustments to this capital structure or cost of capital?

A. Yes, CURB is recommending adjustments to both the capital structure and to the return on equity. Both of CURB's adjustments result from the Merger Stipulation.

Q. Please explain CURB's recommended adjustment to Westar's proposed cost of equity.

A. In the Merger Stipulation, the signatories agreed to recommend that the KCC adopt a cost of equity of 9.3% in this rate case. Specifically, the Merger Stipulation provides that "Signatories agree to recommend a 9.3% return on equity ("ROE") to be utilized in the 2018 rate cases, and if including a range, testimony will not recommend greater than 20 basis points below or above the 9.3% recommended ROE." [2] In addition, the Merger Stipulation contains a five-year base rate case moratorium. During that time, the parties agreed to implement an Earnings Review and Sharing Plan "ERSP", which will also utilize a 9.3% ROE to determine each year whether Westar has earned in excess of its authorized return. Therefore, I have reduced the Company's cost of equity from the 9.85% reflected in the Application to 9.3%, consistent with the Merger Stipulation.

Q. Is the KCC bound to adopt a cost of equity of 9.3% in this case?

A. No, it is not. It is my understanding that the KCC is not bound to adopt a cost of equity of 9.3% - the Merger Stipulation only binds the signatories to make such a recommendation. However, if the KCC authorizes an ROE that is less than 9.3%, then the Merger Stipulation provides that the five-year base rate case moratorium period will be reduced to three years.

Q. Please explain your recommended adjustment to the Company's capital structure.

A. The Merger Stipulation provides that the ERSP will utilize the actual capital structure for Westar, excluding short-term debt and debt due within one year, subject to a cap of 51% common equity in the 2019 reporting year. The equity cap declines to 50.5% in the 2020 reporting year and further declines to 50.0% in 2021 and 2022 reporting years. Therefore, consistent with the Merger Stipulation, I recommend that the Company's rates in this case be based on a capital structure consisting of 51% common equity and 49% long-term debt. Since the Company has also included post-1970 Investment Tax Credits ("ITCs") as a small part of its capital structure, I have scaled back the common equity and long-term debt ratios of 51% / 49% to reflect the 0.44% of the capital structure that consists of post-1970 ITCs. This results in a capital structure consisting of 50.78% common equity, 48.78% long-term debt, and 0.44% post-1970 ITCs.

2 Merger Stipulation, page 15.

Q. What is the overall cost of capital that CURB is recommending for Westar?

A. As shown on Schedule ACC-2, CURB is recommending an overall cost of capital for Westar of 7.02%, based on the following capital structure and cost rates:

	Percentage	Cost	Weighted Cost
Common Equity	50.78%	9.30%	4.72%
Long Term Debt	48.78%	4.65%	2.27%
Post 1970 ITCs	0.44%	7.02%	0.03%
Total			7.02%

VI. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. What Test Year did the Company utilize to develop its rate base claim in this proceeding?

A. The Company selected the Test Year ending June 30, 2017.

Q. How did the Company develop its plant-in-service claim in this case?

A. Westar generally included in rate base its actual plant balances as of June 30, 2017, including non-revenue producing construction work in progress ("CWIP"). Consistent with prior cases, the Company excluded certain plant associated with refurbishing executive office space at the Company's headquarters from its rate base claim.

Q. Are you recommending any adjustment to the Company's utility plant-in-service claim?

A. Yes, I am recommending two adjustments, relating to the Western Plains Wind Farm and to CWIP.

1. Western Plains Wind Farm

Q. Please describe the Company's wind generating resources.

A. As shown on page 5 of Mr. Bridson's testimony, Westar has 1,758 MW of wind generation. The majority of the wind generation is procured through nine PPAs, reflecting generation that was added to the Company's portfolio from December 20, 2009 through December 19, 2016. In addition, Westar owns the 99 MW Central Plains Wind Farm and the 50 MW Flat Ridge 1 Wind Farm, both of which were added to the supply portfolio in 2009. Finally, in this case, Westar is proposing to include in rate base costs associated with a new Western Plains Wind Farm that went into service in February 2017. Western Plains is a 281 MW generating facility.

Q. Did the Company need this additional wind generation in order to meet its service commitments to Kansas ratepayers?

A. No, the Company acknowledges that it did not need additional generation in order to meet its service commitments. Instead, Westar claims that the Western Plains Wind Farm was driven by economic considerations. The Company claims that the addition of new wind generation to the supply portfolio will result in net ratepayer savings by generating fuel savings when the energy from these wind facilities replaces energy from more expensive fossil facilities. In addition, the economic benefit of the new wind generation is impacted by the availability of PTCs for the first ten years of the project, which tends to reduce the overall cost of the project. Accordingly, the Western Plains Wind Farm was undertaken as a purely financial opportunity. On page 13 of his testimony, Mr. Bridson references anticipated savings of $76 million over a twenty-year period relating to the addition of the new wind facilities.

Q. Please describe the impact that the Western Plain Wind Farm has on Westar's utility investment.

A. The Western Plains Wind Farm was constructed at a cost of $417 million[3]. Over the life of the wind farm, the Company is seeking to include these costs in rate base and to earn a return on its investment at its overall weighted cost of capital. Therefore, shareholders can expect significant additional earnings if the Western Plains Wind Farm is included in rate base. These are benefits that shareholders do not get through a PPA. Therefore, utilities have an incentive to own generation facilities instead of procuring generation through PPAs or other market arrangements.

3 Per the testimony of Mr. Bridson at page 8.

Q. Does the Company currently bear any risk associated with increasing fuel prices that would prompt it to invest in wind generation in order to protect its shareholders?

A. No, Westar bears no risk because it recovers its fuel costs dollar-for-dollar from ratepayers through the RECA mechanism. Therefore, if the price of coal, natural gas or other fuels increases, then ratepayers are charged higher costs through the RECA mechanism and the Company is made whole for the higher cost of fuel. While utilities have the responsibility to continually seek to implement the lowest cost options for ratepayers, the addition of the Western Plains Wind Farm is unusual in that the Company does not need this additional generation in order to serve its Kansas customers. Instead, it is proposing to include over $400 million of additional investment in rate base solely on the basis that this investment is expected to result in lower overall costs to ratepayers over the next twenty years.

Q. Given that the Company is not at risk for higher fuel costs and does not need additional generation, do you believe that the Company's desire to bring lower costs to ratepayers is the primary factor driving its proposal for this new investment in wind energy?

A. No, I do not. Given that the Company is not at risk should fuel costs rise, I believe that this transaction is being driven primarily by the desire for higher profits for shareholders. By owning these new facilities, and therefore increasing its rate base, Westar will earn a return on these facilities for many years into the future.

Q. As currently structured, what risks do ratepayers bear under the Company's proposal?

A. Ratepayers bear essentially all of the risk under the Company's proposal. The Company's models are highly sensitive to fuel prices, capacity factors, market prices, and other factors. Ratepayers bear the risk of changes in fuel costs and other assumptions used in the Company's analysis. To the extent that actual results differ from the assumptions used in the Company's modeling, then the actual savings to ratepayers could be less than those estimated in the filing. The Western Plains Wind Farm is being depreciated over 20 years, and no one can predict what may happen over this period with regard to fuel prices, technological innovations, or other factors that could impact the savings projected by Westar.

Ratepayers also bear the risk that the Western Plains Wind Farm will not run at the capacity factors projected by the Company. There are many reasons why capacity factors could be less than projected. These include a lower than projected availability due to maintenance issues or other problems, variations in the weather that result in lower capacity factors, and curtailment by the Southwest Power Pool ("SPP"). Under the Company's proposal, ratepayers will be paying the capital costs associated with these generating facilities regardless of whether they are actually running and producing energy, so any reduction in the amount of energy produced will reduce (or potentially eliminate) the net savings to ratepayers.

Finally, the Company's proposal results in intergenerational inequity, given significant variation in the revenue requirement and projected savings associated with the Western Plains Wind Farm from year to year.

Because the proposal before us does not concern utility assets that are needed to provide service to Kansas customers, and is instead simply an economic opportunity that will provide significant benefits to shareholders, the allocation of risk between shareholders and ratepayers is of paramount importance when addressing many of the concerns I have listed above.

Q. Did Westar discuss its proposal to construct the Western Plains Wind Farm with Staff and CURB prior to proceeding with the project?

A. Yes, it did. While I was not a party to the discussions, I understand that Westar did discuss the possibility of acquiring additional wind generation through an ownership structure in 2015 with both Staff and CURB, as discussed in Ms. Harden's testimony. In addition, I understand that Ms. Harden participated in these discussions on behalf of CURB. Pursuant to a letter dated December 10, 2015 to Jeff Martin of Westar from Jeff McClanahan of Staff, it was Staff's conclusion that "an ownership option places too much risk on ratepayers." Staff indicated that it had several concerns: (1) the displacement of existing fossil fuel units, (2) the high capacity factors reflected in the Company's analysis, (3) the impact of relatively small changes in the assumptions reflected in Westar's modeling, (4) Westar's assumptions regarding the life of the facilities, (5) Westar's failure to include additional capital costs that may be required after the initial twenty-year period, (6) assumptions regarding operating costs and escalation factors, and (7) intergenerational inequities. The letter concluded that "…Staff cannot currently support an ownership option." I understand that CURB had similar concerns and reached a similar conclusion regarding ownership of additional wind facilities.

Q. How did the Company address the issue of intergenerational inequities in its testimony?

A. Recognizing the intergenerational inequities inherent in ownership of the Western Plains Wind Farm, Westar presented an alternative ratemaking approach whereby the revenue requirement associated with the Western Plains Wind Farm could be levelized over the expected life of the plant. Using a levelized approach, Westar would record either a regulatory asset or liability to record the annual difference between the cost of the Western Plains Wind Farm using a traditional revenue requirement calculation and the levelized annual cost.

Q. What is the Company's rationale for acquiring this wind generation through an ownership structure instead of through a PPA?

A. Westar's economic analysis concluded that the ownership structure was approximately $34 million less expensive than a PPA over the first 20 years of the project. Westar also states that the ownership structure will allow utility customers to benefit from the wind projects over the entire service life of the facilities, which it estimates is ten years longer than the traditional twenty-year PPA. Westar also argues that under the PPA structure, the Company would need to replace the energy generated from the facilities after 20 years, at a considerably higher cost.

Q. Is there any guarantee that ratepayers will benefit at all from Westar's ownership of the Western Plains Wind Farm?

A. No, there is no guarantee that the Western Plains Wind Farm will actually result in cost savings for Kansas ratepayers, either relative to existing generation or relative to a PPA. The Company's analysis was based on assumptions regarding fuel prices, market prices, capacity factors, and other considerations over a period of 20 years. To the extent that actual results differ from projections, then Kansas ratepayers could be in the position of paying for over $400 million of wind generation which is not needed and which does not prove to be the most cost-effective option in the long-run. While it is true that ratepayers have the potential to benefit over a longer period through the ownership structure, it is also true that they are exposed to greater risks over this period as well.

Q. But don't ratepayers always bear the burden of paying a return of, and a return on, additions to rate base?

A. It is true that ratepayers provide a return on, and of, capital invested in utility assets. While that traditional risk sharing mechanism is suitable in traditional circumstances, one in which a utility is required to make an investment on behalf of ratepayers in order to provide safe and adequate utility service, it is not suitable when the Company has brought forth a proposal for a purely optional investment opportunity that it hopes will provide economic advantages to both parties. Given the benefits of the Wind Projects to utility shareholders, I believe it is reasonable to require that the Company guarantee that ratepayers will in fact benefit from the wind projects.

Q. In addition to the risk that forecasted savings will not be achieved, does the Company's acquisition of additional wind generation pose other risks for ratepayers?

A. Yes, it does. The discretionary investment in wind energy will likely diminish Westar's ability to take advantage of emerging energy technology, including improvements in wind technology, in the next few years that might otherwise have proven to be even more attractive. It would seem that in such a rapidly changing industry, it makes little sense to bet on current technology, rather than pursue a strategy of judicious and ongoing project analysis and investment that smooths the plant investments into rate base over time, while allowing for an orderly review process.

In addition, it is relatively difficult to determine, even after the fact, if ratepayers actually benefited from the additional wind generation. Given that the Company is a member of the SPP, and bids all generation into that market, it is difficult to isolate the impact of any one particular facility on the ultimate cost of energy in the retail marketplace. In addition, wind generation in the SPP marketplace has and will continue to increase, as new projects are added over the next few years in order to take full advantage of PTCs. In fact, in some cases, the proliferation of these energy resources has resulted in negative prices for wind energy, meaning that a utility must actually pay SPP in order to deliver wind energy to the pool.

Q. Given these risks to ratepayers, what do you recommend?

A. I recommend that the KCC deny the Company's request to include the costs of the Western Plains Wind Farm in rate base. Instead, I recommend that the KCC treat the acquisition of energy from the Western Plains Wind Farm similar to a PPA. In that case, ratepayers would only pay for energy that is actually produced by the generating facilities. My recommendation applies to all energy generated during the 20-year period over which the facilities are being depreciated. If the life of the wind farm is extended past 20 years, then the KCC should address at that time what ratemaking treatment, if any, would be appropriate after the initial 20-year term.

Q. What rate do you recommend the KCC authorize for energy generated by the Western Plains Wind Farm?

A. In response to KIC-16 (Revised), the Company calculated a levelized cost of energy over the 20-year depreciable life of the wind farm, based on the assumptions regarding investment, capacity factors, and operating costs. Based on the cost of capital and capital structure being claimed in this case, Westar estimated a leveled cost of $21.91 per MWh. I recommend that this estimate be updated with the cost of capital authorized by the KCC in this case.

Q. Please describe the specific utility plant-in-service adjustment to the Company's rate base that is necessary in order to reflect your recommendation.

A. If my recommendation to treat the Western Plains Wind Farm similar to a PPA is adopted, then the KCC should eliminate the revenue requirement associated with the Western Plains Wind Farm from the Company's revenue requirement in this case, and require Westar to recover the levelized cost per MWh of the wind energy produced by the wind farm through the RECA. In that case, the Company's utility plant-in-service claim should be reduced by $411,846,055, which is the plant-in-service associated with the wind farm included by Westar in its rate base claim, per the response to KCC-259 (Revised). My adjustment to eliminate this utility plant-in-service is reflected in Schedule ACC-4. In Schedule ACC-4, I have also reflected the associated reduction to accumulated depreciation.

Q. Did you also make an adjustment to the accumulated deferred income tax reserve to reflect the impact of removing the utility plant-in-service associated with the Western Plains Wind Farm from the Company's rate base claim?

A. No. In response to KCC-309, the Company indicated that additions to the deferred tax reserve were offset by additions to the net operating loss ("NOL") deferred tax asset, resulting in no net impact on rate base. Therefore, I don't believe it was necessary to adjust the accumulated deferred income tax reserve.

Q. Are you recommending additional adjustments relating to the Western Plains Wind Farm?

A. Yes, in addition to the rate base adjustments discussed above, it is also necessary to make several operating income adjustments to the Company's claim. I discuss these operating income adjustments later in my testimony.

2. Construction Work in Progress

Q. Please describe your adjustment to the Company's CWIP claim.

A. CWIP is plant that is under construction but not yet been completed and placed into service. Once the plant is completed and serving customers, then the plant is booked to utility plant-in-service and the utility begins to take depreciation expense on the plant. The Company's rate base claim includes all CWIP at June 30, 2017, except for certain categories such as transmission-related CWIP and revenue-producing CWIP.

Q. Do you believe that CWIP is an appropriate rate base element?

A. No, I do not believe that CWIP is an appropriate rate base element. CWIP does not represent facilities that are used or useful in the provision of utility service. In addition, including this plant in rate base violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that is not providing them with utility service and which may never provide current ratepayers with utility service. However, I understand that the inclusion of CWIP in rate base is governed by statute in Kansas.[4]

K.S.A. 66-128 provides for the KCC to determine the value of the property included in rate base. The statute generally requires that "property of any public utility which has not

[4] I am not an attorney and my discussion of the CWIP statute is not intended as a legal interpretation of that statute, but rather provides my understanding of the statute from a ratemaking perspective.

been completed and dedicated to commercial service shall not be deemed to be used and required to be used in the public utility's service to the public."

However, the statute also provides that certain property "shall be deemed to be completed and dedicated to commercial service" under certain circumstances. Specifically, K.S.A. 66-128(b)(2) provides:

> Any public utility property described in subsection (b)(1) shall be deemed to be completed and dedicated to commercial service if: (A) construction of the property will be commenced and completed in one year or less; (B) the property is an electric generation facility that converts wind, solar, biomass, landfill gas or any other renewable source of energy: (C) the property is an electric generation facility or addition to an electric generation facility; or (D) the property is an electric transmission line, including all towers, poles and other necessary appurtenances to such lines, which will be connected to an electric generation facility.

Q. Did Westar demonstrate that the CWIP included in its rate base claim meets the criteria outlined in the statute?

A. No, it did not. Westar did not attempt to justify its CWIP claim based on the statute referenced above. The Company has included significant amounts of distribution plant, general plant, and intangible plant in its CWIP claim. It is unclear from the Company's filing whether these projects meet the requirements of the statute that public utility property "will be deemed to be completed and dedicated to commercial service" if certain conditions are met, one of which is that "construction of the property will be commenced and completed in one year or less." According to the Company's response to CURB-48, at least some of these projects will not be completed within one year.

Q. Did the Company provide any information in its filing explaining why it believes that it should be permitted to include all CWIP in rate base?

A. No. While Mr. Kongs references the statute on pages 5-6 of his testimony, he fails to justify the inclusion of each CWIP project in rate base. While much of the Company's CWIP claim relates to generation projects and would most likely qualify for inclusion in rate base under the statute, there are other CWIP projects included in the Company's rate base claim for which no justification was provided.

Q. Did you ask the Company to identify the CWIP included in its Application that is not yet completed and placed into service?

A. Yes, I did. In response to CURB-48, the Company updated its CWIP workpaper and identified those projects that it does not expect to be completed by June 30, 2018, which is twelve months past the end of the Test Year in this case. In addition, it identified the actual CWIP that has now gone into service. It also identified several projects that have gone into service but which were not included in CWIP at June 30, 2017, the end of the Test Year.

Q. What do you recommend?

A. I recommend that the Commission exclude from rate base the distribution, general, and intangible plant projects that were CWIP at June 30, 2017 but which have not yet been completed and gone into service. To quantify my adjustment, I have deleted all distribution, general, and intangible CWIP that was not yet in-service when the response to CURB-48 was prepared. If the Company provides an update in its rebuttal testimony, then additional projects that were CWIP at June 30, 2017 and which are completed by June 30, 2018 would also be included in my rate base recommendation.

In addition, I recommend that projects that have been completed, but which were not included in CWIP at the end of the Test Year, be disallowed. The statute referenced above is limited to CWIP at the end of a test year, it does not provide for post-test year adjustments to include projects that were not CWIP at the end of a test year. Allowing these additional projects in rate base would expand the test year concept to include projects that were initiated after the end of a test year. My adjustments are shown in Schedule ACC-5.

B. <u>Fossil Fuel Inventory</u>

Q. How did the Company determine its claim for fossil fuel inventory?

A. The Company utilized a 13-month average Test Year balance for its fossil fuel inventory.

Q. Does the Test Year level of inventory represent a period of normal operating conditions?

A. It does not appear so. A review of the historic inventory levels provided in response to KCC-162 indicate that fossil fuel inventory increased significantly in November 2015 and remained relatively high until June 2017. Since the end of the Test Year, inventory levels have declined, generally to the levels experienced prior to November 2015. In response to

CURB-49, the Company stated that "[m]atching coal deliveries to coal burns while participating in the SPP marketplace is challenging." The Company went on to discuss the correlation between coal inventory levels and locational marginal prices ("LMPs"), citing low natural gas prices and increased wind production as drivers that resulted in LMPs dropping below the production cost of the coal plants, thereby increasing inventory levels. Westar subsequently adjusted its market price "more in line with actual LMP pricing", which apparently has allowed the Company to reduce its inventory levels.

Q. What level of inventory do you recommend be reflected in the Company's claim?

A. I am recommending that the most recent 36-month average be used to determine Westar's coal inventory claim. The use of 36-month average will still reflect certain periods of high inventory levels but will also reflect the fact that these levels have dropped since the end of the Test Year. Therefore, I believe that a 36-month average will be more representative of prospective operations than the use of the 13-month inflated Test Year balance. My adjustment is shown in Schedule ACC-6.

C. <u>Regulatory Asset / Liability – Deferred Pension Expense</u>

Q. Please explain the Company's rate base adjustment relating to deferred pension expense.

A. Pursuant to the KCC's Order in Docket No. 10-WSEE-135-ACT, the Company was permitted to defer the difference between its annual pension expense pursuant to Generally

Accepted Accounting Principles ("GAAP") and the amount recovered in rates. In this case, the Company has claimed a deferred liability of $24,177,813, which it is proposing to amortize over five years. In addition, Westar has included a regulatory liability associated with deferred pension costs in rate base.

I am recommending an adjustment to remove the regulatory liability from rate base. The Order in 10-WSEE-135-ACT did not include carrying charges on the deferral. Thus, the Company does not earn carrying charges on deferred assets and ratepayers should not earn carrying charges on deferred liabilities. Therefore, at Schedule ACC-7, I have removed the Company's regulatory liability relating to deferred pension costs from rate base.

D. <u>Accumulated Deferred Income Tax Reserve</u>

Q. Please describe your recommended adjustment to the Company's claim for cost-free capital associated with accumulated deferred income taxes.

A. In Adjustment IS-52/RB-12, the Company included an adjustment to reflect the impact of the new tax rate on its income tax expense, amortization of deferred taxes, and deferred tax balances. As shown in this adjustment, Westar reflected a reduction to accumulated deferred income taxes of $4,189,746. However, the workpapers supporting this adjustment indicate that the actual reduction to accumulated deferred income taxes should have been $5,496,758. In response to KCC-303, the Company confirmed that its filing contained incorrect amounts and indicated that the calculations contained in the workpaper were correct. Therefore, at

Schedule ACC-8, I have made an adjustment to reflect the revised reduction to the accumulated deferred income tax reserve.

E. Summary of Rate Base Adjustments

Q What is the net impact of the rate base adjustments recommended by CURB?

A. My rate base adjustments will result in a pro forma rate base of $5,369,538,469, as summarized on Schedule ACC-3. This pro forma rate base amount includes adjustments of $393,237,602 to the rate base proposed by Westar.

VII. OPERATING INCOME ISSUES

A. Customer Annualization Revenue

Q. Did the Company include a customer annualization adjustment in its Application?

A. Yes, it did. Westar included a customer annualization adjustment to reduce pro forma revenue by $2,667,252. According to the Company, this adjustment is being driven primarily by reductions in sales to residential customers. In fact, Westar's adjustment assumes a net revenue reduction of $3,551,193 in residential sales, which the Company claims is partially offset by increases in commercial rate revenue. Westar also included a small reduction to industrial sales revenue in its customer annualization adjustment.

Q. How did the Company calculate its customer annualization adjustment?

A. Mr. Wilkus states that Westar based its adjustment on the change in customers from June

2016 to June 2017. The Company then assumed that the net change in customers over this period occurred on a proportional basis throughout the year.

Q. Do you believe that the Company's adjustment is reasonable?

A. No, I do not. A review of the underlying month-to-month data shows that Westar's residential RS-R customers increased, not decreased, during the Test Year. Moreover, Schedule 8-F indicates that total residential customers have increased consistently over the past several years, as shown below:

December 2014	606,863
December 2015	609,715
December 2016	613,239

In addition, it is important to note that the Company's customer annualization adjustment is only based on customer counts – it is not intended to account for variations in usage from the Test Year actual sales. Variations in usage are accounted for in the Company's weather normalization adjustment.

Q. What do you recommend?

A. I recommend that the Company's customer annualization adjustment be rejected. At Schedule ACC-10, I have made an adjustment to add back the reduction in revenue proposed by Westar. I am not making any recommendation with regard to the Company's weather normalization adjustment, except to point out that I agree with the use of a thirty-year period to determine "normal" weather. I will defer to Staff's recommendation with regard to the specific mechanics of the weather normalization adjustment.

B. Occidental Contract Revenue

Q. Are you recommending any adjustment to the Company's claim for deferred revenues relating to the Occidental contract?

A. Yes. As discussed in the testimony of Mr. Rinehart on page 6, in KCC Docket No. 17-KG&E-352-CON Westar received approval from the KCC to revise the rates that it charges to Occidental Chemical Corporation ("Oxy") pursuant to an Energy Supply Agreement ("ESA"). The Company also received authorization to defer the amount of revenues lost as result of the reduction in the Oxy rate and to seek recovery of these amounts in a future case. In this case, Oxy has estimated revenue losses associated with the Oxy ESA from July 2017 through September 2018 of $1,399,982. It is proposing to amortize these losses over a three-year period, resulting in an annual amortization expense of $466,660.

I understand that issues relating to the Oxy ESA are being addressed by the KCC in Docket No. 18-KG&E-303-CON, including the issue of whether Westar should recover deferred revenues related to the contract. I also understand that CURB is opposed to such recovery. Therefore, I have eliminated the Company's adjustment relating to the Oxy revenue loss in Schedule ACC-11.

Q. If the KCC authorizes Westar to recover these deferred revenues in KCC Docket No. 18-KG&E-303-CON, over what period of time should the revenues be amortized?

A. If the KCC authorizes Westar to recover revenue losses associated with the Oxy ESA, then these revenue losses should be amortized over a period of five years, instead of over the three-year period included by Westar in its Application. This is consistent with the base rate case moratorium agreed upon by the signatory parties in the Merger Stipulation.

C. <u>Short-Term Incentive Compensation Expense</u>

Q. Please describe the Company's incentive compensation programs.

A. The Company has several incentive compensation plans for its non-bargaining employees. Most non-bargaining employees are covered under the Short-Term Incentive Plan ("STIP"). The plan provides for the establishment of incentive pools for each major business unit. Each employee has a target incentive payment, which is based on a percentage of the employee's base pay. The percentage of incentive compensation relative to base salary varies depending on the pay grade. In the 2017 STIP, there were three areas of performance measurement: financial, operational, and customer satisfaction.

Q. How much is included in the Company's pro forma expense claim relating to short-term incentive compensation plans?

A. As shown in the Company's workpapers to its Payroll Adjustment (IS-9), Westar has included $10,637,004 in its Test Year claim associated with short-term incentives. This claim was based on a five-year average of actual short-term incentive compensation costs.

Q. Do financial results have a significant impact on the short-term incentives paid by Westar?

A. Yes, they do. The STIP includes a financial component of 50%. The financial component is measured by comparing Westar's Total Shareholder Return ("TSR") to the TSR of other electric utilities in a peer group of companies. Thus, not only does Westar's financial performance have a direct impact on the short-term incentives paid to employees, but the financial performance of other utilities has a direct impact as well. In addition, each of the three criteria (financial, operational, and customer satisfaction) also has a maximum payout percentage. For two of the three criteria, the maximum payout percentage is 150% of the target award. However, for the financial criteria, the maximum payout percentage is 200%. Thus, the financial benchmark has a disproportionately larger impact on the overall incentive payments than do the other two benchmarks.

Q. Is it appropriate to have ratepayers fund 100% of these types of incentive programs?

A. No, it is not. Providing employees with a direct financial interest in the profitability of the Company is an objective that is intended to benefit shareholders, but it does not benefit ratepayers. Incentive compensation awards that are based on earnings criteria may violate the principle that a utility should provide safe and reliable utility service at the lowest possible cost. This is because these plans require ratepayers to pay higher compensation costs as a consequence of higher corporate earnings, generating an upward spiral in rates that does not directly benefit ratepayers, but does directly benefit shareholders, as well as management personnel responsible for establishing such programs.

Incentive compensation plans tied to corporate performance result in greater enrichment of company personnel as a company's earnings reach or exceed targets that are predetermined by management. It should be noted that it is the job of regulators, not the shareholders or company management, to determine what constitutes a just and reasonable rate of return award to shareholders in a regulated environment. Regulators make such a determination by establishing a reasonable rate of return award on rate base in a base rate case proceeding.

Allowing a utility to charge customers for additional return that is then distributed to employees as part of a plan devised to divide extraordinary profits violates all sense of fairness to the ratepayers of the regulated entity. It is certain to result in burdensome and unwarranted rates for its ratepayers, and also violates the principles of sound utility regulation, particularly with regard to the requirement of "just and reasonable" utility rates.

Q. Are Westar employees well-compensated, separate and apart from these employee incentive plans?

A. Yes, they are. Both the Company's bargaining and non-bargaining employees regularly receive annual salary and wage increases. According to the response to KCC-205, non-bargaining employees received increases of 3.19%, 3.40%, 3.31%, and 3.40% over the last four years, while bargaining employees received increases of 3.0%. Moreover, Westar's payroll levels do not appear low relative to other companies. As derived from the response to KCC-199, the average annual salary for non-bargaining employees is approximately $94,500.

Q. Given your concerns, are you recommending any adjustment to the Company's claim for its short-term incentive compensation plan costs?

A. Yes, since the STIP is based on financial performance triggers tied to the financial performance of Westar and other companies, I recommend that the KCC limit recovery in rates to 50% of the cost of this incentive compensation award program, which reflects a 50%/50% sharing between ratepayers and shareholders. My recommendation is based on the fact that 50% of the incentive award is directly tied to financial parameters. This recommendation will require the Board of Directors to establish incentive compensation plans that shareholders are willing to finance, at least in part. It is unreasonable to require ratepayers to pay 100% of the costs of these incentive plans especially because the managers of the Company and its stockholders are the primary beneficiaries of such plans, and they have no incentive to control these costs when ratepayers are footing the entire bill. Therefore, I recommend that the KCC adjust the Company's claim for the STIP incentive compensation costs to eliminate recovery of 50% of these costs. My adjustment is shown in Schedule ACC-12.

Q. Did you also make a corresponding adjustment relating to payroll taxes?

A. Yes, in Schedule ACC-13, I have made an adjustment to eliminate the payroll taxes associated with my recommendation to disallow of 50% of short-term incentive costs. To quantify my adjustment, I utilized the statutory payroll tax rate of 7.65%, which is also the rate reflected by Westar in its Application.

D. Restricted Share Units ("RSU") Expense

Q. What incentive plan is provided to officers and other top executives?

A. Officers and other executives participate in a Restricted Share Unit ("RSU") program. The RSU program provides for the issuance of common stock grants. 50% of the RSU grants made under the program vest over a three-year period based on Westar's performance, while the remaining 50% vest at the end of three years regardless of performance.

Q. What are the criteria for awarding the RSUs?

A. The performance awards are based solely on financial criteria. Payouts are dependent upon Westar's TSR relative to the benchmark peer group. TSR is defined as the change in the company's stock price, plus any dividends paid during the year, divided by the beginning stock price. According to plan documents, 100% of the target award will be made if Westar is at or above the 50^{th} percentile of the peer group. There doesn't appear to be specific criteria for the time-based awards. Rather, these awards appear to be made at the discretion of management and the Board of Directors.

Q. Do you have concerns about the methodology used to award RSUs?

A. Yes, I do. The performance-based awards are based exclusively on financial criteria tied to shareholder value. In addition, similar to my concerns expressed above with regard to the short-term incentive compensation plan, the award criteria are based not only on the Company's individual financial performance but rather on how Westar's return to shareholders compares with the returns generated by a peer group of other utilities. Thus, ratepayers pay higher incentive compensation costs as shareholder benefit increases. Higher common equity market prices and dividend increases provide substantial benefits to shareholders, but virtually no benefit to ratepayers, and it is inappropriate to tie utility rates to these benchmarks.

Q. What do you recommend?

A. Given the use of a purely financial benchmark for the performance-based RSU and the absence of any defined benchmark for the time-based awards, as well as my concerns regarding the inappropriate use of a peer group to evaluate Westar's award performance, I am recommending that the KCC eliminate 100% of RSU costs from the Company's regulated cost of service. My adjustment is shown in Schedule ACC-14.

E. Medical and Dental Benefits Expense

Q. How did the Company develop its claim for medical and dental benefits expense?

A. As shown in the workpapers to the Company's Employee Benefits adjustment (IS-8), Westar has included 2018 projected benefit costs in its revenue requirement in this case. This includes projected costs for medical and dental benefits, vision, life insurance, accidental death and dismemberment ("ADD") insurance, long-term disability, and 401K contributions. While the Company's claims for life and ADD insurance, long-term disability, and 401K contributions were adjusted based on the percentage of these benefit costs to payroll, the Company did not provide much detail on how the 2018 medical, dental, and vision benefit costs were determined.

Q. What are the increases proposed by Westar for medical, dental and vision costs?

A. Westar is proposing cost increases totaling $2,397,283. The majority of the increase relates to medical costs, which the Company estimates will increase by $2,238,426 or 9.6% over the Test Year costs. The Company also included increases of 12.4% for dental benefits and of 2.2% for vision benefits.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am. Medical and dental benefit costs can be difficult to estimate because the Company is largely self-insured for these costs. Therefore, actual costs will depend upon many variables. A review of the actual medical and dental expenses over the past few years demonstrates the variability in these costs from year to year, as shown below[5]:

Year	Medical and Dental Expenses
2012	$25,505,049
2013	$24,632,411
2014	$22,075,049
2015	$20,898,202
2016	$27,021,029
2017	$23,435,703

Given the variability of these costs and the lack of documentation supporting the Company's claim, I recommended that the actual medical and dental Test Year costs be reflected in the Company's revenue requirement. My adjustment is shown in Schedule ACC-15. Since the vision plan is a fully insured plan, and since the Company's adjustment to its Test Year vision plan costs is so small, I have not made any adjustment to the Company's claim for the vision plan.

F. <u>Merger Expense Savings</u>

Q. Did the Company include any merger-related savings in its Application?

A. Yes, the Company indicated that the base rate case Application incorporated merger savings of $11.1 million. As described by Mr. Kongs on page 13 of his testimony, the Company calculated merger savings by comparing the payroll costs from the Test Year in its last general base rate case (October 1, 2013 – September 30, 2014), adjusted annually by a 3% merit increase, with the annualized and adjusted payroll costs being claimed in this case.

5 Response to KCC-60.

Based on this methodology, Westar concluded that $11.1 million of merger savings was reflected in the current rate request.

Q. How were merger savings addressed in the Merger Stipulation?

A. In the Merger Stipulation, the signatories agreed that merger savings of at least $22.5 million would be reflected in this base rate case. Specifically, the settlement provides that "[i]f Merger-related savings achieved at the update date for the 2018 rate case shows there is a shortfall from the amounts below [$22.5 million], then an additional adjustment will be made at the update to impute into retail rates the shortfall…"[6] The Company has not updated its filing to reflect any savings in excess of the $11.1 million reflected in its Application. Therefore, at Schedule ACC-16, I have made an adjustment to increase merger savings to a total of $22.5 million, consistent with the Merger Stipulation.

G. <u>Merger Transition Expense</u>

Q. Did the Company include any transition costs related to the merger in its Application?

A. Yes, in Adjustment IS-16, the Company made an adjustment to reflect actual and estimated transition costs through March 2018 of $35.67 million. Westar proposed to amortize these costs over a five-year period, resulting in an annual amortization expense of $7,133,590. The Company did not propose to include recovery of transaction costs, since Westar and KCP&L had proposed to recover transaction costs associated with the merger from

6 Settlement Agreement, page 16.

shareholders.

Q. Did the Merger Stipulation address the issue of transition costs?

A. Yes, it did. The Merger Stipulation limited Westar's recovery of transition costs to $23,183,133. The Merger Stipulation also required a ten-year amortization of transition costs, without carrying costs. Therefore, in Schedule ACC-17, I have made an adjustment to reduce the Company's claim for transition costs to reflect the maximum costs agreed upon in the Merger Stipulation. I have also reflected a ten-year amortization of these costs.

H. <u>Western Plains Wind Farm Expense</u>

Q. Please explain the operating expense adjustments that are required in order to eliminate the operating costs and tax impacts of the Western Plains Wind Farm from the Company's revenue requirement.

A. As discussed in the Rate Base section of my testimony, I am recommending that the Western Plains Wind Farm be treated as a PPA for ratemaking purposes. Therefore, it is necessary to eliminate the impacts of the Western Plains Wind Farm from the Company's base rate revenue requirement. In addition to the rate base adjustments discussed earlier, there are also three operating income adjustments that are necessary in order to eliminate the impact of the wind farm from base rates.

First, I have eliminated the operating and maintenance expenses associated with the Western Plains Wind Farm from the Company's revenue requirement. This adjustment is shown in Schedule ACC-18. Operating and maintenance costs associated with the Western Plains Wind Farm will be recovered through the levelized rate that I recommend be adopted by the KCC and flowed through the RECA.

Second, I have eliminated the depreciation expense associated with the Western Plains Wind Farm. The Company reflected a 20-year depreciable life for the wind farm in its revenue requirement in this case. At Schedule ACC-19, I have made an adjustment to eliminate depreciation expense, which will also be recovered through the levelized rate.

Third, I have eliminated the PTCs associated with the Western Plains Wind Farm. The Company included PTCs of $27,512,364. The loss of these PTCs will increase the Company's pro forma income tax expense by this amount. In addition, the loss of the PTCs will have an even bigger impact on the Company's revenue deficiency/surplus, since the PTCs must be grossed up by the revenue multiplier in order to determine the impact on the Company's proposed rate increase. My adjustment to eliminate the PTCs is shown in Schedule ACC-20.

Q. What is the combined revenue requirement impact of the three operating expense adjustments relating to the Western Plains Wind Farm?

A. These three adjustments will increase the Company's revenue requirement by approximately $12.7 million, because of the loss of the PTCs. However, when combined with the rate base adjustments discussed earlier, eliminating the Western Plains Wind Farm from the Company's base rates will result in a decrease of approximately $26.34 million from the revenue requirement included in Westar's Application. While these costs will no longer be recovered in base rates if the KCC approves my recommendation, Westar will still recover the associated costs for each MWh of energy generated by the wind farms through a levelized rate that is recovered through the RECA.

I. <u>Wolf Creek Outage Expense</u>

Q. Please explain the Wolf Creek Outage adjustment included by Westar in its Application.

A. In its Application, Westar included costs associated with a 2018 spring outage at Wolf Creek Nuclear Generating Station, of which Westar is a partial owner. The Company estimated total outage costs of $19,947,912, which it proposed to amortize over 18 months. Westar utilized an 18-month amortization period because that is the typical period of time between Wolf Creek outages. Therefore, Westar included an annual amortization expense of $13,298,608 associated with the Wolf Creek outage.[7] Westar anticipated that the Wolf Creek outage would be completed in April 2018.

Q. Did Westar subsequently update its outage costs?

A. Yes, in response to KCC-208, the Company provided updated costs through April 30, 2018. In addition, it stated that the Wolf Creek outage would not be completed in April, and instead it projected a completion date of mid-May, 2018. Actual costs through April 27, 2018 and

7 ($19,947,912 / 18 X 12)

projections through April 30, 2018 totaled $15,461,775. Based on an 18-month amortization period, the Company's update reflected an annual amortization expense of $10,307,838.

Q. What do you recommend?

A. I have included the Company's updated annual amortization expense of $10,307,838 in my revenue requirement. My adjustment is shown in Schedule ACC-21. If the Company provides further updates during the course of this proceeding, I will review those updates and adjust my recommendation further, if appropriate.

J. <u>Prepay Program Amortization Expense</u>

Q. Please explain the Company's claim for amortization of deferred costs associated with its Prepay Pilot Program.

A. The Company has deferred $155,928 relating to an Optional Prepay Service Pilot Program that was approved by the KCC in Docket No. 14-WSEE-148-TAR. The parties in that proceeding entered into a settlement agreement that gave the Company authorization to defer the associated costs of the program. However, the settlement agreement stated that the parties could not agree on whether Westar should be entitled to recover the costs of the program from Kansas ratepayers. Therefore, the parties proposed that the issue of cost recovery be deferred "until such time as Westar seeks to include costs associated with the Prepay program in a general rate case."[8] In this case, Westar is seeking recovery of the Prepay

8 Stipulation in Docket No. 14-WSEE-148-TAR, paragraph 19.

Program costs over a three-year period.

Q. Do you believe that these costs should be recovered from ratepayers?

A. No, I do not. The KCC determined on December 15, 2016 that the Prepay Program should be terminated and that customers who participated in the Prepay Program should be transitioned off of the program. Given that the program was not implemented on a permanent basis, and that Westar will not incur costs prospectively associated with the program, I recommend that the Company's request to recover these deferred costs from ratepayers be denied. In addition, these costs are not material and Westar's financial integrity will not be jeopardized if these costs are not recovered from Kansas ratepayers. Accordingly, at Schedule ACC-22, I have made an adjustment to eliminate the Company's proposed annual amortization expense associated with the Prepay Program from the Company's revenue requirement.

K. <u>Grid Security Amortization Expense</u>

Q. Please describe the Company's claim for recovery of grid security costs.

A. In Docket No. 15-WSEE-115-RTS, the KCC authorized the Company to establish a grid security tracker to record non-labor operations and maintenance costs related to protection of infrastructure that were in excess of the grid security costs embedded in base rates. In its Application, Westar is seeking recovery of total deferred grid security costs of $2,137,485, which the Company is proposing to amortize over three years.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that these costs be recovered over a five-year period, instead of over the three-year amortization period proposed by Westar. The five-year period is consistent with the general rate case moratorium agreed to among the signatories of the Merger Stipulation. Thus, at Schedule ACC-23, I have made an adjustment to reflect a five-year amortization of the Company's deferred grid security costs.

L. <u>Rate Case Amortization Expense</u>

Q. How did the Company determine its rate case expense claim in this case?

A. Westar's claim is based on projected costs of $1,527,988 for the current case. In addition, the Company included $80,770 in unrecovered rate case costs from the 2016 Abbreviated Rate Case (Docket No. 17-WSEE-147-RTS). Therefore, the Company is seeking a total of $1,608,758 in rate base costs, which it is proposing to amortize over 3 years, for an annual amortization expense of $536,273.

Q. What are the components of the Company's claim of approximately $1.53 million for costs associated with the current case?

A. As shown in the workpapers to Adjustment IS-14, the Company's claim consists of the following:

CCOS/Rate Design - Brattle	$100,000
CCOS/Rate Design - B&V	$150,000
CCOS/Rate Design - Wolfram	$150,000
Case Review – Key Staffing	$40,000
Depreciation Study	$245,000
Tax Support	$50,000
ROE Support – Madden	$109,800
Testimony Support	$20,000
Legal Support	$160,000
Staff and CURB Consultants	$503,188
Total	$1,527,988

Q. Are you recommending any adjustment to the Company's rate case expense claim?

A. I am not recommending any adjustment to the amount of rate case costs included by Westar in its Application. However, I recommend that these costs be amortized over a five-year period instead of over the three-year period proposed by Westar. Given that the Merger Stipulation provides for a five-year base rate moratorium, a five-year amortization in more appropriate in this case than the three-year amortization period proposed by Westar. My adjustment is shown in Schedule ACC-24.

M. <u>Knock and Collect Program Expense</u>

Q. Please describe the Knock and Collect Program costs included by the Company in its filing.

A. As described in the testimony of Mr. Wilkus, in Docket No. 15-GIMX-344-GIV, the KCC approved a pilot Knock and Collect Program that replaced live on-premises contact prior to disconnection with additional attempts to contact the customer, as well as a lower disconnect fee and elimination of a reconnect fee. This program is on-going. The Company is seeking to recover a net revenue loss of $528,128 associated with the Knock and Collect Program in rates that are approved as a result of this case. This claim includes $972,848 in lost revenues, partially offset by $444,720 in expense savings.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that the Company's claim for incremental net costs associated with the Knock and Collect Program be disallowed. It is my understanding that the purpose of this program is to reduce the Company's costs, not to increase costs. In this case, the Company is claiming a revenue reduction that is more than twice as large as the associated decline in expenses. Therefore, at Schedule ACC-25, I have made an adjustment to eliminate the Company's adjustment associated with incremental costs for the Knock and Collect Program.

N. SmartStar Amortization Expense

Q. Please discuss the Company's adjustment relating to the SmartStar Lawrence pilot program.

A. In its last general base rate case (KCC Docket 15-WSEE-115-RTS), Westar was authorized to amortize $1,964,097of costs associated with the SmartStar Lawrence program over 36 months. The Company has incurred additional costs since its last base rate case for the

SmartStar program. In this case, it included total deferred costs of $596,799, which it proposed to amortize over three years.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending two adjustments. First, the Company acknowledged in the response to KCC-297 that its workpaper contained a formula error, which overstated the current deferred balance. Correcting for this error reduces the Company's deferred balance from $596,799 to $569,520. This correction is shown in Schedule ACC-26.

Second, I recommend that the deferred costs associated with the SmartStar Lawrence program be amortized over five years, instead of over the three years reflected in the Company's Application. This is consistent with the base rate case moratorium agreed upon in the Merger Stipulation. My adjustment is shown in Schedule ACC-26.

O. <u>State Line Amortization Expense</u>

Q. Please discuss the Company's adjustment relating to the State Line Combined Cycle Generating Station.

A. As discussed in Mr. Rinehart's testimony, Westar is authorized to defer the difference between its annual capacity costs associated with State Line and the amount included in the Company's retail rates. In this case, the Company has a regulatory liability of $9,017,370, which it is proposing to amortize over three years. Consistent with my recommendation that other amortizations in this case be recovered over five years, I recommend that the regulatory liability associated with State Line be returned to ratepayers over a five-year period, consistent with the base rate case moratorium in the Merger Stipulation. My adjustment is shown in Schedule ACC-27.

P. Insurance Expense

Q. Did the Company include estimated insurance premium expense increases in its filing?

A. Yes, it did. In Adjustment IS-34, the Company included estimated insurance premium increases in its claim. Westar's Application was based on total pro forma insurance costs of $4,574,287. These estimates were subsequently updated in the response to KCC-235. Based on the actual updated premiums, the Company has pro forma insurance expense of $3,516,649, well below the insurance costs originally estimated by the Company. At Schedule ACC-28, I have made an adjustment to reflect actual premium costs for property and liability insurance as provided in the response to KCC-235.

Q. Internet Technology ("IT") Service Agreements Expense

Q. Please describe the Company's adjustment relating to IT Service Agreements.

A. Ms. Fowler states on page 5 of her testimony that Westar made an adjustment to include costs related to IT Service Agreements that were signed at the end of 2017, and therefore were not reflected in the Test Year. It has included an increase of $2,181,909 in its revenue requirement associated with these agreements. However, a review of the supporting workpapers indicates that at least some of the Company's claim is based on speculative increases, including $260,256 relating to a 3% increase that I understand is based on average historic increases.

Q. What do you recommend?

A. I recommend that this 3% increase be eliminated from the Company's revenue requirement. This projection does not constitute a known and measurable change to the Test Year. At Schedule ACC-29, I have made an adjustment to eliminate $260,256 from the Company's IT Service Agreement claim.

R. <u>Membership and Dues Expenses</u>

Q. Did the Company make any adjustment to its membership and dues expenses?

A. The Company made a small adjustment to eliminate the portion of dues to the Edison Electric Institute ("EEI") that it identified as related to lobbying activities. Otherwise, Westar included 100% of its actual membership and dues expense in its revenue requirement claim.

Q. Are you recommending any other adjustments to the Company's claim for Membership and Dues Expenses?

A. Yes, I am recommending that 50% of the remaining costs be disallowed. This is consistent with KCC practice, and is also consistent with K.S.A. 66-101f(a), which states:

> The commission may adopt a policy of disallowing a percentage, not to exceed 50%, of utility dues, donations and contributions to charitable, civic and social organizations and entities, in addition to disallowing specific dues, donations, and contributions which are found unreasonable or inappropriate.

As Schedule ACC-30, I have made an adjustment to eliminate 50% of all Membership and Dues Expenses from the Company's filing.

Q. Why do you believe that such an adjustment is appropriate?

A. As shown in the response to KCC-55, Westar paid membership dues to many organizations that are not necessarily involved in the provision of safe and adequate utility service and which do not directly benefit ratepayers. For example, many of the membership dues expenses were paid to chambers of commerce and other organizations that routinely participate in lobbying activities, which may not always benefit ratepayers. Other organizations, such as Rotary Clubs, may provide valuable services but these services are not necessary to the provision of utility service and should not be funded by captive ratepayers. Membership dues were also paid to the League of Kansas Municipalities and other groups that have no direct relationship to the provision of utility service. Given the list of organizations that are the recipients of Westar's membership dues, I believe it is appropriate to require a 50/50 sharing of these costs between ratepayers and shareholders.

S. <u>Royalty and Payments In Lieu of Tax ("Pilot") Expense</u>

Q. Please discuss the Company's adjustment relating to royalty and pilot payments.

A. In Adjustment IS-44, the Company eliminated royalty and pilot payments from its revenue requirements claim. Instead, the Company is proposing that payments in lieu of taxes be recovered through the property tax surcharge while royalty payments be recovered through the RECA.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending the costs associated with the Flat Ridge 1 and Central Plains wind farm be retained in base rates. These costs are relatively stable from year to year and are largely within the control of Westar. Therefore, I see no reason why Westar should be permitted to move these costs to adjustment clauses, which would guarantee dollar-for-dollar recovery and effectively shift the risk of recovery from shareholders to ratepayers. Therefore, at Schedule ACC-31, I have eliminated the Company's adjustment to remove these costs from base rates, and instead I have included these costs in my base rate revenue requirement. I did not add back to base rates any royalty or pilot payments associated with the Western Plains Wind Farm, since I am recommending that all costs associated with that wind farm be eliminated from base rates. Since the Company itself had already removed the royalty and pilot payments for the Western Plains Wind Farm from its base rate revenue requirement, no further adjustment was necessary.

T. <u>Depreciation Expense – Rate Change</u>

Q. Are you recommending any adjustment to the Company's depreciation expense claims?

A. Yes, In addition to the depreciation expense adjustment relating to the Western Plains Wind Farm, discussed above, I am also recommending that the Company's request to adopt new depreciation rates in this case be denied.

Q. What is the impact of the depreciation rate change proposed by Westar?

A. Westar is proposing to increase annualized depreciation expense by $56,007,087 in this case. Westar contends that an even larger increase is justified but that the Company has decided to mitigate the rate impact by limiting its request to the $56 million increase.

Q. Do you recommend that the KCC adopt the Company's proposed new depreciation rates in this case?

A. No, I do not. The Company is entering into a dynamic period now that the merger with KCP&L has been approved. This merger will result in fundamental changes to both companies. It is likely that the merger will result in retirements of certain generating facilities as well as revised approaches to dealing with utility investment. It is also likely that the companies will move to consolidate certain business practices and to reexamine management of jointly-owned assets. Given the uncertainty that will result from the merger, I believe that it is premature to adopt dramatically new depreciation rates in this case. Instead, I recommend that the KCC reject the Company's request to increase rates by $56 million in this case, and instead wait until the consolidation process is complete. Westar and KCP&L have agreed to a five-year base rate moratorium. I recommend that new depreciation rates be considered at the end of the rate moratorium period, when the parties can better assess the impact of the merger on the management of utility assets at each company. At Schedule ACC-32, I have made an adjustment to eliminate the Company's proposed adjustment relating to new depreciation rates.

U. Income Tax Expense

Q. **Are you recommending any adjustment to the Company's income tax expense claim?**

A. Yes, as referenced in the Rate Base section of my testimony, the Company indicated in response to KCC-303 that its Tax Rate Change Adjustment (IS-52/RB-12) contained a small error. According to this response, the Company's income tax expense adjustment included in its Application was overstated by $168,822. Therefore, at Schedule ACC-33, I have made an adjustment to decrease pro forma income taxes by this amount.

V. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I made this adjustment at Schedule ACC-34. This adjustment is consistent (synchronized) with CURB's recommended rate base, capital structure, and cost of capital recommendations. Because CURB is recommending a lower rate base than the Company included in its filing, CURB's recommendations result in lower pro forma interest expense for Westar. Since interest expense is an income tax deduction for state and federal tax purposes, my recommendations will result in an increase to the Company's income tax liability. Therefore, CURB’s recommendations result in an interest synchronization adjustment that reflects a higher income tax burden, and a decrease to pro forma income at present rates.

Q. What income tax factor have you used to quantify your adjustments?

A. As shown on Schedule ACC-35, I have used a composite income tax factor of 26.53%, which includes a state income tax rate of 7.00% and a federal income tax rate of 21%.

Q. What revenue multiplier are you recommending in this case?

A As shown in Schedule ACC-36, I am recommending a revenue multiplier of 1.36753. This revenue multiplier includes the state income tax rate of 7.0% and the federal income tax rate of 21%. In addition, it includes a bad debt expense ratio of 0.47%, which is the bad debt rate used in the Company’s schedules. By incorporating the bad debt rate into the Company’s revenue multiplier, the required revenue change (increase or decrease) will be adjusted to reflect the impact of bad debt expense on the new base rates. Therefore, I recommend that the revenue multiplier be adjusted to include the Company’s pro forma bad debt expense ratio.

VIII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in your testimony?

A. My adjustments result in a base rate revenue surplus at present rates of $122,739,935, as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $136,868,356 to the Company's proposed increase of $14,128,421. After the roll-in of the Ad Valorem Property Tax Surcharge, the net result is a revenue decrease of $138,428,042.

Q. Have you developed a pro forma income statement for Westar?

A. Yes, Schedule ACC-37 contains a pro forma income statement, showing utility operating income under several scenarios, including the Company's claimed operating income at present rates, my recommended operating income at present rates, and operating income under my proposed revenue decrease. My recommendations will result in an overall return on rate base of 7.02%.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-38, I have quantified the impact on Westar's revenue requirement of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

IX. PHASE II REVENUE IMPACT

Q. Please describe the Phase II rate change that was proposed by Westar in its Application.

A. In its Application, Westar requested that the KCC authorize a Phase II rate adjustment on February 1, 2019 to address two issues – the loss of wholesale revenue associated with an expiring MKEC contract and the impact of expiring PTCs associated with the Central Plains and Flat Ridge 1 wind farms. Westar proposed a Phase II increase of $54.2 million to address these issues.

In the Merger Stipulation, the signatories agreed that they would support a Phase II adjustment related to these two issues, although the parties were not bound to recommend any specific amount for a Phase II increase. In addition, they agreed that the loss of the MKEC revenue would be flowed through the RECA. Therefore, that revenue loss will not be addressed in a Phase II base rate adjustment.

Q. Please quantify the Phase II adjustment that you are recommending.

A. I am recommending a rate reduction of approximately $1.9 million effective February 1, 2019, as shown in Schedule ACC-39. This recommendation is composed of several adjustments. First, as discussed on page 32 of Mr. Bridson's testimony, Westar does not own the 8% of Jeffrey Energy Center ("JEC") that is being used to serve MKEC. Instead, this 8% of JEC is owned by Wilmington Trust, and is leased back to Westar through a sale/leaseback arrangement. It is my understanding that this lease expires on January 3, 2019. Therefore, commensurate with the inclusion of the MKEC revenue loss in the RECA, ratepayers should receive credit for this $8.3 million lease payment that will no longer be paid to Wilmington Trust.

Second, 8% of the operating costs of JEC should be excluded from the Company's revenue requirement, since these costs should be allocated to Wilmington Trust once the MKEC contract expires. Mr. Bridson states in footnote 2 of his testimony that Westar will attempt to recover these operating costs from Wilmington Trust but that cost recovery is not assured. However, regardless of whether or not Westar is successful in recovering these costs from Wilmington Trust, they should not be passed on to Kansas ratepayers, since Westar does not own this 8% of JEC. As shown in Schedule ACC-38, base rates should be reduced by $15.2 million to reflect the cost savings associated with the 8% of JEC that is currently being utilized to serve MKEC.

Finally, a Phase II rate adjustment should include the impact of the expiring PTCs relating to the Central Plains and Flat Ridge 1 wind farms. The PTCs associated with these generating facilities will increase the Company's income tax expense by $9.77 million.

Q. What is the revenue requirement impact of the Phase II adjustments that you are recommending?

A. I am recommending a Phase II base rate decrease of $1.9 million, as shown in Schedule ACC-38.

Q. Does your recommended Phase II adjustment include any adjustment to the deferred income tax reserve associated with the expiring PTCs?

A. No, it does not. Based on my discussions with the Company, as well as on the Company's response to KCC-309, I do not believe that any such adjustment is necessary since it appears that any change in the deferred income tax reserve would be offset with a corresponding adjustment to the deferred tax NOL asset. However, if the Company believes that an adjustment to the accumulated deferred income tax reserve is necessary, I will review Westar's supporting information and adjust my recommendation, if necessary.

X. <u>2017 TAX REFUND</u>

Q. Did the KCC order Westar and other utilities to defer cost savings associated with the TCJA?

A. Yes, it did. On January 18, 2018, the KCC issued an *Order Opening General Investigation and Issuing Accounting Authority Order Regarding Federal Tax Reform*.[9] In the order, utilities were required to defer the cost savings resulting from the TCJA beginning January 1, 2018. The KCC also required that interest on the deferral be applied at the customer deposit rate, which is currently 1.62%. Finally, the KCC provided utilities with the opportunity to argue that the related tax savings should be offset with revenue deficiencies in other areas.

In its Application, Westar stated that it intended to defer $48.7 million from January 1, 2019 through the effective date of new rates. It proposed to partially offset this amount with other revenue deficiencies. However, as a condition of the Merger Stipulation, Westar agreed to waive its right to argue for any such offset and instead agreed that the full deferral would be refunded to ratepayers.

Q. Has this issue been further addressed by the parties in the 18-248 Docket?

A. Yes, it has. I understand that a settlement agreement has been executed in the 18-248 Docket, whereby the parties agreed to a refund of $49,707,217, excluding interest. With interest at 1.62%, ratepayers would be entitled to a refund of $50,027,522 at October 1, 2018.

Q. How do you recommend that this amount be refunded to ratepayers?

A. In its Application, Westar proposed that the TCJA deferral would be refunded to ratepayers through a bill credit within 120 days of an order in this base rate case. I believe that a one-time bill credit is a reasonable approach for this refund and support the Company's proposal. I recommend that this bill credit be allocated to customers in the same manner as the upfront bill credits discussed on pages 13-14 of the Merger Stipulation.

Q. How is the Company proposing to refund the excess deferred income taxes associated with the TCJA?

A. As discussed in the testimony of Mr. Devin, the methodology for refunding excess deferred income taxes associated with plant-related temporary timing differences must meet certain

9 KCC Docket No. 18-GIMX-248-GIV ("18-248 Docket").

normalization requirements of the Internal Revenue Service ("IRS"). These excess deferred taxes are referred to as "protected" excess deferred taxes. Essentially, protected excess deferred income taxes cannot be returned to customers more rapidly than over the average remaining life of the underlying assets giving rise to the associated deferred taxes. Unprotected excess deferred taxes, those related to factors other than plant, can be amortized over any reasonable period. Westar is proposing to amortize excess deferred taxes associated with the NOL tax asset over five years, and to amortize other unprotected excess deferred taxes over ten years. I am not recommending any adjustment to the Company's proposed amortization periods at this time.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>VERIFICATION</u>

STATE OF FLORIDA)

COUNTY OF BROWARD) ss:

Andrea C. Crane, being duly sworn upon her oath, deposes and states that she is a consultant for the Citizens' Utility Ratepayer Board, that she has read and is familiar with the foregoing Direct Testimony, and that the statements made therein are true to the best of her knowledge, information and belief

Andrea C. Crane
Andrea C. Crane

Subscribed and sworn before me this 5th day of June, 2018.

Notary Public Diane K Pappa

My Commission Expires: November 3, 2020

DIANE K PAPPA
MY COMMISSION # GG021910
EXPIRES November 03, 2020

APPENDIX A

List of Testimonies Filed Since January 2008

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Westar Energy, Inc.	E	Kansas	18-WSEE-328-RTS	6/18	Revenue Requirements	Citizens' Utility Ratepayer Board
Southwestern Public Service Company	E	New Mexico	17-00255-UT	4/18	Revenue Requirements	Office of Attorney General
Empire District Electric Company	E	Kansas	18-EPDE-184-PRE	3/18	Approval of Wind Generation Facilities	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	18-KCPE-095-MER	1/18	Proposed Merger	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Co.	E	New Jersey	GR17070776	1/18	Gas System Modernization Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	17-00044-UT	10/17	Approval of Wind Generation Facilities	Office of Attorney General
Kansas Gas Service	G	Kansas	17-KGSG-455-ACT	9/17	MGP Remediation Costs	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER17030308	8/17	Base Rate Case	Division of Rate Counsel
Public Service Company of New Mexico	E	New Mexico	16-00276-UT	6/17	Testimony in Support of Stipulation	Office of Attorney General
Westar Energy, Inc.	E	Kansas	17-WSEE-147-RTS	5/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	17-KCPE-201-RTS	4/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	16-KCPE-593-ACQ	12/16	Proposed Merger	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	16-KGSG-491-RTS	9/16	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00312-UT	7/16	Automated Metering Infrastructure	Office of Attorney General
Kansas City Power and Light Company	E	Kansas	16-KCPE-160-MIS	6/16	Clean Charge Network	Citizens' Utility Ratepayer Board
Kentucky American Water Company	W	Kentucky	2016-00418	5/16	Revenue Requirements	Attorney General/LFUCG
Black Hills/Kansas Gas Utility Company	G	Kansas	16-BHCG-171-TAR	3/16	Long-Term Hedge Contract	Citizens' Utility Ratepayer Board
General Investigation Regarding Accelerated Pipeline Replacement	G	Kansas	15-GIMG-343-GIG	1/16	Cost Recovery Issues	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00261-UT	1/16	Revenue Requirements	Office of Attorney General
Atmos Energy Company	G	Kansas	16-ATMG-079-RTS	12/15	Revenue Requirements	Citizens' Utility Ratepayer Board
El Paso Electric Company	E	New Mexico	15-00109-UT	12/15	Sale of Generating Facility	Office of Attorney General
El Paso Electric Company	E	New Mexico	15-00127-UT	9/15	Revenue Requirements	Office of Attorney General
Rockland Electric Company	E	New Jersey	ER14030250	9/15	Storm Hardening Surcharge	Division of Rate Counsel
El Paso Electric Company	E	New Mexico	15-00099-UT	8/15	Certificate of Public Convenience - Ft. Bliss	Office of Attorney General
Southwestern Public Service Company	E	New Mexico	15-00083-UT	7/15	Approval of Purchased Power Agreements	Office of Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Westar Energy, Inc.	E	Kansas	15-WSEE-115-RTS	7/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	15-KCPE-116-RTS	5/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR14101099-1120	4/15	Cable Rates (Form 1240)	Division of Rate Counsel
Liberty Utilities (Pine Buff Water)	W	Arkansas	14-020-U	1/15	Revenue Requirements	Office of Attorney General
Public Service Electric and Gas Co.	E/G	New Jersey	EO14080897	11/14	Energy Efficiency Program Extension II	Division of Rate Counsel
Exelon and Pepco Holdings, Inc.	E	New Jersey	EM14060581	11/14	Synergy Savings, Customer Investment Fund, CTA	Division of Rate Counsel
Black Hills/Kansas Gas Utility Company	G	Kansas	14-BHCG-502-RTS	9/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	14-00158-UT	9/14	Renewable Energy Rider	Office of Attorney General
Public Service Company of New Mexico	E	New Mexico	13-00390-UT	8/14	Abandonment of San Juan Units 2 and 3	Office of Attorney General
Atmos Energy Company	G	Kansas	14-ATMG-320-RTS	5/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Rockland Electric Company	E	New Jersey	ER13111135	5/14	Revenue Requirements	Division of Rate Counsel
Kansas City Power and Light Company	E	Kansas	14-KCPE-272-RTS	4/14	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR13100885-906	3/14	Cable Rates	Division of Rate Counsel
New Mexico Gas Company	G	New Mexico	13-00231-UT	2/14	Merger Policy	Office of Attorney General
Water Service Corporation (Kentucky)	W	Kentucky	2013-00237	2/14	Revenue Requirements	Office of Attorney General
Oneok, Inc. and Kansas Gas Service	G	Kansas	14-KGSG-100-MIS	12/13	Plan of Reorganization	Citizens' Utility Ratepayer Board
Public Service Electric & Gas Company	E/G	New Jersey	EO13020155 GO13020156	10/13	Energy Strong Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	12-00350-UT	8/13	Cost of Capital, RPS Rider, Gain on Sale, Allocations	New Mexico Office of Attorney General
Westar Energy, Inc.	E	Kansas	13-WSEE-629-RTS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	13-115	8/13	Revenue Requirements	Division of the Public Advocate
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-447-MIS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Jersey Central Power & Light Company	E	New Jersey	ER12111052	6/13	Reliability Cost Recovery Consolidated Income Taxes	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	13-MKEE-447-MIS	5/13	Transfer of Certificate Regulatory Policy	Citizens' Utility Ratepayer Board
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-452-MIS	5/13	Formula Rates	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	12-450F	3/13	Gas Sales Rates	Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Public Service Electric and Gas Co.	E	New Jersey	EO12080721	1/13	Solar 4 All - Extension Program	Division of Rate Counsel
Public Service Electric and Gas Co.	E	New Jersey	EO12080726	1/13	Solar Loan III Program	Division of Rate Counsel
Lane Scott Electric Cooperative	E	Kansas	12-MKEE-410-RTS	11/12	Acquisition Premium, Policy Issues	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	12-KGSG-835-RTS	9/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	12-KCPE-764-RTS	8/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Woonsocket Water Division	W	Rhode Island	4320	7/12	Revenue Requirements	Division of Public Utilities and Carriers
Atmos Energy Company	G	Kansas	12-ATMG-564-RTS	6/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	110258	5/12	Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company (Western)	E	Kansas	12-MKEE-491-RTS	5/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER11080469	4/12	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	12-MKEE-380-RTS	4/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	11-381F	2/12	Gas Cost Rates	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	EO11110650	2/12	Infrastructure Investment Program (IIP-2)	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	11-384F	2/12	Gas Service Rates	Division of the Public Advocate
New Jersey American Water Co.	W/WW	New Jersey	WR11070460	1/12	Consolidated Income Taxes Cash Working Capital	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	12-WSEE-112-RTS	1/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Puget Sound Energy, Inc.	E/G	Washington	UE-111048 UG-111049	12/11	Conservation Incentive Program and Others	Public Counsel
Puget Sound Energy, Inc.	G	Washington	UG-110723	10/11	Pipeline Replacement Tracker	Public Counsel
Empire District Electric Company	E	Kansas	11-EPDE-856-RTS	10/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR11030116-117	9/11	Forms 1240 and 1205	Division of Rate Counsel
Artesian Water Company	W	Delaware	11-207	9/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS (Remand)	7/11	Rate Case Costs	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	11-MDWE-609-RTS	7/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power & Light Company	E	Kansas	11-KCPE-581-PRE	6/11	Pre-Determination of Ratemaking Principles	Citizens' Utility Ratepayer Board

Company	Utility	State	Docket	Date	Topic	On Behalf Of
United Water Delaware, Inc.	W	Delaware	10-421	5/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company	E	Kansas	11-MKEE-439-RTS	4/11	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
South Jersey Gas Company	G	New Jersey	GR10060378-79	3/11	BGSS / CIP	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	10-296F	3/11	Gas Service Rates	Division of the Public Advocate
Westar Energy, Inc.	E	Kansas	11-WSEE-377-PRE	2/11	Pre-Determination of Wind Investment	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	10-295F	2/11	Gas Cost Rates	Attorney General
Delmarva Power and Light Company	G	Delaware	10-237	10/10	Revenue Requirements Cost of Capital	Division of the Public Advocate
Pawtucket Water Supply Board	W	Rhode Island	4171	7/10	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey Natural Gas Company	G	New Jersey	GR10030225	7/10	RGGI Programs and Cost Recovery	Division of Rate Counsel
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atmos Energy Corp.	G	Kansas	10-ATMG-495-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	10-EPDE-314-RTS	3/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	09-414 and 09-276T	2/10	Cost of Capital Rate Design Policy Issues	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	09-385F	2/10	Gas Cost Rates	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	09-398F	1/10	Gas Service Rates	Division of the Public Advocate
Public Service Electric and Gas Company	E	New Jersey	ER09020113	11/09	Societal Benefit Charge Non-Utility Generation Charge	Division of Rate Counsel
Delmarva Power and Light Company	G	Delaware	09-277T	11/09	Rate Design	Division of the Public Advocate
Public Service Electric and Gas Company	E/G	New Jersey	GR09050422	11/09	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	09-MKEE-969-RTS	10/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy, Inc.	E	Kansas	09-WSEE-925-RTS	9/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08050326 EO08080542	8/09	Demand Response Programs	Division of Rate Counsel
Public Service Electric and Gas Company	E	New Jersey	EO09030249	7/09	Solar Loan II Program	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	09-MDWE-792-RTS	7/09	Revenue Requirements	Citizens' Utility Ratepayer Board

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Westar Energy and KG&E	E	Kansas	09-WSEE-641-GIE	6/09	Rate Consolidation	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	09-60	6/09	Cost of Capital	Division of the Public Advocate
Rockland Electric Company	E	New Jersey	GO09020097	6/09	SREC-Based Financing Program	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	09-29	6/09	Revenue Requirements Cost of Capital	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	08-269F	3/09	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	08-266F	2/09	Gas Cost Rates	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	09-KCPE-246-RTS	2/09	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08090840	1/09	Solar Financing Program	Division of Rate Counsel
Atlantic City Electric Company	E	New Jersey	EO06100744 EO08100875	1/09	Solar Financing Program	Division of Rate Counsel
West Virginia-American Water Company	W	West Virginia	08-0900-W-42T	11/08	Revenue Requirements	The Consumer Advocate Division of the PSC
Westar Energy, Inc.	E	Kansas	08-WSEE-1041-RTS	9/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Artesian Water Company	W	Delaware	08-96	9/08	Cost of Capital, Revenue, New Headquarters	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR08020113	9/08	Form 1205 Equipment & Installation Rates	Division of Rate Counsel
Pawtucket Water Supply Board	W	Rhode Island	3945	7/08	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey American Water Co.	W/WW	New Jersey	WR08010020	7/08	Consolidated Income Taxes	Division of Rate Counsel
New Jersey Natural Gas Company	G	New Jersey	GR07110889	5/08	Revenue Requirements	Division of Rate Counsel
Kansas Electric Power Cooperative, Inc.	E	Kansas	08-KEPE-597-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E	New Jersey	EX02060363 EA02060366	5/08	Deferred Balances Audit	Division of Rate Counsel
Cablevision Systems Corporation	C	New Jersey	CR07110894, et al..	5/08	Forms 1240 and 1205	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	08-MDWE-594-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-246F	4/08	Gas Service Rates	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR07100717-946	3/08	Form 1240	Division of Rate Counsel
Generic Commission Investigation	G	New Mexico	07-00340-UT	3/08	Weather Normalization	New Mexico Office of Attorney General
Southwestern Public Service Company	E	New Mexico	07-00319-UT	3/08	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General
Delmarva Power and Light Company	G	Delaware	07-239F	2/08	Gas Cost Rates	Division of the Public Advocate

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Atmos Energy Corp.	G	Kansas	08-ATMG-280-RTS	1/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

APPENDIX B

Supporting Schedules

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

REVENUE REQUIREMENT SUMMARY

	Company Claim (A)	Recommended Adjustment	Recommended Position	
1. Pro Forma Rate Base	$5,762,776,071	($393,237,602)	$5,369,538,469	(B)
2. Required Cost of Capital	7.33%	-0.31%	7.02%	(C)
3. Required Return	$422,641,997	($45,538,531)	$377,103,466	
4. Operating Income @ Present Rates	412,261,846	54,594,818	466,856,664	(D)
5. Operating Income Deficiency	$10,380,151	($100,133,349)	($89,753,198)	
6. Revenue Multiplier	1.3611		1.3675	(E)
7. Base Rate Increase	**$14,128,421**	**($136,868,356)**	**($122,739,935)**	
8. Property Tax Roll-In	**($15,688,107)**		**($15,688,107)**	
9. Net Increase	**($1,559,686)**		**($138,428,042)**	

Sources:

(A) Response to KCC-131. Reflects Year 1 requested increase only.
(B) Schedule ACC-3.
(C) Schedule ACC-2.
(D) Schedule ACC-9.
(E) Schedule ACC-36.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

REQUIRED COST OF CAPITAL

	Capital Structure	Cost Rate		Weighted Cost
1. Common Equity (A)	50.78%	9.30%	(D)	4.72%
2. Long Term Debt (B)	48.78%	4.65%	(E)	2.27%
3. Post 1970 ITCs (C)	0.44%	7.02%	(F)	0.03%
4. Total Cost of Capital	100.00%			**7.02%**

Sources:
(A) Reflects 51% common equity (exclusive of Post 1970 ITCs), per Merger Stipulation.
(B) Reflects 49% long-term debt (exclusive of Post 1970 ITCs), per Merger Stipulation.
(C) Reflects percentage per Company Filing, Schedule 7-A, page 1.
(D) Reflects 9.3% cost of equity per Merger Stipulation.
(E) Reflects cost of debt per Company Filing, Schedule 7-A, page 1.
(F) Reflects overall cost of capital.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

RATE BASE SUMMARY

	Company Claim (A)	Recommended Adjustment		Recommended Position
1. Utility Plant in Service	$10,332,199,008	($418,767,854)	(B)	$9,913,431,154
Less:				
2. Accumulated Depreciation	(3,344,584,493)	6,816,345	(C)	(3,337,768,148)
3. Net Utility Plant	$6,987,614,515	($411,951,509)		$6,575,663,006
Plus:				
4. Materials and Supplies	$163,145,081	$0		$163,145,081
5. Prepayments	12,968,236	0		12,968,236
6. Fossil Fuel Inventory	107,631,011	(6,770,918)	(D)	100,860,093
7. Nuclear Fuel	62,969,136	0		62,969,136
8. Regulatory Assets/Liabilities	(2,521,644)	24,177,813	(E)	21,656,169
Less:				
9. Cost Free Capital	($1,569,030,264)	$1,307,012	(F)	($1,567,723,252)
10. Total Rate Base	**$5,762,776,071**	**($393,237,602)**		**$5,369,538,469**

Sources:
(A) Response to KCC-131, Schedule 3-A and Schedule 6-A. Reflects Year 1 requested increase only.
(B) Schedule ACC-4 and Schedule ACC-5.
(C) Schedule ACC-4.
(D) Schedule ACC-6.
(E) Schedule ACC-7.
(F) Schedule ACC-8.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

UTILITY PLANT IN SERVICE -
WESTERN PLAINS WIND FARM

1.	Utility Plant in Service	($411,846,055)	(A)
2.	Accumulated Depreciation	6,816,345	(A)
3.	Net Plant Adjustment	**($405,029,710)**	

Sources:
(A) Response to KCC-259, Revised 5/22/18.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

UTILITY PLANT IN SERVICE -
CONSTRUCTION WORK IN PROGRESS

		Distribution	General and Intangible
1.	Company Claim (A)	$44,161,514	24,001,317
2.	Update Per Company (Thru 5/31) (B)	40,706,255	20,534,777
3.	Recommended Adjustment	**($3,455,259)**	**($3,466,540)**

Sources:
(A) Company Filing, Schedule 3-C, page 2 (Adjustment RB-3).
(B) Response to CURB-48. Excludes projects not included at CWIP at June 30, 2018.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

FOSSIL FUEL INVENTORY

1.	36 Month Average	$100,860,093	(A)
2.	Company Claim	107,631,011	(B)
3.	Recommended Adjustment	**($6,770,918)**	

Sources:
(A) Derived from response to KCC-162.
(B) Company Filing, Schedule 6-E.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

REGULATORY ASSETS/LIABILITIES -
DEFERRED PENSION EXPENSE

1.	Deferred Pension Expense	($24,177,813)	(A)
2.	Recommended Adjustment	**$24,177,813**	

Sources:
(A) Company Filing, Schedule 3-C, page 2.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

COST FREE CAPITAL -
ACCUMULATED DEFERRED INCOME TAXES RESERVE

1.	Company Claim	($4,189,746)	(A)
2.	Correction Per Company	(5,496,758)	(A)
3.	Recommended Adjustment	**$1,307,012**	

Sources:
(A) Company Workpaper to Tax Change Adjustment (RB-12, IS-52).

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

OPERATING INCOME SUMMARY

			Schedule No.
1.	Company Claim	$412,261,846	1
2.	Customer Annualization Revenue	1,959,630	10
3.	Occidental Contract Revenue	342,856	11
4.	Short Term Incentive Compensation Expense	3,737,761	12
5.	Payroll Tax Expense	285,939	13
6.	Restricted Share Units Expense	2,898,721	14
7.	Medical and Dental Benefits Expense	1,127,661	15
8.	Merger Expense Savings	8,361,335	16
9.	Merger Transition Expense	1,100,697	17
10.	Western Plains O&M Expense	5,070,164	18
11.	Western Plains Depreciation Expense	13,108,923	19
12.	Western Plains Production Tax Credits	(27,512,364)	20
13.	Wolf Creek Outage Expense	2,197,319	21
14.	Prepay Program Amortization Expense	36,528	22
15.	Grid Security Amortization Expense	209,388	23
16.	Rate Case Amortization Expense	157,594	24
17.	Knock and Collect Program Expense	388,016	25
18.	Smartstar Amortization Expense	62,470	26
19.	State Line Amortization Expense	(883,342)	27
20.	Insurance Expense	743,292	28
21.	Internet Technology Service Agreements Expense	182,904	29
22.	Membership and Dues Expense	335,406	30
23.	Royalty and Pilot Payments Expense	(739,635)	31
24.	Depreciation Expense-Rate Change	43,204,488	32
25.	Income Tax Expense	168,822	33
26.	Interest Synchronization	(1,949,754)	34
27.	Operating Income at Present Rates	$466,856,664	

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

CUSTOMER ANNUALIZATION REVENUE

1. Recommended Adjustment		$2,667,252	(A)
2. Income Taxes @	26.53%	707,622	
3. Operating Income Impact		**$1,959,630**	

Sources:
(A) Company Filing, Schedule 9-B, Adjustment IS-5.

Schedule ACC-11

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

OCCIDENTAL CONTRACT REVENUE

1.	Recommended Adjustment		$466,661	(A)
2.	Income Taxes @	26.53%	123,805	
3.	Operating Income Impact		**$342,856**	

Sources:
(A) Company Filing, Schedule 9-B, Adjustment IS-38.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

SHORT TERM INCENTIVE COMPENSATION EXPENSE

1.	Company Claim (Based on 5 Year Average)		$10,637,004	(A)
2.	Allocation to Shareholders @ 50%		5,318,502	(B)
3.	Recommended Adjustment		$5,318,502	
4.	Allocation to Transmission @	4.34%	231,036	(C)
5.	Distribution Adjustment		$5,087,466	
6.	Income Taxes @	26.53%	1,349,705	
7.	Operating Income Impact		**$3,737,761**	

Sources:
(A) Five Year Average per Company Workpaper to Adjustment IS-9.
(B) Recommendation of Ms. Crane.
(C) Allocation per Company Filing, Workpaper to Adjustment IS-27.

Schedule ACC-13

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

PAYROLL TAX EXPENSE

1.	Incentive Compensation Adjustment		$5,087,466	(A)
2.	Payroll Tax Rate		7.65%	(B)
3.	Payroll Tax Adjustment		$389,191	
4.	Income Taxes @	26.53%	103,252	
5.	Operating Income Impact		**$285,939**	

Sources:
(A) Schedule ACC-12.
(B) Company Filing, Workpapers to Adjustment IS-9.

Schedule ACC-14

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

RESTRICTED SHARE UNITS EXPENSE

1. Company Claim		$8,255,026	(A)
2. Recommended Adjustment (%)		50.00%	(B)
3. Recommended Adjustment ($)		$4,127,513	
4. Allocation to Transmission @	4.41%	182,065	(C)
5. Distribution Adjustment		$3,945,448	
6. Income Taxes @	26.53%	1,046,727	
7. Operating Income Impact		**$2,898,721**	

Sources:
(A) Response to KCC-239.
(B) Recommendation of Ms. Crane.
(C) Company Filing, Workpapers to IS-8.

Schedule ACC-15

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

MEDICAL AND DENTAL BENEFITS EXPENSE

1.	Medical Expense Adjustment		$2,238,438	(A)
2.	Dental Expense Adjustment		157,877	(A)
3.	Total Recommended Adjustment		$2,396,315	
4.	Allocation to Transmission @	4.41%	(105,701)	(B)
5.	Allocation to Capital @	31.54%	(755,754)	(C)
6.	Net Medical and Dental Expense Adjustment		$1,534,860	
7.	Income Taxes @	26.53%	407,198	
8.	Operating Income Impact		**$1,127,661**	

Sources:
(A) Company Filing, Workpapers to IS-8.
(B) Transmission allocation per Company Workpapers to IS-8.
(C) Derived from Company Workpapers to IS-8.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

MERGER EXPENSE SAVINGS

1.	Merger Savings per Settlement		$22,500,000	(A)
2.	Company Claim		11,119,389	(B)
3.	Recommended Adjustment		$11,380,611	
4.	Income Taxes @	26.53%	3,019,276	
5.	Operating Income Impact		**$8,361,335**	

Sources:
(A) Savings per the Stipulation in KCC Docket No. 18-KCPE-095-MER, page 16.
(B) Company Filing, Workpaper to IS-16.

Schedule ACC-17

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

MERGER TRANSITION EXPENSE

1.	Annual Amortization Per Settllement		$2,318,313	(A)
2.	Company Claim		3,816,471	(B)
3.	Recommended Adjustment		$1,498,158	
4.	Income Taxes @	26.53%	397,461	
5.	Operating Income Impact		**$1,100,697**	

Sources:
(A) Required savings per the Stipulation in KCC Docket No. 18-KCPE-095-MER, page 22.
(B) Company Filing, Schedule 9-B, Adjustment IS-16.

Schedule ACC-18

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

WESTERN PLAINS O&M EXPENSE

1.	O&M Expense Included in Filing		$6,730,706	(A)
2.	Insurance Expense Included in Filing		170,293	(A)
3.	Recommended Adjustment		$6,900,999	
4.	Income Taxes @	26.53%	1,830,835	
5.	Operating Income Impact		**$5,070,164**	

Sources:
(A) Response to KCC-259, Revised 5/22/18.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

WESTERN PLAINS DEPRECIATION EXPENSE

1.	Recommended Adjustment		$17,842,552	(A)
2.	Income Taxes @	26.53%	4,733,629	
3.	Operating Income Impact		**$13,108,923**	

Sources:
(A) Response to KCC-259, Revised, 5/22/18.

Schedule ACC-20

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

WESTERN PLAINS PRODUCTION TAX CREDITS

1.	Company Claim	$27,512,364	(A)
2.	Operating Income Impact	**$27,512,364**	

Sources:
(A) Response to KCC-259, Revised 5/22/18.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

WOLF CREEK OUTAGE EXPENSE

1. Annual Amortization Expense Per Filing		$13,298,608	(A)
2. Annual Amortization Expense - Updated		10,307,838	(B)
3. Recommended Adjustment		$2,990,770	
4. Income Taxes @	26.53%	793,451	
5. Operating Income Impact		**$2,197,319**	

Sources:
(A) Company Filing, Workpapers to Adjustment IS-17.
(B) Response to KCC-208.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

PREPAY PROGRAM AMORTIZATION EXPENSE

1.	Company Claim		$51,976	(A)
2.	Allocation to Transmission @	4.34%	2,258	(B)
3.	Distribution Adjustment		$49,718	
4.	Income Taxes @	26.53%	13,190	
5.	Operating Income Impact		**$36,528**	

Sources:
(A) Company Filing, Adjustment IS-30.
(B) Transmission allocation per Company Workpapers to IS-27.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

GRID SECURITY AMORTIZATION EXPENSE

1.	Total Deferred Costs		$2,137,485	(A)
2.	Recommended Amortization Period (Yrs.)		5	(B)
3.	Recommended Annual Amortization		$427,497	
4.	Company Claim		712,495	(A)
5.	Recommended Adjustment		$284,998	
6.	Income Taxes @	26.53%	75,610	
7.	Operating Income Impact		**$209,388**	

Sources:
(A) Company Filing, Workpaper to IS-33.
(B) Recommendation of Ms. Crane

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

RATE CASE AMORTIZATION EXPENSE

1.	Company Claim		$1,608,758	(A)
2.	Proposed Amortization		5	(B)
3.	Pro Forma Annual Amortization		$321,752	
4.	Compay Claim		536,253	(A)
5.	Recommended Adjustment		$214,501	
6.	Income Taxes @	26.53%	56,907	
7.	Operating Income Impact		**$157,594**	

Sources:
(A) Company Filing, Workpapers to IS-14.
(B) Recommendation of Ms. Crane.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

KNOCK AND COLLECT PROGRAM EXPENSE

1.	Revenue Reduction		$972,848	(A)
2.	Expense Reduction		444,720	(A)
3.	Recommended Adjustment		$528,128	
4.	Income Taxes @	26.53%	140,112	
5.	Operating Income Impact		**$388,016**	

Sources:
(A) Company Filing, Workpapers to Adjustment IS-37.

Schedule ACC-26

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

SMARTSTAR AMORTIZATION EXPENSE

1.	Corrected Deferred Costs		$569,520	(A)
2.	Recommended Amortization Period (Yrs.)		5	(B)
3.	Recommended Annual Amortization		$113,904	
4.	Company Claim		198,932	(A)
5.	Recommended Adjustment		$85,028	
6.	Income Taxes @	26.53%	22,558	
7.	Operating Income Impact		**$62,470**	

Sources:
(A) Company Filing, Workpaper to IS-33, Corrected for formula error discussed in KCC-297.
(B) Recommendation of Ms. Crane.

Schedule ACC-27

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

STATE LINE AMORTIZATION EXPENSE

1.	Deferred Liability Per Company		$9,017,370	(A)
2.	Recommended Amortization Period (Yrs.)		5	(B)
3.	Recommended Annual Amortization		$1,803,474	
4.	Company Claim		3,005,790	(A)
5.	Recommended Adjustment		($1,202,316)	
6.	Income Taxes @	26.53%	(318,974)	
7.	Operating Income Impact		**($883,342)**	

Sources:
(A) Company Filing, Workpaper to IS-28.
(B) Recommendation of Ms. Crane.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

INSURANCE EXPENSE

1. Original Company Claim		$4,574,287	(A)
2. Revised Company Claim		3,516,649	(B)
3. Recommended Adjustment		$1,057,638	
4. Allocation to Transmission @	4.34%	45,944	(C)
5. Distribution Adjustment		$1,011,694	
6. Income Taxes @	26.53%	268,402	
7. Operating Income Impact		**$743,292**	

Sources:
(A) Company Filing, Workpapers to Adjustment IS-34.
(B) Response to KCC-235.
(C) Transmission allocation per Company Workpapers to IS-27.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

IT SERVICE AGREEMENT EXPENSE

1.	Recommended Adjustment		$260,256	(A)
2.	Allocation to Transmission @	4.34%	11,306	(B)
3.	Recommended Adjustment		$248,950	
4.	Income Taxes @	26.53%	66,047	
5.	Operating Income Impact		**$182,904**	

Sources:
(A) Company Filing, Workpapers to Adjustment IS-36.
(B) Transmission allocation per Company Workpapers to IS-27.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

MEMBERSHIP AND DUES EXPENSE

1. Company Claim		$955,631	(A)
2. EEI Adjustment Per Filing		1,125	(B)
3. Net Membership Dues		$954,506	
4. Recommended Adjustment (%)		50.00%	(C)
5. Recommended Adjustment ($)		$477,253	
6. Allocation to Transmission @	4.34%	20,732	(D)
7. Distribution Adjustment		$456,521	
8. Income Taxes @	26.53%	121,115	
9. Operating Income Impact		**$335,406**	

Sources:
(A) Response to KCC-55.
(B) Company Filing, Adjustment IS-18.
(C) Recommendation fo Ms. Crane.
(D) Transmission allocation per Company Workpapers to IS-27.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

ROYALTY AND PILOT PAYMENTS EXPENSE

1. Royalty Payments - Flat Ridge		$149,937	(A)
2. Royalty Payments - Central Plains		461,224	(A)
3. PILOT - Flat Ridge		116,016	(A)
4. PILOT - Central Plains		279,540	(A)
5. Total Recommended Adjustment		$1,006,717	
6. Income Taxes @	26.53%	267,082	
7. Operating Income Impact		**$739,635**	

Sources:
(A) Company Filing, Workpaper to Adjustment IS-44.

Schedule ACC-32

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

DEPRECIATION EXPENSE-RATE CHANGES

1.	Depreciation Expense Adjustment	$56,007,087	(A)
2.	Income Taxes	($12,968,774)	(A)
3.	Investment Tax Credit -Net	166,175	(A)
4.	Operating Income Impact	**$43,204,488**	

Sources:
(A) Company Filing, Adjustment IS-7.

Schedule ACC-33

WESTAR ENERGY, INC.

TEST YEAR ENDED SEPTEMBER 20, 2014

INCOME TAX EXPENSE

1.	Impact of Tax Rate Change	$50,993,289
2.	Company Claim	50,824,467
3.	Operating Income Impact	**$168,822**

(A) Response to KCC-303.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

INTEREST SYNCHRONIZATION

1. Pro Forma Rate Base		$5,369,538,469	(A)
2. Weighted Cost of Debt		2.27%	(B)
3. Pro Forma Interest Expense - LTD		$121,869,484	
4. Company Claim		129,218,728	(C)
5. Decrease in Taxable Income		$7,349,244	
6. Increase in Income Taxes @	26.53%	$1,949,754	
7. Operating Expense Impact		**($1,949,754)**	

Sources:
(A) Schedule ACC-3.
(B) Schedule ACC-2.
(C) Company Workpapers, Schedule 11-C, page 1.

Schedule ACC-35

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

INCOME TAX FACTOR

1.	Revenue	100.00%	
2.	State Income Tax Rate	7.00%	(A)
3.	Federal Taxable Income	93.00%	
4.	Income Taxes @ 21%	19.53%	(A)
5.	Operating Income	73.47%	
6.	Total Tax Rate	**26.53%**	(B)

Sources:
(A) Reflects statutory rates.
(B) Line 2 + Line 4.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

REVENUE MULTIPLIER

1.	Revenue		100.00	
2.	Bad Debt Expense		0.47	(A)
3.	State Taxable Income		99.53	
4.	State Income Tax Rate	7.00%	6.97	(B)
5.	Federal Taxable Income		92.56	
6.	Income Taxes @	21.00%	19.44	(B)
7.	Operating Income		73.12	
8	Revenue Multiplier		**1.36753**	(C)

Sources:
(A) Rate Per Company Workpapers, Adjustment IS-22.
(B) Reflects statutory rates.
(C) Line 1 / Line 7.

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

PRO FORMA INCOME STATEMENT

		Per Company	Recommended Adjustments	Pro Forma Present Rates	Recommended Rate Adjustment	Pro Forma Proposed Rates
1. Operating Revenues		$2,069,475,447	$3,133,913	$2,072,609,360	($122,739,935)	1,949,869,425
2. Operating Expenses		1,104,576,089	(34,008,819)	$1,070,567,270	(576,879)	1,069,990,391
3. Depreciation and Amortization		373,549,023	(73,849,639)	299,699,384	0	299,699,384
4. Taxes Other Than Income		135,457,939	(389,191)	135,068,748	0	135,068,748
5. Taxable Income Before Interest Expenses		$455,892,396	$111,381,562	$567,273,958	($122,163,056)	$445,110,902
6. Interest Expense		129,218,728	(7,349,244)	121,869,484		121,869,484
7. Taxable Income		$326,673,668	$118,730,806	$445,404,474	($122,163,056)	$323,241,418
8. Income Taxes @	26.53%	43,630,548	56,786,744	100,417,292	(32,409,859)	68,007,433
9. Operating Income		$412,261,848	$54,594,818	$466,856,666	($89,753,197)	$377,103,469
10. Rate Base		$5,762,776,071		$5,369,538,469	$5,369,538,469	$5,369,538,469
11. Rate of Return		7.15%		8.69%	-1.67%	7.02%

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS

1.	Rate of Return	($24,392,809)
	Rate Base Adjustments:	
2.	Utility Plant in Service	(40,030,117)
3.	Accumulated Depreciation	651,576
4.	Fossil Fuel Inventory	(647,234)
5.	Regulatory Assets/Liabilities	2,311,163
6.	Cost Free Capital	124,938
	Operating Income Adjustments:	
7.	Customer Annualization Revenue	(2,667,252)
8	Occidental Contract Revenue	(466,661)
9.	Medical and Dental Benefits Expense	(1,534,860)
10.	Short Term Incentive Compensation Expense	(5,087,466)
11.	Restricted Share Units Expense	(3,945,448)
12.	Payroll Tax Expense	(389,191)
13.	Merger Expense Savings	(11,380,611)
14.	Merger Transition Expense	(1,498,158)
15.	Western Plains O&M Expense	(6,900,999)
16.	Western Plains Depreciation Expense	(17,842,552)
17.	Western Plains Production Tax Credits	37,447,072
18.	Wolf Creek Outage Expense	(2,990,770)
19.	Prepay Program Amortization Expense	(49,718)
20.	Grid Security Amortization Expense	(284,998)
21.	Rate Case Amortization Expense	(214,501)
22.	Knock and Collect Program Expense	(528,128)
23.	Smartstar Amortization Expense	(85,028)
24.	State Line Amortization Expense	1,202,316
25.	Insurance Expense	(1,011,694)
26.	Internet Technology Service Agreements Expense	(248,950)
27.	Membership Dues	(456,521)
28.	Royalty and Pilot Payments Expense	1,006,717
29.	Depreciation Expense-Rate Change	(58,805,618)
30.	Income Tax Expense	(229,784)
31.	Interest Synchronization	2,653,810
32.	Revenue Multiplier	(576,879)
33.	Summary of Adjustments	($136,868,356)
34.	Company Claim	14,128,421
35.	Recommended Revenue Deficiency	**($122,739,935)**

WESTAR ENERGY, INC.

TEST YEAR ENDED JUNE 30, 2017

PHASE II INCREASE / (DECREASE)

1.	WT Lease Payment		$8,300,000	(A)
2.	8% of JEC O&M Expense		6,900,000	(A)
3.	Total JEC Adjustment		$15,200,000	
4.	Income Taxes @	26.53%	4,032,560	
5.	Operating Income Increase		$11,167,440	
6.	Expiration of PTCs		(9,770,859)	(B)
7.	Net Operating Income Impact		$1,396,581	
8.	Revenue Multiplier		1.368	(C)
9.	Revenue Surplus		$1,909,862	

Sources:
(A) Response to CURB-17.
(B) Company Filing, Workpapers to IS-46, RB-11.
(C) Schedule ACC-36.

APPENDIX C

Referenced Data Requests:

CURB-17
CURB-48*
KCC-55*
KCC-60*
KCC-162*
KCC-199**
KCC-205
KCC-208*
KCC-235*
KCC-239*
KCC-259*
KCC-297
KCC-303
KCC-309
KIC-16*

* Only included partial response
** Confidential – not attached

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [CURB] [David Nickels]
Data Request: CURB-17 :: Wilmington Trust
Date: 0000-00-00

Question 1 (Prepared by Rebecca Fowler)
Regarding the sale and leaseback arrangement with Wilmington Trust referenced on page 32, lines 8-13 of Mr. Bridson's testimony, please provide the revenue requirement included in the Company's claim associated with the 8% of JEC owned by Wilmington Trust. Please include all revenue requirement components including revenues, expenses, and capital costs.

Response:
8% of the original plant cost of Jeffrey Energy Center is owned by the Wilmington Trust as a result of a sale/leaseback transaction and is not in Westar's rate base. Westar purchased capital investments made after the sale/leaseback transaction was complete at a gross book value of $31,438,966, which went into rate base, along with accumulated depreciation of $6,743,880 which reduced rate base. As part of the transaction, Westar also purchased other net assets of $1,859,303 consisting primarily of fuel stock and materials and supplies. Since the purchase, Westar has made environmental and other capital improvements to the plant with a net book value at the end of the test year of $95,684,747. This is included in rate base as leasehold improvements. Westar's plant investment is depreciated. Annual depreciation expense at the rates proposed in the case totals approximately $4.1M, the exact amount of which is not readily determinable or identifiable in the revenue requirement model. To date, the ADIT on the plant investments, which offsets rate base, is approximately $14 million, the exact amount of which is not readily determinable or identifiable in the revenue requirement model. In the test year Westar received $41.5 million of demand revenue from a wholesale customer contracted to take up to 8% of the power generated by the plant. The demand revenue is determined by Westar's net capital investment in the plant at an agreed upon return as well as expenses defined by the contract. Attached is a file showing Westar's costs included in both step 1 and step 2 of the revenue requirement in this case as well as the demand revenue received from the wholesale customer. The file shows an increase of $41.5 million in the operating income required due to the expiration of the contract in 1/2019.

Attachment File Name	Attachment Note
Wilmington Trust CURB-17.xlsx	

Estimated Costs for JEC 8% Lease *in millions* CURB-17

	Step 1 Revenue Requirement	Step 2 Revenue Requirement
Rate Base		
Plant in Service - cost of Leasehold Improvements	$ 127.1	$ 127.1
Less: Accumulated Amortization of Leasehold Improvements	$ (18.5)	$ (18.5)
Net Book Value of Leasehold Improvements	$ 108.6	$ 108.6
Less: ADIT from Leasehold Improvements	$ (14.0)	$ (14.0)
Total Rate Base	$ 94.6	$ 94.6
Rate of Return on Rate Base	9.169%	9.169%
Return on Rate Base	**$ 8.7**	**$ 8.7**
Demand Revenue from MKEC Purchased Power Agreement	$ (41.5)	
Cost of Service		
Non-Fuel O&M	$ 6.9	$ 6.9
Rent Expense (Lease payment to Key)	$ 8.3	$ 8.3
Book Depreciation on Leasehold improvements	$ 4.1	$ 4.1
Property Tax Expense on Leasehold Improvements	$ 3.0	$ 3.0
Operating (Income) Loss	**$ (19.2)**	**$ 22.3**
Operating Income Required	**$ (10.6)**	**$ 30.9**

Source: 1 Final Demand Files MMYY.xls.

MKEC Fuel Revenue

16-Jul	$	1,856,874
16-Aug	$	1,995,941
16-Sep	$	1,519,254
16-Oct	$	1,014,789
16-Nov	$	1,110,066
16-Dec	$	1,554,569
17-Jan	$	1,688,673
17-Feb	$	1,279,137
17-Mar	$	1,168,872
17-Apr	$	581,217
17-May	$	802,932
17-Jun	$	1,851,131
	$	16,423,455

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [CURB] [Thomas Connors]
Data Request: CURB-48 :: CWIP
Date: 2018-05-29

Question 1 (Prepared by Chris Perry)
Regarding the Company's CWIP claim of $233,924,824, please provide, separately for distribution plant, general plant, and intangible plant, a) the amount of CWIP at June 30, 2017 that has gone into service, b) the amount of CWIP at June 30, 2017 that has not yet gone into service but which is expected to go into service by June 30, 2018, c) the amount of CWIP at June 30, 2017 that is not expected to go into service by June 30, 2018.

Response:
See attached file.

Attachment File Name	Attachment Note
Chris Perry Verification.48.pdf	
DR 48 CWIP updated 5.15.18.xlsx	

Row Labels		Sum of Sum of Amount
10000		
Dist Plant - Elec	$	23,897,280.09
General Plant	$	9,288,072.62
Intangible Plant	$	6,177,478.85
10000 Total	$	39,362,831.56
10100		
Dist Plant - Elec	$	20,264,234.18
General Plant	$	11,274,087.30
Intangible Plant	$	(2,738,322.24)
10100 Total	$	28,799,999.24
Grand Total	$	68,162,830.80

Reconciliation of Dist/Gen Plant/Intangible CWIP		
Original CWIP Detail	74,930,087.01	*Original CWIP Detail tab*
Remove: Revenue Producing Work Orders	(1,684,613.80)	*Original CWIP Detail tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(5,082,642.41)	*Original CWIP Detail tab - sort by New Reclass column = RECLASS*
CWIP Adjustment for Distribution, General, Intangible	68,162,830.80	
Distribution Work Orders Completed or In-Service:		
Distribution Work Orders Completed or in-Service as of 5/15/18	41,072,165.25	*Distrib. - Completed or In-Serv tab*
Remove: Revenue Producing Work Orders	(14,806.18)	*Distrib. - Completed or In-Serv tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(351,103.88)	*Distrib. - Completed or In-Serv tab - sort by New Reclass column = RECLASS*
Add: Work Orders NOT included in original CWIP Adjustment	775,286.87	*Distrib. - Completed or In-Serv tab - sort by Not in Adj but placed in service column = y*
Total Distribution Work Orders as of 6/30/17 placed in service by 5/15/18	**41,481,542.06**	
Distribution Work Orders Expected to be In-Service by 6/30/18:		
Blanket Work Orders	3,744,987.63	*Distrib. - Blankets tab*
Remove: Revenue Producing Work Orders	(1,571,524.15)	*Distrib. - Blankets tab - sort by Revenue Producing column = YES*
Blanket Work Orders	2,173,463.48	
Non-Blanket Work Orders that will be In-Service by 6/30/18	1,403,964.25	*Distrib. - Non-Blankets<063018 tab*
Remove: Revenue Producing Work Orders	-	*Distrib. - Non-Blankets<063018 tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	180,870.07	*Distrib. - Non-Blankets<063018 tab - sort by New Reclass column = RECLASS + Original CWIP Detail - sort b*
Non-Blanket Work Orders	1,584,834.32	
Total Distribution Work Orders Expected to be In-Service by 6/30/18	**3,758,297.80**	
Distribution Work Orders that will NOT be In-Service by 6/30/18:	445,451.55	*Distrib. - Non-Blankets>063018 tab*
Remove: Revenue Producing Work Orders	0	*Distrib. - Non-Blankets>063018 tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(37,610.25)	*Distrib. - Non-Blankets>063018 tab - sort by New Reclass column = RECLASS*
Total Distribution Work Orders that will NOT be In-Service by 6/30/18	**407,841.30**	

General and Intangible Plant Work Orders Completed or in-Service:		
Blanket Work Orders	77,898.01	*Gen and Int Blankets tab*
General and Intangible Plant Work Orders Completed or in-Service as of 5/15/18	20,472,313.88	*Gen and Int - Comp and InServ tab*
Remove: Revenue Producing Work Orders	0	*Gen and Int - Comp and InServ tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(15,435.49)	*Gen and Int - Comp and InServ tab - sort by New Reclass column = RECLASS*
Add: Work Orders NOT included in original CWIP Adjustment	1,030,107.69	*Gen and Int - Comp and InServ tab*
Total General and Intangible Plant Work Orders Completed or In-Service:	**21,564,884.09**	
General and Intangible Plant Work Orders Expected to be Completed or In-Service by 6/30/18:		
General and Intangible Plant Work Orders NOT Completed or in-Service as of 5/15/18	4,623,579.43	*Gen and Int<063018 tab*
Remove: Revenue Producing Work Orders	(98,283.47)	*Gen and Int<063018 tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(28,648.14)	*Gen and Int<063018 tab - sort by New Reclass column = RECLASS*
Total General and Intangible Plant Work Orders Expected to be Completed or In-Service:	**4,496,647.82**	
General and Intangible Plant Work Orders NOT Expected to be Completed or In-Service by 6/30/18:	1,477,692.35	*Gen and Int>063018 tab*
Remove: Revenue Producing Work Orders	-	*Gen and Int>063018 tab - sort by Revenue Producing column = YES*
Remove: Work Orders to be Reclassed[1]	(1,477,692.35)	*Gen and Int>063018 tab - sort by New Reclass column = RECLASS*
Total General and Intangible Plant Work Orders NOT Expected to be Completed or In-Service:	-	

[1] Includes work orders with an in-service date > than 6/30/18, cancelled and suspended work orders, maintenance work orders.

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Kristina Luke-Fry]
Data Request: KCC-055 :: Dues
Date: 0000-00-00

Question 1 (Prepared by Beckey Honas)
1. Please provide a listing of all payments made to industry associations, including memberships, included in the Applicant's test year expenses. Please include the amount paid, date paid, payee, and the account to which the payments were recorded. 2. If any association listed in response to this DR is involved in lobbying or political activity, please provide the percentage of dues or amount of payment(s) made to each association that are related to lobbying or political activity.

Response:
1. Attached is a listing of all payments made to industry associations, in the test year expenses. Shown on the attachment is the amount paid, date paid, payee, and the account to which the payments were recorded. 2. The attached file indicates associations which are involved in lobbying activities and the percentage of membership dues related to lobbying by the association.

Attachment File Name	Attachment Note
Becky Honas Verification.55.pdf	
KCC 55 Dues.xlsx	

Summary of Account 9302001 - Company Memberships
For the Period 7/1/2016 Though 6/30/2017

KCC-55

Account	Source	Amount
9302001	Allocations	$2,306.01
9302001	PS-Accounts Payable	$984,249.31
9302001	PS-Expenses	$34,075.05
9302001	PS-General Ledger	($83,300.82)
9302001	PS-PAYHR	$3,192.44
9302001	PS-Purchasing	$15,109.38
		$955,631.37

The remaining tabs contain the detail for the above.

CRITERIA

Account = 9302001
Amount Type = Actuals
Business Unit in 10000, 10100
Month Number BETWEEN '201607' AND '201612' OR MONTH_NUMBER BETWEEN '201701' AND '201706'

Account	Vendor Id	Vendor	Payment Date	Description	Amount	% of membership as indirect lobbying expense
9302001	ABILENEARE-001	ABILENE AREA CHAMBER OF COMMERCE	2/7/2017	2017 chamber dues renewal	$680.00	
9302001	ABILENEARE-001	ABILENE AREA CHAMBER OF COMMERCE	1/25/2017	Annual Member Banquet Tickets	$120.00	
9302001	AMERICANCO-001	AMERICAN COAL COUNCIL	12/30/2016	2017 ACC Membership	$2,800.00	
9302001	ARKANSASCI-002	ARKANSAS CITY AREA CHAMBER OF COMMERCE	1/17/2017	2017 chamber membership renewa	$365.00	
9302001	ARKANSASCI-002	ARKANSAS CITY AREA CHAMBER OF COMMERCE	1/25/2017	annual banquet spons	$300.00	
9302001	ARKANSASCI-002	ARKANSAS CITY CHAMBER OF COMMERCE	2/7/2017	annual banquet	$60.00	
9302001	CHAMBEROFC-001	CHAMBER OF COMMERCE	1/13/2017	Hutch chamber renewal 2017	$3,002.00	
9302001	BLUERAPIDS-002	CHAMBER OF COMMERCE OF BLUE RA	4/19/2017	chamber dues renewal	$100.00	
9302001	COWLEYCOUN-001	COWLEY COUNTY	1/25/2017	2017 Annual Bus. Part. Support	$1,000.00	
9302001	EDISONELEC-001	EDISON ELECTRIC INSTITUTE	1/3/2017	2017 EEI Membership Dues	$727,453.00	
9302001	ELDORADOCH-001	EL DORADO CHAMBER OF COMMERCE	1/17/2017	2017 chamber dues renewal	$1,339.00	
9302001	ELDORADOCH-001	EL DORADO CHAMBER OF COMMERCE	1/17/2017	Annual meeting 2017	$750.00	
9302001	ELDORADOIN-001	EL DORADO INC	9/20/2016	El Dorado Inc membershp rnwal	$1,800.00	
9302001	EMPORIACHA-001	EMPORIA CHAMBER OF COMMERCE	5/3/2017	Annual chamber dues renewal	$2,200.00	
9302001	EMPORIACHA-001	EMPORIA CHAMBER OF COMMERCE	5/3/2017	annual meeting - emporia	$600.00	
9302001	FORTSCOTTA-001	FORT SCOTT AREA CHAMBER OF COMMERCE	4/19/2017	chamber renewal for Kari West	$450.00	
9302001	GOTOPEKA-001	GO TOPEKA	3/7/2017	seizing the opportunity pledge	$10,000.00	
9302001	GREATPLAIN-003	GREAT PLAINS DEVELOPMENT AUTHORITY	1/27/2017	year 3 of committment	$1,000.00	
9302001	GREATERTOP-001	GREATER TOPEKA CHAMBER OF COMMERCE	12/2/2016	Annual Meeting Gold Sponsorshi	$1,200.00	
9302001	GREATERTOP-001	GREATER TOPEKA CHAMBER OF COMMERCE	1/25/2017	Chamber renewal	$21,667.00	
9302001	GREATERTOP-001	GREATER TOPEKA CHAMBER OF COMMERCE	2/2/2017	Military Relations Council spo	$1,200.00	
9302001	GREATERTOP-001	GREATER TOPEKA CHAMBER OF COMMERCE	1/31/2017	State of Community sponsor	$5,000.00	
9302001	GREATERWIC-001	GREATER WICHITA PARTNERSHIP	1/17/2017	economic dev 2017 dues	$22,500.00	
9302001	HAYSVILLEC-001	HAYSVILLE CHAMBER OF COMMERCE	2/24/2017	chamber dues	$300.00	
9302001	HAYSVILLEC-001	HAYSVILLE CHAMBER OF COMMERCE	3/6/2017	company renewal dues	$500.00	
9302001	HOMEBUILDE-001	HOME BUILDERS ASSOCIATION OF SALINA	3/7/2017	Membership Dues	$331.00	
9302001	HUTCHINSON-008	HUTCHINSON/RENO CHAMBER OF COMMERCE INC	1/27/2017	hutch rising pledge	$5,000.00	
9302001	INDEPENDEN-001	INDEPENDENCE CHAMBER OF COMMER	2/23/2017	annual meeting	$355.00	
9302001	INDEPENDEN-001	INDEPENDENCE CHAMBER OF COMMER	3/29/2017	company dues renewal	$1,002.00	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	3/17/2017	IEC monthly Chapte lunches for	$40.02	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	10/4/2016	Wichita IEC invoices for MO Ch	$840.50	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	11/1/2016	Wichita IEC invoices for MO Ch	$24.72	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	11/15/2016	Wichita IEC invoices for MO Ch	$273.68	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	12/21/2016	Wichita IEC invoices for MO Ch	$12.00	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	1/25/2017	Wichita IEC invoices for MO Ch	$22.00	
9302001	IECINC-001	INDEPENDENT ELECTRICAL CONTRACTORS INC	2/13/2017	Wichita IEC invoices for MO Ch	$36.39	
9302001	JUNCTIONCI-001	JUNCTION CITY AREA CHAMBER OF	3/6/2017	2017 capital camp eco dev	$2,500.00	
9302001	KANSASCITY-007	KANSAS CITY AREA DEVELOPMENT C	3/6/2017	2017 dues renewal	$20,000.00	
9302001	KIWANISCLU-001	KIWANIS CLUB OF SHAWNEE	10/20/2016	Kiwanis Club Dues 2016-17	$140.00	
9302001	LAWRENCECH-001	LAWRENCE CHAMBER OF COMMERCE	1/25/2017	Capital Campaign Pledge	$10,000.00	
9302001	LAWRENCECH-001	LAWRENCE CHAMBER OF COMMERCE	1/27/2017	Eco Dev	$750.00	
9302001	LAWRENCECH-001	LAWRENCE CHAMBER OF COMMERCE	1/25/2017	Lawrence chamber dues renewal	$19,350.00	
9302001	LEAGUEOFKA-001	LEAGUE OF KANSAS MUNICIPALITIES	2/23/2017	annual conf	$10,000.00	
9302001	LEGACYOFLE-001	LEGACY OF LEADERSHIP/EDUCATION	3/28/2017	2017 1/2 Page Sponsorship	$500.00	
9302001	LEGACYOFLE-001	LEGACY OF LEADERSHIP/EDUCATION	2/24/2017	2017 program spons leadership	$10,000.00	
9302001	LEGACYOFLE-001	LEGACY OF LEADERSHIP/EDUCATION	5/19/2017	Tution for 2017 leadship Kansa	$2,000.00	
9302001	MANHATTANA-001	MANHATTAN AREA CHAMBER OF COMM	1/17/2017	Annual Advantage Manhattan	$5,000.00	
9302001	MANHATTANA-001	MANHATTAN AREA CHAMBER OF COMM	3/6/2017	annual mtg	$425.00	
9302001	MARSHALLCO-003	MARSHALL COUNTY PARTNERSHIP 4 GROWTH	1/18/2017	membership dues renewal	$130.00	
9302001	MARYSVILLE-001	MARYSVILLE CHAMBER OF COMMERCE	1/17/2017	2017 dues renewal	$473.00	
9302001	MONTGOMERY-002	MONTGOMERY COUNTY ACTION COUNCIL	1/17/2017	2017 annual membership dues	$1,500.00	
9302001	NATIONALCO-001	NATIONAL COAL TRANSPORTATION ASSOCIATION	1/11/2017	2017 NCTA Membership	$1,850.00	
9302001	NEWTONCHAM-001	NEWTON AREA CHAMBER OF COMMERC	1/17/2017	2017 chamber dues renewal	$1,585.00	
9302001	POTTAWATOM-003	POTTAWATOMIE COUNTY ECONOMIC DEVELOPMENT	2/23/2017	eco dev	$2,500.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	10/25/2016	Dues	$250.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	1/1/2017	DUES	$65.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	4/1/2017	DUES	$65.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	10/25/2016	Meals	$120.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	1/1/2017	MEALS	$120.00	
9302001	SALINAROTA-001	SALINA ROTARY CLUB	4/1/2017	MEALS	$120.00	
9302001	SINGLEPAY-001	SINGLE PAY VENDOR- NOT REPORTABLE	7/5/2016	Table for Black & White Ball	$1,000.00	
9302001	SMARTGRID-001	SMART GRID CONSUMER COLLABORATIVE	3/27/2017	2017 SCGG Membership	$10,000.00	
9302001	SOLARELECT-001	SOLAR ELECTRIC POWER ASSOCIATION	9/1/2016	12/1/16-11/30/17 Membership	$6,800.00	
9302001	SOUTHHUTCH-002	SOUTH HUTCHINSON CHAMBER OF COMMERCE	4/20/2017	company dues	$250.00	
9302001	SOUTHEASTK-001	SOUTHEAST KANSAS INC	3/20/2017	Membership Renewal 2107	$1,000.00	
9302001	KANSASCHAM-001	THE KANSAS CHAMBER	1/18/2017	2017 Membership dues	$5,618.00	
9302001	TOPEKACOMM-001	TOPEKA COMMUNITY FOUNDATION	5/9/2017	1st of three installments	$12,500.00	
9302001	TOPEKACOMM-001	TOPEKA COMMUNITY FOUNDATION	9/22/2016	3rd installment yearly dues	$10,000.00	
9302001	VALLEYCENT-001	VALLEY CENTER CHAMBER OF COMMERCE	2/27/2017	2017 chamber dues renewal	$175.00	
9302001	WICHITAMAN-001	WICHITA MANUFACTURERS ASSOCIAT	1/17/2017	2017 membership renewal	$150.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/25/2017	community advancement investme	$4,000.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/30/2017	Gold Sponsor for St Legislativ	$2,500.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/25/2017	membership dues renewal	$12,240.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/25/2017	Wichita insight and honors nig	$5,000.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/25/2017	young professionals corp inves	$4,000.00	
9302001	WICHITAREG-001	WICHITA REGIONAL CHAMBER OF COMMERCE INC	1/25/2017	YPW KS summit	$5,000.00	
9302001	WORKFORCEA-001	WORKFORCE ALLIANCE OF SOUTH CENTRAL KANS	2/8/2017	2017 reap dues	$250.00	
					$984,249.31	

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Kristina Luke-Fry]
Data Request: KCC-060 :: Health Plan
Date: 0000-00-00

Question 1 (Prepared by Kim Rollenhagen)
1. Is the company's health plan self insured? If yes, please provide the dollar amount of the individual stop loss and the dollar amount of the company's aggregate stop loss. 2. Please provide the dollar amount of health claims paid annually for each of the last five years. Each year should be on the same twelve month period as the test year. 3. Does the company during the year (especially at year end) accrue medical expenses? If yes, please explain the purpose of the accrual.

Response:
1. Yes, the company's health plan is self-insured. The individual stop loss amount is $300,000 and the aggregate stop loss amount is $27,255,895. 2. See attached spreadsheets. (KCC-60_DR_2422000.xlsx and KCC-60_DR_9260012.xlsx; KCC-60_DR_2018.xlsx) 3. Westar has a policy to maintain a medical reserve balance equal to two months of average medical, dental, and prescription drug claims. The average claims cost is calculated quarterly based on the prior 12 months of actual claims paid. An accrual is done to maintain the medical reserve balance at this level.

Attachment File Name	Attachment Note
KCC-60_DR_2018.xlsx	
KCC-60_DR_2422000.xlsx	
KCC-60_DR_9260012.xlsx	
Kim Rollenhagen Verification.60.pdf	

9260012 - MEDICAL & DENTAL EXPENSES KCC-60

As of December 31, 2012

C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YTD TOTAL
2	Accruals:													
3	Active (JE 39)	938,495.22	1,306,373.34	2,267,679.86	1,533,149.64	1,073,544.93	1,574,307.89	1,385,340.43	1,714,250.53	535,451.74	1,710,388.28	2,160,580.90	716,943.28	16,916,506.04
4	Admin Expense:													
5	FMH (JE 24)	179,402.40	168,114.46	173,366.45	169,716.50	168,606.45	167,250.36	167,887.46	242,561.64	158,592.16	11,487.63	159,197.65	155,876.91	1,922,060.07
6	Taben Group (Benefits billing for COBRA)		618.00						1,858.25	9,728.25		7,325.00	0.00	19,529.50
7	Express Scripts	550,808.59	579,387.34	537,476.53	316,505.89	880,365.61	628,077.70	561,430.93	586,191.64	578,887.48	538,323.46	591,737.76	579,255.92	6,928,448.85
8	Express Scripts rebate/Performance Guarantees/refunds		(1,543.29)	(100,059.25)			(98,645.50)		(1,919.63)	(101,919.25)			(99,105.50)	(403,192.42)
9	Delta Dental		4,413.20	4,433.77		4,370.19	13,346.09	4,551.12	4,543.28	4,509.96	4,476.64	4,441.36	4,449.20	53,534.81
10	FSA Correction	(6.00)					71,502.01							71,496.01
11	HRA Correction			3,684.95		2,668.04			(9,686.41)					(3,333.42)
12	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
13														
14	CURRENT MONTH	1,668,700.21	2,057,363.05	2,886,582.31	2,019,372.03	2,129,555.22	2,355,838.55	2,119,209.94	2,537,799.30	1,185,250.34	2,264,676.01	2,923,282.67	1,357,419.81	
15	YEAR-TO-DATE	1,668,700.21	3,726,063.26	6,612,645.57	8,632,017.60	10,761,572.82	13,117,411.37	15,236,621.31	17,774,420.61	18,959,670.95	21,224,346.96	24,147,629.63	25,505,049.44	25,505,049.44
16														
17	Kansas Electric	1,047,440.88	1,291,406.78	1,813,279.63	1,267,559.83	1,336,721.81	1,478,759.85	1,330,228.08	1,590,363.69	743,981.63	1,421,537.12	1,834,944.52	852,052.40	16,008,276.22
18	KG&E	621,259.33	765,956.27	1,073,302.68	751,812.20	792,833.41	877,078.70	788,981.86	947,435.61	441,268.71	843,138.89	1,088,338.15	505,367.41	9,496,773.22
19	Total Company	1,668,700.21	2,057,363.05	2,886,582.31	2,019,372.03	2,129,555.22	2,355,838.55	2,119,209.94	2,537,799.30	1,185,250.34	2,264,676.01	2,923,282.67	1,357,419.81	25,505,049.44
20														
21		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

9260012 - MEDICAL & DENTAL EXPENSES

As of December 31, 2013

C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YTD TOTAL
2	Accruals:													
3	Active	1,993,957.83	1,812,472.42	1,054,513.13	1,169,344.04	1,106,050.52	1,351,068.75	1,231,151.65	1,756,548.67	595,011.21	1,208,001.52	1,473,606.24	1,262,338.51	16,014,064.49
4	Admin Expense:													
5	FMH	173,759.41	164,978.14	179,716.83	169,583.20	193,999.01	178,660.87	199,581.82	179,030.42	172,407.12	226,227.62	176,142.10	178,620.94	2,192,707.48
6	Taben Group (Benefits billing for COBRA)	3,692.50		3,798.50	1,614.20		3,592.44	1,952.12	3,931.24	(2,609.84)	1,499.25	1,460.76	1,446.28	20,377.45
7	Express Scripts	587,968.97	579,776.47	526,942.79	477,140.79	249,163.65	839,264.02	484,910.38	560,903.29	522,893.52	517,207.26	617,595.99	792,817.34	6,756,584.47
8	Express Scripts rebate/Performance Guarantees/refunds	0.00	0.00	(96,994.25)	0.00	0.00	(101,244.75)	0.00	0.00	(95,266.81)	0.00	0.00	(86,343.50)	(379,849.31)
9	Delta Dental	1,969.80	4,544.00	6,950.04	4,468.00	4,440.00	4,426.00	4,416.00	4,396.00	4,400.00	4,380.00	4,374.00	4,376.00	53,139.84
10	Warfarin Sodium Litigation settlement	0.00	(92.70)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(92.70)
11	HRA Minimum Funding	(24,382.23)	24,382.23	0.00	(24,382.23)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(24,382.23)
12	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
13	Walgreens refund												(108.20)	(108.20)
14														
15	CURRENT MONTH	2,736,966.28	2,586,060.56	1,674,927.04	1,797,768.00	1,553,653.18	2,275,767.33	1,922,011.97	2,504,809.62	1,196,835.20	1,957,315.65	2,273,179.09	2,153,147.37	
16	YEAR-TO-DATE	2,736,966.28	5,323,026.84	6,997,953.88	8,795,721.88	10,349,375.06	12,625,142.39	14,547,154.36	17,051,963.98	18,248,799.18	20,206,114.83	22,479,293.92	24,632,441.29	24,632,441.29
17														
18	BU 10000	1,711,698.71	1,626,455.85	1,047,499.37	1,115,190.53	971,654.70	1,423,264.90	1,303,132.18	1,567,254.53	748,500.72	1,225,745.95	1,421,646.19	1,346,578.35	15,508,621.98
19	BU 10100	1,025,267.57	959,604.71	627,427.67	682,577.47	581,998.48	852,502.43	618,879.79	937,555.09	448,334.48	731,569.70	851,532.90	806,569.02	9,123,819.31
20	Total Company	2,736,966.28	2,586,060.56	1,674,927.04	1,797,768.00	1,553,653.18	2,275,767.33	1,922,011.97	2,504,809.62	1,196,835.20	1,957,315.65	2,273,179.09	2,153,147.37	24,632,441.29
21														
22		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

9260012 - MEDICAL & DENTAL EXPENSES
As of December 31, 2014
C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #	DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) YTD TOTAL
1														
2	Accruals:													
3	Active	1,810,757.51	759,871.93	634,023.61	808,975.83	1,111,448.29	931,924.67	1,608,615.01	1,158,695.63	1,033,456.62	1,470,002.44	742,565.99	918,234.27	12,988,571.80
4	Admin Expense:													
5	FMH	217,958.38	217,477.33	208,592.94	238,373.23	214,079.14	230,747.02	236,425.53	213,983.83	221,388.88	234,695.53	231,318.42	212,295.54	2,677,335.77
6	Taben Group (Benefits billing for COBRA)	1,429.29		1,436.25	2,964.74	1,443.69	0.00	2,886.50	1,463.99	1,457.12	0.00	2,935.18	1,478.45	17,495.21
7	Express Scripts	252,039.21	581,898.31	452,529.90	505,214.30	466,821.63	502,341.90	523,377.50	344,592.51	506,975.66	841,369.99	592,457.18	538,762.39	6,108,380.48
8	Express Scripts rebate/Performance Guarantees/refunds								(130.81)	0.00				(130.81)
22	Delta Dental	4,346.00	4,617.90	4,613.70	4,603.20	0.00	9,145.50	0.00	9,120.30	4,584.30	4,580.10	4,622.10	4,628.40	54,861.50
10	Warfarin Sodium Litigation settlement													0.00
11	HRA Minimum Funding				(47,119.78)									(47,119.78)
12	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
13	Walgreens refund													0.00
14	Dept of Health - ACA Transitional Reinsurance Contribution												275,655.24	275,655.24
15														
16	CURRENT MONTH	2,286,530.39	1,563,865.47	1,301,196.40	1,513,011.52	1,793,792.75	1,674,159.09	2,371,304.54	1,727,725.45	1,767,862.58	2,550,648.06	1,573,898.87	1,951,054.29	
17	YEAR-TO-DATE	2,286,530.39	3,850,395.86	5,151,592.26	6,664,603.78	8,458,396.53	10,132,555.62	12,503,860.16	14,231,585.61	15,999,448.19	18,550,096.25	20,123,995.12	22,075,049.41	22,075,049.41
18														
19	BU 10000	1,429,996.11	978,041.47	815,496.52	947,961.76	1,112,091.49	1,047,019.10	1,483,013.86	1,080,519.50	1,105,621.26	1,595,175.30	986,047.79	1,221,923.15	13,802,907.31
20	BU 10100	856,534.28	585,824.00	485,699.88	565,049.76	681,701.26	627,139.99	888,290.68	647,205.95	662,241.32	955,472.76	587,851.08	729,131.14	8,272,142.10
21	Total Company	2,286,530.39	1,563,865.47	1,301,196.40	1,513,011.52	1,793,792.75	1,674,159.09	2,371,304.54	1,727,725.45	1,767,862.58	2,550,648.06	1,573,898.87	1,951,054.29	22,075,049.41
22														
23		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

9260012 - MEDICAL & DENTAL EXPENSES
As of December 31, 2015
C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #	DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) YTD TOTAL
1														
2	Accruals:													
3	Active	1,789,708.75	826,324.19	713,940.41	1,255,720.63	1,144,454.14	638,703.57	1,109,918.01	978,665.67	1,021,443.54	1,724,196.72	1,029,464.15	1,407,021.84	13,639,561.62
4	Admin Expense:													
5	CoreSource (formerly FMH)	220,744.23	223,609.24	221,206.43	215,715.02	234,826.44	257,979.72	230,451.71	212,508.88	212,538.62	205,364.57	216,145.67	110,345.59	2,561,436.12
6	Taben Group (Benefits billing for COBRA)	1,453.00	0.00	2,913.02	1,451.95	1,420.44	1,457.33	1,426.06	1,419.84	1,404.04	1,431.18	0.00	1,417.10	15,793.96
7	Express Scripts	338,646.51	866,781.38	558,222.58	570,387.73	573,760.55	568,680.06	567,950.92	713,855.57	541,080.92	601,144.81	684,280.01	586,558.58	7,171,349.62
8	ESI rebate accrual	0.00	0.00	0.00	0.00	0.00	(565,091.82)	0.00	0.00	0.00	0.00	0.00	0.00	(565,091.82)
9	Express Scripts rebates	0.00	(504,112.95)	(298,633.94)	0.00	(327,436.74)	0.00	(394,502.43)	0.00	(335,373.68)	0.00	0.00	(284,028.83)	(2,144,088.57)
10	Express Scripts Performance Guarantees/refunds	0.00	0.00	0.00	0.00	(33,522.37)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(33,522.37)
11	Delta Dental	4,651.50	4,963.20	4,930.20	4,925.80	4,963.20	4,884.00	4,870.80	4,846.60	4,829.00	4,804.80	4,807.00	4,822.40	58,298.50
12	Warfarin Sodium Litigation settlement													0.00
13	HRA Minimum Funding													0.00
14	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
15	Walgreens refund													0.00
16	Dept of Health - ACA Transitional Reinsurance Contribution												194,465.48	194,465.48
17														
18	CURRENT MONTH	2,355,203.99	1,417,565.06	1,202,578.70	2,048,201.13	1,598,465.66	906,612.86	1,520,115.07	1,911,296.56	1,445,922.44	2,536,942.08	1,934,696.83	2,020,602.16	
19	YEAR-TO-DATE	2,355,203.99	3,772,769.05	4,975,347.75	7,023,548.88	8,622,014.54	9,528,627.40	11,048,742.47	12,960,039.03	14,405,961.47	16,942,903.55	18,877,600.38	20,898,202.54	20,898,202.54
20														
21	BU 10000	1,470,462.02	883,568.29	749,567.32	1,278,499.31	872,978.22	688,437.22	798,878.66	1,191,311.15	1,049,852.54	1,581,276.01	1,205,896.53	1,259,441.32	13,030,168.59
22	BU 10100	884,741.97	533,996.77	453,011.38	769,701.82	725,487.44	218,175.64	721,236.41	719,985.41	396,069.90	955,666.07	728,800.30	761,160.84	7,868,033.95
23	Total Company	2,355,203.99	1,417,565.06	1,202,578.70	2,048,201.13	1,598,465.66	906,612.86	1,520,115.07	1,911,296.56	1,445,922.44	2,536,942.08	1,934,696.83	2,020,602.16	20,898,202.54
24														
25		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

9260012 - MEDICAL & DENTAL EXPENSES
As of December 31, 2016
C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YTD TOTAL
2	Accruals:													
3	Active	2,519,373.58	1,386,583.89	1,266,090.81	1,434,786.92	(332,327.61)	1,529,959.86	931,502.76	1,155,916.23	1,876,647.39	1,100,039.97	1,661,700.92	2,789,571.95	17,319,846.67
4	Accrual adjustment	0.00	0.00	0.00	0.00	0.00	1,450,906.89	0.00	0.00	0.00	0.00	0.00	0.00	1,450,906.89
5	Admin Expense:													
6	CoreSource (formerly FMH)	195,875.48	181,782.23	210,037.49	186,503.32	183,232.17	196,816.62	192,356.81	181,376.27	187,706.49	178,624.65	181,440.92	182,381.77	2,258,134.22
7	Taben Group (Benefits billing for COBRA)	1,414.78	1,403.30	7.50	7.50	7.50	7.50	7.50	15.00	7.50	7.50	0.00	22.50	2,908.08
8	Express Scripts	673,689.71	666,890.31	641,940.62	672,842.54	554,721.05	574,801.52	632,671.75	572,737.70	600,517.57	660,339.42	619,790.48	642,457.28	7,513,399.95
9	ESI rebate accrual	0.00	0.00	0.00	0.00	0.00	(127,582.50)	0.00	0.00	0.00	0.00	0.00	0.00	(127,582.50)
10	Express Scripts rebates	0.00	0.00	(372,312.43)	0.00	0.00	(393,633.70)	0.00	0.00	(362,400.16)	0.00	(375,133.67)	0.00	(1,503,479.96)
11	Express Scripts Performance Guarantees/refunds/HCV reimb	0.00	0.00	0.00	(5,906.48)	0.00	(64,593.52)	0.00	0.00	0.00	0.00	0.00	0.00	(70,500.00)
12	Delta Dental	4,807.00	5,135.90	5,089.90	5,066.90	0.00	10,103.90	5,050.80	0.00	10,014.20	5,004.80	4,997.90	4,998.40	60,269.70
13	Warfarin Sodium Litigation settlement													0.00
14	HRA Minimum Funding													0.00
15	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
16	Walgreens refund													0.00
17	Dept of Health - ACA Transitional Reinsurance Contribution												117,126.00	117,126.00
18														
19	CURRENT MONTH	3,395,160.55	2,241,795.63	1,750,853.89	2,293,300.70	405,633.11	3,176,786.57	1,761,589.62	1,910,045.20	2,312,492.99	1,944,016.34	2,092,796.55	3,736,557.90	
20	YEAR-TO-DATE	3,395,160.55	5,636,956.18	7,387,810.07	9,681,110.77	10,086,743.88	13,263,530.45	15,025,120.07	16,935,165.27	19,247,658.26	21,191,674.60	23,284,471.15	27,021,029.05	27,021,029.05
21														
22	BU 10000	2,116,203.58	1,397,311.21	1,093,224.59	1,429,414.33	357,235.97	1,835,615.38	1,099,901.45	1,190,531.18	1,304,860.75	1,211,705.38	1,304,440.09	2,328,996.54	16,669,440.45
23	BU 10100	1,278,956.97	844,484.42	657,629.30	863,886.37	48,397.14	1,341,171.19	661,688.17	719,514.02	1,007,632.24	732,310.96	788,356.46	1,407,561.36	10,351,588.60
24	Total Company	3,395,160.55	2,241,795.63	1,750,853.89	2,293,300.70	405,633.11	3,176,786.57	1,761,589.62	1,910,045.20	2,312,492.99	1,944,016.34	2,092,796.55	3,736,557.90	27,021,029.05
25														
26		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

9260012 - MEDICAL & DENTAL EXPENSES
As of December 31, 2017
C:\Users\Owner\AppData\Local\Packages\Microsoft.MicrosoftEdge_8wekyb3d8bbwe\TempState\Downloads\[KCC-60_DR_9260012.xlsx]9260012

Line #		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YTD TOTAL
2	Accruals:													
3	Active	1,453,606.87	1,419,124.70	986,945.97	1,448,974.11	654,971.78	1,003,589.42	1,082,652.03	1,027,490.79	2,523,043.54	501,138.43	1,759,218.68	1,286,937.74	15,147,694.06
4	Accrual adjustment													0.00
5	Admin Expense:													
6	CoreSource (formerly FMH)		391,161.91	212,318.48	214,315.30	207,703.53	193,483.94	199,349.23	187,637.76	194,975.44	201,432.70	194,084.38	191,941.01	2,388,403.68
7	Taben Group (Benefits billing for COBRA)		7.50	15.00		15.00	7.50		7.50	7.50	7.50	7.50	7.50	82.50
8	**Express Scripts**	**593,795.65**	**704,566.65**	**528,560.19**	**698,934.95**	**626,983.37**	**655,084.28**	**594,365.48**	**621,393.73**	**800,411.94**	**566,742.32**	**422,410.66**	**723,290.30**	**7,536,539.52**
9	ESI rebate accrual			0.00			(33,529.74)			0.00	0.00		0.00	**(33,529.74)**
10	**Express Scripts rebates**			**(352,729.29)**			**(362,144.98)**			**(387,192.24)**	**0.00**		**(430,876.72)**	**(1,532,943.23)**
11	**Express Scripts Performance Guarantees/refunds/HCV reimb/2016 SafeGuard Rx**					**(3,248.86)**					**(2.49)**			**(3,251.35)**
12	**VOYA Stop Loss Receipt**		**(494,460.53)**											**(494,460.53)**
13	Delta Dental	2,398.90	5,111.25	5,066.60	5,038.40	5,012.55	5,003.15	5,003.15	4,972.60	4,953.80	4,935.00	4,918.55	4,897.40	57,311.35
14	Warfarin Sodium Litigation settlement													0.00
15	FSA long standing variance												6,027.80	6,027.80
16	FSA misc deposit												(367.09)	(367.09)
17	McGriff, Seibels, & Williams, Inc (ID Fraud Reimb Coverage - premium)													0.00
18	Invoice accrual (Delta Dental 4,895.05/Express Scripts 359,301.59)												364,196.64	364,196.64
19	Dept of Health - ACA Transitional Reinsurance Contribution													0.00
20														
21	CURRENT MONTH	2,049,801.42	2,025,511.48	1,380,176.95	2,367,262.76	1,491,437.37	1,461,493.57	1,881,369.89	1,841,502.38	3,136,199.98	1,274,253.46	2,380,639.77	2,146,054.58	
22	YEAR-TO-DATE	2,049,801.42	4,075,312.90	5,455,489.85	7,822,752.61	9,314,189.98	10,775,683.55	12,657,053.44	14,498,555.82	17,634,755.80	18,909,009.26	21,289,649.03	23,435,703.61	23,435,703.61
23														
24	BU 10000	1,264,522.50	1,249,538.04	851,431.16	1,460,364.40	920,067.71	906,028.47	1,160,617.09	1,136,025.69	1,934,721.76	786,086.97	1,468,616.68	1,325,777.26	14,463,797.73
25	BU 10100	785,278.92	775,973.44	528,745.79	906,898.36	571,369.66	555,465.10	720,752.80	705,476.69	1,201,478.22	488,166.49	912,023.09	820,277.32	8,971,905.88
26	Total Company	2,049,801.42	2,025,511.48	1,380,176.95	2,367,262.76	1,491,437.37	1,461,493.57	1,881,369.89	1,841,502.38	3,136,199.98	1,274,253.46	2,380,639.77	2,146,054.58	23,435,703.61
27														
		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Kristina Luke-Fry]
Data Request: KCC-162 :: Working Capital Components
Date: 0000-00-00

Question 1 (Prepared by Rebecca Fowler)
Please provide the balance per books for the period of April 2014-March 2018 for the following items included in Westar's Section 6: a. Materials and Supplies b. Prepayments c. Fossil Fuel d. Nuclear Fuel

Response:
See attached file. KCC 162 - Working Capital.xlsx

Attachment File Name	Attachment Note
KCC 162 - Working Capital.xlsx	
Rebecca Fowler Verification.KCC162.pdf	

Westar Energy, Inc.
General Rate Review-Docket No. 18-WSEE-328-RTS
Test Year Ended 6/30/17

Fuel Stock KCC-162

Date	
14-Apr	85,368,268.99
14-May	88,861,361.23
14-Jun	83,455,204.49
14-Jul	75,274,804.25
14-Aug	67,810,831.96
14-Sep	68,659,171.15
14-Oct	72,942,150.39
14-Nov	70,661,290.01
14-Dec	70,415,386.44
15-Jan	73,103,653.18
15-Feb	75,988,540.21
15-Mar	86,400,772.63
15-Apr	92,241,668.01
15-May	99,052,167.35
15-Jun	94,450,135.66
15-Jul	83,693,188.69
15-Aug	86,426,274.80
15-Sep	89,144,238.94
15-Oct	95,083,888.56
15-Nov	102,680,446.75
15-Dec	113,394,459.38
16-Jan	115,303,556.94
16-Feb	113,221,459.31
16-Mar	113,901,808.93
16-Apr	113,003,972.83
16-May	115,163,533.92
Jun-16	107,328,338.97
Jul-16	101,229,020.29
Aug-16	95,604,987.50
Sep-16	95,930,885.90
Oct-16	104,268,751.72
Nov-16	108,850,756.27
Dec-16	107,085,737.36
Jan-17	108,368,079.36
Feb-17	111,737,308.74
Mar-17	115,865,662.75
Apr-17	119,935,498.58
May-17	116,234,263.73
Jun-17	106,763,854.18
Jul-17	94,239,711.00
Aug-17	87,893,356.20
Sep-17	87,429,501.14
Oct-17	93,421,353.89
Nov-17	95,916,529.83
Dec-17	94,038,951.25
Jan-18	91,621,042.29
Feb-18	85,773,716.44
Mar-18	89,124,553.05

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Katie Figgs]
Data Request: KCC-205 :: Payroll
Date: 0000-00-00

Question 1 (Prepared by Kim Rollenhagen)
For all Westar Non-Union and Union employees, please provide for years ending 2015, 2016, 2017, and March 31, 2018, annual merit (salary) increase for all employees and the day it was effective. If effective date occurs at the same designated time for all employees, please state the date and why this procedure was chosen.

Response:
The effective date for annual merit increases occurs at the same time for each employee segment as this is consistent with established practices and is the most common approach for administering an annual compensation program. It is more common to provide annual merit increases to an employee segment all at the same time, versus by anniversary date or at alternate dates driven by another factor. Year Non-Union (March 1) Union (July 1) 2018 3.19% TBD 2017 3.40% 3.00% 2016 3.31% 3.00% 2015 3.40% 3.00%

Attachment File Name	Attachment Note
Kim Rollenhagen Verification.205.pdf	

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Chad Unrein]
Data Request: KCC-208 :: IS-17 - Wolf Creek Outage
Date: 0000-00-00

Question 1 (Prepared by Amber Housholder)
1. Please provide an update to Westar workpaper IS -17 with actual costs through March 31, 2018. 2. Please state whether Westar has completed or anticipates to complete Wolf Creek outage by April 30, 2018. 3. In a secondary tab or column on the update to the IS-17 worksheet, please provide total expenditures Westar incurred in April 2018 and a column of the remaining estimated expenditures through the remaining outage schedule at the end of April. 4. Please include a pivot table for all outstanding work orders expected to be completed in April with total expenses already incurred for each work order and an estimate for any remaining cost for completion. 5. Please provide a pivot table of total expenditures the Westar has incurred during the Spring 2018 Wolf Creek outage. Please include in the pivot total expenses work orders numbers, description of expenses, FERC accounts, dates completed, vendors id, etc.

Response:
Supplemental response: Attached is the updated workpaper of WCNOC outage costs through April 30. See the new tab "No. 22 Cost Est DR208 Supplement". 1) Please see tab "No.22 Cost Est DR208 UPDATE" in file Wolf Creek Outage Workpaper IS-17 DR Update.xls. Column A has been updated with outage costs through March 31, 2018. 2) Wolf Creek Outage No. 22 will not be completed by April 30. The outage is scheduled to be complete in mid-May. 3) Please see tab "No.22 Cost Est DR208 UPDATE" in file Wolf Creek Outage Workpaper IS-17 DR Update.xls. Column B has been updated with outage costs through April 27, 2018. Column C has been updated with the remaining estimated expenditures through the end of April. Those two columns have been combined in column D to project to total project costs as of end of April 2018. Columns E – I use the end of April project total to reflect a new amortization cost. 4/5) Work orders are not used for O&M during the outage and the expense are not being capitalized.

Attachment File Name	Attachment Note
Amber Housholder 328 verification.208.pdf	
KCC-208 -Wolf Creek Outage Workpaper IS-17 DR Supplement Update.xlsx	
Wolf Creek Outage Workpaper IS-17 DR Update.xlsx	

Westar Energy, Inc.
General Rate Review-Docket No. 18-WSEE-328-RTS
Test Year Ended 6/30/17

Note: All Numbers are at Westar's 47% Share. Outage No. 22 is scheduled to be complete Mid-May of 2018.

Line	USoA		(A)	(B)	(C)	(D)	(E)	(F)
No.	Account	Account Description	Total No. 22 Outage Cost through 4/30/18	Amortized Monthly Cost of No. 22 Outage - 18 month amortization period	12 Months of No. 22 Amortized Costs	No. 20 Outage Amortization in the Test Year	No. 21 Outage Amortization in the Test Year	Adjustment - Increase/Decrease to O&M Accounts
				(A)/18	(B)*12			(C)-(D)-(E)
1	517	Oper. Supervision & Engineering	$ 128,699	7,150	85,800	38,657	134,666	(87,523)
2	518	Nuclear Fuel Expense	-	-		-	-	-
3	519	Coolants & Water	172,308	9,573	114,872	42,376	134,050	(61,555)
4	520	Steam Expenses	1,584,389	88,022	1,056,260	889,708	2,182,892	(2,016,340)
5	523	Electric Expenses	-	-		10,108	36,271	(46,379)
6	524	Misc. Nuclear Power Expense	1,966,649	109,258	1,311,099	457,835	1,111,777	(258,513)
7	Total Operations		3,852,045	214,003	2,568,030	1,438,683	3,599,656	(2,470,309)
8	528	Maint. Supervision & Engineering	1,631,692	90,650	1,087,795	539,759	978,953	(430,917)
9	529	Maint. Of Structures	34,200	1,900	22,800	46,335	363,792	(387,327)
10	530	Maint. Of Reactor Plan Equipment	7,788,058	432,670	5,192,039	1,869,593	5,036,780	(1,714,335)
11	531	Maint. Electric Plant	1,798,484	99,916	1,198,989	734,618	1,673,475	(1,209,104)
12	532	Maint. Of Misc Nuclear Plant	26,222	1,457	17,481	38,353	95,395	(116,267)
13	Total Maintenance		11,278,656	626,592	7,519,104	3,228,658	8,148,395	(3,857,949)
14	570	Maint. Of Station Equipment	- *	-	-	7,348	-	(7,348) *
15	920	A&G Salaries	79,524	4,418	53,016	32,991	84,272	(64,247)
16	921	Office Supplies & Expense	18			-	156	(156)
17	923	Outside Services	-			-	-	-
18	925	Injuries & Damages	-			-	-	-
19	926	Employee Pension & Benefits	75,460	4,192	50,307	22,506	67,299	(39,499)
20	Total Administrative & General		155,001	8,610	103,322	55,497	151,727	(103,902)
21	408.1	Taxes Other Than Income	$ 176,073	9,782	117,382	59,336	177,425	(119,380)
22	Total Outage Expense		15,461,775	858,987	10,307,838	4,789,523	12,077,203	(6,558,888)
23	Remove Costs recovered through Transmission Rider		-	-	-	7,348	-	(7,348)
24	Outage Cost Net of Transmission Costs		15,461,775	858,987	10,307,838	4,782,175	12,077,203	(6,551,540)

* These expenses will be recovered through the transmission recovery rider

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Brad Hutton]
Data Request: KCC-235 :: Insurance Premiums
Date: 0000-00-00

Question 1 (Prepared by Scott Unekis)
In reference to the Insurance Premium Increases workpaper for adjustments IS-34, please provide the actual Utility's Portion Cash Premium as of March 31, 2018, for all types of coverage listed in the workpaper.

Response:
Please find attached the file titled: 'Insurance Premium Increase IS-34 3.31.18 update.xls' The adjustment workpaper now reflects significant savings in property insurance premiums Westar was able to achieve since the filing.

Attachment File Name	Attachment Note
Insurance Premium Increase IS-34 3.31.18 update.xlsx	
Scott Unekis Verification.235.pdf	

Westar Energy, Inc.
General Rate Review-Docket No. 18-WSEE-328-RTS
Test Year Ended 6/30/17
Updated Through 3/31/18

Adjustment IS-34
Insurance Premium
Increase

Type of Coverage	(Utility's Portion) Cash Premium	Forecast as of 9/30/2017	Actual as of 3/31/18	Adjustment
Westar Liability (Cyber Security)	$ 548,728.00	$ 748,728.00	$ 637,500.00	$ 88,772.00
Adjustment to liability premiums (account 925004)				$ 88,772.00
Westar Property/Boiler & Machinery	$ 3,710,559.00	$ 3,825,559.00	$ 2,879,149.14	$ (831,409.86)
Adjustment to property premiums (account 924001)				$ (831,409.86)
Total Adjustment				$ (742,637.86)

Westar was able to renew property insurance as of 3/15/2018 at a significant discount from previous estimates.

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Kristina Luke-Fry]
Data Request: KCC-239 :: IS-8 RSUs
Date: 0000-00-00

Question 1 (Prepared by Rebecca Fowler)
1. Under the Active-Medical, Dental Heading there is a line item entitled "RSU's" with adjustments made to Account 920. For this category of costs, please provide all detailed supporting documentation, calculations, and assumptions that support the amounts listed as "Total Company" (WEN Increase and WES Increase). 2. Please provide the amount recorded in the Test Year along with the prior 5 years

Response:
1. See attached file. "RSU Amortization and WCNOC FAS 106 workpaper v3.xlsx" 2. 2013 $7,134,514 2014 $6,162,257 2015 $6,599,547 2016 $7,336,414 2017 $7,132,009 Test Year $7,264,193

Attachment File Name	Attachment Note
Rebecca Fowler Verification.KCC239.pdf	
RSU Amortization and WCNOC FAS 106 workpaper v3.xlsx	

Westar Energy, Inc.
RSU Expense

	2017 Time	2017 Perf	2017 Total	2018 Time	2018 Perf	2018 Total
Officer 3-yr (2015)	1,045,283.68	1,036,860.88	2,082,144.56	16,088.80	-	16,088.80
Officer 2-yr (2015)	12,066.52	-	12,066.52	-	-	-
Officer 3-yr (2016)	1,228,875.00	1,251,532.68	2,480,407.68	1,228,874.50	1,251,531.32	2,480,405.82
Officer 2-yr (2016)	-	22,705.50	22,705.50	-	-	-
Officer 3-yr (2017)	955,994.00	665,695.10	1,621,689.10	1,147,192.80	798,834.12	1,946,026.92
Officer 3-yr (2018)	-	-	-	1,048,930.29	1,048,930.29	2,097,860.59
	3,242,219.20	2,976,794.16	6,219,013.36	3,441,086.39	3,099,295.73	6,540,382.13
A-C (2015)	243,746.19	247,492.08	491,238.27	0.00	0.00	0.00
A-C (2016)	316,433.25	314,524.17	630,957.42	321,103.95	319,159.51	640,263.46
A-C (2017)	236,323.10	164,560.60	400,883.70	283,587.72	197,472.72	481,060.44
A-C (2018)			-	249,634.04	249,634.04	499,268.08
	796,502.54	726,576.85	1,523,079.39	854,325.71	766,266.27	1,620,591.98
PowerMktg (2015)	110,960.61	-	110,960.61	-	-	-
PowerMktg (2016)	12,688.32	-	12,688.32	12,688.30	-	12,688.30
PowerMktg (2017)	(7,119.17)	-	(7,119.17)	43,877.88	-	43,877.88
PowerMktg (2018)	64,796.50	-	64,796.50	64,796.50	-	64,796.50
PowerMktg (2019)	-	-	-	66,740.40	-	66,740.40
	181,326.26	-	181,326.26	188,103.08	-	188,103.08
Total RSU Exp	4,220,048.00	3,703,371.01	7,923,419.01	4,483,515.18	3,865,562.00	8,349,077.18
Per RSU Schedule			7,858,622.51			

Variance	(64,796.50)
2018 PowerMktg (projected amount to be recorded in Dec 2017)	64,796.50
	0.00

	7/1/2016-12/31/2016	1/1/2017-6/30/2017	Totals
Test Year RSU:	4,391,970.50	3,690,479.70	8,082,450.20
Below the Line	(101,269.17)	(16,407.96)	(117,677.13)
Capitalized	(394,929.00)	(305,651.57)	(700,580.57)
	3,895,772.33	3,368,420.17	7,264,192.50
Projected 2017			7,923,419.01
Below the Line			(90,663.13)
Capitalized			(688,863.58)
	-	-	7,832,755.88
Projected 2018			8,349,077.18
Below the Line			(94,051.54)
Capitalized			(728,735.61)
	-	-	8,255,025.64
Adjustment			990,833.14

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Justin Grady]
Data Request: KCC-259 :: Follow up to DR 180
Date: 0000-00-00

Question 1 (Prepared by Rebecca Fowler)
In response to Staff Data Request No. 180, there is a spreadsheet that was provided in support of the amount of revenue requirement included in the rate case for the Western Plains Wind Farm. This spreadsheet does not provide the requested data, which was requested by FERC account, as it is presented in the rate case. Please revise the DR response to provide the requested data by FERC account. Additionally, for each line item of the revenue requirement calculation, please provide a reference to the section of the Application or pro forma adjustment where the amount can be found

Response:
Supplemented on 5/22/18 with a new file, 'Western Plains Revenue Requirement_Revised_v2.xlsx'. -- See attached file. 'Western Plains Revenue Requirement_Revised.xlsx'

Attachment File Name	Attachment Note
Rebecca Fowler Verification.KCC259.pdf	
Western Plains Revenue Requirement_Revised.xlsx	
Western Plains Revenue Requirement_Revised_v2.xlsx	

Westar Energy, Inc.
Western Plains
Revenue Requirement in Test Year
in dollars

1	FERC Account Number		July 2016 through June 2017	Application Section	Rate Case Adjustments
		Plant in Service at 6/30/17:			
	340	Land	$ 12,574,276	4	
	341	Structures & Improvements	$ 12,318,452	4	
	344	Generators	$ 339,190,011	4	
	345	Accessory Electric Equipment	$ 45,943,009	4	
	346	Misc Power Plant Equipment	$ 1,820,308	4	
		Total Project Cost through 6/30/17	$ 411,846,055		
		O&M in test year:			
	4081110	FICA	$ 13,986	9	
	4081112	Fed Unemployment	$ 1,459	9	
	5460000	Supervision and Engineering	$ 200,624	9	
	5490000	Misc. Generation Expenses	$ 746,590	9	
	5500000	Rents	$ 1,190,816	9	
	5530000	Maintenance - Generating & Electric Plant	$ 1,717,223	9	
	5540000	Maintenance - Misc Power Generating Plant	$ 24,863	9	
	9250000	Injuries & Damages Transfer Cr	$ 858	9	
	9260000	Pension & Benefits Transfer Cr	$ 73,858	9	
	5530000	Maintenance - Generating & Electric Plant	$ 4,564,846	9	IS - 40 Budgeted O&M
	5490000	Misc. Generation Expenses	$ (613,602)	9	IS - 44 Remove PILOT and Royalty Payments to roll into RECA (Jan 17 through Jun 17)
	5500000	Rents	$ (1,190,815)	9	IS - 44 Remove PILOT and Royalty Payments to roll into RECA (Jan 17 through Jun 17)
		O&M excluding Royalty and PILOT payments	$ 6,730,706		
	4530000	Wind Production Tax Credit	$ (11,377,608)	9	
	4530000	Wind Production Tax Credit	$ (16,134,756)	9	IS - 46 To Reduce Income Tax Expense
	9240000	Annual Insurance	$ 170,293	9	
		Proposed Depreciation Rates:			
	341	Structures & Improvements	4.95%		See workpaper for IS-24_IS-7 Annualized Depreciation_Depreciation Study
	344	Generators	4.95%		See workpaper for IS-24_IS-7 Annualized Depreciation_Depreciation Study
	345	Accessory Electric Equipment	4.94%		See workpaper for IS-24_IS-7 Annualized Depreciation_Depreciation Study
	346	Misc Power Plant Equipment	4.94%		See workpaper for IS-24_IS-7 Annualized Depreciation_Depreciation Study
		MACRS 5	20.00%		
		Effective Tax Rate	26.53%		

Capital Structure: ***Currently Authorized per Order in Docket #: 15-WSEE-115-RTS***	Percent	Cost	After Tax WACC	Pretax WACC	After Tax w/Tax Shield
Debt	48.41%	4.65%	2.25%	2.25%	1.65%
Equity	51.59%	9.85%	5.08%	6.92%	5.08%
			7.33%	9.17%	6.74%

KCC-259

Depreciation and ADIT Calculations:

		July 2016 through June 2017		
	Gross Plant - Land	$ 12,574,276		
	Book Depreciation	$ -	10	
	Accumulated Depreciation	$ -	5	
	Net Book Plant	$ 12,574,276		
	Gross Plant - Structures and Improvements	$ 12,318,452		
403	Book Depreciation	$ 609,763	10	IS - 44 Annualized Depreciation
	Accumulated Depreciation	$ -	5	
	Net Book Plant	$ 12,318,452		
	Gross Plant - Generators	$ 339,190,011		
403	Book Depreciation	$ 16,789,906	10	IS - 44 Annualized Depreciation
	Accumulated Depreciation	$ 6,816,345	5	See workpaper for IS-24_IS-7 Annualized Depreciation_Depreciation Study
	Net Book Plant	$ 332,373,666		
	Gross Plant - Accessory Electric Equipment	$ 45,943,009		
403	Book Depreciation	$ 2,269,585	10	IS - 44 Annualized Depreciation
	Accumulated Depreciation	$ -	5	
	Net Book Plant	$ 45,943,009		
	Gross Plant - Misc. Power Equipment	$ 1,820,308		
403	Book Depreciation	$ 89,923	10	IS - 44 Annualized Depreciation
	Accumulated Depreciation	$ -	5	
	Net Book Plant	$ 1,820,308		
	Tax Basis - Plant	$ 399,271,779		
	Tax Depreciation Rate	20.0%		
	Tax Depreciation	$ 79,854,356		
	Accumulated Tax Depreciation	$ 79,854,356		
	Net Tax Basis	$ 319,417,423		
	Current Deferred Tax	$ 15,943,251		
	Accumulated Deferred Tax	$ 15,943,251		

Revenue Requirement:

Net Book Plant	$ 405,029,710	
Accumulated Deferred Income Taxes	$ -	See Response to DR KCC-329
Rate Base	$ 405,029,710	
Net Rate Base	$ 405,029,710	
Pre-Tax Rate of Return	9.17%	
Pre-Tax Rate of Return on Rate Base	$ 37,131,706	
Pretax Return on Equity	$ 28,014,224	
Pretax Cost of Debt	$ 9,117,482	
Tax Expense/(Credit) (PTC grossed up for taxes)	$ (37,447,072)	
O&M		
Variable O&M	$ 6,730,706	
Insurance Expense	$ 170,293	
Total O&M	$ 6,900,999	
Depreciation Expense	$ 19,759,177	
Total Revenue Requirement	**$ 26,344,810**	

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Brad Hutton]
Data Request: KCC-297 :: IS-25 Smartstar
Date: 0000-00-00

Question 1 (Prepared by Rebecca Fowler)
In reference to Westar workpaper IS-25 Regulatory Asset - Smartstar Amortization: a. If the merger is approved, would the amortization period be 5 years in this calculation? b. In the General Ledger tab, the amortization amount of (27,279.13) appears in account 1823046 twice for each month except the month of November 2015. Is this a mistake? If not, please explain the reasoning behind this. c. The formula for amortization to be added back for the period 11/16 to 11/17 reads: "= (+SUM(Amortization!B33:B40)+SUM(Amortization!G32:G40))*-1" Please explain why the range is G32:G40 and not G33:G40 to match the months taken from B10000.

Response:
a. The appropriate amortization period for the Smartstar regulatory asset will be determined through this docket. b. No. See detail attached at DR KCC-296. c. The formula should be (+SUM(Amortization!B33:B40)+SUM (Amortization!G33:G40))*-1".

Attachment File Name	Attachment Note
Rebecca Fowler Verification.KCC297.pdf	

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Justin Grady]
Data Request: KCC-303 :: Correction to Adjustment of Tax Change
Date: 0000-00-00

Question 1 (Prepared by Jeff Hall)
Regarding the work paper provided in support of IS-52 and IS-48, please provide the following: The supporting calculations regarding the impact of the tax rate change support a reduction to tax expense of $50,993,289, however, the adjustment in the rate case is -$50,824,467. Please confirm that the correct reduction to tax expense is $50,993, 289, or a reduction to tax expense from Westar's fully adjusted test year of $168,822.

Response:
We agree the correct reduction to tax expense is $50,993,289, or a reduction to tax expense from Westar's fully adjusted test year of $168,822.

Attachment File Name	Attachment Note
Jeff Hall Verification.303.pdf	

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KCC] [Justin Grady]
Data Request: KCC-309 :: Rate Base effects of PTCs
Date: 0000-00-00

Question 1 (Prepared by Jeff Hall)
Please provide an explanation as to why Westar believes it is appropriate to increase the deferred tax asset in Account 190 and thus increase rate base through Adjustment No. RB-11 for the value of the production tax credits adjusted in Income Statement Adjustment No. IS-46.

Response:
The production tax credits adjusted in Income Statement Adjustment No. IS-46 reduces tax expense and as a result reduces our revenue requirement. However, since Westar currently has net operating losses, we are not able to utilize these credits on our tax return and are required to defer these credits in Account 190. This is the same treatment for production tax credits earned during the test period that were not utilized on a tax return. See attached file for a schedule detailing PTC's by month and the resulting annual change to ADIT for Flat Ridge and Central Plains which are the two wind farms whose PTC's will be expiring in early 2019.

Attachment File Name	Attachment Note
Jeff Hall Verification.309.pdf	
KCC - 309 Monthly Production Tax Credits 2009-2018 (2).xlsx	

Home Page Change Password

Wednesday, June 06, 2018
Logged in as: [**Andrea Crane**] Logout

Docket: [18-WSEE-328-RTS] 2018 Rate Review
Requestor: [KIC] [Andrerw French-See Smithyman & Zakoura]
Data Request: KIC-16 :: Bridson's Testimony pg 13 - Wind facility produce $27 million fuel
Date: 0000-00-00

Question 1 (Prepared by John Grace)
On an electronic spreadsheet with all formulas intact, please provide a complete copy of the study supporting Mr. Bridson's Direct Testimony at page 13 that the wind facility would produce $27 million of annual fuel savings, relative to a levelized fixed cost of the wind facility of $23 million. With respect to this testimony, please provide all assumptions used to develop the levelized revenue requirement along with all operating costs based on the $417 million development cost of the Western Plains wind farm.

Response:
The attached "Model Output Avoided Cost 100115.xlsx" supports $27 million of annual fuel savings. The value in cell G13 of the tab "Summary Tab and Graph" shows the average avoided cost of adding 400 MWh of wind equal to $23.49/MWh. PLEXOS model output used to calculate this value is included on the tab "lower price model out." The avoided cost estimate was used to calculate the annual fuel savings estimate as follows: Western Plains Wind Farm = 280 MW capacity factor = 46.57% avoided cost of wind = $23.49/MWh annual fuel savings = 280 MW * 0.4657 * 8760 hours * $23.49/MWh = $26,831,898 Assumptions for the avoided cost estimate shown in the spreadsheet were: 1. Looked at ten-year period from 2016 through 2025 2. Avoided cost based on Westar portfolio only, no market participation 3. PLEXOS model run as "business as usual", no forced CPP compliance 4. Based PLEXOS model on system configuration and pricing in least cost CPP compliance scenario from 09.01.15 analysis, including: a. Lawrence Unit 3, Tecumseh Unit 8 and Hutchinson Steam Unit 4 retired by 01.01.16 b. Tecumseh Unit 7 retired by 01.01.24 c. Murray Gill Units 3 and 4 retired by 01.01.25 d. No other generators retired during the ten-year period e. No other generator additions during the ten-year period f. Wholesale contracts expire as written g. Gas prices from "Westar Long Term Curve 07_23_2015.xlsm" (also attached) The attached "Proposal Summary_2015 12-07 FINAL" computes the $23 million levelized cost of the wind facility during the initial RFP process. Cell D120 on tab, "Infinity_294.63 MW Siemens." Mr. Bridson's testimony indicates the cost of Western Plains was $417 million. Only $415 million is included in this rate application, as about $2 million of additional costs were booked outside of the test period. The attached "Wind_Ownership_Levelized_20 Years_Western Plains_Tax Reform KIC-16" reflects the 20-year levelized cost of Western Plains based on the $415 million cost to construct. This work paper should also replace Exhibit LMW-3 in Mr. Larry Wilkus' Direct Testimony to correct the cost of land for Western Plains. Additionally, the income tax rate in the AAO section of Exhibit LMW-3, line 139, has been corrected to reflect the appropriate tax rate.

Attachment File Name	Attachment Note
John Grace Verification.16.pdf	
Model Output Avoided Cost 100115 KIC16.xlsx	
Proposal Summary 2015 12-07 FINAL.xlsx	
Westar Long Term Curve 07 23 2015.xlsm	
Wind Ownership Levelized 20 Years Western Plains Tax Reform KIC-16 REVISED.xlsx	

Westar Energy, Inc.
Western Plains
Levelized Revenue Requirement
dollars in thousands

KIC-16

Ownership Assumptions:																				
Yr	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Western Plains Wind Farm																				
MW Capacity	280.6																			
Capacity Factor	46.57%																			
Annual MWh	1,144,717																			
Land	$ 12,574	***Gross plant per ledger 6/30/2017***																		
Depreciable Basis	402,183	***Gross plant per ledger 6/30/2017***																		
Decommissioning	13,471	***Exclude from rate base***																		
Total Project Cost	$ 428,228																			
O&M:																				
Labor and overheads	$ 645																			
Subcontract labor	5,353																			
Other O&M	807																			
O&M excluding Royalty and PILOT payments	$ 6,806																			
Variable O&M inflated in annual dollars	$ 6,806	$ 6,976	$ 7,150	$ 7,329	$ 7,512	$ 7,700	$ 7,893	$ 8,090	$ 8,292	$ 8,500	$ 8,712	$ 8,930	$ 9,153	$ 9,382	$ 9,617	$ 9,857	$ 10,103	$ 10,356	$ 10,615	$ 10,880
Royalty Payments:	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,011	$ 3,583	$ 3,583	$ 3,583	$ 3,583	$ 3,583
PILOT and Other fees:	$ 1,227	$ 1,264	$ 1,302	$ 1,341	$ 1,381	$ 1,423	$ 1,465	$ 1,509	$ 1,555	$ 1,601	$ 1,649	$ 1,699	$ 1,750	$ 1,802	$ 1,856	$ 1,912	$ 1,969	$ 2,028	$ 2,089	$ 2,152
	Wind																			
Book Depreciation	4.95%																			
MACRS 5	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%														
Property Tax - Wind	Lifetime exemption		0.00%	Property Tax Rate - *Western Plains qualifies for the lifetime property tax exemption*																
Wind Production Tax Credit	$ (24.00)	per MWh	1	1 = tax credit, 2 = no tax credit																
Fuel $/MWh - Wind	$ (24.00)	$ (24.60)	$ (25.22)	$ (25.85)	$ (26.49)	$ (27.15)	$ (27.83)	$ (28.53)	$ (29.24)	$ (29.97)										
Ten Year Tax Credit from In-Service	$ (24.00)	$ (25.00)	$ (25.00)	$ (26.00)	$ (26.00)	$ (27.00)	$ (28.00)	$ (29.00)	$ (29.00)	$ (30.00)										
Annual Insurance	$ 170																			
Insurance Rates (inflated)	$ 170	$ 179	$ 188	$ 197	$ 207	$ 217	$ 228	$ 240	$ 252	$ 264	$ 277	$ 291	$ 306	$ 321	$ 337	$ 354	$ 372	$ 390	$ 410	$ 430
General Inflation	2.5%																			
Insurance Inflation	5.0%																			
Tax Rate	26.53%	*Reflects 21% federal and 7% state tax rates*																		

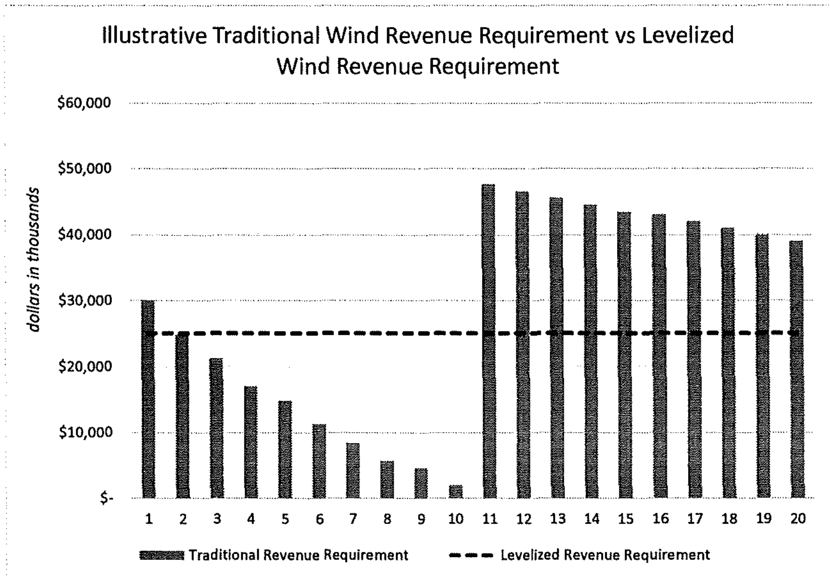
Capital Structure:					
	Percent	Cost	After Tax WACC	Pretax WACC	After Tax w/Tax Shield
Debt	48.41%	4.65%	2.25%	2.25%	1.65%
Equity	51.59%	9.85%	5.08%	6.92%	5.08%
			7.33%	9.17%	6.74%

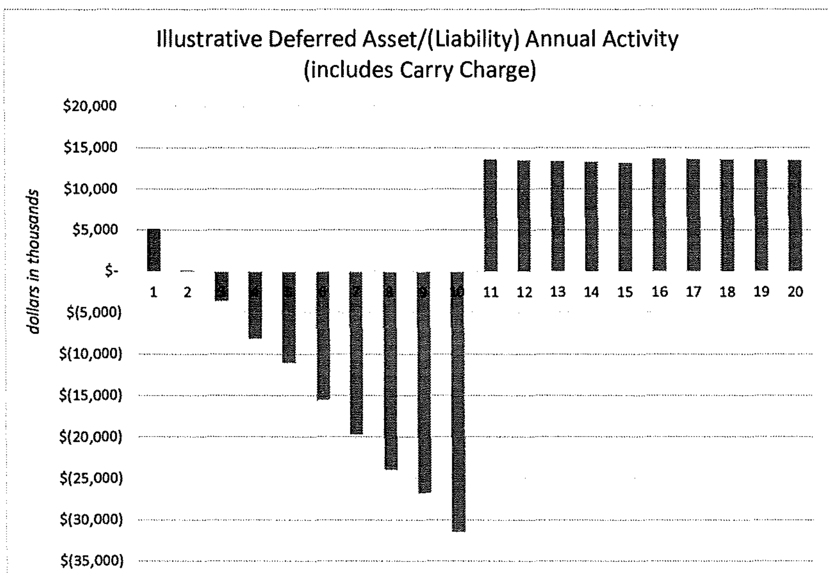
Capital Outlay:

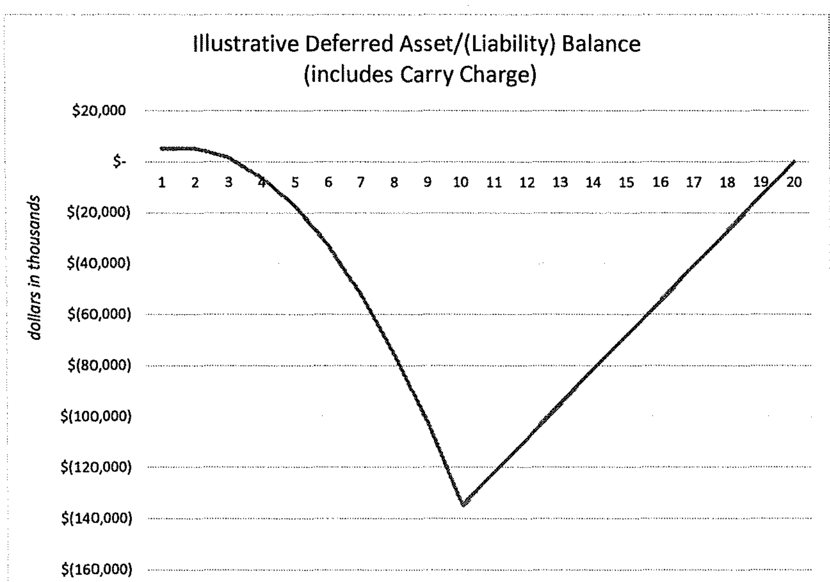
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Western Plains Wind Farm										
Gross Plant - Land	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574
Book Depreciation										
Accumulated Depreciation										
Net Book Plant	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574
Gross Plant - Generators	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183
Book Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Accumulated Depreciation	19,908	39,816	59,724	79,632	99,540	119,448	139,356	159,264	179,172	199,081
Net Book Plant	$ 382,275	$ 362,367	$ 342,459	$ 322,551	$ 302,643	$ 282,735	$ 262,826	$ 242,918	$ 223,010	$ 203,102
Tax Basis	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183
Tax Depreciation Rate	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%	0.00%	0.00%	0.00%	0.00%
Tax Depreciation	80,437	128,699	77,219	46,331	46,331	23,166	0	0	0	0
Accumulated Tax Depreciation	80,437	209,135	286,354	332,686	379,017	402,183	402,183	402,183	402,183	402,183
Net Tax Basis	$ 321,746	$ 193,048	$ 115,829	$ 69,497	$ 23,166	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Current Deferred Tax	$ 16,058	$ 28,862	$ 15,205	$ 7,010	$ 7,010	$ 864	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)
Accumulated Deferred Tax	$ 16,058	$ 44,920	$ 60,125	$ 67,135	$ 74,145	$ 75,009	$ 69,728	$ 64,446	$ 59,165	$ 53,883
Revenue Requirement:										
Net Book Plant	$ 394,849	$ 374,941	$ 355,033	$ 335,125	$ 315,217	$ 295,309	$ 275,401	$ 255,493	$ 235,585	$ 215,677
Accumulated Deferred Income Taxes	16,058	44,920	60,125	67,135	74,145	75,009	69,728	64,446	59,165	53,883
Rate Base	$ 378,791	$ 330,021	$ 294,908	$ 267,990	$ 241,072	$ 220,299	$ 205,673	$ 191,046	$ 176,420	$ 161,794
Average Rate Base	$ 396,774	$ 354,406	$ 312,464	$ 281,449	$ 254,531	$ 230,685	$ 212,986	$ 198,360	$ 183,733	$ 169,107
Pre-Tax Rate of Return	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%
Pre-Tax Rate of Return on Rate Base	$ 36,375	$ 32,491	$ 28,646	$ 25,802	$ 23,334	$ 21,148	$ 19,526	$ 18,185	$ 16,844	$ 15,503
Pretax Return on Equity	$ 27,443	$ 24,513	$ 21,612	$ 19,467	$ 17,605	$ 15,956	$ 14,731	$ 13,720	$ 12,708	$ 11,696
Pretax Cost of Debt	$ 8,932	$ 7,978	$ 7,034	$ 6,336	$ 5,730	$ 5,193	$ 4,794	$ 4,465	$ 4,136	$ 3,807
Tax Expense/(Credit) (PTC grossed up for taxes)	$ (37,394)	$ (38,952)	$ (38,952)	$ (40,510)	$ (40,510)	$ (42,068)	$ (43,626)	$ (45,184)	$ (45,184)	$ (46,742)
O&M										
Variable O&M	$ 6,806	$ 6,976	$ 7,150	$ 7,329	$ 7,512	$ 7,700	$ 7,893	$ 8,090	$ 8,292	$ 8,500
Royalty Payments	3,011	3,011	3,011	3,011	3,011	3,011	3,011	3,011	3,011	3,011
PILOT Payments	1,227	1,264	1,302	1,341	1,381	1,423	1,465	1,509	1,555	1,601
Insurance Expense	170	179	188	197	207	217	228	240	252	264
Property Tax - Wind										
Total O&M	$ 11,214	$ 11,430	$ 11,651	$ 11,878	$ 12,111	$ 12,351	$ 12,597	$ 12,850	$ 13,109	$ 13,376
Depreciation Expense	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908
Total Revenue Requirement	**$ 30,103**	**$ 24,876**	**$ 21,253**	**$ 17,078**	**$ 14,844**	**$ 11,339**	**$ 8,405**	**$ 5,758**	**$ 4,677**	**$ 2,045**
	31,827	26,479	22,735	18,471	16,160	12,587	9,602	6,913	5,790	3,116
Total GWh of Generation	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717
Total Revenue Requirement Per MWh	$ 26.30	$ 21.73	$ 18.57	$ 14.92	$ 12.97	$ 9.91	$ 7.34	$ 5.03	$ 4.09	$ 1.79
Levelized Revenue Requirements										
20 Yr NPV	$ 258,973									
Discount Rate	7.33%									
20 Yr Levelized Revenue Requirement	$ 25,081									
20 Yr Levelized Revenue Requirement per MWh	**$ 21.91**									
Levelized Revenue Requirements	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**
Delta between levelized and traditional	$ (5,022)	$ 204	$ 3,828	$ 8,003	$ 10,237	$ 13,741	$ 16,676	$ 19,322	$ 20,404	$ 23,036
NPV of delta	($0.00)									

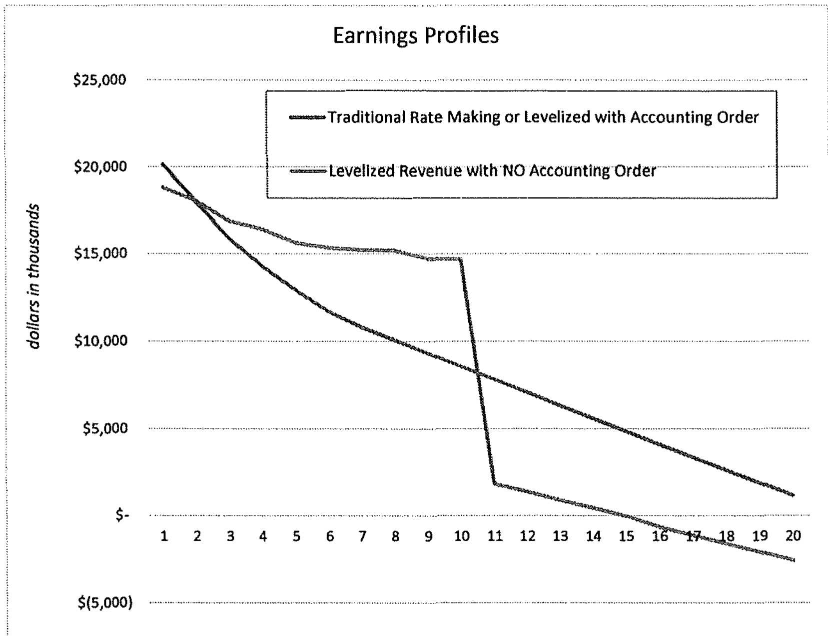
	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Western Plains Wind Farm										
Gross Plant - Land	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574	12,574
Book Depreciation										
Accumulated Depreciation										
Net Book Plant	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574	$ 12,574
Gross Plant - Generators	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183
Book Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Accumulated Depreciation	218,989	238,897	258,805	278,713	298,621	318,529	338,437	358,345	378,253	398,161
Net Book Plant	$ 183,194	$ 163,286	$ 143,378	$ 123,470	$ 103,562	$ 83,654	$ 63,746	$ 43,838	$ 23,930	$ 4,022
Tax Basis	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183	$ 402,183
Tax Depreciation Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax Depreciation	0	0	0	0	0	0	0	0	0	0
Accumulated Tax Depreciation	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183	402,183
Net Tax Basis	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
Current Deferred Tax	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)
Accumulated Deferred Tax	$ 48,601	$ 43,320	$ 38,038	$ 32,757	$ 27,475	$ 22,193	$ 16,912	$ 11,630	$ 6,349	$ 1,067
Revenue Requirement:										
Net Book Plant	$ 195,769	$ 175,861	$ 155,952	$ 136,044	$ 116,136	$ 96,228	$ 76,320	$ 56,412	$ 36,504	$ 16,596
Accumulated Deferred Income Taxes	48,601	43,320	38,038	32,757	27,475	22,193	16,912	11,630	6,349	1,067
Rate Base	$ 147,167	$ 132,541	$ 117,914	$ 103,288	$ 88,661	$ 74,035	$ 59,408	$ 44,782	$ 30,156	$ 15,529
Average Rate Base	$ 154,480	$ 139,854	$ 125,227	$ 110,601	$ 95,975	$ 81,348	$ 66,722	$ 52,095	$ 37,469	$ 22,842
Pre-Tax Rate of Return	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%
Pre-Tax Rate of Return on Rate Base	$ 14,162	$ 12,821	$ 11,480	$ 10,140	$ 8,799	$ 7,458	$ 6,117	$ 4,776	$ 3,435	$ 2,094
Pretax Return on Equity	$ 10,685	$ 9,673	$ 8,661	$ 7,650	$ 6,638	$ 5,627	$ 4,615	$ 3,603	$ 2,592	$ 1,580
Pretax Cost of Debt	$ 3,477	$ 3,148	$ 2,819	$ 2,490	$ 2,160	$ 1,831	$ 1,502	$ 1,173	$ 843	$ 514
Tax Expense/(Credit) (PTC grossed up for taxes)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M										
Variable O&M	$ 8,712	$ 8,930	$ 9,153	$ 9,382	$ 9,617	$ 9,857	$ 10,103	$ 10,356	$ 10,615	$ 10,880
Royalty Payments	3,011	3,011	3,011	3,011	3,011	3,583	3,583	3,583	3,583	3,583
PILOT Payments	1,649	1,699	1,750	1,802	1,856	1,912	1,969	2,028	2,089	2,152
Insurance Expense	277	291	306	321	337	354	372	390	410	430
Property Tax - Wind	-	-	-	-	-	-	-	-	-	-
Total O&M	$ 13,649	$ 13,931	$ 14,219	$ 14,516	$ 14,821	$ 15,706	$ 16,027	$ 16,358	$ 16,697	$ 17,046
Depreciation Expense	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908
Total Revenue Requirement	**$ 47,720**	**$ 46,660**	**$ 45,608**	**$ 44,564**	**$ 43,527**	**$ 43,072**	**$ 42,052**	**$ 41,042**	**$ 40,040**	**$ 39,048**
	48,749	47,647	46,553	45,467	44,389	43,891	42,830	41,777	40,734	39,700
Total GWh of Generation	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717	1,144,717
Total Revenue Requirement Per MWh	$ 41.69	$ 40.76	$ 39.84	$ 38.93	$ 38.02	$ 37.63	$ 36.74	$ 35.85	$ 34.98	$ 34.11
Levelized Revenue Requirements	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**	**$ 25,081**
Delta between levelized and traditional	$ (22,639)	$ (21,579)	$ (20,527)	$ (19,483)	$ (18,446)	$ (17,991)	$ (16,971)	$ (15,961)	$ (14,959)	$ (13,967)

Accounting Order Journal Entries:																				
(Credit) Debit Revenue	$ (5,022)	$ 204	$ 3,828	$ 8,003	$ 10,237	$ 13,741	$ 16,676	$ 19,322	$ 20,404	$ 23,036	$ (22,639)	$ (21,579)	$ (20,527)	$ (19,483)	$ (18,446)	$ (17,991)	$ (16,971)	$ (15,961)	$ (14,959)	$ (13,967)
Reg Asset (Liability)	$ 5,022	(204)	(3,828)	(8,003)	(10,237)	(13,741)	(16,676)	(19,322)	(20,404)	(23,036)	22,639	21,579	20,527	19,483	18,446	17,991	16,971	15,961	14,959	13,967
Debit Reg Asset (Liability)	$ 184	$ 374	$ 254	$ (161)	$ (842)	$ (1,783)	$ (3,029)	$ (4,571)	$ (6,362)	$ (8,421)	$ (9,053)	$ (8,096)	$ (7,146)	$ (6,203)	$ (5,267)	$ (4,318)	$ (3,352)	$ (2,391)	$ (1,433)	$ (477)
(Credit) Interest Expense	$ (184)	$ (374)	$ (254)	$ 161	$ 842	$ 1,783	$ 3,029	$ 4,571	$ 6,362	$ 8,421	$ 9,053	$ 8,096	$ 7,146	$ 6,203	$ 5,267	$ 4,318	$ 3,352	$ 2,391	$ 1,433	$ 477
Deferred Asset (Liability) Beginning Balance	$ -	$ 5,206	$ 5,376	$ 1,802	$ (6,362)	$ (17,441)	$ (32,965)	$ (52,670)	$ (76,563)	$ (103,329)	$ (134,786)	$ (121,201)	$ (107,718)	$ (94,337)	$ (81,057)	$ (67,878)	$ (54,205)	$ (40,586)	$ (27,016)	$ (13,490)
Deferred Asset (Liability) Current Year Activity	5,022	(204)	(3,828)	(8,003)	(10,237)	(13,741)	(16,676)	(19,322)	(20,404)	(23,036)	22,639	21,579	20,527	19,483	18,446	17,991	16,971	15,961	14,959	13,967
Deferred Asset (Liability) Carry Charge	184	374	254	(161)	(842)	(1,783)	(3,029)	(4,571)	(6,362)	(8,421)	(9,053)	(8,096)	(7,146)	(6,203)	(5,267)	(4,318)	(3,352)	(2,391)	(1,433)	(477)
Deferred Asset (Liability) Ending Balance	$ 5,206	$ 5,376	$ 1,802	$ (6,362)	$ (17,441)	$ (32,965)	$ (52,670)	$ (76,563)	$ (103,329)	$ (134,786)	$ (121,201)	$ (107,718)	$ (94,337)	$ (81,057)	$ (67,878)	$ (54,205)	$ (40,586)	$ (27,016)	$ (13,490)	$ 0
Accounting Order:																				
Income Statement:																				
Revenue from customers	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081	$ 25,081
Revenue - accounting entries	5,022	(204)	(3,828)	(8,003)	(10,237)	(13,741)	(16,676)	(19,322)	(20,404)	(23,036)	22,639	21,579	20,527	19,483	18,446	17,991	16,971	15,961	14,959	13,967
O&M	11,214	11,430	11,651	11,878	12,111	12,351	12,597	12,850	13,109	13,376	13,649	13,931	14,219	14,516	14,821	15,706	16,027	16,358	16,697	17,046
Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Operating Income	$ (1,019)	$ (6,461)	$ (10,306)	$ (14,708)	$ (17,175)	$ (20,920)	$ (24,100)	$ (26,999)	$ (28,340)	$ (31,239)	$ 14,162	$ 12,821	$ 11,480	$ 10,140	$ 8,799	$ 7,458	$ 6,117	$ 4,776	$ 3,435	$ 2,094
Theoretical Interest - plant	8,932	7,978	7,034	6,336	5,730	5,193	4,794	4,465	4,136	3,807	3,477	3,148	2,819	2,490	2,160	1,831	1,502	1,173	843	514
Theoretical Interest - short/(excess) cash	184	374	254	(161)	(842)	(1,783)	(3,029)	(4,571)	(6,362)	(8,421)	(9,053)	(8,096)	(7,146)	(6,203)	(5,267)	(4,318)	(3,352)	(2,391)	(1,433)	(477)
Carry charge - accounting entries	(184)	(374)	(254)	161	842	1,783	3,029	4,571	6,362	8,421	9,053	8,096	7,146	6,203	5,267	4,318	3,352	2,391	1,433	477
Income before taxes	$ (9,951)	$ (14,439)	$ (17,340)	$ (21,043)	$ (22,905)	$ (26,112)	$ (28,895)	$ (31,464)	$ (32,476)	$ (35,046)	$ 10,685	$ 9,673	$ 8,661	$ 7,650	$ 6,638	$ 5,627	$ 4,615	$ 3,603	$ 2,592	$ 1,580
Income tax	(2,640)	(3,831)	(4,600)	(5,583)	(6,077)	(6,928)	(7,666)	(8,348)	(8,616)	(9,298)	2,835	2,566	2,298	2,029	1,761	1,493	1,224	956	688	419
Income tax credits	(27,473)	(28,618)	(28,618)	(29,763)	(29,763)	(30,907)	(32,052)	(33,197)	(33,197)	(34,342)	-	-	-	-	-	-	-	-	-	-
Net income	$ 20,163	$ 18,010	$ 15,878	$ 14,302	$ 12,934	$ 11,723	$ 10,823	$ 10,080	$ 9,337	$ 8,593	$ 7,850	$ 7,107	$ 6,364	$ 5,620	$ 4,877	$ 4,134	$ 3,391	$ 2,647	$ 1,904	$ 1,161
ROE	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%
Cash Flow:																				
Net Income:	$ 20,163	$ 18,010	$ 15,878	$ 14,302	$ 12,934	$ 11,723	$ 10,823	$ 10,080	$ 9,337	$ 8,593	$ 7,850	$ 7,107	$ 6,364	$ 5,620	$ 4,877	$ 4,134	$ 3,391	$ 2,647	$ 1,904	$ 1,161
Add: Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Add: Accounting Revenue	(5,022)	204	3,828	8,003	10,237	13,741	16,676	19,322	20,404	23,036	(22,639)	(21,579)	(20,527)	(19,483)	(18,446)	(17,991)	(16,971)	(15,961)	(14,959)	(13,967)
Add: Deferred Income Taxes (def asset/liability)	1,332	(54)	(1,016)	(2,123)	(2,716)	(3,646)	(4,424)	(5,126)	(5,413)	(6,112)	6,006	5,725	5,446	5,169	4,894	4,773	4,503	4,234	3,969	3,705
Add: Deferred Income Taxes (plant related)	16,058	28,862	15,205	7,010	7,010	864	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)
Cash Flow	$ 52,439	$ 66,930	$ 53,804	$ 47,100	$ 47,374	$ 42,591	$ 37,702	$ 38,902	$ 38,954	$ 40,145	$ 5,844	$ 5,879	$ 5,909	$ 5,933	$ 5,951	$ 5,542	$ 5,548	$ 5,547	$ 5,540	$ 5,526
NPV	$ 352,122																			
Traditional Rate Making:																				
Income Statement:																				
Revenue from customers	$ 30,103	$ 24,876	$ 21,253	$ 17,078	$ 14,844	$ 11,339	$ 8,405	$ 5,758	$ 4,677	$ 2,045	$ 47,720	$ 46,660	$ 45,608	$ 44,564	$ 43,527	$ 43,072	$ 42,052	$ 41,042	$ 40,040	$ 39,048
O&M	11,214	11,430	11,651	11,878	12,111	12,351	12,597	12,850	13,109	13,376	13,649	13,931	14,219	14,516	14,821	15,706	16,027	16,358	16,697	17,046
Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Operating Income	$ (1,019)	$ (6,461)	$ (10,306)	$ (14,708)	$ (17,175)	$ (20,920)	$ (24,100)	$ (26,999)	$ (28,340)	$ (31,239)	$ 14,162	$ 12,821	$ 11,480	$ 10,140	$ 8,799	$ 7,458	$ 6,117	$ 4,776	$ 3,435	$ 2,094
Interest	8,932	7,978	7,034	6,336	5,730	5,193	4,794	4,465	4,136	3,807	3,477	3,148	2,819	2,490	2,160	1,831	1,502	1,173	843	514
Income before taxes	$ (9,951)	$ (14,439)	$ (17,340)	$ (21,043)	$ (22,905)	$ (26,112)	$ (28,895)	$ (31,464)	$ (32,476)	$ (35,046)	$ 10,685	$ 9,673	$ 8,661	$ 7,650	$ 6,638	$ 5,627	$ 4,615	$ 3,603	$ 2,592	$ 1,580
Income tax	(2,640)	(3,831)	(4,600)	(5,583)	(6,077)	(6,928)	(7,666)	(8,348)	(8,616)	(9,298)	2,835	2,566	2,298	2,029	1,761	1,493	1,224	956	688	419
Income tax credits	(27,473)	(28,618)	(28,618)	(29,763)	(29,763)	(30,907)	(32,052)	(33,197)	(33,197)	(34,342)	-	-	-	-	-	-	-	-	-	-
Net income	$ 20,163	$ 18,010	$ 15,878	$ 14,302	$ 12,934	$ 11,723	$ 10,823	$ 10,080	$ 9,337	$ 8,593	$ 7,850	$ 7,107	$ 6,364	$ 5,620	$ 4,877	$ 4,134	$ 3,391	$ 2,647	$ 1,904	$ 1,161
ROE	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%
Cash Flow:																				
Net Income:	$ 20,163	$ 18,010	$ 15,878	$ 14,302	$ 12,934	$ 11,723	$ 10,823	$ 10,080	$ 9,337	$ 8,593	$ 7,850	$ 7,107	$ 6,364	$ 5,620	$ 4,877	$ 4,134	$ 3,391	$ 2,647	$ 1,904	$ 1,161
Add: Depreciation	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908	19,908
Add: Accounting Revenue																				
Add: Deferred Income Taxes (def asset/liability)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Add: Deferred Income Taxes (plant related)	16,058	28,862	15,205	7,010	7,010	864	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)	(5,282)
Cash Flow	$ 56,129	$ 66,780	$ 50,991	$ 41,220	$ 39,852	$ 32,495	$ 25,450	$ 24,706	$ 23,963	$ 23,220	$ 22,477	$ 21,733	$ 20,990	$ 20,247	$ 19,504	$ 18,760	$ 18,017	$ 17,274	$ 16,530	$ 15,787
NPV	$ 352,122																			


Illustrative Traditional Wind Revenue Requirement vs Levelized Wind Revenue Requirement
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
dollars in thousands
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Traditional Revenue Requirement
Levelized Revenue Requirement


Illustrative Deferred Asset/(Liability) Annual Activity (includes Carry Charge)
$20,000
$15,000
$10,000
$5,000
$-
$(5,000)
$(10,000)
$(15,000)
$(20,000)
$(25,000)
$(30,000)
$(35,000)
dollars in thousands
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20


Illustrative Deferred Asset/(Liability) Balance (includes Carry Charge)
$20,000
$-
$(20,000)
$(40,000)
$(60,000)
$(80,000)
$(100,000)
$(120,000)
$(140,000)
$(160,000)
dollars in thousands
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20


Earnings Profiles
Traditional Rate Making or Levelized with Accounting Order
Levelized Revenue with NO Accounting Order
dollars in thousands
$25,000
$20,000
$15,000
$10,000
$5,000
$-
$(5,000)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20

CERTIFICATE OF SERVICE

18-WSEE-328-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing document was served by electronic service on this 11th day of June, 2018, to the following:

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 S HICKORY
PO BOX 17
OTTAWA, KS 66067
jflaherty@andersonbyrd.com

KURT J. BOEHM, ATTORNEY
BOEHM, KURTZ & LOWRY
36 E SEVENTH ST STE 1510
CINCINNATI, OH 45202
kboehm@bkllawfirm.com

JODY KYLER COHN, ATTORNEY
BOEHM, KURTZ & LOWRY
36 E SEVENTH ST STE 1510
CINCINNATI, OH 45202
jkylercohn@bkllawfirm.com

MARTIN J. BREGMAN
BREGMAN LAW OFFICE, L.L.C.
311 PARKER CIRCLE
LAWRENCE, KS 66049
mjb@mjbregmanlaw.com

DANIEL R. ZMIJEWSKI
DRZ LAW FIRM
9229 WARD PARKWAY STE 370
KANSAS CITY, MO 64114
dan@drzlawfirm.com

DAVID BENDER
EARTHJUSTICE
3916 Nakoma Road
Madison, WI 63711
dbender@earthjustice.org

SHANNON FISK, ATTORNEY
EARTHJUSTICE
1617 JOHN F KENNEDY BLVD
SUITE 1675
PHILADELPHIA, PA 19103
sfisk@earthjustice.org

JILL TAUBER
EARTHJUSTICE
1625 Massachusetts Ave., NW
Suite 702
Washington, DC 20036
jtauber@earthjustice.org

ELIZABETH A. BAKER
6610 SW 29th St.
Topeka, KS 66614
betsy@bakerlawks.com

GREG WRIGHT
EMG, INC.
420 NE LYMAN RD.
TOPEKA, KS 66608
greg@emgnow.com

DAVID BANKS, CEM, CEP
FLINT HILLS ENERGY CONSULTANT
117 S PARKRIDGE
WICHITA, KS 67209
david@fheconsultants.net

MATTHEW H. MARCHANT
HOLLYFRONTIER CORPORATION
2828 N HARWOOD STE 1300
DALLAS, TX 75201
matthew.marchant@hollyfrontier.com

DARIN L. RAINS
HOLLYFRONTIER CORPORATION
2828 N Harwood, Ste. 1300
Dallas, TX 75201
darin.rains@hollyfrontier.com

JUSTIN WATERS, Energy Manager
JUSTIN WATERS
USD 259 School Serv. Cntr.
3850 N. Hydraulic
Wichita, KS 67219
jwaters@usd259.net

PHOENIX ANSHUTZ, LITIGATION ATTORNEY
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
p.anshutz@kcc.ks.gov

MICHAEL DUENES, ASSISTANT GENERAL COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
m.duenes@kcc.ks.gov

AMBER SMITH, CHIEF LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
a.smith@kcc.ks.gov

TIMOTHY MAXWELL, Vice President, Specialty Finance
KEF UNDERWRITING & PORTFOLIO MGMT.
1000 South McCaslin Blvd.
Superior, CO 80027
timothy_maxwell@keybank.com

KEVIN HIGGINS
KEVIN C. HIGGINS
PARKSIDE TOWERS
215 S STATE ST STE 200
SALT LAKE CITY, UT 84111
khiggins@energystrat.com

MATTHEW B. McKEON, SVP & Senior Counsel II
KEY EQUIPMENT FINANCE
17 Corporate Woods Blvd.
Albany, NY 12211
matthew.b.mckeon@key.com

AMY G. PAINE, SVP Asset Mgmt.
KEY EQUIPMENT FINANCE
1000 South McCaslin Blvd.
Superior, CO 80027
amy.g.paine@key.com

GENE CARR, CO-CEO
NETFORTRIS ACQUISITION CO., INC.
6900 DALLAS PKWY STE 250
PLANO, TX 75024-9859
gcarr@telekenex.com

SUNIL BECTOR, ATTORNEY
SIERRA CLUB
2101 WEBSTER, SUITE 1300
OAKLAND, CA 94312-3011
sunil.bector@sierraclub.org

ANDREW J. FRENCH, ATTORNEY AT LAW
SMITHYMAN & ZAKOURA, CHTD.
7400 W 110TH ST STE 750
OVERLAND PARK, KS 66210-2362
andrew@smizak-law.com

DIANE WALSH, PARALEGAL
SMITHYMAN & ZAKOURA, CHTD.
7400 W 110TH ST STE 750
OVERLAND PARK, KS 66210-2362
DIANE@SMIZAK-LAW.COM

JAMES P. ZAKOURA, ATTORNEY
SMITHYMAN & ZAKOURA, CHTD.
7400 W 110TH ST STE 750
OVERLAND PARK, KS 66210-2362
jim@smizak-law.com

TOM POWELL, General Counsel-USD 259
TOM POWELL
903 S. Edgemoor
Wichita, KS 67218
tpowell@usd259.net

JOHN M. CASSIDY, General Counsel
TOPEKA METROPOLITAN TRANSIT AUTHORITY
201 N. Kansas Avenue
Topeka, KS 66603
jcassidy@topekametro.org

AMY FELLOWS CLINE, ATTORNEY
TRIPLETT, WOOLF & GARRETSON, LLC
2959 N ROCK RD STE 300
WICHITA, KS 67226
amycline@twgfirm.com

TIMOTHY E. MCKEE, ATTORNEY
TRIPLETT, WOOLF & GARRETSON, LLC
2959 N ROCK RD STE 300
WICHITA, KS 67226
TEMCKEE@TWGFIRM.COM

EMILY MEDLYN, GENERAL ATTORNEY
U.S. ARMY LEGAL SERVICES AGENCY
REGULATORY LAW OFFICE
9275 GUNSTON RD., STE. 1300
FORT BELVOIR, VA 22060-5546
emily.w.medlyn.civ@mail.mil

KEVIN K. LACHANCE, CONTRACT LAW
ATTORNEY
UNITED STATES DEPARTMENT OF
DEFENSE
ADMIN & CIVIL LAW DIVISION
OFFICE OF STAFF JUDGE ADVOCATE
FORT RILEY, KS 66442
kevin.k.lachance.civ@mail.mil

CATHRYN J. DINGES, SENIOR
CORPORATE COUNSEL
WESTAR ENERGY, INC.
818 S KANSAS AVE
PO BOX 889
TOPEKA, KS 66601-0889
cathy.dinges@westarenergy.com

JEFFREY L. MARTIN, VICE PRESIDENT,
REGULATORY AFFAIRS
WESTAR ENERGY, INC.
818 S KANSAS AVE
PO BOX 889
TOPEKA, KS 66601-0889
JEFF.MARTIN@WESTARENERGY.COM

DAVID L.WOODSMALL
WOODSMALL LAW OFFICE
308 E HIGH ST STE 204
JEFFERSON CITY, MO 65101
david.woodsmall@woodsmalllaw.com

Della Smith
Administrative Specialist