BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

REBUTTAL TESTIMONY

OF

LARRY WILKUS

WESTAR ENERGY, INC.

DOCKET NO. 18-WSEE-328-RTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Larry Wilkus.

Q. ARE YOU THE SAME LARRY WILKUS WHO SUBMITTED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will provide a summary of the adjustments by other parties that we accept as well as the effect of the this rate review of the agreements that were reached by the parties and approved by the Commission in its order in Docket No. 18-KCPE-095-MER (the "Merger Docket") approving the merger of Westar and Great Plains (the agreement will be referred to herein as the "Merger Agreement"). Westar witness Greg Greenwood discusses the specific details of the merger impacts in his rebuttal testimony. I will also provide rebuttal testimony on weather normalization and customer annualization adjustments and address:

- various adjustments related to our newest wind farm, Western Plains,
- Kroger's proposed treatment of our revenue loss associated with the end of the power sale to Mid-Kansas Electric Company ("MKEC") and the end of the Jeffrey Energy Center ("JEC") lease,
- Staff's and the Citizens' Utility Ratepayer Board's ("CURB's) proposed treatment of royalty payments and payments in lieu of taxes ("PILOT"),
- use of the Retail Energy Adjustment Clause ("RECA") as the preferred recovery mechanism for the MKEC contract along with the JEC lease and NDT funding increase,
- recovery of costs related to pilot programs,
- the allocation of tax credits.

I will also confirm Staff's calculations of the bill credit associated with the Tax Cut and Jobs Act "(TCJA") and provide our response to Staff's position concerning proposed changes to our General Terms and Conditions ("GT&C") related to direct buried cable.

II. SUMMARY OF AGREED-UPON ADJUSTMENTS

Q. PLEASE PROVIDE A LIST OF THE ADJUSTMENTS WHICH WESTAR IS NOT CONTESTING AND ADJUSTMENTS WHICH IMPLEMENT PROVISIONS OF THE SETTLEMENT REACHED IN THE "MERGER DOCKET.

A. When making adjustments to our filing to implement elements of the settlement in the Merger Docket, Westar's revenue requirement becomes a reduction of $36.7 million for Step 1 followed by a $12.7 million increase in Step 2 for a net base rate decrease of $24.0 million. The second step items reflect base rate treatment for expiring Production Tax Credits ("PTCs") and Retail Energy Cost Adjustment ("RECA") recovery for the MKEC contract expiration. In addition, Westar accepts Staff's position of RECA recovery for the JEC lease in Step 2. As such, Step 2 base rates would be reduced by another $8.3 million to $4.4 million. This results in a net base rate decrease of $32.3 million. Table 1 is a list of Staff adjustments Westar is not contesting.

Table 1

Adj. No.	Description	Effect on Rate Base or Operating Income
RB-1	Western Plains Wind Farm - ADIT on PTC's	(20,324,502)
RB-2	Western Plains Wind Farm - Net Book Value of Plant	(405,029,711)
RB-3	Reverse Pension Plan Rate Base - Correction	24,177,813
RB-4	Analog Meter Retirements	5,462,584
RB-6	Rate Base Reduction Update - True-up Cost Free Items	1,624,705
RB-7	Reverse Elimination Adjustment	(1,258,941)
IS-4	Western Plains Wind Farm Removal	(20,611,366)
IS-5	Western Plains Wind Farm Levelized amount	(24,432,631)
IS-7	Pension & Postretirement Benefit Tracker - True-up/Amortization Upc	(821,219)
IS-8	Analog Meter Retirements	1,440,899
IS-9	Property Tax Surcharge Revenue	(379,069)
IS-12	Distributed Generation Docket Amort.	234,964
IS-13	Customer Deposits	21,994
IS-16	Donations	118,554
IS-17	Advertising	61,564
IS-19	SmartStar	85,029
IS-20	Insurance Premiums - True-up	1,011,694
IS-21	Credit Card Expense	(66,744)
IS-23	IT Service Agreements	248,951
IS-24	Knock and Collect	(218,215)
IS-26	Reg. Asset Grid Security	196,116
IS-28	State Line Regulatory Liability Amort.	(1,202,316)
IS-29	Payroll to March 31,2018	5,447,234
IS-30	Benefits to March 31, 2018	(67,856)
IS-31	Merger Savings	6,726,984
IS-34	JEC 8% - Lease	8,330,916
IS-35	Wind Farm PTCs	(9,770,859)

III. WESTERN PLAINS WIND FARM

Q. WHAT ISSUES DO YOU ADDRESS CONCERNING THE WESTERN PLAINS WIND FARM ("WESTERN PLAINS")?

A. In our filing, in order to address concerns of intergenerational equities that can arise under traditional ratemaking, we proposed, as an alternative to our filed position, to recover the costs associated with

Western Plains on a levelized basis. I will respond to Staff witness Mr. Grady's testimony concerning the mechanics of implementing this approach and his proposal to apply a performance standard to recovery. I will also respond to CURB witness Ms. Crane's testimony that we treat Western Plains as a purchased power agreement ("PPA") and recover its costs on a per MWh basis when the wind farm produces energy.

Q. WHAT IS STAFF'S POSITION CONCERNING WESTERN PLAINS?

A. Staff witness Mr. Grady recommends use of the levelized revenue requirement approach we proposed as an alternative in this application. However, he also recommends that we be required to calculate the annual benefit actually produced by Western Plains for customers at the time of each future rate review and that such calculation be the basis of a potential limitation on the future levelized revenue requirement.[1]

Q. WHAT IS THE PURPOSE OF THE LEVELIZED RATE AND THE RELATED REGULATORY ASSET/LIABILITY ACCOUNT?

A. The purpose of the levelized rate and the related regulatory asset/liability account is to ensure that Westar recovers over the 20-year period the same amount as it would under traditional ratemaking.

[1] Grady Direct Testimony, at 15-16.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL?

A. We agree with the use of the levelized revenue requirement with only one small adjustment which I will discuss later in my rebuttal testimony. However, we do not agree with Mr. Grady's proposal to limit recovery of the cost of the investment or operating cost of the plant. Mr. Greenwood and Mr. Bridson discuss Mr. Grady's cost recovery limitation proposal further in their testimony. We also oppose the proposal on the ground that it is inconsistent with the prohibition on retroactive ratemaking long recognized by the Commission and courts.

Q. FROM AN ACCOUNTING STANDPOINT, WHAT WOULD BE REQUIRED TO IMPLEMENT THE LEVELIZED REVENUE REQUIREMENT?

A. Specific items need to be addressed and memorialized in an accounting order or the rate review order if the Commission determines the alternative rate making approach of levelizing the revenue requirement for Western Plains be implemented as we proposed and Staff accepted as preferable. Those items to be addressed and memorialized are:

1. The cost of service related to Western Plains to be included in the levelized amount.
2. The costs determined to be included in the levelized calculation need to be removed from all future rate cases and handled through the levelized calculation for the duration of the 20-year levelized time-period.
3. The levelized time-period is 20-years.

4. The carrying charge needs to equal the authorized rate of return.

5. The authorized rate of return should be stated for this alternative rate making proposal.

6. At each future rate case, an updated calculation, which will re-establish the levelized revenue requirement will be computed and implemented.

7. The updated annual levelized revenue requirement amount would account for the current regulatory asset/liability, which includes the update from past activity related to energy production levels versus the assumed capacity factor, O&M levels versus those used in the past levelization calculations and the then projected revenue requirement over the remaining levelization period with inclusion of the regulatory asset/liability considered with the goal of having no remaining regulatory asset/liability at the end of the 20-year period.

8. The amortization period of any remaining regulatory liability or asset over a reasonable period of time after the 20-year levelized time-period concludes.

9.. To sunset the alternative rate making for Western Plains during the rate review after the levelized time-period concludes and customers would then enjoy the benefits of the remaining service life, paying for only the incremental cost of operating the wind farm (return on and of capital improvements, O&M, etc.).

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE ACCOUNTING WOULD WORK?

A. Yes. On a quarterly basis, the levelized revenue requirement for Western Plains established in this case would be compared to the revenue requirement for Western Plains using traditional rate-making. If the levelized revenue requirement is greater than the traditional revenue requirement, a regulatory liability with a carry charge equal to the authorized rate of return is booked. Conversely, if the levelized revenue requirement is less than the traditional revenue requirement, a regulatory asset or a reduction to the regulatory liability balance with the appropriate carry charge is booked. Illustrative examples of the accounting can be found in Mr. Bridson's direct testimony (Figure 5 and Figure 6), and numeric examples can be found in Mr. Grady's direct testimony (Staff Exhibit JTG-2).

The accounting is designed to simulate traditional rate-making from a GAAP reporting perspective with one exception. Based on accounting standard 980-340, the levelization of Western Plains would be considered a "phase-in-plan." Phase-in-plan rules will prevent Westar from booking a regulatory asset, for GAAP accounting purposes, during the first few years Western Plains is reflected in rates, because the traditional revenue requirement will be greater than the levelized revenue requirement. However, this does not change the regulatory construct of the mechanism.

The levelized approach works for Western Plains from both a regulatory and GAAP accounting perspective because of the nature of a wind farm's revenue requirement being affected by production tax credits.

Q. DO YOU ACCEPT MR. GRADY'S EXHIBIT JTG-2, THAT REFLECTS THE LEVELIZED REVENUE REQUIREMENT OF WESTERN PLAINS WIND FARM?

A. Yes, with one small exception. Exhibit JTG-2 reflects Westar's updated capital structure provided in response to data request KCC-159, and reflects a 9.3% ROE as stated in the Non-Unanimous Settlement Agreement in Docket 18-KCPE-095-MER. However, Exhibit JTG-2 did not reflect the update to Westar's cost of debt provided in response to KCC-159. Attached is Exhibit LMW-5, which includes the updated cost of debt. This update results in a levelized revenue requirement of $24,374,720, which is a difference of only $25,949.

Q. WHAT IS CURB WITNESS MS. CRANE'S PROPOSAL?

A. CURB witness Ms. Crane recommends that the wind farm be excluded from rate base and its costs recovered as though the energy it generates is being acquired by Westar through a PPA. She proposes that all energy generated by Western Plains be recovered through Westar's fuel clause at a levelized price of $21.91 per MWh.

Q. DO YOU OBJECT TO MS. CRANE'S PROPOSAL?

A. Yes.

Q. WHY?

A. The levelized revenue approached suggested by Westar as an alternative rate making mechanism and supported by Staff Witness, Mr. Grady, is cash flow neutral to customers and earnings neutral to shareholders as compared to traditional ratemaking, which allows for the full recovery "on" and "of" a prudent investment. Mr. Grady states,

> The goal of this approach would be to ensure that the levelized revenue requirement resulted in a Regulatory Asset/Liability balance that was as close to zero as possible at the end of 20 years and to ensure that Westar is not over-recovering or under-recovering its revenue requirement for Western Plains.

Grady Direct, at p. 18.

Ms. Crane's proposal would not allow for the full recovery "on" and "of" the investment in Western Plains if Western Plains does not perform to expectations – whether the failure is due to turbine performance, wind conditions experienced, market conditions, or a natural disaster – and result in a future disallowance of some portion of the investment. In addition, Ms. Crane's proposal does not allow for the levelized revenue requirement to be reviewed and updated at future rate proceedings where significant changes to the cost of capital or depreciation rates could be updated. Ms. Crane essentially would like customers to receive both the benefits of a PPA and the benefits of ownership after a traditional PPA would terminate, without any of the risks.

Q. DO YOU OBJECT TO HAVING WESTERN PLAINS RECOVERED THROUGH THE RETAIL ENERGY COST ADJUSTMENT (RECA)?

A. Yes. We agree with Staff that Western Plains should be recovered through base rates. Shifting recovery of Western Plains to the RECA would require significant modification of the RECA and could result in under-recovery of the Western Plains investment.

Managing the levelized revenue requirement through the RECA would unnecessarily add complexity to the process beyond just accounting for the levelized revenue requirement in base rates as proposed by Westar and Staff.

IV. MKEC REVENUE

Q. WHAT IS THE MKEC ADJUSTMENT?

A. We requested that the Commission in a second phase of this proceeding recognize the expiration of a wholesale power sale to Mid-Kansas Electric Company ("MKEC") that will end on January 3, 2019. This sale is tied to our lease of 8% of the Jeffrey Energy Center ("JEC") that expires at the same time. The adjustment reflects costs associated with the lease payment as well as return on and of an allocated portion of improvements to the 8% leased property and JEC operations and maintenance expense that are part of the wholesale contract, but excluded from the JEC lease.

Q. WHAT IS KROGER'S PROPOSAL WITH REGARD TO WESTAR'S MKEC ADJUSTMENT?

A. Kroger witness Mr. Higgins argues that the adjustment should be rejected as an out-of-period adjustment. Alternatively, he proposes that if the Commission accepts the adjustment, that the Commission should adjust Westar's expenses by removing costs he calculates as being associated with the 8% share of JEC used to serve the MKEC contract.

Q. DO YOU AGREE WITH MR. HIGGINS' PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. We have proposed a two-step process to reflect significant known and measurable changes occurring after the operation of law date in order to avoid the need to file a second rate case immediately upon the implementation of rates in this matter. This two-step process is what made the five-year rate moratorium related to the approved Merger Docket possible. The expiration of the MKEC contract – a loss of $41.5 million in annual revenues – is one of those significant changes and will occur in January 2019. However, given the need to file a rate application to reflect the effect of the TCJA and other costs in early 2018, this approach seemed a reasonable way to avoid multiple rate review filings and also facilitate the Merger Docket-related moratorium. I would note that Staff, CURB and other parties agreed to this approach in the settlement in the Merger Docket and in testimony in this proceeding.[2] Mr. Higgins and other witnesses address the treatment of other aspects of the MKEC contract and the JEC lease. Westar witness Mr. Bridson addresses those arguments in his rebuttal testimony.

[2] Grady Direct Testimony, at 8.

V. TAX CUT AND JOBS ACT BILL CREDIT

Q. STAFF WITNESS MR. GRADY ADDRESSED THE TCJA. DO YOU AGREE WITH HIS TESTIMONY CONCERNING THE APPROPRIATE LEVEL OF BILL CREDIT RELATED TO THE TCJA?

A. Yes. We agree with his calculation of the bill credit of $50,027,522 which includes interest of $320,305 that he quantified and discussed in his testimony.

Q. **DO YOU AGREE WITH STAFF'S RECOMMENDATION ON HOW TO DISTRIBUTE THE BILL CREDITS?**

A. Yes. The bill credit will be distributed as shown in Staff witness Dr. Glass's testimony.

VI. PAYMENTS IN LIEU OF PROPERTY TAXES AND ROYALTY PAYMENTS

Q. WHAT ARE WESTAR'S PROPOSALS FOR PAYMENTS IN LIEU OF PROPERTY TAXES AND ROYALTY PAYMENTS?

A. We proposed in our original application to remove wind generation Payments in Lieu of Taxes (PILOT) and royalty payments from test year operating expense and instead recover them in the PTS rider and RECA, respectively.

Q. WHAT PARTIES HAVE TAKEN POSITIONS ON THIS ISSUE?

A. Staff supports recovering PILOT payments through the PTS rider but opposes recovering royalty payments in the RECA. CURB witness Ms. Crane opposes both proposals.

Q. WHAT IS MS. CRANE'S POSITION?

A. She proposes keeping these costs in base rates. She states they are relatively stable from year to year and are "largely within the control of Westar."[3]

Q. DO YOU AGREE WITH MS. CRANE'S POSITION CONCERNING PILOT PAYMENTS?

A. No. As I noted in my direct testimony, wind generation is exempt from property taxes in Kansas. However, as the name indicates, these dollars represent payments Westar makes to local governments and school districts in lieu of taxes that would be due in the absence of the exemption. As such, they are appropriately collected in the same manner as property taxes – through the PTS.

Moreover, contrary to Ms. Crane's contention, the PILOT payments are not within Westar's control. They are the result of negotiations with local authorities who have significant control over whether and where wind generation is constructed. We negotiate for the best result for our customers but ultimately the determination of the size of these payments is not within our control. Moreover, the amounts required to be paid each year are not stable but change from year to year.

Q. DO YOU AGREE WITH CURB AND STAFF'S POSITION CONCERNING RECOVERY OF ROYALTY PAYMENTS?

---

[3] Crane Direct Testimony, at 54.

A. No. Royalty payments are made to land owners where wind generation is constructed. They are assessed based on the amount of energy produced by each generator. Consequently, the amount of royalties owed for generators will vary from month to month and from location to location and is not controlled by Westar or predictable. Additionally, royalty payments are directly related to energy production and a necessary and unavoidable cost of production. Consequently, royalty payments are appropriate for inclusion in the RECA with other costs of production such as fuel and purchased power.

VII. EXPIRING PRODUCTION TAX CREDITS (PTCS)

Q. DO YOU HAVE ANY UPDATES TO YOUR TESTIMONY REGARDING PTCS?

A. Yes. Westar proposed an adjustment to remove the PTCs that are expiring in January and March 2019 respectively from its Flat Ridge and Central Plains wind farms. In addition, Westar made a pro forma adjustment to include a full test year of PTCs from its Western Plains wind farm that began generating PTCs in February 2017. Since rates are proposed to go into effect in February 2019, we propose to flow back any PTCs received from Central Plains in February and March 2019 through the RECA.

Q. WHY IS THIS ACTION NECESSARY?

A. This step is necessary to avoid any double recovery of PTCs by Westar for the Central Plains wind farm. The PTCs for Central Plains will have been removed from base rates. If Westar receives PTCs after new rates go into effect in February 2019, Westar would over-recover tax expense until the PTCs expire. Therefore, Westar is proposing to flow back any of these residual credits though the RECA after they have become known and measurable and will work with Staff to ensure the full amount is captured in the RECA annual cost adjustment mechanism.

VIII. WEATHER NORMALIZATION AND CUSTOMER ANNUALIZATION

Q. DO YOU AGREE WITH STAFF'S WEATHER NORMALIZATION ADJUSTMENT?

A. Not entirely. Staff is correct that Westar agreed to use the two "tier 1" weather stations of Topeka and Wichita. However, we calculated the adjustment before that agreement was reached. As a result, the calculation reflected in the application did not match our agreement. Staff is correct that when the agreed-upon weather stations are used to provide data for Westar's as-filed model, Westar's income statement adjustment goes from ($9,681,457) to ($10, 659,843).

Q. WHAT IS YOUR DISAGREEMENT WITH STAFF?

A. We did not agree with Staff's calculation of heating degree days (HDD) and cooling degree days (CDD) before we filed our application. There is a difference between our quantification of HDD and CDD used in calculating the adjustment because Westar and Staff used different data rounding conventions. The method we used was consistent with past filings by Staff and us and consistent with NOAA practices. In this case, Staff changed its method and used a different rounding methodology. We believe that a deviation from previously agreed upon NOAA methodology going back multiple rate cases is not necessary or appropriate and the Commission should reject the portion of Staff's proposed adjustment related to the rounding methodology

Q. DO YOU AGREE WITH STAFF'S CUSTOMER ANNUALIZATION ADJUSTMENT?

A. No. Westar disagrees with Staff's adjustment in three major areas. First, Staff's identical treatment of Residential and Residential Conservation customers, the second, Staff's inclusion of large customer classes in the annualization and third, Staff's use of less than all of the customers as the basis for establishing billing determinants.

Q. **WHY WAS IT INCORRECT FOR STAFF TO TREAT RESIDENTIAL AND RESIDENTIAL CONSERVATION CUSTOMERS THE SAME IN THE ANNUALIZATION CALCULATION?**

A. The customer annualization calculation is in part based on the weather normalized energy usage per customer. Westar's Residential Conservation rate is a rate designed for customers with lower than average usage. As a result, the usage per customer on that tariff is significantly lower than for customers on the standard residential tariff. In the test year, Westar had a net increase in customers on the Residential Conservation tariff and a net decrease in customers on the base Residential tariff. In total, however, there was a net increase in customers between the two tariffs. However, since the additional customers on the Residential Conservation tariff had a lower overall usage per customer than customers on the standard Residential tariff, their addition did not completely counter the decrease in energy use resulting from the loss of Residential tariff customers.

Staff's Customer Annualization calculation does not account for the difference in customer sizes between the tariffs. Because of the difference in usage per customer, the additional Residential Conservation customers using Staff's improper weighting method added $7,398,745 in revenue when they should have only added $3,690,159. Similarly, Staff's improper weighting of the reduction of the number customers on the standard Residential tariff resulted in a loss of $5,829,019 in revenue instead of $6,906,802. This accounts for $4,786,377 of the difference between Staff's and Westar's adjustment.

Q. WHAT DO YOU RECOMMEND?

A. To properly annualize these revenues and achieve a more accurate result that reflects future revenues, I recommend the Residential Conservation customers and the Residential tariff customers be annualized separately as was performed in our application. The result will be better accuracy. As such, Staff adjustment related to customer annualization should be rejected.

Q. WHAT IS YOUR DISAGREEMENT WITH STAFF'S ADJUSTMENT REGARDING THE CLASSES THAT SHOULD BE INCLUDED IN THE CUSTOMER ANNUALIZATION ADJUSTMENT?

A. Westar disagrees with the inclusion of the large customer classes (MGS, LGS, and ILP) in Staff's customer annualization adjustment.

Q. WHY?

A. Inclusion of the MGS, LGS, and ILP classes is inappropriate due to the heterogenous nature of these customer classes and is inconsistent with past practice. One of the assumptions behind the customer annualization adjustment is that the smaller classes, specifically, the residential, residential conservation, and small general service classes, are reasonably homogeneous. Based on that assumption the impact of the addition or subtraction of customers during the year can be reasonably estimated by using the monthly average usage per customer of the class. For the MGS, LGS, and ILP classes, however, usage amounts and patterns vary too much between customers for the annualization to be accurately captured by merely calculating the average usage per customer. For example, Westar's MGS tariff is applicable to customers with average demand between 200 kW and 1,100 kW. This allows for customers with as little as 20,000 kWh to as much as 500,000 kWh of monthly usage to be in the class.

The size of the customers is also reflected in the calculated usage per customer in Staff's adjustment. For the SGS class, the average monthly usage per customer was approximately 3,000 kWh for commercial customers and 6,500 kWh for industrial customers. For the MGS customers, the monthly usage per customer is approximately 150,000 kWh. That is 25 to 50 times larger than for the average SGS customer. For LGS, the monthly average usage per customer is over 1,000,000 kWh. Because of the wide variations of usage among class members, MGS, LGS, and ILP (the last of which was included in the calculation, but since there was no variance in customers, the impact was zero) should not be included in the customer annualization adjustment.

In addition, in the 1991 rate cases of Westar's predecessor companies KPL and KGE, Docket Nos. 193,306-U and 193,307-U, neither Staff nor the companies included industrial customers in the customer annualization adjustment. In that case, Staff and the companies agreed that for the large customer classes, "changes in customer counts, provided by the usual method is not representative of the trend of customer growth over the test year." Motion to Approve Settlement Agreement Regarding Rate Design and Billing Determinants, at ¶15, Docket Nos. 193,306-U and 193,307-U

(November 7, 1996). In Westar's {1995 case}, it was decided to include the newly created small general service class in the customer annualization because the size limitation imposed on the class was viewed as providing sufficient homogeneity to allow its inclusion in the calculation. This agreed-upon methodology was subsequently used by Company and Staff in the 05-WSEE-981-RTS, 08-1041-WSEE-RTS, 12-WSEE-112-RTS and the 15-WSEE-115-RTS general rate cases. Exclusion of these classes accounts for $3,644,645 of the difference between Staff's and Westar's adjustments. The Commission should reject Staff's adjustment to annualize these large customer classes.

Q. WHAT IS THE COMPANY'S DISAGREEMENT WITH THE BILLING DETERMINANTS STAFF USED IN ITS CUSTOMER ANNUALIZATION?

A. Staff did not use the Company's test year book revenue billing determinants as a starting point. This is inconsistent with the order in the 193,306-U and 196,307-U dockets in which it was agreed to use test year billing determinants for the customer annualization adjustment for all customer classes. This is also inconsistent with the method used by Staff in the most recent four general rate cases listed above.

Q. WHAT CUSTOMERS DID STAFF USE TO CALCULATION THE CUSTOMER ANNUALIZATION CALCULATION?

A. Staff based its calculation on the customers that were used to calculate the weather normalization adjustment as the starting point for its calculation.

Q. WHY IS THAT A PROBLEM?

A. The weather normalization adjustment has never included 100% of the test year customers, as not all customers' load is sensitive to fluctuations in the weather. Even within classes that are subject to the weather normalization adjustment, there is a small portion of customers that are not included, due to the process for assigning customers to a weather station. That process captures over 99% of the customers in the classes subject to the weather normalization adjustment, but not all of them. Because Staff's annualization was based on the customers used to calculate the weather normalization adjustment, its customer annualization did not take all of our customers into consideration as it should have.

Q. IS STAFF'S METHOD CONSISTENT WITH PAST PRACTICE?

A. No. Staff's methodology is inconsistent with the method agreed-to and used by Staff and us over the past twenty-five plus years.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH STAFF'S APPROACH?

A. Yes. If Staff's failure to use actual test year billing determinants in this adjustment is not corrected, it will impair our ability to reflect the proper level of revenues when designing rates in the Proof of Revenue.

IX. RATE ANNUALIZATION

Q. DO YOU AGREE WITH STAFF'S RATE ANNUALIZATION ADJUSTMENT?

A. No. The Rate Annualization is a simple adjustment to account for a rate change that occurs during the test year. It uses the actual billing determinants booked in the test year and calculates what the revenue would be with new rates compared to what was booked using current rates. This is consistent to Company's and Staff's Rate Annualization adjustments in past rate cases.

Q. IS STAFF'S METHOD IN THIS CASE CONSISTENT WITH PRIOR PRACTICE?

A. No.

Q. HOW DID STAFF DEVIATE FROM PRIOR PRACTICE?

A. Staff's adjustment is not based on actual billing determinants. Instead, Staff created a weighted average calculation to come up with a new rate and used weather normalized billing determinants instead of what was actually billed in the test year. Because Staff's method would calculate revenue recovery using determinants that were not actually experienced in the test year, it is flawed and does not measure the actual impact of implementation of a rate change during the test year.

X. DIRECT BURIED CABLE

Q. WHAT IS THE COMPANY'S PROPOSAL CONCERNING DIRECT BURIED CABLE?

A. We are proposing a change to our GT&C concerning customers' responsibility for costs of repairing and replacing failed direct buried cable – that is for service lines that are buried but not in conduit.

Q. DID ANY PARTY OPPOSE YOUR PROPOSAL?

A. No. The only party that responded to the proposal was Staff. Staff witness Mr. Haynos recommends that our proposal be approved. In connection with his recommendation, Mr. Haynos recommends that Westar review its construction standards to determine if there are reasonable construction methods that can be used for reducing the overall costs of installing conduit for service lines or methods that can reduce the potential for disruption of the ground surface from excavation.

Q. DO YOU CONTEST MR. HAYNOS' RECOMMENDATION?

A. No. We agree with Mr. Haynos that such a review would be worthwhile.

XI. PREPAY PILOT PROGRAM COSTS

Q. WHAT IS THE PREPAY PILOT PROGRAM?

A. With the Commission's approval, we implemented a pilot program under which customers could voluntarily prepay for their service. Participation in the plan would benefit customers by allowing them to make smaller payments in advance for service rather than receiving a larger bill at the end of the monthly billing period. The program was approved in May 2014 as a pilot program but in December 2016, the Commission denied Westar's motion to convert the program into a permanent program. In connection with the program, with the Commission approval, Westar recorded the program costs as a regulatory asset. In this proceeding, Westar has proposed to recover those costs through a three-year amortization.

Q. WHAT ARE STAFF'S AND CURB'S POSITION CONCERNING THIS MATTER?

A. Staff witness Mr. Franz and CURB witness Ms. Crane oppose recovery of the Prepay Pilot program costs.

Q. WHAT IS THE BASIS FOR THE OPPOSITION?

A. Staff believes that since the pilot was not supported by a cost-benefit analysis, it was not successful and shareholders should pay for the costs of the program. CURB opposes recovery on the ground that because the program was not implemented on a permanent basis, the costs will not be incurred in the future. Ms. Crane further argues against recovery because the costs are not material to Westar and will not jeopardize its financial integrity if they are not recovered.

Q. DO YOU AGREE?

A. No. Ms. Crane's arguments are unfounded. First, it should be recognized that pilot programs are used as an inexpensive way to explore new ways of doing business that may provide benefits to customers. Since pilot programs are undertaken with Commission approval to see if a proposal will be beneficial to customers, it is appropriate for customers to pay program costs.

Second, it was precisely because the program was a pilot that the Commission authorized creation of the regulatory asset to provide Westar the possibility of future recovery. The fact that the costs are not material and will not, in and of themselves, jeopardize Westar's financial integrity is immaterial. The costs were reasonable and prudently incurred to provide service and should be allowed in rates.

Third, Staff's reliance on a cost-benefit analysis as the sole determining factor as to whether costs should be allowed to be recovered is inconsistent with long-standing regulatory principles. In accordance with those principles, whether costs can be recovered for an approved pilot program should be based on whether they were incurred prudently. Staff dismisses Westar's application for recovery because it does not contain a traditional cost-benefit analysis. However, Staff made no finding concerning our prudence in managing the pilot program.

From the beginning of the program, Westar insisted that the prepay program was not a stand-alone program but an addition to the options customers have to interact with and pay for their Westar service (much like the call center) and should be evaluated as such.

Prepay was offered to all residential customers and all costs associated with it were actively managed. The types of customers that signed up for the service were tracked, and Westar was able to draw conclusions about how it would market and offer the service again in the future if it chooses to do so. There was no mismanagement of any portion of the program alleged by any of the parties involved. While the Commission decided that the pilot should not be made permanent, there is no indication that costs of the pilot program were not prudently incurred and should not be eligible for recovery by Westar. Staff's adjustment should be rejected.

Q. THANK YOU.

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

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	48.54%	4.68%	2.27%	2.27%	1.67%
Equity	51.46%	9.30%	4.79%	6.51%	4.79%
			7.06%	8.79%	6.45%

Cost of debt

4.68% updated on response to data request KCC-159

4.65% original to filing

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capital Outlay:																				
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	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	$ 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	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	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	218,989	238,897	258,805	278,713	298,621	318,529	338,437	358,345	378,253	398,161
Net Book Plant	$ 382,275	$ 362,367	$ 342,459	$ 322,551	$ 302,643	$ 282,735	$ 262,826	$ 242,918	$ 223,010	$ 203,102	$ 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	$ 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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	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	0	0	0	0	0	0	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	402,183	402,183	402,183	402,183	402,183	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)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (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)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (5,282)	$ (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	$ 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	$ 394,849	$ 374,941	$ 355,033	$ 335,125	$ 315,217	$ 295,309	$ 275,401	$ 255,493	$ 235,585	$ 215,677	$ 195,769	$ 175,861	$ 155,952	$ 136,044	$ 116,136	$ 96,228	$ 76,320	$ 56,412	$ 36,504	$ 16,596
Accumulated Deferred Income Taxes	16,058	44,920	60,125	67,135	74,145	75,009	69,728	64,446	59,165	53,883	48,601	43,320	38,038	32,757	27,475	22,193	16,912	11,630	6,349	1,067
Rate Base	$ 378,791	$ 330,021	$ 294,908	$ 267,990	$ 241,072	$ 220,299	$ 205,673	$ 191,046	$ 176,420	$ 161,794	$ 147,167	$ 132,541	$ 117,914	$ 103,288	$ 88,661	$ 74,035	$ 59,408	$ 44,782	$ 30,156	$ 15,529
Average Rate Base	$ 396,774	$ 354,406	$ 312,464	$ 281,449	$ 254,531	$ 230,685	$ 212,986	$ 198,360	$ 183,733	$ 169,107	$ 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	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%	8.79%
Pre-Tax Rate of Return on Rate Base	$ 34,859	$ 31,137	$ 27,452	$ 24,727	$ 22,362	$ 20,267	$ 18,712	$ 17,427	$ 16,142	$ 14,857	$ 13,572	$ 12,287	$ 11,002	$ 9,717	$ 8,432	$ 7,147	$ 5,862	$ 4,577	$ 3,292	$ 2,007
Pretax Return on Equity	$ 25,846	$ 23,086	$ 20,354	$ 18,333	$ 16,580	$ 15,027	$ 13,874	$ 12,921	$ 11,968	$ 11,015	$ 10,063	$ 9,110	$ 8,157	$ 7,204	$ 6,252	$ 5,299	$ 4,346	$ 3,393	$ 2,441	$ 1,488
Pretax Cost of Debt	$ 9,013	$ 8,051	$ 7,098	$ 6,394	$ 5,782	$ 5,240	$ 4,838	$ 4,506	$ 4,174	$ 3,842	$ 3,509	$ 3,177	$ 2,845	$ 2,512	$ 2,180	$ 1,848	$ 1,516	$ 1,183	$ 851	$ 519
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	$ 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 Payments	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
Insurance Expense	170	179	188	197	207	217	228	240	252	264	277	291	306	321	337	354	372	390	410	430
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	$ 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	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908	$ 19,908
Total Revenue Requirement	**$ 28,587**	**$ 23,522**	**$ 20,059**	**$ 16,003**	**$ 13,871**	**$ 10,458**	**$ 7,591**	**$ 5,001**	**$ 3,975**	**$ 1,399**	**$ 47,130**	**$ 46,126**	**$ 45,129**	**$ 44,141**	**$ 43,161**	**$ 42,761**	**$ 41,797**	**$ 40,843**	**$ 39,897**	**$ 38,960**
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	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	$ 24.97	$ 20.55	$ 17.52	$ 13.98	$ 12.12	$ 9.14	$ 6.63	$ 4.37	$ 3.47	$ 1.22	$ 41.17	$ 40.29	$ 39.42	$ 38.56	$ 37.70	$ 37.36	$ 36.51	$ 35.68	$ 34.85	$ 34.03
Levelized Revenue Requirements																				
20 Yr NPV	$ 257,067																			
Discount Rate	7.06%	J. Grady	Difference																	

Exhibit LMW-5

107	20 Yr Levelized Revenue Requirement	$ 24,374	$ 24,349	$ 25																	
108	**20 Yr Levelized Revenue Requirement per MWh**	**$ 21.29**																			
109																					
110																					
111	**Levelized Revenue Requirements**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**	**$ 24,374**
112	**Delta between levelized and traditional**	$ (4,214)	$ 851	$ 4,315	$ 8,371	$ 10,502	$ 13,916	$ 16,783	$ 19,373	$ 20,399	$ 22,975	$ (22,756)	$ (21,752)	$ (20,756)	$ (19,767)	$ (18,787)	$ (18,387)	$ (17,424)	$ (16,469)	$ (15,523)	$ (14,587)
113	**NPV of delta**	($0.00)																			
114																					

Accounting Order Journal Entries:																				
(Credit) Debit Revenue	(4,214)	851	4,315	8,371	10,502	13,916	16,783	19,373	20,399	22,975	(22,756)	(21,752)	(20,756)	(19,767)	(18,787)	(18,387)	(17,424)	(16,469)	(15,523)	(14,587)
Reg Asset (Liability)	4,214	(851)	(4,315)	(8,371)	(10,502)	(13,916)	(16,783)	(19,373)	(20,399)	(22,975)	22,756	21,752	20,756	19,767	18,787	18,387	17,424	16,469	15,523	14,587
Debit Reg Asset (Liability)	149	278	115	(324)	(1,013)	(1,946)	(3,167)	(4,666)	(6,399)	(8,381)	(8,981)	(8,044)	(7,111)	(6,183)	(5,259)	(4,319)	(3,360)	(2,401)	(1,442)	(481)
(Credit) Interest Expense	(149)	(278)	(115)	324	1,013	1,946	3,167	4,666	6,399	8,381	8,981	8,044	7,111	6,183	5,259	4,319	3,360	2,401	1,442	481
Deferred Asset (Liability) Beginning Balance	-	4,362	3,789	(411)	(9,106)	(20,621)	(36,483)	(56,433)	(80,473)	(107,270)	(138,627)	(124,851)	(111,143)	(97,499)	(83,915)	(70,388)	(56,319)	(42,255)	(28,188)	(14,106)
Deferred Asset (Liability) Current Year Activity	4,214	(851)	(4,315)	(8,371)	(10,502)	(13,916)	(16,783)	(19,373)	(20,399)	(22,975)	22,756	21,752	20,756	19,767	18,787	18,387	17,424	16,469	15,523	14,587
Deferred Asset (Liability) Carry Charge	149	278	115	(324)	(1,013)	(1,946)	(3,167)	(4,666)	(6,399)	(8,381)	(8,981)	(8,044)	(7,111)	(6,183)	(5,259)	(4,319)	(3,360)	(2,401)	(1,442)	(481)
Deferred Asset (Liability) Ending Balance	4,362	3,789	(411)	(9,106)	(20,621)	(36,483)	(56,433)	(80,473)	(107,270)	(138,627)	(124,851)	(111,143)	(97,499)	(83,915)	(70,388)	(56,319)	(42,255)	(28,188)	(14,106)	0
Accounting Order:																				
Income Statement:																				
Revenue from customers	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374	24,374
Revenue - accounting entries	4,214	(851)	(4,315)	(8,371)	(10,502)	(13,916)	(16,783)	(19,373)	(20,399)	(22,975)	22,756	21,752	20,756	19,767	18,787	18,387	17,424	16,469	15,523	14,587
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	(2,535)	(7,815)	(11,500)	(15,783)	(18,148)	(21,801)	(24,914)	(27,757)	(29,042)	(31,885)	13,572	12,287	11,002	9,717	8,432	7,147	5,862	4,577	3,292	2,007
Theoretical interest - plant	9,013	8,051	7,098	6,394	5,782	5,240	4,838	4,506	4,174	3,842	3,509	3,177	2,845	2,512	2,180	1,848	1,516	1,183	851	519
Theoretical interest - short/(excess) cash	149	278	115	(324)	(1,013)	(1,946)	(3,167)	(4,666)	(6,399)	(8,381)	(8,981)	(8,044)	(7,111)	(6,183)	(5,259)	(4,319)	(3,360)	(2,401)	(1,442)	(481)
Carry charge - accounting entries	(149)	(278)	(115)	324	1,013	1,946	3,167	4,666	6,399	8,381	8,981	8,044	7,111	6,183	5,259	4,319	3,360	2,401	1,442	481
Income before taxes	(11,548)	(15,866)	(18,598)	(22,177)	(23,930)	(27,041)	(29,752)	(32,263)	(33,216)	(35,727)	10,063	9,110	8,157	7,204	6,252	5,299	4,346	3,393	2,441	1,488
Income tax	(3,064)	(4,209)	(4,934)	(5,883)	(6,349)	(7,174)	(7,893)	(8,559)	(8,812)	(9,478)	2,670	2,417	2,164	1,911	1,659	1,406	1,153	900	648	395
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	18,989	16,961	14,954	13,470	12,181	11,040	10,193	9,493	8,793	8,093	7,393	6,693	5,993	5,293	4,593	3,893	3,193	2,493	1,793	1,093
ROE	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%
Cash Flow:																				
Net Income:	18,989	16,961	14,954	13,470	12,181	11,040	10,193	9,493	8,793	8,093	7,393	6,693	5,993	5,293	4,593	3,893	3,193	2,493	1,793	1,093
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	(4,214)	851	4,315	8,371	10,502	13,916	16,783	19,373	20,399	22,975	(22,756)	(21,752)	(20,756)	(19,767)	(18,787)	(18,387)	(17,424)	(16,469)	(15,523)	(14,587)
Add: Deferred Income Taxes (def asset/liability)	1,118	(226)	(1,145)	(2,221)	(2,786)	(3,692)	(4,452)	(5,140)	(5,412)	(6,095)	6,037	5,771	5,506	5,244	4,984	4,878	4,623	4,369	4,118	3,870
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	51,859	66,357	53,237	46,538	46,815	42,036	37,150	38,353	38,406	39,599	5,301	5,338	5,370	5,397	5,417	5,010	5,018	5,020	5,015	5,003
NPV	350,923																			
Traditional Rate Making:																				
Income Statement:																				
Revenue from customers	28,587	23,522	20,059	16,003	13,871	10,458	7,591	5,001	3,975	1,399	47,130	46,126	45,129	44,141	43,161	42,761	41,797	40,843	39,897	38,960
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	(2,535)	(7,815)	(11,500)	(15,783)	(18,148)	(21,801)	(24,914)	(27,757)	(29,042)	(31,885)	13,572	12,287	11,002	9,717	8,432	7,147	5,862	4,577	3,292	2,007
Interest	9,013	8,051	7,098	6,394	5,782	5,240	4,838	4,506	4,174	3,842	3,509	3,177	2,845	2,512	2,180	1,848	1,516	1,183	851	519
Income before taxes	(11,548)	(15,866)	(18,598)	(22,177)	(23,930)	(27,041)	(29,752)	(32,263)	(33,216)	(35,727)	10,063	9,110	8,157	7,204	6,252	5,299	4,346	3,393	2,441	1,488
Income tax	(3,064)	(4,209)	(4,934)	(5,883)	(6,349)	(7,174)	(7,893)	(8,559)	(8,812)	(9,478)	2,670	2,417	2,164	1,911	1,659	1,406	1,153	900	648	395
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	18,989	16,961	14,954	13,470	12,181	11,040	10,193	9,493	8,793	8,093	7,393	6,693	5,993	5,293	4,593	3,893	3,193	2,493	1,793	1,093
ROE	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%	9.30%
Cash Flow:																				
Net Income:	18,989	16,961	14,954	13,470	12,181	11,040	10,193	9,493	8,793	8,093	7,393	6,693	5,993	5,293	4,593	3,893	3,193	2,493	1,793	1,093
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																				

174	Add: Deferred Income Taxes (def asset/liability)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
175	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)
176	Cash Flow	$ 54,955	$ 65,731	$ 50,067	$ 40,388	$ 39,099	$ 31,812	$ 24,819	$ 24,120	$ 23,420	$ 22,720	$ 22,020	$ 21,320	$ 20,620	$ 19,920	$ 19,220	$ 18,520	$ 17,820	$ 17,120	$ 16,420	$ 15,720
177	NPV	$ 350,923																			

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

VERIFICATION

Larry Wilkus, being duly sworn upon his oath deposes and states that he is the Regulatory Affairs Director, for Westar Energy, Inc., that he has read and is familiar with the foregoing Rebuttal Testimony, and attests that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Larry Wilkus
Larry Wilkus

Subscribed and sworn to before me this 3 day of July, 2018.

Leslie R. Wines
Notary Public

My Appointment Expires: 5/30/2022

NOTARY PUBLIC - State of Kansas
LESLIE R. WINES
My Appt. Exp. 5/30/22