BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION OF BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC, d/b/a BLACK HILLS ENERGY, FOR APPROVAL OF THE COMMISSION TO MAKE CERTAIN CHANGES IN ITS RATES FOR NATURAL GAS SERVICE.	]	KCC DOCKET NO. 25-BHCG-298-RTS

DIRECT TESTIMONY

AUDREY BENHAM

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

MAY 9, 2025

Redacted Version of Testimony

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, employer, and business address.

A. My name is Audrey Benham. I am employed by the Citizens' Utility Ratepayer Board ("CURB"). My business address is 1500 S.W. Arrowhead Road, Topeka, KS 66614.

Q. Please describe your educational background and qualifications.

A. I earned a Bachelor's Degree in Business Administration from Washburn University of Topeka, Kansas in 2009, majoring in accounting and business management.

Q. Please describe your professional background.

A. In 2017, I began employment with the Kansas Corporation Commission ("KCC" or "Commission") as an Accountant in the Fiscal Department. My duties consisted of managing KCC's accounts receivables, including assisting with the yearly reconciliation of the Agency's accounts receivable system against the State of Kansas' Statewide Management, Accounting, and Reporting Tool (SMART); accounts payables; assisting in large information technology purchases; review and calculation of regulated utility and telecommunication company assessments for KCC and CURB, and the gas pipeline meter assessment for KCC. In May of 2023, I began employment with CURB. My current position is a Regulatory Accountant.

Q. Have you previously testified before the Commission?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On February 3, 2025, Black Hills Energy ("Black Hills" or "Company") filed an Application with the KCC requesting a base revenue increase of $21,593,881 for its natural gas operations in Kansas. The Company's filing includes specific costs which are currently collected through the Gas System Reliability Surcharge ("GSRS"). The GSRS recovered $4,386,129 from ratepayers at the time of filing. With the roll-in of the GSRS costs into base rates, which resets the GSRS to $0, the net revenue increase is $17,207,752.

Black Hills provides natural gas to approximately 119,500 Kansas customers located in 68 communities across 50 Kansas counties.

On behalf of CURB, I will be providing recommendations regarding revenue requirement issues. In addition to my testimony, CURB is sponsoring testimony from Dr. J. Randall Woolridge regarding cost of capital and capital structure issues; Josh Frantz regarding tariff modifications; and Glenn A. Watkins regarding rate design and class cost of service.

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

A. The most significant issues driving Black Hills' rate increase are 1) increased operating expenses since the Company's last rate case in 2021; 2) increased cost of debt due to rising interest rates; 3) the Company's request for a 10.50% return on equity; 4) increases in capital investments since the Company's last rate case; 5) continuation of the GSRS; 6) the request for an abbreviated rate case; and 7) the request to establish a deferred accounting tracker for insurance costs.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement?

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

1. The 12-month test period ending September 30, 2024, is acceptable for use in this case.
2. The update period ending February 28, 2025, is an acceptable period for use for certain rate base and income adjustment items.
3. Black Hills has a test year, *pro forma* rate base of $300,475,962 as reflected in Schedule ALB-3.
4. Black Hills has *pro forma* operating income at present rates of $10,601,774 as shown in Schedule ALB-12.
5. Based on my adjustments and the recommendations of Dr. Woolridge, Black Hills has a test year, *pro forma* revenue deficiency of $10,747,043, which contrasts with Black Hills' deficiency claim of $13,594,125. This is shown in Schedule ALB-1.
6. I recommend a net revenue increase of $13,690,444.

IV. 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's filing consists of an overall cost of capital of 7.63%, which is displayed below and in Section 7 of its Application:

	Percentage	Cost	Weighted Cost
Long-Term Debt	49.56%	4.71%	2.33%
Common Equity	50.44%	10.50%	5.30%
Total	100.00%		7.63%

Q. Is CURB recommending adjustments to the Company's capital structure or cost of capital?

A. Yes, Dr. Woolridge discusses in detail the cost of capital and capital structure recommendations in his testimony.

CURB is recommending a return on equity of 9.50% and a capital structure of 50% common equity and 50% long-term debt for Black Hills. This results in an overall cost of capital of 7.11%. The table below is shown in schedule ALB-2.

	Percentage	Cost	Weighted Cost
Long-Term Debt	50.00%	4.71%	2.36%
Common Equity	50.00%	9.50%	4.75%
Total	100.00%		7.11%

V. <u>RATE BASE ISSUES</u>

Q. What test year did the Company utilize to determine its rate base in this case?

A. The Company selected a historical 12-month test year ending September 30, 2024. However, the Company utilized a *pro forma* 12-month test year ending September 30, 2025, to reflect the addition of capital investments and retirements.

Q. Do you agree with the Company's inclusion of post-test year additions through September 30, 2025?

A. No, I do not agree. Kansas utilizes a historic test year in utility rate cases. Including post-test year additions violates the historical test year concept. It results in a partially forecasted test year. However, KCC Staff has previously permitted an update period of post-test year additions prior to the filing of Staff and intervenor testimony. KCC Staff has selected an update period for the 12 months ending February 28, 2025, for this case. While I oppose the Company's *pro forma* test year ending September 30, 2025, I do concede that utilizing an update period of February 28, 2025, for certain rate base items would reflect known and measurable costs more accurately.

Q. Do you recommend any adjustments to the Company's Rate Base?

A. Yes, I recommend adjustments to Plant-in Service, Accumulated Depreciation, and Deferred Income Tax.

Q. Did the Company include Construction Work in Progress ("CWIP") in rate base?

A. Black hills did not specifically include CWIP separately in rate base; however, they did include CWIP within plant-in service.

Q. Did the Company provide an update of actual plant additions and retirements through February 28, 2025?

A. Yes. In response to data request KCC-111, the Company included plant additions of $32,962,860 and actual plant retirements of ($5,889,923) which resulted in net plant additions of $27,072,937. The Company included net plant additions of $33,744,923 forecasted through

September 30, 2025. This resulted in a reduction of $6,671,986 in actual plant additions. My adjustment is reflected in Schedule ALB-4.

Q. Did you make a similar update to accumulated depreciation?

A. Yes. Since plant-in service was adjusted, accumulated depreciation must be adjusted as well. I adjusted accumulated depreciation for actual reserve plant additions and retirements through February 28, 2025. This resulted in an adjustment of $143,816 for accumulated depreciation. My recommendation is reflected in Schedule ALB-5.

Q. Did the Company include adjustments to deferred income taxes?

A. Black Hills included adjustments to the balances of deferred income tax assets, accumulated deferred income tax ("ADIT") liabilities relating to property, regulatory liabilities associated with excess deferred income tax ("EDIT") related to the Tax Cut and Jobs Act of 2017 ("TCJA"), regulatory liabilities associated with the Kansas EDIT, and deferred tax liabilities allocated from Black Hills Service Company ("BHSC").

Black Hills reflected actual deferred income tax balances as of February 28, 2025, in response to KCC-110. Because these deferred income tax categories above are related to plant-in service, and I have made a recommendation to plant-in service, it is appropriate to update the deferred income tax balances to reflect balances as of February 28, 2025.

Schedule ALB-6 includes a reduction adjustment in the amount of $1,297,957 to deferred income tax assets. Schedule ALB-7 includes a reduction adjustment in the amount of $2,780,903 to ADIT related to property. Schedule ALB-8 includes a reduction adjustment to EDIT-TCJA in the amount of $377,551. Schedule ALB-9 reflects an adjustment of $359,160 to Kansas EDIT. Schedule ALB-10 reflects an adjustment to other ADIT-Other in the amount of $13,922. Finally, Schedule ALB-11 reflects an adjustment in the amount of $142,980 for BHSC's allocated portion of ADIT to Black Hills Direct.

Q. What rate base are you recommending in this case?

A. Given the recommendations I made to plant-in service, accumulated depreciation, and deferred income taxes, I am recommending a rate base in the amount of $300,475,962. Schedule ALB-3 displays my recommendation.

VI. OPERATING INCOME ISSUES

A. Salaries and Wage Expense

Q. How did the Company determine its salary and wage claim for direct employees?

A. Black Hills used payroll data as of November 4, 2024, to determine the salary and wage adjustment. As of November 4, 2024, the company had 118 filled positions and two vacant positions for a total headcount of 120 employees. The Company included the employees' gross pay, callout pay, standby pay, overtime pay, merit increases, incentive pay, 401K contributions, medical insurance, dental insurance, life insurance, and accidental death and dismemberment insurance costs to determine the annualized expense. While the Company used actual payroll and benefits data for the 118 employees, they estimated the payroll and benefits data for the two vacant positions. Blacks Hills included a salary and wage adjustment of $609,858.

Q. Do you agree with Black Hills salary and wage adjustment?

A. I agree with how Black Hills annualized salary and wages for direct employees; however, I believe the annualized costs should be updated to reflect the period ending February 28, 2025. In response to CURB-53, the Company advised one of the vacant positions was filled on November 11, 2024, and the other was filled on January 27, 2025. Since the two vacant positions were filled, I agree with the headcount of 120 employees.

In response to CURB-70, the Company included actual payroll and benefits data, rather than estimated data, for the period ending March 11, 2025, because it encompasses the 2024 incentive payout. For this reason, it is more appropriate to use the update period to annualize salary and wage expense for direct employees. My recommendation is illustrated in Schedule ALB-13.

Q. Are you making any recommendations to BHSC salary and wage expense?

A. Yes. The company made an adjustment to the test year in the amount of $986,304 to account for the annualization of the 2025 merit increases and the adjusting of the Annual Incentive Plan ("AIP") and the Short-term Incentive Plan ("STIP") payout to 100% of target. Similarly to Black Hills' direct salary and wage adjustment, I propose to annualize the costs using the payroll data for the update period ending February 28, 2025. This results in an adjustment of $81,382 which is reflected in Schedule ALB-14.

B. <u>Incentive Compensation Expense</u>

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

A. Black Hills offers variable compensation ("incentive compensation") programs to its employees which includes the AIP, the STIP, and the Long-Term Incentive Plan ("LTIP").

Employees that are below a director's level position, except for interns and temporary employees, are eligible to participate in the AIP. Employees that are in a director's level position or above are eligible to participate in the STIP. Both the AIP and the STIP use a target percentage which is based on the employee's pay grade. They both have the same performance metrics and goals, which is based on the Company's annual AIP scorecard. For AIP and STIP awards issued during the **[redacted]** scorecard timeframe, **[redacted]** of the award was based on earnings per share, or financial metrics, and **[redacted]** of the award was based on non-financial metrics.[1]

Employees that hold a Vice President position and above are eligible for the LTIP. LTIP awards issued during the **[redacted]** scorecard timeframe were based on **[redacted]**, which vested over a three-year period, and **[redacted]**, which are tied to a three-year metric.[2]

Q. Has the Commission set a precedent regarding incentive compensation?

A. Yes. In KCC Docket No. 19-ATMG-525-RTS ("19-525"), the Commission ruled that incentive compensation tied to financial metrics is disallowed.

> The Commission concludes there is no reason to revisit its prior decisions on incentive compensation. Likewise, the Commission concludes there is no reason to revisit its decision announced in the 10-415 Docket to disallow incentive programs that focus on the financial aspect, rather than operational aspects. Accordingly, the Commission reaffirms its intent to disallow the costs of management incentive programs that focus on financial criteria.[3]

In docket 19-525, the Commission also ruled that 50% of the time lapse portion of the LTIP and 100% of the performance-based portion of the LTIP be disallowed.

[1] Confidential response to KCC-197.
[2] Confidential response to KCC-198.
[3] Order on *Atmos Energy Corporation's Application for Rate Increase*, 19-525 Docket, pg. 17, paragraph 46 (February 24, 2020).

> The Commission adopts Staffs recommendation to remove 100% of Atmos' s short term Management Incentive Plan expenses, 50% of the time lapse portion of the Long Term Incentive Plan, and 100% of the expense associated with the Performance Based portion of the Long Term Incentive Plans allocated to Atmos's Kansas operations.[4]

Q. What adjustments are you recommending to the Company's incentive compensation claim?

A. Since **[redacted]** of the AIP and STIP awards are tied to financial metrics and keeping with Commission precedent in docket 19-525, I recommend the Commission deny the portion of incentive compensation tied to financial metrics. I recommend a **[redacted]** exclusion of the AIP and STIP test year amounts.

Because the LTIP is based on **[redacted]** restricted stock and **[redacted]** performance shares, it is fitting to exclude 50% or half of the LTIP metrics tied to restricted stock and 100% of the LTIP metrics tied to performance shares. This results in **[redacted]** of the LTIP incentive compensation to be excluded from test year amounts. My recommendation is reflected in Schedule ALB-15.

C. Payroll Tax Expense

Q. Are you recommending any adjustments to payroll tax expense?

A. Since I adjusted Black Hills direct salaries and wages, BHSC allocated salaries and wages, and incentive compensation, it is necessary to make a corresponding adjustment to payroll taxes. My recommendation results in an adjustment of $73,425 which is reflected in Schedule ALB-16.

[4] Order on *Atmos Energy Corporation's Application for Rate Increase*, 19-525 Docket, pg. 17, paragraph 46 (February 24, 2020).

D. Pension and Retiree Healthcare Expense

Q. How did the Company determine its pension and retiree healthcare Expense Adjustment?

A. The Company adjusted the test year pension and retiree healthcare actual expenses based on the January 2024 actuarial study. In the direct testimony of Company Witness Thomas Stevens, he explains that for the period of October through December 2024, actual accrual amounts were used based on the January 2024 actuarial study, and for January through September 2025, the accrual amounts were projected.[5] The Company determines their actuarial study annually in January. At the time of determining the pension and healthcare expense adjustment, the January 2025 actuarial study was not available.

Q. Are you recommending any adjustments to pension and retiree healthcare expenses?

A. Yes. Since the accrual amounts for pension and retiree healthcare are projected for January through September 2025, it is more appropriate to use the actual accrual amounts through the update period ending February 28, 2025. The net adjustment to pension and retiree healthcare expenses is $25,859, which is reflected in Schedule ALB-17.

E. Pension and Retiree Healthcare Expense Trackers

Q. Has the Company established a pension and retiree healthcare expense tracker?

A. In KCC Docket No. 07-GIMX-1041-GIV, the Commission approved Black Hills' request to establish pension, postretirement, and post-employment trackers in their next general rate

[5] Direct Testimony of Thomas D. Stevens on Behalf of Black Hills, pgs. 20-21, lns 21-22, 1 (February 3, 2025).

proceeding. Black Hills established the pension and retiree healthcare expense trackers in KCC Docket No. 14-BHCG-502-RTS. The pension and retiree healthcare expense trackers are recorded as a regulatory asset or liability which account for the difference between actual pension and retiree healthcare expenses and the amounts collected in rates. In a following rate case, these trackers are amortized over a specific period of time.

Q. What is the Company's claim regarding the pension and retiree healthcare expense trackers?

A. The company requests continuation of the pension and retiree healthcare expense trackers and to amortize the September 30, 2025, projected regulatory liability amounts for three years.

Q. Are you recommending any adjustments to the pension and retiree healthcare expense trackers?

A. While I do agree with continuing the trackers, I am recommending two adjustments. Because I recommended using the actual February 28, 2025, balances for pension and retiree healthcare expense, it is appropriate to use the actual February 28, 2025, pension and retiree healthcare tracker liability balances. Next, I recommend an amortization period of five years rather than the Company's amortization period of three years. The average time between Black Hills' last four general rate cases is approximately five years. Not only does the average time between rate cases support a five-year amortization, but the Company uses a GSRS, which, per K.S.A. 66-2203(b), requires the Company to file a general rate case within five years of the last general rate case in order to meet the financial metrics of the GSRS statute. This results in an adjustment of $97,068 which is reflected in Schedule ALB-18.

F. Bad Debt Expense

Q. How did the Company determine bad debt expense?

A. Black Hills determined the average net write-offs and average billed revenue using three years of net write-offs and billed revenue. The three-year timeframe used was October 2020 through September 2023. The Company divided the average net write-offs by the average billed revenue which resulted in a bad debt rate of 0.6002%. They multiplied the bad debt rate by the adjusted revenue and subtracted that amount from the test year per book balance to arrive at an adjustment of $187,896.

Q. Do you recommend any adjustments to bad debt expense?

A. The Company used net write-offs and billed revenue during October through December 2020. However, during calendar year 2020, Kansas and the United States suffered from the COVID-19 pandemic, which had an effect on utility disconnections, net write-offs and billed revenue. In the Company's last rate case, KCC Docket No. 21-BHCG-418-RTS ("21-418"), Black Hills' witness, Ms. Schuldt states, the calendar year 2020 was excluded in determining the bad debt ratio due to abnormal impacts on net write-offs in 2020 resulting from the COVID-19 pandemic and the disconnection moratorium.[6] In KCC Docket No. 20-GIMX-393-MIS, the Commission ordered a disconnection moratorium which started on March 16, 2020, and extended through December 31, 2020. While I agree with the Company's use of a three-year average for net write-offs and unbilled revenue, I do not agree with the timeframe they used. I recommend net write-offs and unbilled revenue during the calendar year 2020 not be used in

[6] Direct testimony of Ms. Schultz on Behalf of Black Hills in Docket 21-BHCG-418-RTS, pg. 44, lns 5-7 (May 7, 2021).

calculating the bad debt rate. I recommend using the three-year timeframe of October 2021 through September 2024 to determine the bad debt rate. My adjustment is reflected in Schedule ALB-19.

G. <u>Rate Case Expense</u>

Q. How did the Company determine what rate case costs to include in this case?

A. In response to CURB-58, the Company determined $700,000 in rate case expenses in this docket based on the amount requested in docket 21-418 less the cost for a depreciation consultant.

The Company also included the remaining amortization from Anadarko Acquisition (KCC Docket No. 16-BHCG-144-ACQ) and rate case expenses from the 2021 Black Hills rate case per the Commission's Order Approving the Settlement Agreement. However, included in the settlement agreement, the Commission also approved the stipulation for KCC Staff and CURB to reserve the right to object to the inclusion of these costs. While I believe Anadarko Acquisition should be separate from rate case expense, I do not oppose the inclusion of the remaining amortization in this current rate case docket. I do not oppose the remaining amortization of 2021 Black Hills rate case expenses included in this current rate case.

Q. Do you agree with including $700,000 in rate case expenses in this docket?

A. No. The Company submitted the final rate case expenses for docket 21-418 in the amount of $621,934. Of the $621,934 expenses in docket 21-418, $48,304 was for the depreciation study. The Company is utilizing depreciation rates from docket 21-418 in this current case, so there are no costs for a depreciation study in this current case. Subtracting out the depreciation study costs from $621,934, this results in rate case expenses of $573,630. Since the company is requesting $700,000 based on what was requested in the 21-418 docket, the Company is overstating rate case expenses in this current docket.

Q. What do you recommend in rate case expenses?

A. I recommend $580,000 in rate case expenses. Currently, actual expenses through April 11, 2025, for the Company and KCC Staff and actual expenses through April 16, 2025, for CURB amount to $174,686. This provides approximately $405,314 in rate case expenses to accrue. Since the last rate case expenses (minus the depreciation study) were just shy of $580,000, I believe my recommendation is just and reasonable.

Q. What amortization period do you recommend?

A. As stated above, the average time between Black Hills' last four general rate cases is approximately five years. Not only does the average time in between rate cases support a five-year amortization, but the Company uses a GSRS which, per K.S.A. 66-2203(b), requires the Company to file a general rate case within five years of the last in order to meet the financial metrics of the GSRS statute. The Commission also approved a five-year amortization of rate case expenses in docket 21-418. For these reasons, I recommend rate case expenses be amortized over five years. My recommendation is reflected in Schedule ALB-20.

H. <u>Payment Fee Expense</u>

Q. Please explain the payment fee expense adjustment.

A. Payment fees are fees that Black Hills pays on behalf of the customer when the customer pays their bill by credit card, debit card, digital wallet, or with a checking or savings account.

Effective January 2024, the Company switched to a new card processing vendor, Paymentus/JP Morgan. The Company projected the pro forma year payment fees by increasing the 2024 transaction count by 18%.

Q. Are you recommending an adjustment to payment fee expense?

A. While there has been some increase in the volume of transactions over the last four years, the additional 18% increase is speculative and not known and measurable. I recommend the payment fee expense be based on current test year levels. My recommendation is reflected in schedule ALB-21.

I. <u>Data Improvement Integrity Program ("DIIP")</u>

Q. Please describe the DIIP.

A. The DIIP was approved docket 21-418. In the direct testimony of Company Witness Marc Eyre, the DIIP is designed to "improve the knowledge of Black Hills gas pipeline system, provide the ability to positively confirm the integrity of the pipeline system, close known data gaps, and verify current data for accuracy."[7] The Company is requesting inclusion of $400,000 in annualized DIIP expenses.

Q. What adjustment do you recommend to the DIIP?

A. In response to CURB-64, the table below shows annual DIIP expenses since implementation.

[7] Direct Testimony of Marc T. Eyre on Behalf of Black Hills, pg. 17, lns 7-10. (February 3, 2025).

DIIP Expenses	
October 2020-September 2021:	$349,281
October 2021-September 2022:	$225,016
October 2022-September 2023:	$162,140
October 2023-September 2024:	$149,724

The table illustrates that the Company has not reached total annual DIIP costs of $400,000 over the four-year period, when in fact, the costs have decreased each year. I do believe this program is important to help Black Hills provide safe and reliable service, but I also believe the Company's request of $400,000 is excessive. I am recommending a three-year average of DIIP expenses during October 2021 through September 2024. My recommendation is reflected in Schedule ALB-22.

J. Research and Development ("R&D") Expense

Q. Please describe the Company's claim regarding R&D costs.

A. The company is requesting to recover $59,712 relating to an Operations Technology Development ("OTD") membership fee. OTD funds the research and development of new technologies partially based on OTD membership fees from participating utilities, like Black Hills. Per the direct testimony of Company Witness Nick Smith, "OTD is a not-for-profit focused on developing, testing, and implementing new technologies to improve the safety, reliability, and environmental stewardship of natural gas distribution systems."[8]

[8] Direct Testimony of Nick W. Smith on Behalf of Black Hills, pg. 14, lns 14-16. (February 3, 2025).

Q. Do you support the Company's request to recover R&D costs related to OTD membership?

A. No, I do not. The Company is exploring new technologies by participating in the OTD membership. The technologies are not definitive tangible projects that Black Hills is currently completing; thus, the projects are not known and cannot be measured. Since the membership fees help fund the research and development of the new technologies generally, I believe the request for these costs are not reasonable to recover from Kansas ratepayers. Black Hills should only be allowed to recover costs from ratepayers when such programs and technologies are deployed to serve customers and not before, or even through a separate docket creating the program or deploying the technology.

The Company requested approval to recover R&D costs in the 21-418 docket. CURB and KCC Staff recommended denial of recovery of the R&D costs at that time. For the reasons stated, I recommend the Commission deny the Company's request to recover $59,712 in R&D costs. Schedule ALB-23 shows my recommendation.

K. <u>Damage Prevention Expense</u>

Q. Please briefly describe the Company's claim for damage prevention expense.

A. The Company is requesting $50,000 in additional funding to create a public awareness and education campaign by way of advertising through social media, community events, brochures, post cards, radio, and television. Black Hills aims to increase awareness to excavators' and homeowners' knowledge regarding safe digging practices, such as calling 811 before digging.

Q. Do you have any recommendations regarding the Company's damage prevention expense adjustment?

A. In the direct testimony of Company Witness Marc Eyre, he states "the Company's focused damage prevention program has been effective as evidenced by the reduction in damages to the system as measured by per thousand locate tickets or HPT. Kansas pipeline damages have been reduced from a rate of 2.43 HPT in 2022 to 1.94 HPT in 2024."[9] This shows that the Company can effectively reduce the amount of damage based on the current budget available for the damage prevention program.

In the direct testimony of Company Witness Nick Smith, he uses the example of Black Hills Energy's Arkansas operations experiencing a 71% reduction in excavation damages per thousand locate tickets from 2016 to 2023 after implementing an education and awareness campaign to support the need for additional funding in Kansas.[10] However, in the testimony of Mr. Eyre in the Arkansas docket 23-074-U (ALB Exhibit-1), he states the Arkansas jurisdiction "experienced 351 damages to the system in 2022 and 271 through September 2023."[11] Black Hills Energy Arkansas has several more damage incidents than Kansas. While additional funding may be needed in Arkansas to combat a higher percentage of damages to the system, that is not the case in Kansas. The Company has shown they can reduce damages to the system with the current budget and advertising expense available.

Finally, educational and safety related advertising is usually 100% recoverable and included in the general advertising expense in rate cases, so additional funding is unnecessary.

[9] Direct Testimony of Marc T. Eyre on Behalf of Black Hills, pg. 20, lns 12-16. (February 3, 2025).
[10] Direct Testimony of Nick W. Smith on Behalf of Black Hills, pg. 17, lns 16-17. (February 3, 2025).
[11] Direct Testimony of Marc T. Eyre on Behalf of Black Hills Energy Arkansas, Inc., docket 23-074-U, pg. 24, lns 12-13. (December 4, 2023).

For these reasons stated, I recommend the Commission deny the additional $50,000 in damage prevention expenses. My recommendation is shown in Schedule ALB-24.

L. Vegetation Management Expense

Q. Did the Company make an adjustment to vegetation management expense?

A. Yes. The Company is requesting to include $100,000 in annual vegetation costs to manage vegetation and right of way clearing. The Company accesses right of ways to work on their equipment. Unmanaged vegetation in the right of ways causes potential reliability risks, safety hazards and can lead to possible natural gas leaks if not maintained. Black Hills' actual vegetation management costs for 2020 were $75,615. They used the CPI inflation calculator to determine a 23.69% increase in vegetation costs from 2020 to February 2025. This resulted in projected costs based on inflation of $93,527.

Q. Are you making any adjustments to the vegetation management expense?

A. I believe it is important to clear right of ways of vegetation to prevent reliability issues, safety issues and potential natural gas leaks, but I do not agree with the amount the Company is requesting. In response to CURB-66, below are the vegetation management expenses from 2020 through 2024.

2020	$75,615
2021	$26,167
2022	$17,164
2023	$46,015
2024	$76,497
Total	**$241,457**
Average	**$48,291**

The table above shows that the vegetation costs vary from year to year. The Company has not reached $100,000 in vegetation costs for the last five years. In fact, the average vegetation costs are well below $100,000 in vegetation costs. Per the same CPI Inflation Calculator the Company used, the 2024 costs of $76,497 have the same buying power as $77,513.55 in March 2025. Also, the CPI Inflation Calculator estimates future costs which can be manipulated based on the timeframe and data entered. Therefore, I recommend including vegetation management costs of $80,000 which is based on 2024 vegetation costs. My recommendation is reflected in Schedule ALB-25.

M. Depreciation Expense

Q. Are you making any adjustments to depreciation expense?

A. Yes. Because I adjusted plant-in service and accumulated depreciation to reflect the actual balances as of February 28, 2025, I have made a corresponding adjustment to depreciation expense to reflect the actual balance as of February 28, 2025. My adjustment is reflected in Schedule ALB-26.

N. Income Taxes-Interest Expense

Q. Are you recommending an adjustment to income taxes?

A. Yes. The Company calculated interest expense by multiplying their pro forma total rate base by their determined weighted cost of debt. I recommend using CURB's recommended rate base of $300,475,962 and CURB's recommended weighted cost of debt of 2.36%. My adjustment is shown in Schedule ALB-27.

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

A. I have used a composite income tax factor of 21.00% which only includes federal income taxes. Black Hills is no longer subjected to state income taxes in Kansas. This is reflected in Schedule ALB-28.

Q. What revenue multiplier have you used to gross up the Company's revenue deficiency?

A. I have used a revenue multiplier of 1.27388. This reflects a bad debt rate of 0.6325% as well as the 21.00% income tax factor. This is reflected in Schedule ALB-29.

VII. <u>Revenue Requirement Summary</u>

Q. Please summarize CURB's revenue requirement recommendation.

A. Based on my adjustments, the Company has a net base revenue deficiency of $13,690,444 as reflected in Schedule ALB-1. This recommendation reflects revenue requirement adjustments of $3,517,308 to the Black Hills' net revenue increase of $17,207,752.

Q. Have you quantified the revenue requirement impact of each of the recommended adjustments.

A. Yes. In Schedule ALB-30, it shows the impact of the revenue requirement based on CURB's rate of return, rate base, and operating expense adjustments.

Q. Have you developed a *pro forma* income statement?

A. Schedule ALB-31 compares CURB's *pro forma* income statement against the Company's. My adjustments reflect an overall return on rate base of 7.11%, as recommended by Dr. Woolridge.

VIII. Insurance Expense Tracker

Q. Please summarize the Company's request for an insurance expense tracker.

A. Black Hills purchases insurance policies from the commercial marketplace in the event of insured loss. The types of insurance purchased are general liability, excess liability, commercial auto, workers compensation, property, business interruption, directors and officers, and terrorism insurance. The Company utilizes a captive insurance company for some of their policies which can help manage risk and volatility in the market.

Q. What is your recommendation regarding the insurance expense tracker?

A. It is evident that insurance costs are on the rise, but by how much is the question. The market is volatile, however, utilizing a captive insurance company for more of their policies should help mitigate risk. However, in some cases, establishing a tracker reduces the Company's incentive to control costs. Since the Company proposes an abbreviated rate case, I propose the insurance expense tracker be re-examined in the abbreviated rate case.

IX. Abbreviated Rate Case

Q. What is your recommendation regarding the abbreviated rate case?

A. The Company requested approval to file an abbreviated rate case to address plant in service through December 31, 2025, and update accumulated depreciation, depreciation expense, and ADIT accordingly. The Company also requested to include in the abbreviated rate case any items that may remain outstanding from this rate proceeding.

I recommend the Commission approve the Company's request for an abbreviated rate case limited to the following: 1) plant-in service additions and updates to items associated with plant-in service through December 31, 2025, and 2) the re-examination of the insurance expense tracker.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF KANSAS)
)
COUNTY OF SHAWNEE) ss:

I, Audrey Benham, of lawful age and being first duly sworn upon my oath, state that I am a Regulatory Analyst for the Citizens' Utility Ratepayer Board; that I have read and am familiar with the above and foregoing document and attest that the statements therein are true and correct to the best of my knowledge, information, and belief.

Audrey Benham
Audrey Benham

SUBSCRIBED AND SWORN to before me this 9th day of May, 2025.

DELLA J. SMITH
Notary Public - State of Kansas
My Appt. Expires January 26, 2029

Della J. Smith
Notary Public

My Commission expires: 01-26-2029.

APPENDIX A

SUPPORTING SCHEDULES

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REVENUE REQUIREMENT SUMMARY

	Company Claim (A)	Recommended Adjustment	Recommended CURB	
1. Pro Forma Rate Base	$305,947,330	($5,471,367)	$300,475,962	(B)
2. Required Cost of Capital	7.63%	-0.53%	7.11%	(C)
3. Required Return	$23,343,781	($1,994,964)	$21,348,817	
4. Operating Income @ Present Rates	$9,749,657	$852,117	$10,601,774	(D)
5. Operating Income Deficiency	$13,594,125	($2,847,082)	$10,747,043	
6. Revenue Multiplier	1.2658		1.2739	(E)
7. Required Revenue Increase	**$17,207,752**	**($3,517,308)**	**$13,690,444**	

Sources:
(A) Company Filing, Section 3, Schedule 1
(B) Schedule ALB-3
(C) Schedule ALB-2
(D) Schedule ALB-12
(E) Schedule ALB-29

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REQUIRED COST OF CAPITAL

	Capital Structure	Cost Rate		Weighted Cost
1. Common Equity	50.00%	9.50%	(A)	4.75%
2. Long Term Debt	50.00%	4.71%	(A)	2.36%
3. Total Cost of Capital	100.00%			**7.11%**

Sources:
(A) Recommendation of Dr. Woolridge

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

RATE BASE SUMMARY

		Company Claim (A)	Recommended Adjustment		Recommended Position
1.	Utility Plant in Service	$495,300,471	($6,671,986)	(B)	$488,628,485
	Less:				
2.	Depreciation & Amortization	($138,756,353)	($143,816)	(C)	($138,900,169)
3.	Net Utility Plant	$356,544,118	($6,815,802)		$349,728,316
	Plus:				
4.	Construction Work In Progress	$0	$0		$0
5.	Materials and Supplies	2,899,107	0		2,899,107
6.	Gas Storage	2,662,837	0		2,662,837
7.	Prepayments	52,303	0		52,303
8.	Cash Working Capital	0	0		0
9.	Deferred Income Tax Assets	6,296,023	(1,297,957)	(D)	4,998,066
	Less:				
10.	Customer Advances	($506,945)	$0		($506,945)
11.	Customer Deposits	(1,090,806)	0		(1,090,806)
12.	Acc. Deferred Inc. Taxes-Property	(47,994,139)	2,780,903	(E)	(45,213,236)
13.	Regulatory Liability-Fed. TCJA EDIT	(11,257,324)	377,551	(F)	(10,879,773)
14.	Regulatory Liability-KS EDIT	0	(359,160)	(G)	(359,160)
15.	ADIT-Other	(157,328)	(13,922)	(H)	(171,250)
16.	Allocated BHSC ADIT and EDIT	(1,500,517)	(142,980)	(I)	(1,643,497)
17.	Total Rate Base	**$305,947,330**	**($5,471,367)**		**$300,475,962**

Sources:
(A) Company Filing, Section 3, Schedule 2, Page 1
(B) Schedule ALB-4
(C) Schedule ALB-5
(D) Schedule ALB-6
(E) Schedule ALB-7
(F) Schedule ALB-8
(G) Schedule ALB-9
(H) Schedule ALB-10
(I) Schedule ALB-11

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

UTILITY PLANT IN SERVICE

1.	Actual Plant Additions Through 2/28/2025	$32,962,860	(A)
2.	Actual Plant Retirements Through 2/28/2025	(5,889,923)	(A)
3.	Total Gross Plant Additions Through 2/28/2025	$27,072,937	
4.	Per Company Filing	33,744,923	(B)
5.	Recommended Adjustment	**($6,671,986)**	

Sources:
(A) Response to KCC-111
(B) Company Filing, Section 3, Schedule 2, Page 1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

ACCUMULATED DEPRECIATION

1.	Actual Reserve Additions Through 2/28/2025	$12,766,288	(A)
2.	Actual Retirements Through 2/28/2025	(5,895,444)	(A)
3.	Total Reserve Additions Through 2/28/2025	$6,870,843	(B)
4.	Per Company Filing	6,727,027	
5.	Recommended Adjustment	**$143,816**	

Sources:
(A) Response to KCC-112
(B) Company Filing, Section 3, Schedule 2, Page 1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

DEFERRED INCOME TAX ASSETS

1.	Actual Balance as of 2/28/2025	$4,998,066	(A)
2.	Company Claim	6,296,023	(B)
3.	Recommended Adjustment	**($1,297,957)**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

ACCUMULATED DEFERRED INCOME TAXES-PROPERTY

1.	Actual Balance as of 2/28/2025	$45,213,236	(A)
2.	Company Claim	47,994,139	(B)
3.	Recommended Adjustment	**($2,780,903)**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REGULATORY LIABILITIES FOR FEDERAL TCJA EDIT

1.	Actual Balance as of 2/28/2025	$10,879,773	(A)
2.	Company Claim	11,257,324	(B)
3.	Recommended Adjustment	**($377,551)**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REGULATORY LIABILITIES FOR KANSAS EDIT

1.	Actual Balance as of 2/28/2025	$359,160	(A)
2.	Company Claim	0	(B)
3.	Recommended Adjustment	**$359,160**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

ACCUMULATED DEFERRED INCOME TAXES-OTHER

1.	Actual Balance as of 2/28/2025	$171,250	(A)
2.	Company Claim	157,328	(B)
3.	Recommended Adjustment	**$13,922**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

ALLOCATED BHSC ADIT AND EDIT

1.	Actual Balance as of 2/28/2025	$1,643,497	(A)
2.	Company Claim	1,500,517	(B)
3.	Recommended Adjustment	**$142,980**	

Sources:
(A) Response to KCC-110
(B) Company Filing, Schedule C-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REVENUE REQUIREMENT SUMMARY

			Schedule No.
1.	Company Claim	$9,749,657	1
	Recommended Adjustments:		
2.	Salary and Wage Expense-Direct	$42,916	13
3.	Salary and Wage Expense-BHSC	64,292	14
4.	Incentive Compensation Expense	592,731	15
5.	Payroll Tax Expense	53,545	16
6.	Pension and OPEB Expense	20,429	17
7.	Amortization of Pension & OPEB Trackers	76,684	18
8.	Bad Debt Expense	85,983	19
9.	Rate Case Expense	92,694	20
10.	Payment Fee Expense	54,531	21
11.	Data Improvement Integrity Program Expense	174,622	22
12.	Research and Development Expense	47,172	23
13.	Damage Prevention Expense	39,500	24
14.	Vegetation Management Expense	15,800	25
15.	Depreciation Expense	(497,784)	26
16.	Interest Synchronization	(10,996)	27
17.	Operating Income	**$10,601,774**	

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

SALARIES AND WAGES

1.	Salary & Wages - 12 months ending February 28, 2025		$555,534	(A)
2.	Company Claim		609,858	(B)
3.	Recommended Adjustment		$54,324	
	Income Taxes @	21.00%	11,408	
	Operating Income Impact		**$42,916**	

Sources:
(A) Response to CURB-53, CURB-70
(B) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-5

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

SALARIES AND WAGES - BHSC

1.	Annualized Costs - 12 months ending February 28, 2025		$11,433,612	(A)
2.	Company Claim		11,514,994	(B)
3.	Recommended Adjustment		$81,382	
4.	Income Taxes @	21.00%	17,090	
5.	Operating Income Impact		**$64,292**	

Sources:
(A) Response to KCC-205
(B) Response to KCC-205; Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-8

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

INCENTIVE COMPENSATION EXPENSE

		Company Claim (A)	Recommended Adjustment (%) (B)	Recommended Adjustment ($)
1. Annual Incentive Plan		[redacted]	[redacted]	$353,623
2. Short-Term Incentive Plan		[redacted]	[redacted]	101,435
3. Long-Term Incentive Plan		[redacted]	[redacted]	295,234
4. Total Recommended Adjustment				$750,293
5. Income Taxes @	21.00%			157,561
6. Operating Income Impact				**$592,731**

Sources:
(A) Response to CURB DR-68
(B) Recommendation of Ms. Benham

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

PAYROLL TAX EXPENSE

1.	Salary & Wage Adjustment-BH		$54,324	(A)
2.	Salary & Wage Adjustment-BHSC		81,382	(B)
3.	Incentive Compensation Adjustment		750,293	(C)
4.	Total Labor Adjustment		$885,999	
5.	FICA Tax Rate		7.65%	(D)
6.	Total Recommended Adjustment		$67,779	
7.	Income Taxes @	21.00%	$14,234	
8.	Operating Income		**$53,545**	

Sources:
(A) Schedule ALB-13
(B) Schedule ALB-14
(C) Schedule ALB-15
(D) Company Filing, KSG Direct Exhibit SKJ-2, Schedule L-1

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

PENSION AND OPEB EXPENSE

1.	Pension Expense - 12 Months ending February 28, 2025		$262,612	(A)
2.	Retiree Healthcare Expense - 12 Months ending February 28, 2025		167,600	(B)
3.	Total Pension/Ret. Healthcare Expense - 12 Months ending February 28, 2025		$430,212	
4.	Company Claim		$456,071	(C)
5.	Recommended Adjustment		$25,859	
6.	Income Taxes @	21.00%	5,430	
7.	Operating Income		**$20,429**	

Sources:
(A) Response to KCC DR-102
(B) Response to KCC DR-102
(C) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-6

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

AMORTIZATION OF PENSION AND OPEB TRACKER

1.	Pension Plan Tracker Liability Balance at 2/28/2025		($286,331)	(A)
2.	Amortization Period		5	(B)
3.	Pension Plan Tracker Liability Annual Amortization		($57,266)	
4.	Retiree Healthcare Plan Tracker Liability Balance at 2/28/2025		($2,153,845)	(A)
5.	Amortization Period		5	(B)
6.	Retiree Healthcare Plan Tracker Liability Annual Amortization		($430,769)	
7.	Total Recommended Annual Amortization of Pension & OPEB Tracker		($488,035)	
8.	Company Claim		(585,103)	(C)
9.	Recommended Adjustment		$97,068	
10.	Income Taxes @	21.00%	20,384	
11.	Operating Income Impact		**$76,684**	

Sources:
(A) Response to KCC-104
(B) Recommendation of Ms. Benham
(C) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-7

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

BAD DEBT EXPENSE

1.	Requested Rate Increase		$17,207,752	(A)
2.	Three Year Average Rate		0.6325%	(B)
3.	Recommended Adjustment		$108,839	
4.	Income Taxes @	21.00%	22,856	
5.	Operating Income Impact		**$85,983**	

Sources:
(A) Company Filing, Section 3, Schedule 1, Page 1
(B) Recommendation of Ms. Benham

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

RATE CASE EXPENSE

1.	Recommended Rate Case Expenses		$580,000	(A)
2.	Recommended Amortization Period		5	(A)
3.	Recommended Rate Case Annual Amortization		$116,000	
4.	Prior Rate Case Exp.			
5.	Anadarko Acquisition Exp.		$19,154	(B)
6.	2021 KS Gas Rate Case Exp.		155,484	(B)
7.	Total Prior Rate Case Exp.		$174,638	
8.	Amortization Period Remaining		1.25	
9.	Total Prior Rate Case Annual Amortization		$139,710	
10.	Total Annual Amortization		$255,710	
11.	Company Claim		373,044	(B)
12.	Recommended Adjustment		$117,334	
13.	Income Taxes @	21.00%	24,640	
14.	Operating Income		**$92,694**	

Sources:
(A) Recommendation of Ms. Benham
(B) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-10

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

PAYMENT FEE EXPENSE

1.	Cost at Current Levels		$316,471	(A)
2.	Company Claim		385,497	(B)
3.	Recommended Adjustment		$69,026	
4.	Income Taxes @	21.00%	14,495	
5.	Operating Income Impact		**$54,531**	

Sources:
(A) Based on actual test year payments per company workpapers
(B) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-12

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

DATA IMPROVEMENT INTEGRITY PROGRAM EXPENSE

1.	3-Year Average of Actual Expenses		$178,960	(A)
2.	Company Claim		400,000	(B)
3.	Recommended Adjustment		$221,040	
4.	Income Taxes @	21.00%	46,418	
5.	Operating Income Impact		**$174,622**	

Sources:
(A) Response to CURB-64 and KSG Direct Exhibit SKJ-2, Schedule H-14
(B) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-14

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

RESEARCH AND DEVELOPMENT EXPENSE

1.	Recommended Adjustment		$59,712	(A)
2.	Income Taxes @	21.00%	12,540	
3.	Operating Income Impact		**$47,172**	

Sources:
(A) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-17

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

DAMAGE PREVENTION EXPENSE

1.	Recommended Adjustment		$50,000	(A)
2.	Income Taxes @	21.00%	10,500	
3.	Operating Income Impact		**$39,500**	

Sources:
(A) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-18

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

VEGETATION MANAGEMENT EXPENSE

1.	Recommendation		$80,000	(A)
2.	Company Claim		100,000	(B)
3.	Recommended Adjustment		$20,000	
4.	Income Taxes @	21.00%	4,200	
5.	Operating Income Impact		**$15,800**	

Sources:
(A) Recommendation of Ms. Benham
(B) Company Filing, KSG Direct Exhibit SKJ-2, Schedule H-20

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

DEPRECIATION EXPENSE ADJUSTMENT

1.	Gross Plant Adjustment		$244,373	(A)
2.	Company Claim		874,479	(B)
3.	Recommended Adjustment		($630,106)	
4.	Income Taxes @	21.00%	(132,322)	
5.	Operating Income Impact		**($497,784)**	

Sources:
(A) Response to KCC-113
(B) Company Filing, KSG Direct Exhibit SKJ-2, Statement J

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

INTEREST SYNCHRONIZATION

1.	Pro Forma Rate Base		$300,475,962	(A)
2.	Weighted Cost of Debt		2.36%	(B)
3.	Pro Forma Interest Expense		$7,076,209	
4.	Company Claim		7,128,573	(C)
5.	Adjustment to Interest Expense		($52,364)	
6.	Income Taxes @	21.00%	**($10,996)**	

Sources:
(A) Schedule ALB-3
(B) Weighted Cost of Long-Term Debt per Schedule ALB-2
(C) Company Filing, KSG Direct Exhibit SKJ-2, Statement K

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

INCOME TAX FACTOR

1.	Revenue	100.00%	
2.	State Income Tax Rate	0.00%	(A)
3.	Federal Income Tax Rate	100.00%	
4.	Income Taxes @ 21%	21.00%	(A)
5.	Operating Income	79.00%	
6.	Total Tax Rate	**21.00%**	(B)

Sources:
(A) Rates per Company Filing, KSG Direct Exhibit SKJ-2, Statement K
(B) Line 2 + Line 4

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REVENUE MULTIPLIER

1.	Revenue	100.00%	
2.	Bad Debt Rate	0.6325%	(A)
3.	Taxable Income	99.37%	
4.	State Income Tax @ 0.00%	0.00%	(B)
5.	Federal Taxable Income	99.37%	
6.	Income Taxes @ 21%	20.87%	(B)
7.	Operating Income	78.50%	
8.	Revenue Multiplier	1.273880	(C)

Sources:
(A) Rate per Schedule ALB-22
(B) Rates per Company Filing, KSG Direct Exhibit SKJ-2, Statement K
(C) Line1/Line 7

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS

1.	Rate of Return	($2,033,194)
	Rate Base Adjustments:	
2.	Utility Plant in Service	($600,056)
3.	Accumulated Depreciation	(12,934)
4.	Deferred Income Tax Assets	(116,734)
5.	Acc. Deferred Inc. Taxes-Property	250,105
6.	Regulatory Liability-Fed. TCJA EDIT	33,956
7.	Regulatory Liability-KS EDIT	(32,302)
8.	ADIT-Other	(1,252)
9.	Allocated BHSC ADIT and EDIT	(12,859)
	Operating Income Adjustments	
10.	Salary and Wage Expense-Direct	(54,324)
11.	Salary and Wage Expense-BHSC	(81,382)
12.	Incentive Compensation Expense	(750,293)
13.	Payroll Tax Expense	(67,779)
14.	Pension and OPEB Expense	(25,859)
15.	Amortization of Pension & OPEB Trackers	(97,068)
16.	Bad Debt Expense	(108,839)
17.	Rate Case Expense	(117,334)
18.	Payment Fee Expense	(69,026)
19.	Data Improvement Integrity Program Expense	(221,040)
20.	Research and Development Expense	(59,712)
21.	Damage Prevention Expense	(50,000)
22.	Vegetation Management Expense	(20,000)
23.	Depreciation Expense	630,106
24.	Interest Synchronization	13,920
25.	Revenue Multiplier	86,593
26.	Total Recommended Adjustments	($3,517,308)
27.	Company Claim	17,207,752
28.	Recommended Revenue Requirement	**$13,690,444**

BLACK HILLS ENERGY

TEST YEAR ENDED SEPTEMBER 30, 2024

PRO FORMA INCOME STATEMENT

		Per Company	Recommended Adjustments	Pro Forma Present Rates	Recommended Rate Adjustment	Pro Forma Proposed Rates
1.	Operating Revenues	$63,727,085	$0	$63,727,085	$13,690,444	$77,417,529
2.	Operating Expenses	32,351,842	(1,654,876)	$30,696,966	86,592	30,783,558
3.	Depreciation and Amortization	12,746,995	630,106	$13,377,101	0	13,377,101
4.	Taxes Other Than Income	8,963,372	(67,779)	$8,895,593	0	8,895,593
5.	Taxable Income Before Interest Expenses	$9,664,876	$1,092,549	$10,757,425	$13,603,852	$24,361,277
6.	Interest Expense	7,128,573	(52,364)	7,076,209		7,076,209
7.	Taxable Income	$2,536,303	$1,144,913	$3,681,216	$13,603,852	$17,285,068
8.	Income Taxes @ 21.00%	(84,781)	240,432	155,651	2,856,809	3,012,459
9.	Operating Income	$9,749,657		$10,601,774	$10,747,043	$21,348,817
10.	Rate Base	$305,947,330		$300,475,962		$300,475,962
11.	Rate of Return	**3.19%**		**3.53%**		**7.11%**

APPENDIX B
REFERENCED DATA REQUESTS

CURB-60**

CURB-64

CURB-66

CURB-68

CURB-70**

KCC-102*

KCC-104

KCC-111

KCC-112*

KCC-113

KCC-197**

KCC-198**

KCC-205

*Voluminous – does not include all attachments

**Does not include Confidential response or attachments

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
CITIZEN'S UTILITY RATEPAYER BOARD
DATA REQUEST NO. CURB-64

DATE OF REQUEST:	03/19/2025
DATE RESPONSE DUE:	03/28/2025
REQUESTOR:	Citizen's Utility Ratepayer Board
AUDITOR:	Joseph R. Astrab
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	03/28/2025
SUBJECT:	Income Statement
REFERENCE:	DIIP

REQUEST:

In reference to the Data Improvement Integrity Program (DIIP) Adjustment (IS-25), please provide actual DIIP expenses for the prior five years prior to the test year.

RESPONSE:

See the table below for DIIP expense for the five years prior to the test year.

DIIP Expenses		
October 2018 - September 2019	$	-
October 2019 - September 2020		-
October 2020 - September 2021		349,281
October 2021 - September 2022		225,016
October 2022 - September 2023		162,140
Total	$	736,436

ATTACHMENTS:

None

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 28, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
CITIZEN'S UTILITY RATEPAYER BOARD
DATA REQUEST NO. CURB-66

DATE OF REQUEST:	03/19/2025
DATE RESPONSE DUE:	03/28/2025
REQUESTOR:	Citizen's Utility Ratepayer Board
AUDITOR:	Joseph R. Astrab
ANSWERED BY:	Marc Eyre
DATE RESPONDED:	03/28/2025
SUBJECT:	Income Statement
REFERENCE:	Schedule H-20 IS-30 – Vegetation Management Expense

---

REQUEST:

In reference to Schedule H-20 workpapers for IS-30-Vegetation Management Expense, please explain in detail how $100,000 was determined for the Vegetation Management Expense. Please provide all supporting documentation.

RESPONSE:

Please see the attachment identified below for vegetation management expenditures, by year, from 2020 through 2024.

In 2020, the Company spent $75,615 on vegetation management projects, which, when adjusted for the 23.69% CPI increase since January 2020, equates to $93,527 in February 2025 dollars [1]. While there are some natural variations in annual spend based on specific pipeline right of ways to be trimmed, $100,000 is needed to keep critical pipeline facilities safe from vegetation related hazards. This will help continue and improve the Company's vegetation management program which benefits all parties through the enhanced safety of the public and Company personnel while lowering the risk of asset damages from overgrown vegetation.

ATTACHMENTS:

Attachment CURB-66 Vegetation Management Expense.xlsx

[1] www.bls.gov/data/inflation_calculator.htm

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 28, 2025

Black Hills/Kansas Gas Utility Company, LLC
Attachment CURB-66
Vegetation Management Expense

Sum of Merch Amt - Cor	Years (Invoice Date)					
Dept	2020	2021	2022	2023	2024	Grand Total
5066	$ 47,245			$ 19,621	$ 60,770	$ 127,635
5384	$ 7,452	$ 14,706				$ 22,158
5385	$ 4,522	$ 1,828	$ 4,154	$ 6,013	$ 848	$ 17,365
5386	$ 6,029	$ 1,983	$ 3,949	$ 7,637	$ 5,639	$ 25,237
5387	$ 7,855	$ 4,915	$ 6,311	$ 8,344	$ 4,590	$ 32,015
5388	$ 2,514	$ 2,734	$ 2,750	$ 4,400	$ 4,650	$ 17,048
Grand Total	**$ 75,615**	**$ 26,167**	**$ 17,164**	**$ 46,015**	**$ 76,497**	**$ 241,457**

Average $ 48,291

Attachment CURB-66

TOP PICKS
SERIES REPORT
PUBLIC DATA API
DISCONTINUED DATABASES
FAQS
SPECIAL NOTICES
MORE SOURCES OF DATA

CPI Inflation Calculator

CPI Inflation Calculator

$ 75,615.00

in January 2020

has the same buying power as

$93,527.51

in February 2025

Calculate

About the CPI Inflation Calculator

The CPI inflation calculator uses the Consumer Price Index for All Urban Consumers (CPI-U) U.S. city average series for all items, not seasonally adjusted. This data represents changes in the prices of all goods and services purchased for consumption by urban households.

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
CITIZEN'S UTILITY RATEPAYER BOARD
DATA REQUEST NO. CURB-68

DATE OF REQUEST:	03/26/2025
DATE RESPONSE DUE:	04/04/2025
REQUESTOR:	Citizen's Utility Ratepayer Board
AUDITOR:	Joseph R. Astrab
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	04/04/2025
SUBJECT:	Incentive Compensation
REFERENCE:	

REQUEST:

Please provide the amount of incentive compensation paid during the test year (10/1/2023-9/30/2024) broken down by plan (AIP, STIP, LTIP) for Black Hills Kansas Gas Direct and Black Hills Service Company. Please also provide the account code incentive compensation is recorded to.

RESPONSE:

Please see below the amount of incentive compensation expensed during the test year (10/1/2023-9/30/2024) broken down by plan (AIP, STIP, LTIP) for Black Hills Kansas Gas Direct and Black Hills Service Company. The detail below was pulled from the general ledger, as explained in the Direct Testimony of Samantha K. Johnson, page 41, lines 12-13.

O & M Payroll	Direct	Allocated	Total
AIP	604,948	573,796	1,178,744
STIP	44,079	294,038	338,117
LTIP - Restrictive Stock	27,088	159,337	186,425
LTIP - Performance Shares	12,428	170,190	182,618
Total	**688,543**	**1,197,361**	**1,885,904**

The Company records Incentive Compensation within accounts 850 - 932.

ATTACHMENTS:

None

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: April 4, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
CITIZEN'S UTILITY RATEPAYER BOARD
DATA REQUEST NO. CURB-70

DATE OF REQUEST:	04/11/2025
DATE RESPONSE DUE:	04/22/2025
REQUESTOR:	Citizen's Utility Ratepayer Board
AUDITOR:	Joseph R. Astrab/Audrey Benham
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	04/17/2025
SUBJECT:	Headcount/Payroll
REFERENCE:	

REQUEST:

In reference to CURB data request #53, it states that the Operations Support Specialist position was filled on January 27, 2025, and the Gas Operations Tech II position was filled on November 11, 2024. Since these positions are now filled, please provide the breakout of actual payroll amounts for Kansas Direct employees for the period ending 2/28/2025. Please submit in the exact same format as Ms. Johnson's workpaper IS-15_Sched H-5 WP 21, specifically under tab "KSG Employees as of 11.04.2024."

a. In Ms. Johnson's workpaper IS-15_Sched H-5 WP 21, under tab "KSG Employees as of 11.04.2024", the 401k Match $, 2024 Medical, 2024 Dental, 2024 AD&D, and Life Insurance list those amounts as estimates. Please include the actual amounts for these benefits when submitting the updated workpapers, specifically under tab "KSG Employees as of 11.04.2024."

RESPONSE:

Please see the Excel attachment identified below for the requested information.

The Company has updated the attachment to include the actual amounts for the Gas Operations Tech II position that was filled on November 11, 2024. Since the Operations Support Specialist position was filled on January 27, 2025, there are no actual amounts for these benefits for that employee available for the 2024 Rates tab.

In order to include actual amounts for the Operations Support Specialist position, the Company has additionally provided the breakout of actual payroll amounts for Kansas Direct employees for the period ending 3/11/2025.

The Company elected to provide data as of 3/11/2025 rather than the requested 2/28/2025 because the 2024 incentive payout was on 2/28/2025 and in anticipation that many employees changed their 401k contribution, so the 2/28/2025 data would not be an accurate representation of actual 401k rates.

ATTACHMENTS:

Attachment CURB-70 CONFIDENTIAL Employee Payroll.xlsx
PUBLIC VERSION ATTACHMENT CURB-70.pdf

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: April 17, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-102

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Bill Baldry
ANSWERED BY:	Tom Stevens
DATE RESPONDED:	03/18/2025
SUBJECT:	Pension Expense
REFERENCE:	

REQUEST:

Please provide pension expense for the twelve months ending February 28, 2025.

RESPONSE:

Please see "Attachment KCC-102 – Benefits Expense for the Twelve Months Ending February 28, 2025.xlsx".

ATTACHMENTS:

Attachment KCC-102 – Benefits Expense for the Twelve Months Ending February 28, 2025.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-104

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Bill Baldry
ANSWERED BY:	Tom Stevens
DATE RESPONDED:	03/18/2025
SUBJECT:	Pension Trackers Update
REFERENCE:	

REQUEST:

Updating the pension Trackers 1 and 2 from September 30, 2024 to February 28, 2025.

a. Please provide the pension Tracker 1 balance as of February 28, 2025.

b. Please provide the pension Tracker 2 balance as of February 28, 2025.

RESPONSE:

Please see the attached file for the pension and retiree healthcare tracker balances.

ATTACHMENTS:

Attachment KCC-104 - Tracker Balances.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS KANSAS GAS
Attachment KCC-104
PENSION AND RETIREE HEALTHCARE TRACKERS

(a)	(b)	(c)	(d) (d) = (b) - (c)	(e)	(f) prev (f) + (d) + (e)	(g)	(h)	(i) (i) = (g) - (h)	(j)	(k) prev (k) (i) + (j)
	Retiree Healthcare Plan Tracker Regulatory Asset/(Liability) Summary					Pension Plan Tracker Regulatory Asset/(Liability) Summary				
Balances as of	Actual Expense	Tracker Amount Allowed (1)	Expense in Excess of (less than) Amount in Tracker	Amoritization of Regulatory Liability Over-recovery (2)	Cumulative Regulatory Asset/ (Liability)	Actual Expense	Tracker Amount Allowed (1)	Expense in Excess of (Less than) Amount in Tracker	Amoritization of Regulatory Liability Over-recovery (2)	Cumulative Regulatory Asset/ (Liability)
12/31/2015 (3)	$ 238,116	$ 276,855	$ (38,739)		$ (38,739)	$ 1,409,845	$ 1,267,730	$ 142,115		$ 142,115
12/31/2016 (3)	$ 172,776	$ 276,855	$ (104,079)		$ (142,817)	$ 638,099	$ 1,267,730	$ (629,631)		$ (487,516)
12/31/2017 (3)	$ 189,959	$ 276,855	$ (86,896)		$ (229,713)	$ 130,836	$ 1,267,730	$ (1,136,894)		$ (1,624,410)
12/31/2018 (3)	$ 185,503	$ 276,855	$ (91,352)		$ (321,065)	$ 419,396	$ 1,267,730	$ (848,334)		$ (2,472,745)
12/31/2019 (3)	$ 157,149	$ 276,855	$ (119,706)		$ (440,771)	$ 150,176	$ 1,267,730	$ (1,117,554)		$ (3,590,299)
12/31/2020 (3)	$ 178,426	$ 276,855	$ (98,429)		$ (539,200)	$ 290,111	$ 1,267,730	$ (977,619)		$ (4,567,918)
6/30/2021 (3)(4)	$ 116,858	$ 138,428	$ (21,570)		$ (560,769)	$ 82,679	$ 633,865	$ (551,186)		$ (5,119,104)
12/31/2021 (4)	$ 108,343	$ 138,427	$ (30,084)		$ (590,853)	$ 55,219	$ 633,865	$ (578,646)		$ (5,697,750)
12/31/2022	$ 186,841	$ 201,614	$ (14,773)	$ 112,154	$ (493,472)	$ 264,045	$ 184,471	$ 79,574	$ 1,023,821	$ (4,594,355)
12/31/2023	$ 204,521	$ 201,614	$ 2,907	$ 112,154	$ (378,411)	$ 314,041	$ 184,471	$ 129,570	$ 1,023,821	$ (3,440,964)
12/31/2024	$ 171,045	$ 201,614	$ (30,569)	$ 112,154	$ (296,826)	$ 263,452	$ 184,471	$ 78,981	$ 1,023,821	$ (2,338,162)
2/28/2025 (5)	$ 25,404	$ 33,602	$ (8,198)	$ 18,692	**$ (286,331)**	$ 44,425	$ 30,745	$ 13,680	$ 170,637	**$ (2,153,845)**

Notes

(1) Tracker Amounts Allowed are per the 2014 and 2021 Black Hills Kansas rate case final Commission Orders
(2) Amortization amounts are per 2021 Order; 5 year amortization period was approved
(3) 2015 through June 30, 2021, agree to values presented in 2021 case. June 30, 2021, regulatory liability balances agree with amounts used in Order for amortization of liability.
(4) Amounts are for six months of 2021.
(5) Amounts are for the first two months of 2025.

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-110

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Bill Baldry
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	03/18/2025
SUBJECT:	ADIT and EDIT
REFERENCE:	

REQUEST:

Please provide the total balance for accumulated deferred income taxes (ADIT) and excess deferred income taxes (EDIT) as of February 28, 2025.

RESPONSE:

Please refer to the attachment below for details of the ADIT and EDIT as of February 28, 2025.

ATTACHMENTS:

Attachment KCC-110 ADIT and EDIT as of 02.28.25.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC
OTHER RATE BASE ITEMS - TAX
FOR THE PERIOD ENDING FEBRUARY 28, 2025

Attachment KCC-110
Schedule C-1

(a) Line No.	(b) Account & Description	(c) Test Year Ended September 30, 2024	(d) For the Period Ended February 28, 2025
1	**Deferred Income Tax Assets**		
2	190300 - DTA LT - VACATION:	$ 107,390	$ 118,580
3	190300 - DTA LT - BAD DEBT RESERVE:	576,298	720,815
4	190300 - DTA LT - EMPLOYEE GROUP INSURANCE:	26,999	34,274
5	190300 - DTA LT - AIP BONUS:	172,079	22,046
6	190300 - DTA LT - WORKMANS COMP:	(45,485)	(40,601)
7	190300 - DTA LT-OTHER:	2,533,810	2,359,431
8	190300 - DTA LT-RETIREE HEALTHCARE:	-	-
9	190300 - DTA LT-TAX ON TAX FED GROSS UP - TCJA	83,263	745
10	190300 - DTA LT-PERFORMANCE PLAN:	0	0
11	190300 - DTA LT-LINE EXTENSION DEP GAS:	162,933	143,966
12	190300 - DTA LT-PENSION FAS 87:	(403,647)	(386,797)
13	190300 - DTA LT-PENSION FAS 158 LIAB:	1,086,907	1,107,721
14	190300 - DTA LT-RET HLTH FAS158 LIAB:	141,642	114,435
15	190300 - DTA LT-NOL CARRYFORWARD:	(1)	-
16	190300 - DTA LT-INS RESERVE LIAB:	1	(0)
17	190300 - DTA LT - ALT FUEL VEHICLE CREDIT:	50,000	50,000
18	190300 - DTA LT - R&D CREDIT:	549,676	614,049
19	190300 - DTA LT - PUC FEES:	83,215	69,211
20	190998 - DTA LT - SVC CO FAS 109 OTHER:	72,966	70,192
21	**Subtotal Deferred Income Tax Assets**	**$ 5,198,048**	**$ 4,998,066**
22			
23	**Accelerated Deferred Income Taxes - Property**		
24	282300 - DEF TAX PROPERTY LT-ACCELERATED DEP:	$ (42,182,475)	$ (45,475,272)
25	282300 - DEF TAX PROPERTY LT-CWIP:	218,644	177,660
26	282300 - DEF TAX PROPERTY LT-OTHER PROPERTY:	177,660	84,377
27	**Subtotal Accelerated Deferred Income Taxes - Property**	**$ (41,786,171)**	**$ (45,213,236)**
28			
29	**Regulatory Liabilities**		
30	254015 - PROTECTED PROPERTY RB	$ (12,189,693)	$ (11,962,694)
31	254015 - NON-PROTECTED COST OF REMOVAL - ARAM	$ 724,243	804,932
32	254015 - NON-PROTECTED PROPERTY RB_PT	(386,997)	-
33	254015 - NON-REFUNDED ARAM	142,296	277,990
34	**Subtotal Regulatory Liabilities**	**$ (11,710,151)**	**$ (10,879,773)**
35			
36	**Regulatory Liabilities**		
37	254015 - REG LIAB EXCESS DEF STATE	$ (752,105)	$ (359,160)
38	**Subtotal Regulatory Liabilities**	**$ (752,105)**	**$ (359,160)**
39			
40	**Accumulated Deferred Income Taxes - Other**		
41	283300 - DTL LT - PREPAID EXPENSES:	$ (10,168)	$ (11,593)
42	283300 - DTL LT-RETIREE HEALTHCARE:	(143,491)	(155,495)
43	283300 - DTL DEFERRED REGULATORY	-	(4,161)
44	**Subtotal Accumulated Deferred Income Taxes - Other**	**$ (153,659)**	**$ (171,250)**
45			
46	**Other Utility Plant**		
47	282998 - BHSC ALLOC DEF TAX PROPERTY-LT ACCELERATED DEP	$ (1,221,469)	$ (1,311,554)
48	254998 - BHSC ALLOC REG LIAB EDIT PROTECTED PROPERTY	(331,068)	(319,029)
49	254998 - BHSC ALLOC REG LIAB EDIT NONPROTECTED PROPERTY	(13,970)	(12,913)
50	**Subtotal Other Utility Plant**	**$ (1,566,507)**	**$ (1,643,497)**
51			
52	**Total Other Rate Base Items - Tax**	**$ (50,770,545)**	**$ (53,268,848)**
	Total EDIT		$ (11,570,874)

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-111

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Daniel Buller
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	03/18/2025
SUBJECT:	Plant
REFERENCE:	

REQUEST:

Please provide updated versions of SKJ-2 Statement D and SKJ-2 Schedules D-1 and D-2 to reflect plant data for the 12-month period ending February 28, 2025.

RESPONSE:

Please see "Attachment KCC-111 Stmt D & Sched D-1 & D-2.xlsx", which includes the update to Statement D, Schedule D-1, and Schedule D-2 to reflect plant data for the 12-month period ending February 28, 2025.

ATTACHMENTS:

Attachment KCC-111 Stmt D & Sched D-1 & D-2.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-112

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Daniel Buller
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	03/18/2025
SUBJECT:	Accumulated Depreciation
REFERENCE:	

REQUEST:

Please provide updated versions of SKJ-2 Statement E and SKJ-2 Schedules E-1, E-2, and E-3 to reflect accumulated depreciation data for the 12-month period ending February 28, 2025.

RESPONSE:

Please see "Attachment KCC-112 Stmt E & Sched E-1 & E-2.xlsx", which includes the update to Statement E, Schedule E-1, and Schedule E-2 to reflect accumulated depreciation data for the 12-month period ending February 28, 2025.

ATTACHMENTS:

Attachment KCC-112 Stmt E & Sched E-1 & E-2.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-113

DATE OF REQUEST:	03/07/2025
DATE RESPONSE DUE:	03/18/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Daniel Buller
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	03/18/2025
SUBJECT:	Depreciation Expense
REFERENCE:	

REQUEST:

Please provide updated versions of SKJ-2 Statement J and SKJ-2 Schedules J-1 to reflect depreciation and amortization expense data for the 12-month period ending February 28, 2025.

RESPONSE:

Please see "Attachment KCC-113 Depreciation Expense.xlsx" for updated versions of SKJ-2 Statement J and SKJ-2 Schedules J-1 to reflect depreciation and amortization expense data for the 12-month period ending February 28, 2025.

ATTACHMENTS:

Attachment KCC-113 Depreciation Expense.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: March 18, 2025

BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC
Attachment KCC-113 Depreciation Expense
12-months ending February 28, 2025
KCC-113 Stmt J
Updated KSG-SKJ RRS IS-31_Stmt J Sched J-1 WP 48

KSG Direct Exhibit SKJ-2
Statement J
Attachment KCC-113

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Description**	**Reference**	**Test Year Expenses**	**12-Months Ended February 28, 2025**	**Adjusted Depreciation Expenses, Sched. J-1**	**Depreciation/Amortization Adjustment**
1	**Depreciation**					
2						
3	Intangible	Sched. J-1 Ln. 9 (g)	$ 94,473	$ 93,969	$ 106,944	$ 12,975
4						
5	Production and Gathering Plant	Sched. J-1 Ln. 13 (g)	5,607	5,607	-	$ (5,607)
6						
7	Storage Plant		-			
8						
9	Transmission	Sched. J-1 Ln. 30 (g)	947,807	983,342	1,023,905	$ 40,563
10						
11	Distribution	Sched. J-1 Ln. 54 (g)	7,977,123	8,208,622	8,495,480	$ 286,858
12						
13	General (less Vehicles)	Sched. J-1 Ln. 75 (g) - Ln. 64 through Ln. 68 & Ln. 72 (g)	860,683	829,043	826,201	$ (2,842)
14						
15	Amortization of Unrecovered Reserve	As approved in Docket No. 21-BHCG-418-RTS	(5,105)	(5,105)	(5,105)	-
16						
17	**Direct Depreciation & Amortization Expense less Vehicles**		**$ 9,880,588**	**$ 10,115,478**	**$ 10,447,425**	**$ 331,947**
18						
19	**Other Utility Plant**					
20	Other Utility Plant - BHSC	Sched. J-1 Ln. 78 (g) + Ln. 79 (g)	1,742,216	1,754,603	1,667,028	$ (87,574)
21	Amortization of Unrecovered Reserve - BHSC		249,713	249,713	249,713	-
22	**Total Other Utility Plant**		**$ 1,991,929**	**$ 2,004,315**	**$ 1,916,741**	**$ (87,574)**
23						
24	**Total Depreciation & Amortization Expense less Vehicles**	Note (1)	**$ 11,872,517**	**$ 12,119,793**	**$ 12,364,166**	**$ 244,373**
25						
26	Depreciation charged to Fleet Clearing Accounts (Vehicles)	Sched. J-1 Ln. 64 through Ln. 68 & Ln. 72 (g)	$ 754,919	$ 787,404	782,524	$ (4,880)
27	Depreciation charged to BHSC Allocated Plant (Vehicles)	Sched. J-1 Ln. 80 (g)	41,911	60,008	76,477	$ 16,469
28						
29	**Total Depreciation and Amortization Expense**	Ln. 24 + Ln. 26 + Ln. 27	**$ 12,669,347**	**$ 12,967,205**	**$ 13,223,167**	**$ 255,962**
30						
31	Note (1) The Adjusted Depreciation Expense and Test Period amounts includes the removal of fleet capitalization which is charged through the vehicle loadings process.					

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-197

DATE OF REQUEST:	04/04/2025
DATE RESPONSE DUE:	04/15/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Katie Figgs
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	04/15/2025
SUBJECT:	Incentive Compensation – AIP and STIP

REQUEST:

For all 5 of the AIP and STIP performance metrics (financial, customer service, reliability, safety, and diversity), please provide the performance goal, threshold, target, and maximum level for the years 2019 through 2025.

RESPONSE:

Please see the attachment identified below for the requested information for non-executive employees.

ATTACHMENTS:

Attachment KCC-197 CONFIDENTIAL KSG AIP & STIP Metrics 2019-2025.xlsx
PUBLIC VERSION ATTACHMENT KCC-197

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: April 15, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-198

DATE OF REQUEST:	04/04/2025
DATE RESPONSE DUE:	04/15/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Katie Figgs
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	04/15/2025
SUBJECT:	Incentive Compensation – LTIP

REQUEST:

Please provide the LTIP performance goal, threshold, target, and maximum level for the years 2019 through 2025.

RESPONSE:

Vice Presidents and above are eligible for LTIP. The amount of the award varies by position and each award is split between restricted stock that vests ratably over a three-year period and performance shares which are tied to metrics over a three-year period. Please see the attachment identified below for the requested information. Note that we do not disclose the threshold, target and max goal amounts and they have been redacted from the attachment. The attachment shows LTI plan years beginning in 2019 through 2025, the metrics and corresponding weights for each performance plan year.

ATTACHMENTS:

Attachment HIGHLY CONFIDENTIAL KCC-198 KSG LTIP 2019-2025.xlsx
PUBLIC VERSION ATTACHMENT KCC-198

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: April 15, 2025

BLACK HILLS / KANSAS GAS UTILITY COMPANY, LLC
d/b/a BLACK HILLS ENERGY
DOCKET NO. 25-BHCG-298-RTS
KANSAS CORPORATION COMMISSION
DATA REQUEST NO. KCC-205

DATE OF REQUEST:	04/08/2025
DATE RESPONSE DUE:	04/17/2025
REQUESTOR:	Kansas Corporation Commission
AUDITOR:	Katie Figgs
ANSWERED BY:	Samantha Johnson
DATE RESPONDED:	04/16/2025
SUBJECT:	Intercompany Charges – Labor

REQUEST:

Regarding the workpaper provided in response to Staff Data Request No. 1 titled "KSG-SKJ RRS IS-18_Sched H-8 WP 24," please provide updates to the tabs labeled "SC Labor Per Books" and "SC Labor Per Books 18A" by providing the monthly Service Company per book balances, by FERC Account No., for the months of October 2023 through February 2025.

RESPONSE:

Please see the attachment identified below for the requested information.

ATTACHMENTS:

Attachment KCC-205 Intercompany Charges – Labor.xlsx

Verification of Response

I have read the foregoing information request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this information request.

Signed: /s/Rob Daniel

Date: April 16, 2025

BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC
Attachment KCC-205 Intercompany Charges - Labor
October 2023 - February 2025

FERC		2023			2024											2025	
Acct. No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	October	November	December	January	February
850	TRANS OPS SUPERV & ENG	7,505	11,673	6,860	8,809	8,574	5,515	7,787	14,847	5,052	4,675	6,025	3,458	5,202	7,112	7,596	11,325	6,933
851	TRANS SYS CONTR & LOAD DISPATC	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	579
863	TRANS MAINT OF MAINS	(142)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
870	DIST OPS SUPERVISION AND ENGIN	77,901	61,525	64,040	61,603	68,772	63,768	68,890	77,429	51,050	62,108	67,547	55,843	73,285	57,975	53,204	59,192	60,742
872	DIST COMPR STAT LABR & EXP	(567)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
874	OPER/INSPECT UG DIST MAINS-GAS	-	-	-	185	(17)	166	30	66	102	18	(5)	(13)	-	-	-	-	-
880	DIST OPS OTHER EXPENSE	-	-	227	4,465	(2,003)	(7)	-	1,160	(339)	(149)	808	510	(409)	-	2,514	1,126	3,809
887	PERF UG DISTRIB LINE MAINT-GAS	919	(501)	-	202	-	-	-	-	-	-	-	-	-	-	8	(2)	-
893	DIST MAINT METERS & HSE REGS	4,162	4,150	3,468	3,371	4,021	3,764	4,050	4,087	2,469	4,212	2,928	3,317	3,936	2,813	3,866	3,988	3,889
901	CUST ACCTS SUPERVISION	9,254	9,876	8,031	10,569	10,361	9,959	10,505	10,726	9,500	8,993	12,216	9,947	12,618	8,871	9,739	12,316	10,240
902	READ METERS	358	444	1,276	669	716	1,095	2,170	673	1,069	1,563	816	1,419	1,913	11,965	(4,830)	921	1,753
903	CUST ACCTS RECORDS & COLLECTIO	95,132	93,266	84,070	100,630	94,488	95,562	100,837	93,316	85,147	99,862	95,973	89,389	103,617	88,391	94,848	103,502	96,457
905	MISC CUSTOMER ACCOUNTS	1,940	1,233	1,547	1,995	3,791	3,541	3,774	3,719	3,676	3,705	3,592	3,385	4,144	3,394	3,359	3,793	3,895
907	CUSTOMER SERVICE SUPERVISION	4,176	4,789	4,800	4,046	4,205	4,713	4,996	4,431	2,981	5,710	5,231	4,430	5,009	4,587	3,868	5,499	3,191
908	CUSTOMER ASSISTANCE EXP	12,909	11,046	9,721	10,129	11,219	11,118	10,344	10,288	9,419	7,304	9,826	9,764	10,573	15,929	10,350	9,278	9,346
909	INFORMATIONAL & INSTRUCT ADS	-	-	-	-	-	-	-	-	-	-	-	73	-	-	-	-	110
910	MISC CUST SERVICE & INFO	-	-	-	-	-	-	-	-	-	-	-	395	-	-	-	-	-
912	SALES DEMONSTRATING & SELLING	19,493	13,686	14,064	18,043	18,828	14,907	16,293	22,418	14,237	15,492	13,439	10,939	19,857	16,418	10,529	15,038	11,739
920	ADMIN AND GENERAL SALARIES	472,087	554,967	457,326	528,862	513,674	459,304	486,460	505,568	470,140	564,229	500,114	524,675	495,414	493,075	439,951	594,440	527,278
921	OFFICE SUPPLIES & EXPENSE	3,399	1,388	2,130	5,111	786	880	3,685	405	742	4,365	1,808	479	4,123	318	9,817	694	2,717
926	EMPLOYEE PENSIONS & BENEFITS	162,058	135,146	190,484	113,823	174,273	124,553	208,007	158,421	106,699	161,728	199,432	134,471	186,639	165,197	75,997	193,374	210,124
930.1	GENERAL ADVERTISING	-	-	-	152	-	-	-	-	-	-	-	269	-	151	-	-	-
930.2	MISCELLANEOUS GENERAL EXP	491	360	114	1,262	521	555	298	501	308	456	439	(181)	-	-	-	-	-
932	MAINTENANCE GENERAL PLANT GAS	-	-	2,456	(53)	-	-	-	-	-	-	-	-	-	-	-	-	-

BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC
Attachment KCC-205 Intercompany Charges - Labor
October 2023 - February 2025

FERC		2023			2024												2025	
Acct. No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	October	November	December	January	February
920	ADMIN AND GENERAL SALARIES	-	-	-	-	-	-	-	-	-	549	74	1,725	468	(273)	-	-	238
926	EMPLOYEE PENSIONS & BENEFITS	-	-	-	-	-	-	-	-	-	106	14	335	102	(59)	-	-	53

APPENDIX C

REFERENCED EXHIBIT

BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	
OF BLACK HILLS ENERGY ARKANSAS, INC.	**)**	**DOCKET NO. 23-074-U**
FOR APPROVAL OF A GENERAL CHANGE	**)**	
IN RATES AND TARIFFS	**)**	

DIRECT TESTIMONY AND EXHIBITS

OF

MARC T. EYRE

ON BEHALF OF

BLACK HILLS ENERGY ARKANSAS, INC. D/B/A BLACK HILLS ENERGY

Filed: December 4, 2023

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Marc Eyre. My business address is 655 E. Millsap Road, Fayetteville, Arkansas 72703.

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?

A. I am employed by Black Hills Energy Arkansas, Inc. ("BHEA" or the "Company") as its Vice President of Operations. I also serve as Vice President of Operations for Black Hills' natural gas utility operations in Kansas.

II. STATEMENT OF QUALIFICATIONS

Q. WHEN DID YOU BEGIN YOUR EMPLOYMENT WITH BLACK HILLS CORP. ("BHC")?

A. I began full time employment with BHC in 2008.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF OPERATIONS FOR BHEA?

A. I am responsible for the financial and operational performance of BHEA's natural gas operations in Arkansas and Kansas. Through the operations leadership team, I oversee all operations functions in Arkansas, including natural gas distribution, transmission, gathering, storage, compression, maintenance, construction, and customer relations. A significant part of my role also involves engaging with other functions that, while centralized in BHC, provide support to Arkansas operations. These centralized functions include regulatory, legal, human resources, engineering, gas supply, pipeline safety, customer experience, government affairs, the field resource center (dispatch), and our call center.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I attended the University of Wyoming, where I received a Bachelor of Science degree in Electrical Engineering. I was first an intern for BHC during my senior year of college, following graduation in 2008, I joined BHC fulltime as an Electrical Engineer in its Cheyenne Wyoming operations. I worked for BHC in Cheyenne for approximately ten years during which time I had responsibilities as an Electrical Engineer, Natural Gas Engineer, Gas Operations Supervisor and Electric Operations Manager. In 2018, I relocated to Rapid City, South Dakota where I served for five years in operations leadership roles including two years as Director of Electric Operations and three years as Vice President of Electric Operations. In June 2023 I assumed my new duties as Vice President of Operations for BHC's Arkansas and Kansas natural gas utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION ("COMMISSION" OR "APSC") OR OTHER REGULATORY COMMISSIONS?

A. This is my first time appearing before the Arkansas Public Service Commission, but I have previously testified before the Wyoming and South Dakota Commissions.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS DOCKET?

A. My testimony will:

- describe the Company's Arkansas operations, and success in delivering safe and reliable service;
- explain the Company's need for a rate application at this time;
- explain the impact of higher inflation on BHEA's cost of service;
- explain the Company's growth, integrity, and reliability capital expenditures;
- describe the Company's Safety & Integrity Rider ("SI Rider") and Act 310 Rider;
- discuss the Company's proposal to add reliability expenditures to the SI Rider;
- describe the Company's long range system planning; and
- provide a concluding recommendation.

IV. DESCRIPTION OF BHEA'S OPERATIONS

Q. PLEASE DESCRIBE BLACK HILLS' ARKANSAS GAS SERVICE AREAS.

A. BHEA is engaged in the storage, gathering, transmission and distribution of natural gas to over 184,000 customers in 106 communities located in the following counties in Arkansas: Baxter, Benton, Boone, Carroll, Clay, Craighead, Crawford, Crittenden, Franklin, Greene, Izard, Johnson, Lawrence, Logan, Madison, Marion, Mississippi, Sebastian, Stone, and Washington. BHEA's state operations leadership team and corporate support staff (human resources, regulatory, legal, engineering, safety, gas supply, financial management, call center, and dispatch center) are in Fayetteville. Our operations team is organized into five operating divisions, each covering a defined geographic region. BHEA has major division service centers located in Fayetteville, Lowell, Ozark, Harrison, and Blytheville. BHEA has satellite service centers in Siloam Springs, Mountain Home, Leachville, and Piggott. BHEA also owns and operates two underground natural gas storage facilities directly connected to its system, making it unique among Arkansas gas utilities.

Q. PLEASE DESCRIBE THE DISTRIBUTION ASSETS OF BHEA.

A. As filed in the 2022 PHMSA Gas Distribution Annual Report, the BHEA distribution system consists of approximately 5,196 miles of pipeline mains and approximately 194,295 service lines, which run from the pipeline main to the meter.

Q. PLEASE DESCRIBE THE GATHERING ASSETS OF BHEA.

A. The BHEA gathering system consists of approximately 395 miles of gathering pipeline predominantly in the Arkansas River Valley within the Ozark operating division. The gathering system transports third party producer's gas from the well head and delivers it primarily to BHEA transportation customers who purchase the gas from producers or marketers. Producers also have the option to have BHEA deliver their gas to interstate pipelines at a rate set by the Federal Energy Regulatory Commission ("FERC").

Q. PLEASE PROVIDE AN OVERVIEW OF THE NATURAL GAS TRANSMISSION SYSTEM OF BLACK HILLS.

A. BHEA has approximately 875 miles of transmission pipeline that provide critical supply to the Arkansas customers it serves. The BHEA transmission system has multiple interconnects with Federal Energy Regulatory Commission jurisdictional interstate pipelines. These connections include interconnections with Enable Gas Transmission (Energy Transfer) and Ozark Gas Transmission (Black Bear Transmission). BHEA's northeast Arkansas system also interconnects with Liberty Utilities at the Arkansas – Missouri border where it receives gas supply acquired from or through Texas Eastern Transmission (Enbridge).

Q. DOES THE COMPANY HAVE NON-REGULATED OPERATIONS IN ARKANSAS?

A. Yes. BHEA offers limited natural gas operations, maintenance, and construction expertise performed through technical service agreements. BHEA also partners with HomeServe to offer customers protection plans for heating, cooling, plumbing, and electrical repairs typically not covered by homeowners' insurance. In accordance with the CAM, costs incurred to support and administer non-regulated activities are charged to non-regulated accounts to avoid any inadvertent subsidization of these activities in tariffed rates. The CAM is discussed in the Direct Testimony of Ms. Wendy H. Robbins.

Q. PLEASE SUMMARIZE THE MANAGEMENT STRUCTURE OF THE STATE OPERATIONS.

A. BHEA's operations are divided into five operating regions. Managers in these regions are responsible for safety, operations, customer service, and community relations within the region. BHEA also has a centralized Gas Technical Services department for measurement, regulation, and corrosion protection. In addition to the employees located in Arkansas, BHEA also receives centralized shared services.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CENTRALIZED SHARED SERVICES.

A. Black Hills Service Company, LLC ("BHSC") provides centralized corporate services to all BHC subsidiaries. Examples of centralized shared services include information technology, tax, regulatory, financial, gas supply, shipper services, legal, human resources, safety, business development, engineering, customer experience, community affairs, government affairs, communications, call center, and field resource center (dispatch) services. Having centralized service functions avoids the cost of duplication of the functions within each subsidiary. Accordingly, BHC subsidiaries, such as BHEA, realize lower costs through the sharing of these services with other BHC subsidiaries. The cost allocation methodology for the services provided by BHSC is discussed in greater detail in the Direct Testimony of Ms. Wendy H. Robbins.

Q. HOW DOES BHEA BENEFIT FROM THE SHARED SERVICES AND INVESTMENTS IN COMMON ASSETS PROVIDED BY BHSC?

A. Having a central source for the necessary services provided by function minimizes the need for each subsidiary, including BHEA, to provide such services independently. The result is that the business units gain access to specialized skills and resources in a more efficient and cost-effective manner.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE TYPES OF CUSTOMERS SERVED BY BHEA.

A. BHEA serves a wide range of sales customers including residential, commercial, and industrial customers including irrigation customers. Some larger business customers contract for transportation service which requires the customer to purchase their own gas and pay BHEA to transport the gas to the customer's premises. These include multiple steel industry customers in northeast Arkansas which will be the top steel producing region in the nation upon completion of a steel mill now under construction.

Q. HOW DOES BHEA DEMONSTRATE ITS COMMITMENT TO THE SAFETY OF THE COMMUNITIES AND CUSTOMERS IT SERVES?

A. Safety, including system reliability, is always the number one priority for BHEA. For example, the Company partners with local fire departments to provide natural gas fire demonstrations and trainings for first responders in the community at no cost to attendees. BHEA also leads damage prevention efforts throughout its service territory in partnership with Arkansas 811, and annually sends damage prevention materials to excavators in the counties Black Hills serves. BHEA is also active in industry trade associations to promote pipeline safety and industry best practices. A Company Manager serves as the Arkansas Gas Association ("AGA") Executive Committee Chairperson and two additional Company employees serve on the AGA Board of Directors. The AGA helps to promote natural gas as a safe and efficient energy source, provides quality training for industry personnel, and supports new natural gas technologies. The Company's General Manager is also on the Arkansas 811 Board of Directors. The Company communicates critical safety and damage prevention information with customers via a variety of methods, including bill messages, customer emails, media alerts to local publications, on our website, and social media. In addition to education and customer outreach, a key component of providing safe, reliable service is replacing aging infrastructure through capital investments. The BHEA SI Rider allows for proactive replacement of aging and obsolete infrastructure, at-risk meters as well as other safety improvements, helping to reduce risk and increase safety in the communities it serves. Reliability goes hand in hand with system safety and integrity. Adding reliability expenditures to the SI Rider will further improve the safety of BHEA's system. The Company also adheres to Pipeline Safety Regulations and strives to implement integrity management programs targeted at reducing system risks and furthering our mission to serve our customers and communities safely and reliably.

Q. BEYOND BHEA'S COMMITMENT TO SAFETY, HOW DOES BHEA DEMONSTRATE ITS COMMITMENT TO THE COMMUNITIES AND CUSTOMERS IT SERVES?

A. As a community partner, BHEA remains active in numerous civic and community engagement and economic development efforts. BHEA has been involved in a broad range of projects to improve its local communities, including local United Way campaigns, United Way Day of Caring/Live United Day, employee involvement in numerous community and civic organizations, extensive involvement in chambers of commerce and economic development, Energy Saving Tree planting programs through the Arbor Day Foundation, and participation in numerous safety education and career development programs.

The Company estimates it made a $120 million economic impact in Arkansas in 2022 with compensation to over 480 employees located in Arkansas, charitable contributions, payments to suppliers and taxes. The Company encourages involvement and empowers its employees by supporting the causes they are passionate about. Charitable contributions and sponsorships in Arkansas totaled $532,000 in 2022. Arkansas employees contributed more than 4,400 volunteer hours last year supporting nearly 150 community organizations, in addition to in-kind donations made to nonprofit organizations.

BHEA employees serve on boards including community and state chambers of commerce, Arkansas 811, city planning and utility commissions, United Way agencies, a regional home builders association, civic clubs such as Rotary, state commissions, professional development organizations, and other community-based organizations.

In 2023, the United Way of Northwest Arkansas presented three awards to BHEA for growth and creativity with its 2022 workplace giving campaign, along with volunteering and contributing to all the agency's service initiatives. At the United Way award luncheon recognizing corporate partners, BHEA was the only company to receive three awards — Spirit of Giving, Growth, and Corporate Partner.

BHEA proudly supports approximately twenty local chambers with board leadership, ambassadors, volunteer service, event participation, memberships and sponsorships including annual meetings, city receptions, leadership programs, coffee events, e-newsletter content to share safety education and energy efficiency messages, and other community events. At the state level, BHEA supports the Arkansas Economic Developers and Chamber Executives, along with the Arkansas State Chamber.

BHEA actively supports and provides resources and assistance to customers and communities in Arkansas through Black Hills Cares. The Black Hills Cares program is the BHEA utility assistance program where donated funds from local employees and customers stays local and is matched dollar for dollar by the Black Hills Corporation Foundation for the benefit of individuals and families in our community.

The Company is invested in its communities and prioritizes serving their needs today and into the future. To protect BHEA's communities for tomorrow, the Company gives customers trees to reduce their carbon footprint and to provide energy saving shade. The Company has given away hundreds of trees over recent years.

BHEA participates in community engagement opportunities thanks to its volunteer Ambassador program. This community-focused program taps emerging leaders and community service-minded team members and puts them on a two-year path to specifically demonstrate BHEA's commitment to the communities we call home. Ambassadors are charged with identifying micro-giving projects that have a big impact on the macro level. Examples of these projects include supporting student educational initiatives, food pantries and first responders, along with volunteering for "fill the backpack" programs in school districts, highway clean ups and at food banks. Ambassadors also initiate additional employee giving by collecting food, school supplies, fans, socks, and other drives to meet local needs. In summary, BHEA supports and assists with community development and growth in a variety of manners.

Q. PLEASE EXPLAIN THE BLACK HILLS CARES PROGRAM.

A. BHEA actively supports energy assistance programs in Arkansas through financial contributions and by educating customers on assistance options. The Company works primarily through the Black Hills Cares program that is funded by employees, customers, and the Black Hills Corporation Foundation, a 501(c)(3) nonprofit. BHEA transitioned to a new program administrator for Black Hills Cares in Arkansas in July 2023. BHEA is now partnering with the United Way of Northwest Arkansas and its Arkansas 211 program to provide energy assistance funding and help create awareness of resources for Arkansans in BHEA's 18-county service territory. Customers have the option to make a tax-deductible donation through their regular bills and online. Employees also donate to Black Hills Cares through payroll deduction and special fundraising events. Black Hills Corporation Foundation matches customer and employee donations to Black Hills Cares dollar for dollar. In addition, BHEA has provided multi-year pledges to Arkansas 211, as well as supplemental contributions to The Salvation Army Arkansas and Oklahoma Division, which administered Hearts Warming Homes/Black Hills Cares from 2006 through June 2023. Black Hills Energy provided $143,067, which includes contributions from customers, employees, and the Foundation in 2021 and 2022. The Foundation also distributed $9,010.88 to Salvation Army for Black Hills Cares energy assistance to

Arkansas residents at the end of December 2022. These costs are charitable contributions and are not included the revenue requirement.

Q. PLEASE DESCRIBE BHEA'S GREENHOUSE GAS REDUCTION TARGETS AND ITS APPROACH IN ACHIEVING THOSE TARGETS.

A. The Company's natural gas utilities are committed to achieving net zero greenhouse gas (GHG) emissions intensity by 2035 based on a 2005 baseline[1]. BHEA will strive to achieve this goal primarily through methane emissions reductions resulting from execution of our transmission integrity management plan ("TIMP"), distribution integrity management plan ("DIMP"), and storage integrity management plan ("SIMP") which include projects such as programmatic replacement of unprotected bare steel pipe and replacement of storage reservoir well heads. Since 2016, BHEA has replaced over 165 miles of bare and unprotected steel pipe across Arkansas through its TIMP and DIMP programs. The TIMP bare steel replacement program was substantially completed in 2019 and BHEA plans to complete the distribution bare steel replacement program by 2034. BHEA's comprehensive damage prevention program lowers the potential for methane to be released from a damaged pipeline while increasing system safety. Our leak surveying program also helps detect fugitive emissions from our system so they can be repaired in a timely manner.

Q. PLEASE DESCRIBE BHEA'S ENERGY EFFICIENCY PROGRAMS AND THEIR CUSTOMER AND ENVIRONMENTAL BENEFITS.

[1] Scope 1 Emissions.

A. BHEA strives to provide a comprehensive Energy Efficiency Portfolio that conforms to the APSC rules for Investor-Owned Utilities. Programs are offered to all rate types to provide maximum opportunities to conserve natural gas usage and save customers money. Since the initial plan, beginning in 2012, the Company has exceeded its Commission-established savings goals, cumulatively saving more than 13,000,000 Ccf of natural gas.

Included in this total is BHEA's very successful residential weatherization program. This program, first offered during 2014, provides multiple benefits to the Company's residential customers. As needed, BHEA contractors will install air infiltration measures, seal duct work, add attic insulation, and install water savings measures to reduce hot water usage. This program complies with the APSC mandate that requires all Investor-Owned Utilities to offer the consistent weatherization program. There are many other benefits to our customers participating in this program that cannot be measured in Ccf savings alone. Customers are able to reduce their monthly heating bill and report that their houses are quieter and more comfortable as HVAC systems run more efficiently and drafts have been eliminated.

Residential customers are also offered rebates for installing high efficiency natural gas equipment, including smart thermostats. The Company's non-residential customers have many options available to them as well. High efficiency food service equipment, comfort heating systems, and water heating all have rebates intended to encourage natural gas reduction. BHEA also offers rebates for industrial process improvements to improve energy efficiency.

Q. PLEASE DESCRIBE BHEA'S ENERGY EFFICIENCY AWARDS AND RECOGNITIONS.

A. Each of the past four years (2019-2022), BHEA has been recognized by the U.S. Environmental Protection Agency ("EPA") as an Energy Star Partner of the Year for our work conducting energy audits at residential customer premises. The Company partners with qualified contractors to perform the weatherization, check and repair leaky ducts, check and add attic insulation if needed, install energy efficient showerheads and aerators, and install weather stripping. In 2023, BHEA received the EPA's Energy Star Partner of the Year Award - Sustained Excellence for achieving this recognition five years in a row.

Q. PLEASE GENERALLY DESCRIBE BHEA'S EFFORTS TO DEVELOP RENEWABLE NATURAL GAS PROJECTS IN ITS SERVICE AREA.

A. BHC currently receives or transports renewable natural gas ("RNG") from six facilities across the natural gas utilities and continues to explore additional RNG opportunities across its footprint. BHEA is actively working with third party companies to develop and interconnect RNG onto the BHEA system. In Docket No. 23-013-TF, BHEA received approval to offer a voluntary RNG and Carbon Offset tariff for residential and small business customers in our service territory.

Q. PLEASE DESCRIBE BHEA'S RECENT J.D. POWER RANKINGS.

A. BHC subscribes annually to the J.D. Power Gas Residential Customer Satisfaction Study to better understand residential customer perception of BHEA and other affiliates. For 20 years, J.D. Power has conducted customer surveys quarterly from approximately 85 natural gas utilities, with more than 125,000 residential customers, across the country. The utilities included are segmented by size and geographical region. BHEA is the only BHC affiliate in the J.D. Power midsize south region. J.D. Power uses the customer perception survey results to score and rank natural gas utilities across categories including Overall Satisfaction, Safety & Reliability, Billing & Payment, Price, Corporate Citizenship, Communications, and Customer Care. BHEA is the #23 (of 84) ranked natural gas utility in the country in J.D. Power's overall satisfaction score for the combined first three quarters (a.k.a. waves) of 2023. Additionally, BHEA is ranked #4 in the country in Customer Care.

Q. HOW DOES BHEA'S J.D. POWER RANKINGS COMPARE TO OTHER UTILITIES?

A. MTE Direct Table 1 and MTE Direct Table 2 below show BHEA's J.D Power customer satisfaction rankings compared to other gas utility peers in the Midsize South Region and nationally, respectively. BHEA's J.D. Power customer satisfaction rankings have improved from near the bottom quartile in 2017 or 2018 to near the top quartile as of Q3 2023 reporting with the exception of 2022. J.D. Power reported declines in Overall Satisfaction for all natural gas utilities across the nation with record setting weather events and increases to the cost of natural gas.

MTE Direct Table 1
J.D. Power Midsize South Region Ranking Trend

	2019	2020	2021	2022	2023
	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South
Overall Satisfaction	5 of 8	5 of 7	2 of 8	6 of 8	5 of 8
Safety & Reliability	2 of 8	5 of 7	1 of 8	5 of 8	4 of 8
Billing & Payment	2 of 8	5 of 7	1 of 8	5 of 8	3 of 8
Price	5 of 8	5 of 7	4 of 8	7 of 8	7 of 8
Corporate Citizenship	6 of 8	5 of 7	2 of 8	6 of 8	5 of 8
Communications	5 of 8	5 of 7	4 of 8	7 of 8	4 of 8
Customer Care	1 of 8*	6 of 7*	2 of 8	5 of 8	2 of 8

MTE Direct Table 2
National J.D. Power Midsize Gas Utility Ranking Trend

	2019	2020	2021	2022	2023
	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South	Black Hills Energy-South
Overall Satisfaction	23 of 84	45 of 83	2 of 83	54 of 84	23 of 84
Safety & Reliability	14 of 84	48 of 83	1 of 83	55 of 84	35 of 84
Billing & Payment	8 of 84	36 of 83	1 of 83	32 of 84	9 of 84
Price	22 of 84	34 of 83	10 of 83	65 of 84	41 of 84
Corporate Citizenship	55 of 84	67 of 83	4 of 83	71 of 84	38 of 84
Communications	37 of 84	69 of 83	13 of 83	65 of 84	11 of 84
Customer Care	2 of 83*	69 of 83*	3 of 83	46 of 84	4 of 84

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT WORKFORCE.

A. As of November 1, 2023, BHEA's current workforce includes 250 employees, with several vacant positions as result of retirements and other natural attrition. In the 2021 rate review, several positions were added to reduce outside service costs and increase the safety and reliability of the system. These positions included Utility Locators, Damage Prevention Coordinators, and an Operations Technician. In addition, and as discussed above, BHSC employees perform key functions for Arkansas gas operations, such as engineering, financial management, accounting, customer service/call centers, regulatory services, etc. BHEA is committed to the communities we serve, and we are pleased to maintain and add quality jobs in Arkansas. BHEA has included 257 employees in this case. This is slightly lower than the 261 headcount that is included in the base rates established in Docket No. 21-097-U. In addition to the direct BHEA employees, there are approximately 200 BHSC employees that are located in Arkansas, including call center employees located at the Company's Millsap office in Fayetteville.

Q. HOW HAS GROWTH IN BHEA'S SERVICE AREA IMPACTED ITS OPERATIONS?

A. Since 2021, BHEA has added over 7,400 new customers. This customer growth has occurred across the entire service territory, but predominantly in northwest Arkansas. Northwest Arkansas has had population growth of approximately 24% from 2010 to 2020 and grew approximately 5% more from 2020 through 2022. Benton County's population has grown 37% since 2010. Northwest Arkansas is now the 100th largest metropolitan statistical area and continues to grow at an estimated rate of 36 people per day.

This growth has translated into three primary areas of impact for BHEA. First, significant increases in the number of requests for BHEA to locate its pipelines prior to excavation activity being carried out ("line locates") along with a high level of third-party excavation damages to our pipelines. Second, growth in demand for typical utility services related to growing customer counts including the installation of new meters, service calls, and coordination with builders and contractors. Finally, increased customer count and resulting demand growth now requires that BHEA plan for and implement multiple reliability projects over the next few years, some of which will require significant capital investment. These projects may include investments to improve storage utilization and additional interstate pipeline interconnections. BHEA customers have benefitted from this growth as the resulting incremental revenues have reduced BHEA's current revenue deficiency by approximately $3.5 million.

Q. PLEASE ELABORATE ON THE DRAMATIC INCREASES IN LINE LOCATES THE COMPANY HAS EXPERIENCED.

A. The Company continues to see an increase in the volume of line locate requests due to increased construction activity within its service territory including extensive fiber optic broadband installation projects by telecommunications companies. Prior to 2021, the Company utilized both internal employees and a contractor to complete line locating work. Beginning in early 2021, in an effort to increase efficiency and public safety, BHEA added additional Utility Locating employees and brought all locating work back in house due to the importance of this work from a safety perspective. Since that time BHEA's excavation damages, measured in hits per thousand locate tickets ("HPT"), has decreased from a four-year average of 4.7 HPT prior to bringing locates in house in 2021 to 3.36 HPT in 2022 and a 3.18 HPT rate as of November 1st for 2023.

Q. WHAT IS THE MAGNITUDE OF THE THIRD-PARTY DAMAGE ISSUE?

A. Damage by external excavators is the number one threat to BHEA's pipeline system identified pursuant to BHEA's Distribution Integrity Management Plan ("DIMP"). A significant part of our workload is emergency response and leak repair caused by third-party excavation damage. Every time our system is damaged, our operations employees must respond to make the scene safe, and we mobilize a crew to repair the damage. It became evident after the SourceGas acquisition that BHEA had an unacceptably high rate of excavation damages. In 2016, BHEA had 11.12 hits per thousand locate tickets called into Arkansas One Call, a rate much higher than other BHC utilities and typical rates across the industry. In analyzing the issue, we found some of the drivers were the high rate of construction in Northwest Arkansas, inattention to One Call laws by some excavators, and issues with unlocatable plant (due to broken tracer wires from construction damage or corrosion for example). Our response to this problem was to create a focused and robust damage prevention program.

Q. WHAT EFFORTS DO YOU HAVE IN PLACE TO DECREASE WORKLOAD RESULTING FROM THIRD-PARTY DAMAGES?

A. From an operational and safety standpoint, we are highly focused on reducing third party damages. Reducing these preventable damages will improve public safety and reduce our workload. We also utilize work management software, Click, and an artificial intelligence predictive analytics tool, Urbint, to manage, optimize, and route field technician work as efficiently as possible.

BHEA's Damage Prevention Program takes a holistic approach and addresses each damage causation category including Excavation Practices Not Sufficient ("EPNS"), Locating Practices Not Sufficient ("LPNS"), and One Call Practices Not Sufficient ("OCPNS"). In September 2017, BHEA hired a full-time Damage Prevention Coordinator, whose sole focus was to reduce third-party damage on our natural gas system in collaboration with internal and external stakeholders. Since 2017, BHEA has added two additional for a total of three Damage Prevention Coordinators to further reduce damages. The coordinators partnered with Arkansas One Call, the APSC Pipeline Safety Staff, excavators, and with BHEA leadership in an aggressive effort to reduce damages. To address EPNS, the coordinators initiate constructive communication with contractors who damage our system and began training them on One Call laws, safe excavation procedures, and best practices as well as proactively reaching out to companies performing large scale fiber optics installation programs. Coordinators and operations employees visit excavation sites utilizing Urbint to prioritize outreach to the highest risk locate tickets.

To address LPNS, the coordinators have worked to unify BHEA's internal process to identify and replace unlocatable plant by improving tracking, prioritization, and mapping updates Approximately 339,400 feet of unlocatable pipe have been repaired or replaced since 2018. Additional damage prevention initiatives have included implementing a process to identify and address high risk pipeline stand-by and locating process, standardizing locating equipment, and providing locator training for both internal and third-party locators.

To address OCPNS, BHEA has utilized media advertising, social media outreach, and multiple public awareness campaigns. BHEA also worked with the Commission's General Staff, the Attorney General and other stakeholders to pass improvements to the Arkansas Underground Facilities Damage Prevention Act in 2023 and since that time has worked with the Attorney General on enforcement actions.

Q. WHAT BENEFITS FLOW FROM A DAMAGE PREVENTION PROGRAM?

A. The most important benefit is improved public, excavator, and employee safety. Reducing damage to our system and improving One Call law compliance reduces the likelihood of serious injury to the excavator who hits the line, first responders, our employees who respond to uncontrolled, blowing gas incidents, and the general public. Historically, damage rates in Arkansas have been high and continued collaboration and partnership between all stakeholders involved will help to continue to improve the ability to safely serve our customers and communities. It also reduces workload associated with responding to and repairing line hits. Another benefit is improved reliability to our customers since damages to our system can require stopping the flow of gas to the affected region and customer outages while system repairs are completed in an unplanned timeframe. Finally, BHEA's damage prevention program plays an important role in achieving our GHG reduction goals by reducing methane emissions that occur due to excavation damage and resulting uncontrolled release of methane.

Q. HAS THE DAMAGE PREVENTION PROGRAM BEEN SUCCESSFUL?

A. Yes. BHEA's focused damage prevention program has been effective as evidenced by the successful reduction in damages to the system as measured by HPT. HPT has been reduced from 11.12 HPT in 2016 to 3.36 in 2022. This has resulted in a reduction of over 500 damages to our system on an annualized basis when compared to 2016.

Q. IS ADDITIONAL IMPROVEMENT NECESSARY?

A. Yes. BHEA's goal is to collaborate with all stakeholders to reduce damages year over year and to achieve a rate within the top quartile performance across the industry. Even with the improvements over the past few years, BHEA still experienced 351 damages to our system in 2022 and 271 through September 2023. Each of these damages has the potential to become a serious incident. BHEA is still working to continuously improve its damage prevention program.

V. NEED FOR RATE CASE APPLICATION

Q. WHY IS BHEA FILING A RATE APPLICATION AT THIS TIME?

A. BHEA requires an overall increase in revenues to continue to provide safe and reliable service to its customers. As noted in the Direct Testimony of Mr. Robert Daniel, BHEA is experiencing a revenue deficiency of approximately $44.1 million. As further discussed by Mr. Daniel, there are several drivers that have caused BHEA to file this rate application. In addition to BHEA's normal ongoing capital investment program, the primary driver is the comprehensive cost of service impact of historically high inflation and the Federal Reserve's efforts to slow it with a rapid series of interest rate increases. This has had a very significant impact on nearly every component of BHEA's cost of service, including pipeline construction costs, materials, labor, outside services, general operating and maintenance expenses, cost of debt, and ROE.

BHEA recovers the portion of its capital expenditures related to compliance with safety requirements, pipe replacements, and road relocation projects that result from governmental improvements to roads and highways through its SI Rider. However, BHEA's total investments in its system have substantially exceeded amounts and types of projects that are recoverable through these riders. Reliability capital expenditures and operating expenses associated with SI Rider eligible projects are not currently recovered through the SI Rider. BHEA provides natural gas distribution and other utility services that are critical to public safety, convenience, and necessity. Although BHEA has prudently, and effectively managed expenses and investments, BHEA's cost of service has increased substantially. BHEA is filing this rate application to enable the continued investment in its system and to provide safe and reliable natural gas service.

Q. PLEASE DESCRIBE THE ACTIONS BHEA HAS TAKEN TO CONTROL COSTS AND INCREASE EFFICIENCY.

A. BHEA is continually looking for ways to control costs and increase efficiency. Some of the steps taken include improvements in customer service, automating and standardizing processes, and using work management and dispatching software for more efficient routing and dispatching of technicians. In November 2023, BHC realigned its workforce to ensure that the right people are doing the right things and are focused on key business objectives and results. As a result of this realignment, BHC eliminated 44 positions across the company. A majority of these were Service Company positions whose costs get allocated to the business units. This was done in an effort to mitigate increased labor costs and operate as efficiently as possible while maintaining critical support to serve our customers.

VI. IMPACT OF HIGHER INFLATION

Q. HOW HAS HIGHER INFLATION AFFECTED BHEA's COST OF SERVICE

A. The rate of inflation accelerated coming out of the Covid-19 pandemic and peaked at 9.1% for the twelve months ended June 2022. This was the highest inflation rate since the twelve-month period ending November 1981. BHEA's operating expenses increased across many categories. The cost of pipeline construction also increased significantly due to increases in internal and contract labor, materials, odorant and other consumables, fuel, vehicles, equipment and tools, property, and other right of way costs. Finally, BHEA's cost of capital has increased substantially due to interest rate increases by the Federal Reserve to fight inflation.

Q. HOW DO TEST YEAR OPERATIONS AND MAINTENANCE ("O&M") EXPENSES COMPARE TO THOSE IN THE LAST RATE PROCEEDING?

A. Even though BHEA has closely and prudently managed its O&M Expenses since the 2021 rate proceeding, historically high inflation has resulted in substantial cost increases. On a per customer basis excluding depreciation and property tax expenses, our expense cost per customer has increased from $323.09 per customer in 2020 to $352.13 per customer in 2022 or an 8.9% increase over two years. Since the October 2022 effective date of BHEA's rates established in Docket No. 21-097-U, BHEA's cost of doing business has increased substantially. The specific drivers of this case are discussed in more detail in the Direct Testimonies of Mr. Robert Daniel and Ms. Wendy H. Robbins.

Q. HOW HAS INFLATION AFFECTED THE COST OF PIPELINE CONSTRUCTION?

A. The cost of steel and other materials used in pipeline construction has increased substantially. Since 2020 we have seen an 81% increase in the price of steel pipe. The cost of valves, flanges, and other fitting has gone up approximately 15% and is expected to increase an additional 2.5% to 3.5% over the next year. The cost of internal and contract labor has also increased significantly. As a result, pipeline construction costs have increased substantially.

Q. HOW HAS INFLATION AFFECTED BHEA'S COST OF CAPITAL?

A. In order to fight inflation, the Federal Reserve increased the federal funds rate by 525 basis points between March 2022 and July 2023. These increases quickly translate to increases in BHEA's cost of short-term debt. They also result in higher long term debt costs as BHC enters into new long-term financing transactions. Investors in utility equity require a premium over the risk-free rate represented by the 30-year U.S. treasury bond. Since the 30-year treasury yield has recently been in a range that is 120 to 188 basis points higher than it was on the hearing date of BHEA's last rate case, investors now expect a substantially greater ROE than the 9.6% ROE established in Docket No. 21-097-U.

VII. GROWTH, INTEGRITY, AND RELIABILITY CAPITAL EXPENDITURES

Q. PLEASE PROVIDE AN OVERVIEW OF GENERAL OPERATIONAL IMPROVEMENTS AND DIRECT INVESTMENTS BENEFITTING BHEA'S CUSTOMERS.

A. BHEA is committed to providing safe and reliable natural gas service to its customers and communities. In order to provide the continued safe and reliable delivery of natural gas service, BHEA strives to ensure all assets are installed per the applicable requirements, comprised of approved materials, are in good operating condition, are in low-risk locations, can be located, and have adequate records of installation and maintenance. Employee and customer safety is a core value of BHEA and all BHC entities.

The transmission and distribution Main Replacement Program ("MRP") was implemented in 2014 as a 20-year program to systematically replace aging and higher risk pipe materials including bare steel, wrapped steel mains that are not cathodically protected, and other mains that the Company has determined are in unsatisfactory condition. BHEA has completed replacing all known bare steel transmission mains and plans for all remaining bare steel distribution mains to be replaced by the end of 2033. The Company replaced its bare steel transmission mains with cathodically protected, wrapped steel mains.

BHEA is replacing its bare steel distribution mains with either cathodically protected, wrapped steel mains or polyethylene mains. The At-Risk Meter Relocation Program ("ARMRP") was implemented as a 20-year program in 2014 to relocate at risk, property line meters to safer locations near a customer's premise. BHEA made additional investments in its underground natural gas storage facilities as required by integrity rules of the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the Arkansas Oil and Gas Commission ("AOGC"). BHEA has replaced or eliminated farm taps as required by the PHMSA and the APSC Farm Tap Rule. These proactive programs focus on improving the integrity of the BHEA system and benefits customers by increasing safety and reliability. An example of this is BHEA's main replacement project in and around Eureka Springs. This is a multi-year project replacing sections of the pipeline system which have reached the end of its design life. BHEA witness Mr. Steven C. Coleman discusses BHEA's integrity programs and investments in more detail in his Direct Testimony.

Numerous main extensions have been required to continue to provide safe and reliable natural gas to new customers in BHEA's rapidly growing service area. With that growth and the lessons learned from Winter Storm Uri, also comes the need for substantial investments to maintain reliable service.

Q. PLEASE DISCUSS CAPITAL INVESTMENTS IN THE ARKANSAS SYSTEM SINCE BHEA'S LAST RATE CASE.

A. BHEA made significant investment in its gas system since its last rate proceeding. Through the end of the Pro Forma Year, the gross plant in service increased by approximately $ $175 million, leading to a total rate base of $988 million in this rate proceeding. The costs for construction work that was a part of the Company's integrity programs have been partially recovered through the Company's SI Rider. However, BHEA has made investments above and beyond those recovered under its current riders. The investments were prudent and necessary to either comply with applicable changes in pipeline safety regulations, to ensure the provision of reliable service, or to meet the growth experienced across the system.

Q. DESCRIBE THE ADDITIONAL CAPITAL INVESTMENTS IN THE PRO FORMA YEAR?

A. BHEA has included $89.9 million of planned capital additions through the end of the Pro Forma Year, December 31, 2024, for expenditures related directly to the Arkansas system. These investments include system improvements to accommodate growth, system integrity and reliability. BHEA has also begun a multiple year program to replace Automated Meter Reading ("AMR") meters reaching the end of their design life with Advanced Metering Infrastructure ("AMI") technology. AMI capable meters will modernize the monthly meter reading process and provide both customers and BHEA added usage data for forecasting, data analytics, and consumption information. PHMSA's Mega-Rule Phase 1 and Phase 3 will require substantial additional integrity capital investments and expenditures through the end of the pro-forma test year and beyond. As with capital investments made during the Test Year, these investments are prudent and necessary to either comply with safety regulations, to ensure the provision of reliable service, or to meet the reasonable growth experienced on different parts of the distribution system. These projects benefit the overall system, thus providing customers with reliable and safe service.

Q. PLEASE BRIEFLY DESCRIBE THE "DATA INFRASTRUCTURE IMPROVEMENT PROGRAM."

A. The Company implemented a Data Infrastructure Improvement Program ("DIIP") to close known data gaps and to verify current data for accuracy related to the BHEA system. As PHMSA stated in its explanation of the Mega Rule: "PHMSA strongly believes that knowledge of pipeline physical properties and attributes are essential for a modern IM [integrity management] program."[2] The DIIP initiative began in 2021 for BHEA and full implementation of the DIIP is currently anticipated to take up to sixteen years at current unit prices and funding levels. The DIIP is intended to improve knowledge of the BHEA gas pipeline system and to better enable managing the integrity of the pipeline system. In order to prioritize integrity management programs and projects more accurately, it is vital for the Company to have improved and accurate system data. The DIIP will implement specific initiatives to improve system data, including data gap reduction, GIS (Geographic Information System) updates, and programmatic improvements. This program will help BHEA to comply with its responsibility of safely, reliably, and prudently, managing the system to serve customers long-term. BHEA witness Mr. Coleman discusses DIIP in more detail.

[2] 84 Fed. Reg. 52194.

Q. WHAT DOES THE DIIP ENTAIL?

A. The DIIP focuses on the improvement of data within the Company's GIS databases. The DIIP will evaluate, populate, and verify information that is missing with respect to main and service line locations, materials, diameter, cathodic protection, air test, and maximum allowable operating pressure ("MAOP"). As a part of the program, multiple data improvement projects will be undertaken including efforts to survey our assets using high accuracy GPS, digitize and link legacy construction records to our assets, update and populate missing GIS data and features, and model systems including cathodic protection systems, pressure systems, and emergency response zones. These projects are planned to be completed over a 16-year period. Mr. Coleman explains each of these projects in his Direct Testimony.

Q. WHAT DIIP PROJECTS WERE UNDERTAKEN DURING THE TEST YEAR?

A. The Transmission/Gathering Traceable, Verifiable and Complete ("TVC") Records project involves gathering, scanning, and storing original construction records in a document management system and linking those records to the asset in GIS. The documents will be used to verify MAOP attributes and update any missing pipeline attributes and features in GIS. For each transmission pipeline, a detailed GIS build will be performed using all available information collected from the digitized records. Relevant data will be extracted and used to perform MAOP calculations and verification. Data generated from the calculations will then be repopulated into the GIS creating a more robust database. The TVC Records project was started in 2021 and is anticipated to be complete in 2025.

Q. ARE ANY DIIP PROJECTS INCLUDED IN THE PRO FORMA YEAR?

A. Yes, year four of the Transmission/Gathering TVC Records project is included in the Pro Forma Year as shown below in MTE Direct Exhibit – 2 BHEA Data Infrastructure Improvement Program 16-Year Plan Costs.

Q. WHAT ARE THE PROJECTED COSTS OF BHEA'S DIIP?

A. BHEA started scaling up the DIIP in 2021 and by 2023 the projected program cost is planned to be an average of $1,500,000 per year for the remaining thirteen years (2024-2036) for a total program cost of approximately $21,778,336. The annual DIIP O&M expense is also discussed in the Direct Testimony of Ms. Robbins and is included in IS-11 adjustment in the revenue requirement. Cost by project is shown in Direct Exhibit MTE-2-BHEA Data Infrastructure Improvement Program 16-Year Plan Costs.

VIII. ACCELERATED REPLACEMENT AND RELOCATION PROGRAMS

Q. PLEASE DESCRIBE THE COMPANY'S SUCCESS IN DELIVERING SAFE AND RELIABLE SERVICE.

A. The Company has an obligation to provide safe and reliable service to its utility customers and communities. BHEA and its predecessors have been doing so for over 90 years in the state of Arkansas. Our employees recognize that safety is the number one priority. BHEA has a demonstrated record of continuing to make investments in safety, infrastructure, employee training, and system monitoring to ensure safety and reliability while maintaining high levels of service. As Arkansas continues to grow, so will the demand for natural gas requiring continued investments to maintain reliable service. In addition to significant customer growth, we have experienced increased extreme weather as illustrated during winter storms Uri and Elliott in recent years. This has highlighted the close connection of system reliability with safety and integrity as we continue to evaluate and make system improvements to ensure gas will be available to sustain life and property during the most extreme weather conditions.

Q. PLEASE EXPLAIN THE COMPANY'S PIPELINE REPLACEMENT POLICY.

A. At the beginning of each construction season, BHEA utilizes a worst-first and highest risk prioritization model to determine which projects to perform in each construction season. That model considers leak history, type and age of material, class location, potential risks, and other factors. The Company ranks projects using a point system. BHEA appropriately prioritizes projects to accelerate the replacement of bare steel pipe, PVC, Pre-1973 Aldyl A pipe, and bare steel high-pressure transmission pipe. Mr. Steven C. Coleman, in his Direct Testimony, explains the Company's pipeline replacement program in more detail.

Q. PLEASE DESCRIBE THE MAIN REPLACEMENT PROGRAM.

A. The Main Replacement Program ("MRP") was initially proposed and approved in Docket. No. 13-079-U with MRP costs being recovered through an MRP Rider. In Docket No. 21-097-U the MRP Rider was replaced with the SI Rider. The purpose of the MRP is to accelerate the replacement of aging and at-risk mains within our system, thus increasing overall system safety, integrity, and reliability. The MRP facilitates the expedited replacement of a) bare steel mains, b) coated steel mains that are not cathodically protected,

c) mains that are the subject of a federal or state agency advisory, and d) the services associated with these types of mains.

Q. PLEASE DESCRIBE THE AT-RISK METER RELOCATION PROGRAM (ARMRP) EFFORT.

A. The ARMRP was proposed in Docket No. 13-079-U to remedy the problem of third-party damage of meters that are located at customer property lines, often within close proximity to roadways. The program is designed to move at-risk meters to the customer's primary structure, unless it is better to install the meter at another, safer location. The program benefits customers by decreasing the number of meters hit by vehicles, thereby reducing the possibility of ignitions and injuries to motorists. Costs for the ARMRP program were initially recovered through BHEA's ARMRP Rider and are now recovered through the SI Rider.

Q. HOW MANY METERS HAS THE COMPANY RELOCATED UNDER THE ARMRP?

A. From January 1, 2019 to October 31, 2023, the Company has relocated 4,398 meters. As outlined in Docket No. 13-079-U, this program is intended to run for twenty years, through 2034. We intend to continue to evaluate annual leaks caused by vehicular damage on meter loops and will continue to focus and invest in this important program.

Q. HAS BHEA SEEN BENEFITS FROM THE ARMRP?

A. Yes. We have continued to observe a steady decrease in above ground meter damages from outside forces. These damages have decreased from 471 in 2014 to 299 in 2022. Through

October 31st of 2023, 193 meters have been damaged by outside forces. We intend to continue to reduce risk by decreasing these damages thanks to this effective relocation program. The ARMRP also helps BHEA achieve its GHG reduction target by reducing present and future methane emissions resulting from damage to at risk meters.

Q. PLEASE DESCRIBE BHEA'S ACT 310 SURCHARGE RIDER.

A. BHEA's Act 310 Rider is a mechanism that allows BHEA to recover the costs of projects eligible for recovery under Act 310 of 1981 as amended. These are projects that are required by government regulations related to health, safety, or the environment and which meet the specific requirements of Act 310. Each time BHEA files for recovery of costs under this rider it is required to file a detailed application and supporting testimony. The Commission then sets a procedural schedule under which BHEA, General Staff, and any intervenors file multiple rounds of testimony leading to a determination by the Commission of whether the costs are eligible for recovery under Act 310. Currently, capital expenditures eligible for the Act 310 Rider are being recovered through the SI Rider and any Act 310 eligible expenses would be recovered through the Act 310 Rider.

Q. HAS BHEA FILED ANY SURCHARGES UNDER THE ACT 310 RIDER TO RECOVER ITS ELIGIBLE COSTS SINCE ITS LAST GENERAL RATE CASE?

A. No. Since the SI Rider covers capital expenditures that would be Act 310 eligible, those expenditures are currently being recovered through the SI Rider. Although BHEA may still recover Act 310 eligible expenses through the Act 310 Rider, BHEA has made no such expense recovery filings since December 31, 2022, which was the end of the Pro Forma Year in BHEA's last general rate case.

IX. PROPOSED CHANGE TO SAFETY & INTEGRITY RIDER

Q. IS BHEA PROPOSING A CHANGE TO THE SI RIDER

A. Yes. BHEA is proposing to add recovery of reliability expenditures to the SI Rider. For purposes of the SI Rider, BHEA has defined reliability projects to also include projects that improve system resiliency. More specifically, BHEA proposes to include any project which is deemed to have an underlying need centered around natural gas system strength, including the ability to deliver services in the quantity and quality demanded by customers and the ability to prevent, withstand, adapt to, and quickly recover from system damage or operational disruption. BHEA witness Mr. Coleman, in his Direct Testimony, provides more details about the reliability projects that would be eligible for recovery through the proposed changes to the SI Rider. BHEA witness Mr. Daniel describes the proposed changes to the rider in more detail in his Direct Testimony. BHEA is also proposing modifications to the SI Rider to include recovery of eligible operating expenses and current recovery of property taxes. Those changes are discussed by Mr. Daniel.

Q. IS THERE A DEMONSTRATED NEED FOR BHEA AND OTHER ARKANSAS UTILITIES TO MAKE ADDITIONAL INVESTMENTS IN SYSTEM RELIABILITY?

A. Yes. During Winter Storm Uri in February 2021, the nation experienced widespread failures of natural gas supplies and mechanical problems with the pipeline systems delivering natural gas. In Arkansas this resulted in gas and electric service curtailments and extremely high prices for available gas supplies. Mechanical problems on interstate pipelines delivering natural gas to Arkansas, resulting in curtailments. System constraints and curtailments were also experienced during Winter Storm Elliott in December 2022. Following Winter Storm Uri, Governor Hutchinson appointed a task force known as the Arkansas Energy Resources Planning Task Force ("Task Force"). The Task Force conducted a collaborative investigation and in October of 2021 issued a report (attached as Direct Exhibit MTE-1) which made several recommendations related to improving the reliability of the state's natural gas delivery system ("Task Force Report"). This report recommends critical reliability investments in pipeline infrastructure similar to those BHEA proposes to include in the SI rider, as well as consideration of financial incentives and new rate structures to encourage such investments.

Q. PLEASE DESCRIBE THE RECOMMENDATIONS OF THE TASK FORCE RELATED TO NATURAL GAS SYSTEM RELIABILITY IMPROVEMENTS.

A. The Task Force Report contains the following recommendations related to improving the reliability of Arkansas' natural gas infrastructure:

> 2. The Task Force recommends that PSC, the MISO and SPP RTOs, and E&E's Arkansas Oil and Gas Commission ***evaluate whether it is reasonable and cost effective to develop standard criteria for weatherization of natural gas supply infrastructure*** and electric generation infrastructure in Arkansas. ***As part of PSC's resource planning process, a continued evaluation of the investments is needed to ensure adequate electric and natural gas supplies are available in Arkansas.*** The Task force recommends exploring potential opportunities to coordinate with Oklahoma, Texas, and the private sector ***to identify key components of the electrical, natural gas, and LP-Gas supply system that need protection***

> ***from extreme cold and to examine whether there are cost effective opportunities to implement weatherization of these components.*** The Task Force recognizes that it will be beneficial to take advantage of the established procedures of PSC, MISO and SPP RTOs, and other state entities to pursue these evaluations.
>
> …
>
> 5. The Task Force recommends that PSC, RTOs, E&E's Arkansas Oil and Gas Commission, and the LP-Gas Board ***consider whether it would be appropriate to implement any incentives for measures that could improve reliability in the form of financial incentives, formal recognition, expedited permitting, new rate structures*** and service offerings, or waiver of fees. The Task Force recommends evaluating ***whether it is technically feasible and cost effective to implement incentives for one or more of the following measures that could improve the reliability of Arkansas and regional energy infrastructure***: …
>
> - Addition of natural gas storage facilities:
>
> …
>
> 8. The Task Force recommends that E&E's Arkansas Oil & Gas Commission coordinate with the Arkansas Geological Survey and representatives from the natural gas producers and natural gas utilities to ***evaluate whether there are any additional geological formations or existing abandoned gas fields in the state capable of storing natural gas or propane. If additional sites suitable for storage are identified, the Task Force recommends that the state work with stakeholders to evaluate the technical and economic feasibility of incorporating the sites into Arkansas's energy infrastructure.***
>
> 9. The Task Force recommends that the appropriate stakeholders evaluate whether there are any additions or revisions to Arkansas statutes to ***help promote investments and assist in providing reliable energy resources for the state in the future***. The stakeholders should ***evaluate whether any state policy could be enacted through legislation or adopted under state agency rules if authorizing legislation already exists***.[3] (Emphasis Added)

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN RELIABILITY AND SAFETY AS IT RELATES TO THE OPERATION OF BHEA'S SYSTEM.

[3] 2021 Report of Arkansas Energy Resource Planning Task Force pp. 16-19 (Direct Exhibit MTE-1).

A. Safety and reliability are inseparable. It is not possible for an unreliable natural gas distribution system to be a safe system. Our customers rely on natural gas to heat their homes and businesses, protect their property from freeze damage during cold weather, and provide products and services that are essential to public health and safety. Therefore, system failures, near failures, or curtailments can create unsafe conditions for our customers, employees, and the public.

Q. CAN YOU PROVIDE A RECENT EXAMPLE OF THE INSEPARABILITY OF SAFETY AND RELIABILITY?

A. Yes. During Winter Storm Uri in February 2021, BHEA lost service (reliability) to approximately 2,000 mostly residential customers in Pea Ridge. At that time, BHEA delivered gas to the Pea Ridge area through a single pipeline. BHEA had already begun construction on a Commission approved reliability pipeline project to provide an additional feed to the Pea Ridge area. Reliability investments are especially important in growing service territories such as Northwest Arkansas since continuity of service and capacity to serve growing customer total loads supports the basic human need for heating to protect life and property. In addition, lack of system capacity, or reliability, like those that occurred during the Pea Ridge outage also present additional safety risk to BHE employees that have to respond in adverse conditions when over 100 BHE employees from four states (Arkansas, Kansas, Iowa, and Nebraska) responded to restore service. Employees and contractors worked in harsh, adverse conditions for approximately two days to restore service to customers. This also presents safety risk to customers and communities that depend on reliable service to provide heat to sustain life in the most adverse weather conditions.

Q. DO CURTAILMENTS OF SERVICE CREATE PUBLIC HEALTH AND SAFETY RELATED ISSUES?

A. Yes. Curtailment of BHEA business customers could result in property damage, substantial economic loss, and public health and safety issues. For example, curtailment of BHEA business customers in the food processing business such as poultry growers and processors could cause disruptions in the food supply chain. Curtailment of customers in the medical business such as hospitals and medical device manufacturing could cause disruptions in medical services or environmental issues due to release of environmentally hazardous materials.

Q. DO THE RECOMMENDATIONS OF THE ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE ("TASK FORCE") RECOGNIZE THE INSEPARABILITY OF SYSTEM RELIABILITY AND PUBLIC SAFETY?

A. Yes. The Task Force Report contains the following recommendation related to dealing with threats to public health and safety resulting from curtailments:

> … the stakeholders consider what steps are necessary [under curtailment conditions] to establish procedures for prioritizing energy to occupied dwellings, natural gas-fired electric generation to serve human needs customers, food supply production, and other commercial and industrial facilities ***whose operations are necessary to preserve human life, health, and safety***, including whether any executive, administrative, regulatory, or legislative action may be required.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE RECOMMENDATIONS CONTAINED IN THE TASK FORCE REPORT?

A. Given the lessons learned from Storm Uri, and the findings in the Task Force Report, there is a demonstrated need and strong desire to take action to improve the reliability of the state's energy systems, including its natural gas systems. The Task Force Report clearly recommends that the Commission and other stakeholders evaluate regulatory policies, rates and incentives that encourage reliability improvements to the state's natural gas systems.

Q. DOES BHEA'S PROPOSED SI RIDER PROVIDE THE COMMISSION WITH AN OPPORTUNITY TO ACT ON THE TASK FORCE RECOMMENDATIONS?

A. Yes. Inclusion of reliability projects in BHEA's SI Rider presents a clear opportunity for the Commission to adopt a regulatory policy and streamlined rate mechanism that encourages and facilitates accelerated action to improve the reliability of the state's energy systems.

Q. IN DOCKET NO. 07-045-U, STAFF'S CONSULTANT FILED TESTIMONY ON NOVEMBER 16, 2023, MAKING CERTAIN RECOMMENDATIONS RELATED TO BHEA'S GAS SUPPLY PLANNING. ARE ANY OF THESE RECOMMENDATIONS RELATED TO RELIABILITY?

A. Yes. Staff witness Melissa Whitten recommended that the Commission require BHEA to revise its gas supply and capacity plans to include, prior to the winter period, a new firm, flexible resource that can provide a backstop to the volumes that may be curtailed under the Liberty contract. The Liberty contract is a firm transportation contract with Liberty Utilities Midstates ("Liberty"). Liberty is the natural gas utility that serves Southeast Missouri. The Liberty contract is used to deliver BHEA firm storage and no-notice gas supplies that Liberty receives on behalf of BHEA in Missouri and redelivers to BHEA at the Arkansas – Missouri border. Implementing this recommendation may require additional reliability investments by BHEA. These investments may include additional pipeline interconnections, reconfiguration of existing interconnections, improvements to BHEA's storage facilities, or a combination of these.

X. LONG RANGE SYSTEM PLANNING

Q. PLEASE EXPLAIN BHEA'S LONG RANGE SYSTEM PLANNING AND WHY IT IS NECESSARY.

A. The BHSC Engineering team that supports BHEA performs several types of system planning. First, the engineering team frequently completes system hydraulic modeling to assess main extensions and other capital projects. The hydraulic modeling and engineering analysis reviews the adequacy of the BHEA transmission or distribution system to support the project while maintaining adequate system characteristics such as delivery pressures and flows. The engineering team also completes transmission system modeling using actual system data such as pressures during peak periods to identify priority areas of the system that may need reliability upgrades to support typical system load growth and also identify the most cost effective and prudent solution.

While BHEA has historically evaluated immediate and forecasted reliability investments over a five-year plan period, in 2021 BHEA initiated a planning study to develop a long-range plan. This long-range outlook in necessary to ensure BHEA's system reliability, resiliency and capability to meet long-term forecasted load growth and gas supply needs. The initial engineering study included assessing the annual system load and peak day load projections, completing an extreme weather and impact analysis, assessing alternative supply strategies to meet future demand while mitigating extreme weather impacts. Since its last rate case, BHEA has entered a second phase of this process which will result in a long-range integrated resource plan ("IRP"). This IRP is still being developed and will identify and offer support for future reliability projects, the cost of which could be recovered through the SI Rider.

XI. CONCLUSION AND RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the Commission approve BHEA's request for an increase in its rates along with the proposed SI Rider modification to include reliability projects, recovery of expenses, and current property tax recovery. I also recommend approval of the other tariff changes BHEA has proposed in its Application.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

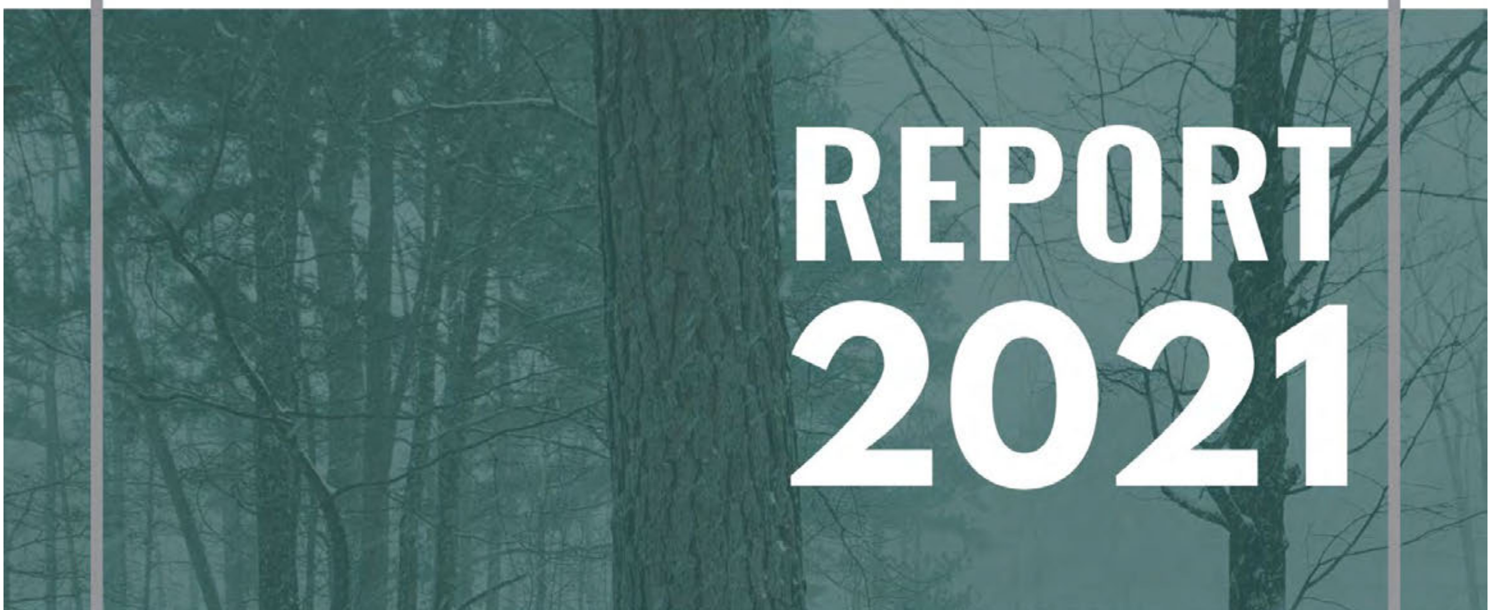
A. Yes, it does.

CERTIFICATE OF SERVICE

I, Jeff Dangeau, do hereby certify that I have caused to be served a copy of the foregoing Direct Testimony upon all parties of record in this docket, via the Commission's electronic filing system, this 4th day of December 2023.

/s/Jeff Dangeau
Jeff Dangeau

ARKANSAS ENERGY RESOURCES PLANNING TASK FORCE



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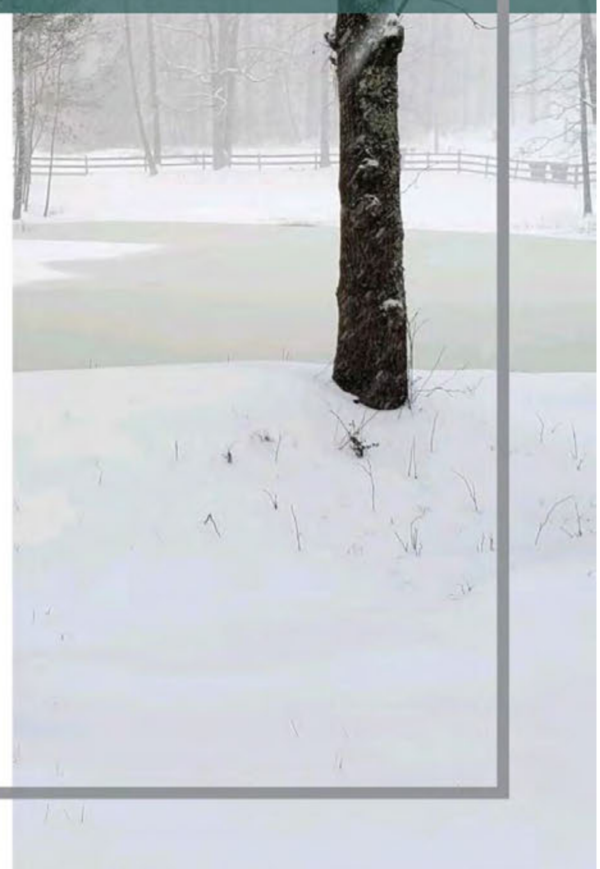

TASK FORCE MEMBERS:

BECKY W. KEOGH, Chair
Secretary, Arkansas Department of Energy & Environment

MIKE PRESTON
Secretary, Arkansas Department of Commerce

LAWRENCE BENGAL
Energy Administrator, Arkansas Department of Energy & Environment
Director, E&E Oil & Gas Commission

KEVIN PFALSER
Director, E&E Liquefied Petroleum Gas Board

I. EXECUTIVE SUMMARY

Extreme cold temperatures and snow in Arkansas and surrounding states during a February 2021 winter weather event disrupted fuel supply, primarily natural gas, for electricity generation and heating. Furthermore, some electric generating units underperformed during the event, and transmission constraints resulted in stranded capacity. At the same time fuel supply and transmission were constrained, electric and gas utilities experienced unprecedented winter demand in the region. In some cases, the demand exceeded summer peaks.

Despite the challenges experienced during the February 2021 winter weather event, coordination among the utilities, state departments and agencies, and multiple regional transmission organizations ("RTOs") ensured that Arkansas fared well during the storm with only limited, short-duration outages during the storm. Arkansas benefited from utility participation in RTOs that were able to draw energy from a wide geographic region with a diverse portfolio of electricity generating assets. The state also benefitted from the existence and availability of interruptible tariffs for large electric customers who voluntarily accept curtailment to reduce the load on the electricity grid in exchange for discounted electricity rates. Where natural gas supply was constrained, human needs were prioritized to ensure that Arkansans stayed warm. Communication of the need to conserve energy was broadcast widely across the state and Arkansans stepped up to meet the need.

Although Arkansas demonstrated that it is well-prepared for events like the February 2021 winter weather event, lessons learned during the storm provide the state with the opportunity to examine what processes worked well and what can be improved upon to ensure reliability during extreme events. To review and analyze lessons learned and develop recommendations, Governor Asa Hutchinson created the Energy Resource Planning Task Force ("Task Force").

After reviewing testimony from regulators, fuel suppliers and transporters, utilities, and energy users, the Task Force has identified potential opportunities for improved communication in advance of and during energy disruptive events and potential opportunities for improving the reliability of energy infrastructure. If outages are necessary to ensure the reliability of the electricity grid or curtailment is necessary due to limited fuel supply or weather-related electric outages, the Task Force recommends prioritizing energy so as to preserve human life, health, and safety and, to the extent possible, to businesses and industry that would otherwise incur damage to equipment or experience severe economic harm. The lessons learned and Task Force recommendations are discussed in more detail within this report.

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II. ACRONYMS AND ABBREVIATIONS

AECC	Arkansas Electric Cooperatives Corporation
AEEC	Arkansas Electric Energy Consumers, Inc.
AEF	Arkansas Environmental Federation
AF&PC	Arkansas Forest and Paper Council
AGC	Arkansas Gas Consumers, Inc.
AIPRO	Arkansas Independent Producers and Royalty Owners
AMPA	Arkansas Municipal Power Association
AGA	American Gas Association
AOGC	Arkansas Oklahoma Gas Corporation
APGA	Arkansas Propane Gas Association
Black Hills	Black Hills Energy Arkansas, Inc. and Black Hills Corporation
CenterPoint	CenterPoint Energy, Inc.
Commerce	Arkansas Department of Commerce
DEQ	Division of Environmental Quality
E&E	Arkansas Department of Energy and Environment
Empire	Empire District Electric Company, Liberty Utilities Co., and their parent company: Algonquin Power & Utilities Corp.
EPN	Energy Policy Network
Entergy	Entergy Corporation and Entergy Arkansas, LLC
EO 21-05	Executive Order 21-05
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
LP-Gas	Liquefied Petroleum Gas (Propane)
MISO	Midcontinent Independent System Operator, Inc.
NERC	North American Electric Reliability Corporation
O&GC	Arkansas Oil and Gas Commission
OG&E	Oklahoma Gas and Electric and OGE Energy Corp.
PPGMR	PPGMR Law, PLLC
PSC	Arkansas Public Service Commission
Quattlebaum	Quattlebaum, Grooms & Tull PLLC
RTO	Regional Transmission Operator
SPP	Southwest Power Pool, Inc.
SWEPCO	Southwestern Electric Power Company
Task Force	Energy Resource Planning Task Force established under Executive Order 21-05

III. INTRODUCTION

On March 3, 2021, Governor Asa Hutchinson issued EO 21-05, creating the Task Force to review lessons learned from the February 2021 winter storms by hearing testimony from a list of identified public and private sector leaders and any other citizen as the Task Force deems necessary; provide recommendations to the Governor for actions needed to ensure adequate supply of critical energy sources during extreme events; and develop priorities for allocation of limited energy resources should supply shortages due to emergency situations necessitate action to preserve life, health, and safety. Becky Keogh, Secretary of E&E; Lawrence Bengal, Director of the Arkansas O&GC; Kevin Pfalser, Director of the Arkansas LP-Gas Board; and Mike Preston, Secretary of Commerce, served as members of the Task Force. Secretary Keogh served as the Task Force Chair. Attached and marked for identification purposes as "Appendix A" is the full text of EO 21-05.

The Task Force conducted three meetings between March 10, 2021, through May 12, 2021, to discuss the entities from which the Task Force should request testimony, the schedule and format of Task Force meetings and hearings, and pre-hearing testimony questions. On April 9, 2021, the Task Force submitted pre-hearing questionnaires to interested parties and requested that each entity respond by April 30, 2021. Between May 27, 2021, and June 2, 2021, the Task Force held three hearings to provide responsive parties the opportunity to discuss lessons learned from the February winter storms, and to allow the Task Force members to ask questions regarding the responsive party's pre-filed written testimony and any oral testimony provided at the hearing. Attached and marked for identification purposes as "Appendix B" are Task Force Meeting and Hearing Materials.

This report presents the findings and recommendations of the Task Force after reviewing the testimony gathered through pre-hearing questions and hearings, and all documentation submitted to the Task Force in association with this testimony.

A copy of this report was delivered to each entity named in Section V.

IV. REVIEW OF LESSONS LEARNED DURING THE FEBRUARY 2021 WINTER WEATHER EVENT

Pursuant to EO 21-05, Governor Asa Hutchinson's first directive to the Task Force was to review the lessons learned from the February winter storms, including lessons from surrounding states and information gathered by hearing testimony from the following:

- The Chair of PSC, or his or her designee;
- A representative of MISO;
- A representative of SPP;
- A representative of Entergy;
- A representative of AECC;
- A representative of SWEPCO;
- A representative of OG&E;
- A representative of Empire;
- A representative of AMPA;
- A representative of CenterPoint;
- A representative of AOGC;
- A representative of Black Hills;
- A representative of AEEC;
- A representative of the Arkansas State Chamber of Commerce;[1]
- The Executive Director of AEF, or his or her designee;
- The President of AIPRO association, or his or her designee;
- Additional citizens, as the Task Force deems necessary, with knowledge and expertise in energy and environmental matters; and
- Additional citizens, as the Task Force deems necessary

The Task Force received written and/or oral testimony from the following entities:

1. Chairman Ted Thomas of PSC – Oral and Written
2. Attorney General's Office – Oral and Written
3. MISO – Oral and Written
4. SPP – Oral and Written

[1] Arkansas State Chamber of Commerce was sent a request to provide testimony to the Task Force, but the entity did not provide written or oral testimony to the Task Force.

5. AEF – Oral and Written
6. AEEC and AGC – Oral and Written
7. AF&PC – Oral and Written
8. Quattlebaum – Oral and Written
9. Black Hills – Oral and Written
10. CenterPoint – Oral and Written
11. AIPRO - Oral
12. AMPA – Oral and Written
13. Empire – Oral and Written
14. OG&E – Oral and Written
15. SWEPCO – Oral and Written
16. AECC – Oral and Written
17. Entergy – Oral and Written
18. EPN and Jackson Walker Law Firm – Oral and Written
19. PPGMR – Oral and Written
20. Ozark Mountain Petroleum, Inc. – Oral and Written
21. Craft Propane Inc. – Oral and Written
22. NGL Supply Wholesale – Oral and Written
23. APGA and Island Energy – Oral and Written
24. Enable Midstream - Oral
25. Summit Utilities - Oral
26. AOGC
27. CHS, Inc. – Oral and Written
28. Enterprise Products Partners LP - Written
29. AGA - Written

Attached and marked for identification purposes as "Appendix C" are the written responses received by the Task Force to pre-hearing testimony questions and supporting documents provided to the Task Force.

A. Communication

1. Notification of Potential for Curtailments

   Across the board, electric and gas utilities engaged in extensive outreach efforts to notify their customers of the potential for curtailments and the need to conserve energy during the February 2021 winter weather event. Local utility companies employed a variety of communication strategies, including: media notices, press releases, social media, text messaging, email, and webpage updates. Nevertheless, a few natural gas customers reported that they were unaware that they were being curtailed until a technician showed up to turn off their gas. In other cases, customers received notices that their home or business was part of a circuit selected for curtailment after the outages had already begun. In their testimony to the Task Force, utility company representatives provided lessons learned on how they could potentially improve their process for notifying customers of curtailment based on the challenges experienced during the February 2021 winter weather event.

One challenge to the notification process identified by representatives from CenterPoint and AOGC during the February 2021 winter weather event was contacting the right person within large industrial organizations. This challenge presents an opportunity to be better prepared in the future by updating contact information more frequently. In addition, CenterPoint representatives suggested that increasing the number of staff to make phone calls would help improve the notification process if a future energy emergency arises.

Another challenge identified by Entergy representatives was the short-time frame between being informed by the RTO about the directive to initiate curtailments and when the first curtailment commenced. This short time frame made it difficult for utility companies to provide advance notice to individual customers that their power would be curtailed. Entergy representatives stated that the Company has taken steps to enable it to be better able to direct communication about which customers are next to experience outages if they were to identify and maintain a contact list for the customers served on each of their circuits. Additionally, Entergy representatives noted that it may continue to be difficult to notify customers on the first circuits curtailed during a coordinated outage directed by an RTO but that it would be possible to provide advance notice to customers on the subsequent circuits that would be curtailed in those events.

2. Notification of Shifts in Pricing

Some energy consumers and municipal utilities were unaware and surprised by high energy bills after the February 2021 winter weather event. Multiple energy consumer representatives indicated that they had no real-time indication of prices. If there had been a system in place to notify them when energy prices exceeded a specified threshold, they testified that they may have chosen to curtail operations voluntarily instead of continuing to operate.

This challenge presents an opportunity for energy consumers and their suppliers to add additional language to their private service contracts to implement a system that would provide for real-time price signaling to consumers. Various presenters noted that both MISO and SPP provide timely information on the wholesale prices of electricity on their web pages. Additionally, presenters noted that the market prices for natural gas are also publicly available. Electric and natural gas utilities file their energy cost rates with PSC, and those rate schedules are available on PSC web page. Municipal electric utilities that purchase wholesale electric capacity and energy may want to discuss opportunities to obtain price information from their wholesale providers.

3. Availability of Special Needs Affidavits

Prior to the February 2021 winter weather event, some natural gas consumers were unaware of the need to file a human-needs affidavit certifying that they have a facility with human-needs usage requirements. Examples of human-needs customers include hospitals, housing, greenhouses, poultry farms, and schools (except those with central boiler plants for heating and an alternative fuel source). Human-needs customers are exempt from curtailment. The human needs affidavits are a component of the interstate natural gas pipeline companies with FERC approving tariffs to their customers who either are or who serve human needs customers. Those transactions are not subject to any regulation at the state level.

AGC representatives also discussed the availability of special needs affidavits for plant protection. When gas supplies are limited, some pipelines may reduce their load by reducing the flow of gas to a transportation customer (a customer who buys directly from the pipeline) to the minimum necessary to keep equipment from freezing if the customer has a special needs affidavit, plant protection affidavit, or both on file with the pipeline. Otherwise, the customer may be completely shut off from gas or incur substantial penalties for burning gas during a curtailment event. Being completely shut off from gas may damage equipment for some transportation customers.

Representatives from AEEC, AGC, AF&PC, Quattlebaum, and Black Hills suggested that more education about human-needs, special needs, and plant-protection affidavits would be beneficial to prevent those facilities serving human needs or for which curtailment would damage equipment from being curtailed because they don’t have an affidavit in place.

B. Adequacy of Existing Energy Infrastructure

In their testimony to the Task Force, some representatives provided lessons learned about the challenges the existing energy infrastructure faced during the February 2021 winter weather event.

1. Natural Gas

Testimony from representatives of multiple entities indicated that the shortage of natural gas supply during the February 2021 winter weather event was due in large part to freeze-offs at natural gas production facilities in Texas and Oklahoma that deliver natural gas for use in Arkansas and other states. At the same time supply of natural gas was reduced, demand for natural gas for heating and electricity generation experienced unprecedented winter peaks. The supply and demand imbalance contributed to spiking prices for natural gas and the need for natural gas curtailment and short-term, localized, and controlled electric load shedding events. Following review of the pre-filed written testimony, and listening to the testimony of those who appeared before the Task Force, it is evident that the natural gas industry in the state performed remarkably well under the most extreme circumstances. All personnel working in the natural gas industry here in Arkansas should be commended for their performance and success at preserving enough supply to be used for meeting human needs.

a. Preparation of Natural Gas Production Facilities for Freezing Conditions

The natural gas production facility freeze-offs that occurred in Arkansas appear to be the result of insufficient weatherization of Arkansas natural gas wells and compressors in freezing temperatures experienced during the February 2021 winter weather event. For example, the representative from AIPRO testified that many of the natural gas producers in Arkansas worked to borrow heater facilities for their systems. However, Arkansas producers were only able to access approximately sixty heating units; whereas, there are thousands of wells in the state. Therefore, producers prioritized top producing wells for weatherization during the February 2021 winter weather event. In addition, road closures due to snow and ice also imposed a difficulty for producers to access wells. While additional heating equipment may have helped maintain production of additional wells, the AIPRO representative suggested that the cost of preparing for a fifty year event may not be economically feasible for producers.

A MISO representative suggested that setting winter weatherization standards to protect generation and fuel supplies from freezing conditions would mitigate risk of diminished generation and supply during rare winter weather events. If developed, such standards would be established in coordination between RTOs and their members. However, increased weatherization of wells and well compressors would come with increased costs for equipment that are not needed on a routine basis, and those costs need to be weighed against the potential benefits.

b. Natural Gas Supply Streams and Storage

Although Arkansas has ample natural gas resources and is a net exporter of natural gas, some of the natural gas used in Arkansas is produced out of state. The Fayetteville Shale gas development in Arkansas in the mid-2000s occurred after infrastructure to bring natural gas into Arkansas had already been established. Therefore, the majority of natural gas produced within the state is transported out of the state to the east. This dependence on interstate supply for natural gas obtained from un-weatherized wells in Oklahoma and Texas resulted in a shortage of supply to Arkansas utilities in February 2021.

Examples of affirmative measures that could be taken to reduce Arkansas's dependence on interstate natural gas supply include development and connection to additional supply basins, additional local supply or local storage capability, and improved or new interconnects for pipelines. A representative from CenterPoint suggested that such measures add incremental reliability. However, the improved reliability from these measures would come at a cost to the utility companies, customers, and upstream providers and those costs would need to be evaluated relative to any potential benefits.

Local storage of natural gas, either at storage facilities along the pipeline or at industrial or utility company sites where the natural gas is used, can mitigate temporary imbalances in production and demand. For example, a Black Hills representative described additional storage facilities approved by PSC in 2015 as a means to allow utility companies and other providers to meet demand during the February 2021 winter weather event. However, the low cost of natural gas means that onsite storage solutions are not economically favored without outside incentives.

2. LP-Gas (Propane)

Based on a review of the testimony provided, the month of February in 2021 may have been the worst month in the history of the LP-Gas industry in Arkansas. The freezing temperatures that affected the natural gas pipelines also affected the LP-Gas pipelines, which caused terminals in the area to go off-line. Unlike natural gas, from the terminal to the end user, LP-Gas is delivered by truck, so deteriorating road conditions prevented transport deliveries. In addition to this, NGL Energy Partners, LP made a business decision in 2020 to de-commission a million-gallon storage terminal in the central part of the state. This required transporters to travel further distances to pull more LP-Gas from outside the state. By February 20, 2021, there were several LP-Gas dealers that had little or no supply of propane. The LP-Gas industry personnel should be commended for their tireless effort to make sure their customers had heat in their homes during this challenging time period.

The Task Force heard testimony from representatives in the LP-Gas industry regarding constraints on propane supply and distribution during the February 2021 winter event. Prior to the event, supply was already constrained due to higher demand during the winter than in summer, creating an imbalance in pipeline allocations. The LP-Gas needs during the events exceeded forecasted demand and pipeline shipment of ordered LP-Gas from Texas was delayed. In addition, LP-Gas supply from the Valero Refinery was unavailable during the February 2021 winter weather event due to a small explosion at the refinery. Some LP-Gas that was ordered by dealers was not delivered. There are also no LP-Gas terminals or other supply in the western part of Arkansas. As a result of the supply interruptions and lack of supplemental local supply, LP-Gas carriers traveled farther to obtain supply to meet demands in Arkansas. Further complicating matters, hazardous road conditions made delivery of LP-Gas by truck more difficult.

LP-Gas industry representatives explained that lifting the hours of service requirements for LP-Gas drivers during the emergency enhanced their ability to serve customer demand during the February 2021 winter weather event. LP-Gas industry representatives suggested that lifting the requirements sooner in anticipation of an event would be beneficial. Additionally, temporary exceptions to gross vehicle weight limits for LP-Gas transports in anticipation of extreme weather events was recommended by LP-Gas industry representatives to enhance transport of propane supply.

LP-Gas industry representatives suggested that additional propane storage at retail locations and additional terminals might mitigate supply disruptions and insufficient pipeline allocation. A representative from Ozark Mountain Petroleum, Inc. suggested that strategic placement of rail facilities around the state would help secure adequate propane supply. However, additional storage also comes with additional cost. APGA representatives suggested reducing taxes and fees as an incentive to invest in storage and equipment. In addition, ensuring that existing storage is kept full would also help to mitigate potential supply disruptions.

3. Electricity

The coordination among PSC, electric utility companies, and RTOs helped Arkansas manage the challenges experienced during the February 2021 winter event. Arkansans benefited from the participation by Arkansas utilities in two RTOs that were able to pull electricity from a wide geographic region with a diverse energy resource mix. Utility companies and RTOs had well-rehearsed plans in place prior to the event to effectively disseminate information about conservative and emergency operating conditions that allowed them to react quickly to maintain the reliability of the grid. The electricity industry personnel should be commended for their tireless effort to power Arkansas homes during the February 2021 winter weather event.

a. Performance of Existing Electric Generation Fleet

Electric industry representatives testified that each fuel source within the existing electric generating fleet experienced some challenges during the February 2021 winter weather event, which further constrained energy resources. However, the electric industry representatives noted that Arkansas utilities' diverse fuel resources and participation in the MISO and SPP RTOs significantly limited the number of outages actually experienced during the event. An Empire representative explained that they had issues across their generating fleet, including coal plants that had frozen coal or tripped offline, low gas pressure issues on some natural gas thermal generators, and some frozen turbines on wind farms that were not winterized. A SPP representative confirmed that both coal and natural gas generating facilities in the region experienced weather-related challenges that affected the performance of those units relative to how those resources are accredited for reliability purposes. Although wind turbines were not very productive during the period of the February winter storm, an SPP representative confirmed that this lack of productivity was consistent with forecast.

A MISO representative explained that winterization of generators, in addition to fuel supply winterization, might mitigate risks associated with conditions like those experienced during the February 2021 winter weather event. There are currently no standardized winterization criteria in the MISO region. However, the MISO representative suggested that such criteria would need to be assessed by MISO and its members. The MISO representative also suggested that there would be a need for an entity to monitor or verify weatherization of the generation fleet. Further, the MISO representative noted that it would be essential to evaluate the cost associated with weatherization of the generation fleet and whether those expenditures would be reasonable and appropriate relative to the expected benefits.

The MISO representative also explained that the February 2021 winter weather event, as well as other maximum generation event days that have occurred outside of the summer months in recent years, suggests that resource adequacy planning should be refined. Past practice was to plan for adequate resources to meet the projected summer peak. The MISO representative explained that changing to a seasonal resource adequacy construct could help account for seasonal variation in fuel availability and generation capability.

b. Performance of Existing Transmission Infrastructure

Some of the load shedding events during the February 2021 winter weather event were a result of transmission constraints rather than lack of energy. However, as the electric utility and RTO representatives noted, there were limited customer interruptions both in number and duration during the event. At times during the winter weather event, overloading of transmission lines and regional transfer limits hindered the ability to move energy to specific areas where it was needed. In addition, an Entergy representative also explained that transmission constraints caused a derate at one of the units at the Nuclear One facility in Arkansas for a few hours, which was otherwise performing exceptionally. Entergy Arkansas representatives further noted that its investment in its transmission infrastructure over the past several years helped ensure reliable electric service and limited the impact of the event.

Although there were localized transmission constraints, the ability for MISO and SPP to pull energy from other regions in the Eastern Interconnect dramatically reduced the impact from weather-related challenges such as insufficient gas supply and generating units that tripped offline in the MISO and SPP regions during the February 2021 winter weather event. The MISO representative explained that the addition of new transmission capacity and improved interregional coordination and interconnection would bring significant efficiency and reliability benefits. The PSC Chairman, as well as the electric utility and RTO representatives, all noted that participation in the MISO and SPP RTOs significantly contributed to reliable performance during the event and helped limit the number and duration of any outages.

c. Diversity of Generation Assets

Several entities provided testimony about how diversity of types and geographic location of generating assets provide a significant reliability benefit. Both MISO and SPP representatives explained that the interconnection of RTO regions on the Eastern Interconnect was a tremendous benefit to reliability because they were able to pull energy from areas that were not severely impacted by the February 2021 winter weather event. Both RTOs have a diverse mix of generation asset types. As noted by the PSC Chairman and the electric utility and RTO representatives, the diverse fuel mix in the Arkansas generation portfolio mitigated the number of and duration of outages.

While the majority of testimony pointed to a natural gas supply shortage used for electric generation due to freeze-offs and transmission constraints as the primary cause of the power shortage during the February 2021 winter weather event, EPN representatives cited a different cause. EPN representatives opined that the primary cause of the power shortage during the February 2021 winter weather event was “Arkansas’s contractual ties to RTOs that have collectively closed 60 baseload power plants (over 22,000 MW) in the past five years” and the replacement of those plants with intermittent generating resources. The EPN representatives suggested that, if those baseload power plants had not been retired, the region would not have had the outages experienced during the February 2021 winter weather event. However, the electric utility and RTO representatives all provided testimony that the outages in Arkansas and in the MISO and SPP regions were limited in numbers and duration during the event. Those representatives further noted that the diverse fuel mix of Arkansas’s generation fleet, investments in generation, transmission, and distribution assets, as well as participation in the MISO and SPP RTOs helped Arkansas manage the storm and mitigate outages.

C. Planning for Reliable Energy

There were numerous suggestions regarding how to ensure the reliability of future energy infrastructure. These suggestions touched on transmission, current and planned generation assets, and load management.

1. Transmission

As previously noted, transmission constraints hindered the movement of electricity during the February 2021 winter weather event. The MISO representative explained to the Task Force that transmission expansion in the present could mitigate risks associated with such events, but transmission expansion will become even more necessary to accommodate significant increases in renewable energy generation and other projected changes to the grid, including electrification of vehicles and other sectors. The MISO representative explained that MISO’s plans evaluate additional interconnection, examine load pockets, and work with seams partners to increase coordination. The SPP representative explained that strong transmission interconnections increase their ability to rely on generation in its footprint as well as energy transfers from neighbors to mitigate supply deficiencies during an emergency. Both MISO and SPP have established processes to evaluate the transmission investment needs within their footprints and to make plans to ensure that the investments necessary to maintain a reliable bulk electric system are made by the transmission owners. That process includes participation from the electric utilities, state regulators including PSC, and transmission customers. The MISO and SPP processes are open forums where the investments needed to ensure reliability are discussed and evaluated. Further, many of the electric utilities' transmission investments require PSC review and approval in an open, public process.

2. Current and Planned Generation Assets

Arkansas investor-owned utility companies participate in RTOs that operate a market-based system for directing dispatch of generation assets within their region. RTOs are responsible for ensuring the reliability of the high-voltage electric transmission system and directing dispatch of generation resources to ensure the reliable and cost-effective delivery of energy. RTOs use an energy market to direct dispatch of energy resources. The energy market takes into account forecasted energy needs, system constraints, state laws, and operation profiles of different types of generation assets to manage risk and deliver least-cost energy. In addition, the RTOs have established procedures for ensuring the reliability of the electric grid in preparation for potential events and during energy emergency events. Additionally, pursuant to statutory authority in Arkansas, PSC conducts reviews of electric utility resource plans every three years. Those plan reviews are conducted in an open forum that allows for participation and input from stakeholders. Those "integrated resource plans" help utilities plan for the generation investments needed to meet the load that they serve.

The Task Force heard different perspectives on the maintenance of current generation assets and how to direct investment in new generation capacity. The electric utility company and MISO representatives indicated that they were in the process of re-evaluating planning and market products to meet the reliability imperative, taking into consideration the evolving grid, and to move to a seasonal construct for resource adequacy determinations. EPN representatives recommended enacting legislation and rules in Arkansas to direct retention of and investments in baseload thermal generation. However, PSC resource planning process described above provides a forum to evaluate the electric utility plans for generation needed to meet their load. Furthermore, the Arkansas General Assembly enacted Act 694 during the 2021 session, which requires electric utilities to consider the costs and benefits of extending the life of existing generating resources as part of the established resource planning process.

An SPP representative explained that Arkansas benefits from vertically integrated regulatory systems in Arkansas and in other states whose utilities participate in SPP and MISO markets. In deregulated systems without a capacity market, like ERCOT, the cheapest generation is built first. In ERCOT, the cheapest energy resource is wind, which often bids into the market in negative prices due at least, in part, to the impact of the production tax credits for wind generation facilities. Regulated systems allow the states to enact policies to direct prudent investments in energy infrastructure with a focus on reliability as well as economics because utility companies must justify investments to PSC in order to earn a return on their investment from ratepayers. The experience of the Arkansas electric utilities that are members of the MISO and SPP RTOs during the winter weather event was significantly different than the participants in ERCOT.

EPN representatives suggested that existing baseload dispatchable generation planned for cessation of operations should be retained and used for operating reserve. EPN specifically mentioned three power plants in Arkansas (one natural gas and two coal plants) where Entergy plans to cease operations or cease use of coal. The Entergy representatives explained that, given the required investments needed for these facilities that are nearing the end of their useful lives, maintaining those units as a backup would not be efficient or cost-effective, and there are better alternatives. The Entergy representatives suggested it would be more cost-effective to invest in newer, more efficient technologies that can serve as longer-term resources to customers.

EPN representatives also suggested that any new intermittent generation assets should be backed with a firm power purchase contract to purchase from dispatchable thermal generation assets. This resource adequacy approach was also mentioned in a report provided by MISO.[2] The MISO report suggested that they would need to consider how to incorporate fuel assurance requirements in a cost-effective manner when such a resource may only be needed a few times a year. PSC's established resource planning process provides an opportunity for evaluating the needs for generating resources, including whether new resources are cost-effective and how they affect reliability. Further, the MISO and SPP RTO planning processes under the FERC and NERC regulations require the participating electric utilities to have adequate generation to meet their load plus an adequate reserve margin. These requirements help ensure that there are adequate resources to meet the needs of Arkansas customers.

MISO provided the Task Force with a detailed report of lessons learned with regards to systems planning, as well as other MISO operations, that the RTO plans to implement in coordination with market participants and other stakeholders.[3] Specifically, MISO plans to move to a sub-annual (4-season) resource adequacy construct and implement changes to its resource accreditation criteria to better reflect resource availability during hours when the system is most in need and during extreme weather events. In its seasonal assessments, MISO plans to focus more attention to extreme scenarios (high loads and high outages). MISO explained that these changes should provide an incentive to

[2] "The February Arctic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative" included in Appendix C of this Report.

[3] MISO provides a comprehensive list of Lessons Learned and Actions to Address the Lessons starting on page 48 of it's "The February Arctic Event: Event Details Lessons Learned and Implications for MISO's Reliability Imperative" report provided to the Task Force during the May 27, 2021, hearing.

resource owners to invest in winterization, fuel assurance, and other means of ensuring resource availability. This market-based approach mitigates risk while providing flexibility to keep the cost of the bulk electric system low. The RTOs continue to evaluate their resource adequacy constructs as the energy resource mix and risk profiles evolve. The PSC and RTO resource planning processes provide open forums to evaluate the electric utility industry's actions to ensure that their customers receive reliable electric service at reasonable rates.

3. Load Management

The goal of energy resource planning and operations is to reliably match supply of energy with demand for energy. Many of the representatives spoke to energy supply management, but demand-side management also can be used to balance supply and demand. All of the electric and natural gas utilities offer demand response programs.

For example, Entergy offers a Smart Direct Load Control Pilot Program as part of its energy efficiency programs. The program allows customers to opt in to a programmable thermostat that the utility company can adjust by a few degrees to reduce load during summer peaks between June 1 and September 30 each year. In exchange for the utility company's ability to perform this service, customers get a free smart thermostat, which can save them money by reducing heating and cooling when no one is home, and an annual enrollment incentive to encourage continued participation.

Interruptible tariffs also provide a mechanism for load management. AEEC testified that many industrial and agricultural customers take electric services on interruptible tariffs. An interruptible tariff makes the customer subject to curtailment in the event of a utility's peak load exceeding the available capacity. In exchange, these customers receive a discount on rates. Curtailment for customers on interruptible tariffs helped reduce the need for load shedding during the February 2021 winter weather event.

PSC Chairman Ted Thomas suggested further exploration of demand response and ensuring that demand response programs create appropriate price signals to incentivize consumers to voluntarily reduce load when needed. Demand response can also be used to address the intermittent nature of many of the renewable generation assets that are being brought online by matching intermittent supply with intermittent demand. PSC has an open proceeding to consider existing and planned demand response offerings by the electric utilities in Arkansas. The open PSC proceeding provides an open forum to address demand response programs in Arkansas.

V. RECOMMENDED ACTIONS TO ENSURE ADEQUATE SUPPLY OF CRITICAL ENERGY SOURCES DURING EXTREME EVENTS

A. Creation of an "Energy Resources Council"

The Task Force recommends creating an "Energy Resources Council." The Energy Resources Council would meet at least once annually to facilitate technical and policy discussion among regulators and energy stakeholders and would work to develop and maintain educational materials on best practices regarding preparation and communication in advance of and during events that may disrupt supply of critical energy resources. The list below provides recommended potential organizations for the Governor to nominate as Energy Resources Council members:

- Representative(s) from E&E;
- Representative(s) from Commerce;
- Representative(s) from PSC;
- Representative(s) from the Arkansas Attorney General's Office
- Representative(s) from electric and gas utility companies;
- Representative(s) from the Natural Gas and LP-Gas industry;
- Representative(s) from the MISO and SPP; and
- Representative(s) from community and business organizations, such as the Arkansas State Chamber of Commerce, AF&PC, AEEC, and AGC.

The Task Force also recommends that E&E host educational materials developed by the Energy Resources Council on its website and coordinate logistics for the annual meetings. Further, the Task Force recommends that RTOs, APSC, and utilities share with the Energy Resources Council any reports or other publications that quantify the outcomes of efforts these entities are undertaking to address lessons learned during the February 2021 winter weather event.

B. Creation of an "Energy Disruption Preparedness" Tool Kit

The Task Force recommends creating a webpage to serve as a central research location for information related to energy resources in the state. This central location would provide access links to the various utility companies and expert groups and provide a tool kit for best practices for preparedness for potential energy disruption events. E&E would host the tool kit and coordinate discussions with the energy industry participants on content and updates to the tool kit. This coordination would occur in conjunction with the proposed Energy Resources Council or in some other forum.

Examples of tool kit contents might include:

- Best Practices for Preparing A Business' Operation for a Potential Energy Disruption
  - Creating a facility-specific plan including consideration of:
    - Whether back-up fuel or generation is necessary;
    - What are minimum energy or fuel requirements to protect equipment from damage;
    - What level of energy or fuel, if any, is necessary to sustain human needs functions;
    - Who is responsible for making decisions to voluntarily curtail operations to conserve energy and reduce exposure to price surges;
    - Whether a human needs or plant protection affidavit should be filed with the energy supplier;
  - Electric and natural gas utilities that take service from interstate natural gas pipeline companies should submit a human needs affidavit for their operation pursuant to the pipeline company's FERC tariff:
    - Educational materials about what a human needs affidavit is and why it is important to keep a human needs affidavit on file if a portion of an energy provider's operations serve human needs;
    - Links to relevant FERC tariffs that establish the legal foundation;
  - Ensuring fuel and electricity suppliers and utilities know who to contact in the event of an energy disruption event;

- Best Practices for Communication in Advance of and During an Energy Disruption Event:
  - Implement a regular, periodic review by utility companies of the appropriate contacts for customers that may be curtailed during an energy disruption event;
  - Identify customers and ensure up-to-date contact information for each circuit so that the appropriate customers can potentially be notified promptly after a decision is made about a planned outage that is necessary for the stability of the grid;
  - Create a list of the call center numbers and other applicable contacts for each utility company so that state agencies can refer citizens to this list if there are concerns during an energy disruption event;
  - Review procedures and protocols for advance warning of service interruptions for customers served on interruptible rate schedules, coordinated outages, or other energy curtailments;
  - Reach out to PSC, E&E, Commerce, and prominent community business organizations to amplify the message to conserve energy when needed;
  - Include in-messaging implications of an energy disruptive event, such as the potential for outages and any associated price increases;

- Information about energy pricing (links or embedded tools):
  - Daily Natural Gas Spot Prices: https://fred.stlouisfed.org/series/DHHNGSP#;
  - MISO Locational Marginal Price Data: https://www.misoenergy.org/markets-and-operations/real-time--market-data/real-time-displays/;
  - SPP Price Contour Map: https://pricecontourmap.spp.org/pricecontourmap/; and
  - Best practices for ensuring that energy contracts provide for notification of price spikes, opportunities for voluntary curtailment and to direct customers to the public sources for wholesale electricity prices and natural gas prices so customers can monitor the prices and adjust their consumption accordingly.

The Task Force recommends sending out social media, press releases, and other methods of disseminating the availability of the tool kit once it is launched and at least twice a year each year thereafter in advance of the summer and winter seasons. The Task Force also recommends disseminating information about the availability of the tool kit when extreme weather events are forecasted.

C. Areas for Additional Consideration and Study

The Task Force notes that there are other items that may warrant further consideration within the appropriate existing forums, where they exist, to continue monitoring whether any additional actions may be appropriate. The following are potential areas identified by the Task Force upon reviewing testimony received. However, before taking actions under one or more of the following, the Task Force recommends a robust evaluation of the anticipated ratepayer impacts, environmental impacts, reliability impacts, and economy-wide impacts of any action.

1. The Task Force recommends that PSC continue its examination of demand-response programs in Arkansas and evaluation of whether it is in the best interest of Arkansas customers to expand those programs. The Tasks Force suggests that PSC consider whether it would be beneficial to expand the demand-response programs that are included in electric and natural gas utility rate schedules and financial incentives to customers for the widespread installation of demand-response technology for air conditioning, heating, and water heaters above and beyond the measures included in current utility company energy efficiency plans. Alternatively, or in addition, the Task Force recommends that the Energy Office within E&E consider whether it is beneficial to provide rebates for installation of demand-response equipment if state or federal funding becomes available. In addition to considering the potential for providing incentives to invest in demand-response technology, the Task Force recommends that PSC and E&E consider producing and distributing educational materials on the value of demand response for both reliability and cost-savings.

2. The Task Force recommends that PSC, the MISO and SPP RTOs, and E&E's Arkansas Oil and Gas Commission evaluate whether it is reasonable and cost effective to develop

standard criteria for weatherization of natural gas supply infrastructure and electric generation infrastructure in Arkansas. As part of PSC's resource planning process, a continued evaluation of the investments is needed to ensure adequate electric and natural gas supplies are available in Arkansas. The Task force recommends exploring potential opportunities to coordinate with Oklahoma, Texas, and the private sector to identify key components of the electrical, natural gas, and LP-Gas supply system that need protection from extreme cold and to examine whether there are cost effective opportunities to implement weatherization of these components. The Task Force recognizes that it will be beneficial to take advantage of the established procedures of PSC, MISO and SPP RTOs, and other state entities to pursue these evaluations.

3. The Task Force recommends the evaluation of investments in electric generation, including back-up generation, transportation, transmission, distribution, and storage assets that improve the reliability of Arkansas's electric infrastructure. This evaluation can be accomplished through the existing PSC and MISO and SPP RTO processes. The PSC's resource planning proceedings provide an open forum to consider the resource plans of the electric utilities. Further, individual utility proceedings to obtain approval of specific generation investments are also public opportunities to evaluate planned investments.

   Continued participation by PSC and other Arkansas stakeholders in RTO stakeholder processes provides value to Arkansas energy customers at no additional cost. The RTO stakeholder process ensures a rigorous evaluation of how to address reliability needs at the least cost. The RTOs have already begun implementing their lessons learned, including: evaluations of transmission gaps, changing to a seasonal construct for resource adequacy planning and capacity accreditation, and other measures for improving reliability.

4. The Task Force recommends that Arkansas's congressional delegation remain engaged in national policy discussions with respect to future tax credits for energy resources. Currently, there are investment tax credits for solar generation and production tax credits for wind generation. Congress should evaluate whether there are opportunities to provide incentives, such as tax credits, for the development and scaling of novel generation and storage technologies. The Task Force recommends working with Arkansas's Congressional delegation to evaluate whether changes to energy tax credits are appropriate and to encourage development of legislation to implement any changes determined appropriate.

5. The Task Force recommends that PSC, RTOs, E&E's Arkansas Oil and Gas Commission, and the LP-Gas Board consider whether it would be appropriate to implement any incentives for measures that could improve reliability in the form of financial incentives, formal recognition, expedited permitting, new rate structures and service offerings, or waiver of fees. The Task Force recommends evaluating whether it is technically feasible and cost effective to implement incentives for one or more of the following measures that could improve the reliability of Arkansas and regional energy

infrastructure:

- Transmission upgrades and expansion, particularly in load pockets and at RTO seams;
- Increased deployment of energy storage technologies, such as pump storage and battery storage;
- Increased deployment of back-up generation or dual-fuel generation that is capable of using a different fuel, such as diesel, LP-Gas, or liquefied natural gas, instead of the primary fuel used for generation;
- Addition of strategically-placed supply pulling points for LP-Gas, including pipeline terminals, rail terminals, and transloading facilities;
- Addition of natural gas storage facilities; and
- Addition of retail storage for LP-Gas.

The Task Force suggests that evaluating implementation of incentives for the electric energy infrastructure can and should occur as part of the established PSC resource planning process and the established processes of the MISO and SPP RTOs. Meetings of the proposed Energy Resources Council could serve as a forum for sharing ideas with respect to best practices for resource planning among electricity, natural gas, and LP-gas industry representatives and regulators.

6. The Task Force recommends that E&E evaluate whether it is reasonable and cost effective to expand current recognition programs to include reliability similar to the Arkansas Energy and Environment Stewardship Award ("ENVY"), the Arkansas Energy and Environment Technology Award ("TECHe"), the Energy Excellence Award ("E2"), and Quest Science Award that E&E uses to highlight what Arkansas companies are doing in the areas of sustainability, innovative technology, and energy and environmental stewardship.[4]
7. The Task Force recommends that the LP-Gas Board examine whether it is technically feasible and cost effective to expedite inspections of new retail and terminal-level LP-Gas storage and waive fees to promote the addition of LP-Gas storage, pipeline terminals, rail terminals, and transloading facilities.
8. The Task Force recommends that E&E's Arkansas Oil & Gas Commission coordinate with the Arkansas Geological Survey and representatives from the natural gas producers and natural gas utilities to evaluate whether there are any additional geological formations or existing abandoned gas fields in the state capable of storing natural gas or propane. If additional sites suitable for storage are identified, the Task Force recommends that the state work with stakeholders to evaluate the technical and economic feasibility of incorporating the sites into Arkansas's energy infrastructure.

[4] https://www.adeq.state.ar.us/poa/enterprise-services/awards/

9. The Task Force recommends that the appropriate stakeholders evaluate whether there are any additions or revisions to Arkansas statutes to help promote investments and assist in providing reliable energy resources for the state in the future. The stakeholders should evaluate whether any state policy could be enacted through legislation or adopted under state agency rules if authorizing legislation already exists.

10. The Task Force recommends that the Arkansas Department of Transportation coordinate with E&E, PSC, utility companies, and county and local governments to identify priority routes for delivering diesel fuel used for backup generation and propane used for heat. The stakeholders should evaluate whether it would be beneficial to develop a communications protocol to determine whether these routes should be among the first cleared during winter weather events that threaten to disrupt energy supply and delivery. The coordinated effort should include development of a plan for ensuring that the identified routes are kept clear during an energy disruption event.

11. The Task Force recommends that PSC coordinate with the electric and natural gas utility companies to ensure that there are appropriate and adequate communications plans to notify customers of potential coordinated outages or other interruptions of service during weather events. Further, PSC should coordinate with the utility companies to determine whether it is necessary to develop communications advising customers of potential prices increases caused by weather events, including consideration of the costs of developing such communications and notifications.

12. The Task Force also recommends that PSC evaluate its rules and tariffs and consider whether it is reasonable and necessary to require utility companies to notify a customer of an impending curtailment so that the customer may take steps to protect equipment and plan for changes to its operations during the curtailment, including evaluation of the costs and feasibility of such procedures, and if the procedures implemented by the utilities are sufficient.

13. The Task Force recommends that the appropriate stakeholders consider whether Arkansas should implement policies to extend the human needs-based system for prioritization of natural gas and electricity to all energy resources, including LP-Gas. If outages are necessary to ensure the reliability of the electricity grid or curtailment is necessary due to limited fuel supply or other weather-related electric infrastructure outages, the Task Force recommends that the stakeholders consider what steps are necessary to establish procedures for prioritizing energy to occupied dwellings, natural gas-fired electric generation to serve human needs customers, food supply production, and other commercial and industrial facilities whose operations are necessary to preserve human life, health, and safety, including whether any executive, administrative, regulatory, or legislative action may be required. The stakeholders should also consider what steps are necessary to establish the procedures necessary, after ensuring energy resources are adequate to sustain human needs, to ensure that adequate supplies of energy to businesses and industry that would otherwise suffer damage to equipment or severe economic harm are prioritized.

14. The Task Force recognizes that there may be limited opportunities for prioritization of energy resources for human needs under state authority. However, the Task Force recommends that the appropriate stakeholders evaluate whether it would be appropriate to implement legislation in Arkansas similar to the Louisiana statute that establishes an Emergency Gas Allocation Plan (see Louisiana Code Title 43, Part XI, Subpart 1, Section 143). Implementation of a state law of that nature may assist human needs customers during emergency situations like the February 2021 winter storm event. It may be appropriate to consider opportunities to coordinate with the state's federal delegation to identify opportunities for state and federal regulatory authorities coordination to determine whether to implement new rules or revise existing rules to implement prioritization of human needs. Examples of rules for consideration include requiring prioritization of fuels used for energy to meet human needs, such as LP-Gas and natural gas, in pipeline allocations over other pipeline products. The state and federal regulatory authorities might also consider whether it should be permissible for pipelines to limit allocations on the pipeline for fuels used to support human needs based on nominations during the summer, when less fuel is needed.

15. Pursuant to the Arkansas Emergency Petroleum Set-Aside Act, Ark. Code Ann. § 15-72-801 *et seq*., the Arkansas Energy Office has promulgated rules and regulations for the implementation and operation of the Arkansas state set-aside program. However, the implementation of this program is commenced when the Governor, in his discretion, finds that the program is necessary to manage a shortage of specified petroleum products which threatens the continuation of emergency services and essential industrial or agricultural activities. While the Task Force recognizes that this set-aside program was not applicable during the February 2021 winter weather event, this program may be a resource that could help with energy resource shortage events should they occur in the future. The Task Force believes further discussion of the set-aside program may be warranted in development of implementation priorities.

VI. ACKNOWLEDGMENTS

The Task Force would like to acknowledge and extend gratitude to each of the following persons and organizations that provided written and/or oral testimony to the Task Force:

- Arkansas Attorney General's Office;
- Craft Propane, Inc.;
- AECC;
- AMPA;
- EPN;
- Empire;
- OG&E;
- PPGMR Law, PLLC;
- SWEPCO;
- AEF;
- AEEC and AGC;
- AF&PC;
- Quattlebaum;
- Enterprise Product Partners, LP;
- NGL Energy Partners, LP;
- CHS Inc;
- Ozark Mountain Petroleum, Inc.;
- Black Hills;
- CenterPoint;
- Entergy;
- Ted Thomas (Chair of PSC);
- MISO;
- SPP;
- AIPRO;
- APGA
- Enable Midstream Partners, LP
- Summit Utilities, Inc.
- Jackson Walker LLP
- AOGC
- Island Energy, Inc.

- Dover Dixon Horne PLLC
- AGA

The Task Force would also like to acknowledge the assistance of the following E&E staff in coordinating meetings and correspondence and in preparing documents in support of Task Force objectives pursuant to EO 21-05:

Tricia Treece
Daniel Pilkington
Andrea Hopkins
Donnally Davis
Beth Thompson
Troy Deal
Shane Khoury

APPENDIX A. EXECUTIVE ORDER 21-05

STATE OF ARKANSAS
EXECUTIVE DEPARTMENT

PROCLAMATION

EO 21-05

TO ALL TO WHOM THESE PRESENTS COME – GREETINGS:

EXECUTIVE ORDER TO ESTABLISH THE ENERGY RESOURCES PLANNING TASK FORCE

WHEREAS: Recent winter storms revealed vulnerabilities in critical energy resources in Arkansas and the surrounding region; and

WHEREAS: Increased demand and inadequate available supply of critical energy resources such as natural gas, electricity, and liquefied petroleum gas caused Arkansas citizens to suffer service outages and forced Arkansas businesses to close; and

WHEREAS: Preparedness for the provision and allocation of critical energy resources during extreme events is necessary to preserve the health and safety of citizens and protect the critical infrastructure of this state; and

WHEREAS: It is in the best interest of the state and its citizens to evaluate the ability of Arkansas's critical energy resources and infrastructure to withstand extreme events;

NOW, THEREFORE, I, ASA HUTCHINSON, acting under the authority vested in me as Governor of the State of Arkansas, do hereby order the following:

(1) There is hereby created the Energy Resources Planning Task Force, which shall serve as an investigative and advisory body of the Governor.

(2) The Task Force shall be composed of public and private sector leaders with requisite knowledge and expertise to represent the interests of the public, energy sectors, and industry.

(3) The Task Force shall be composed of members appointed by the Governor and shall serve at the pleasure of the Governor. The chair of the committee shall be designated by the Governor. The Commission shall be composed of:

a) The Secretary of the Department of Energy and Environment, or his or her designee;
b) The Director of the Arkansas Oil and Gas Commission, or his or her designee;
c) The Director of the Arkansas Liquefied Petroleum Gas Board, or his or her designee; and
d) The Secretary of the Department of Commerce, or his or her designee.

(4) The members of the Task Force shall have the following duties:

a) Review the lessons learned from the February winter storms, including lessons from surrounding states and information gathered by hearing testimony from the following:
   i. The Chair of the Arkansas Public Service Commission, or his or her designee;
   ii. A representative of the Midcontinent Independent System Operator (MISO);
   iii. A representative of the Southwest Power Pool (SPP);
   iv. A representative of Entergy Arkansas;

v. A representative of the Arkansas Electric Cooperatives Corporation;
vi. A representative of Southwestern Electric Power Company;
vii. A representative of Oklahoma Gas and Electric Company;
viii. A representative of the Empire District Electric Company;

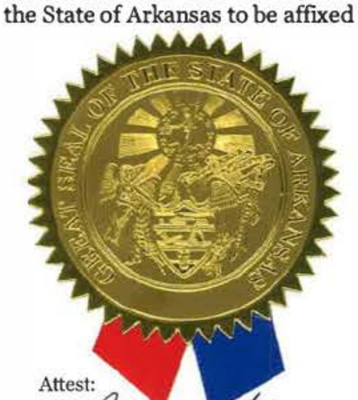
ix. A representative of the Arkansas Municipal Power Association (AMPA);
x. A representative of CenterPoint Energy;
xi. A representative of Arkansas Oklahoma Gas Corporation;
xii. A representative of Black Hills Energy;
xiii. A representative of the Arkansas Electric Energy Consumers (AEEC);
xiv. A representative of the Arkansas State Chamber of Commerce;
xv. The Executive Director of the Arkansas Environmental Federation, or his or her designee;
xvi. The President of the Arkansas Independent Producers and Royalty Owners (AIPRO) association, or his or her designee;
xvii. Additional citizens, as the Task Force deems necessary, with knowledge and expertise in energy and environmental matters; and
xviii. Additional citizens, as the Task Force deems necessary.

b) Make recommendations for actions needed to ensure adequate supply of critical energy sources during extreme events; and
c) Develop priorities for allocation of limited energy resources should supply shortages due to emergency situations necessitate action to preserve life, health, and safety.

(2) The Task Force shall have an initial meeting within seven (7) days of this order and shall meet as necessary to accomplish its objectives. The Task Force shall provide a report of its findings and recommendations to the Governor by September 30, 2021. The Task Force may provide earlier reports and recommendations to the Governor as necessary.

(3) Upon request, the Arkansas Department of Energy and Environment and the Arkansas Public Service Commission may provide staff and other personnel to support the work of the Task Force.

IN TESTIMONY WHEREOF, I have hereunto set my hand and caused the Great Seal of the State of Arkansas to be affixed the 3rd day of March, in the year of our Lord 2021.



Asa Hutchinson, Governor

Attest:

John Thurston, Secretary of State

BHEA Data Infrastructure Improvement Program 16-year Plan

DIIP Project	2021 Actuals	2022 Actuals	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast	2034 Forecast	2035 Forecast	2036 Forecast
BPI and SME Pipeline Attribute Assessment														$65,837		
Distribution Data Attribute Improvement					$157,015	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$215,434	$227,055	
GIS Emergency Response Zones														$79,139		
GIS Pressure Systems														$151,947		
AR Rejectied Distribution As-Built Clean-up																$451,792
Distribution Main & Service Centerline Survey					$628,062	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$1,200,000	$861,737	$908,223	
Document Management Migration														$14,751		
Gathering Centerline Survey																$479,805
GIS CP Zones																$427,986
High Pressure Distribution Centerline Survey Corrections	$122,828															
Transmission/Gathering TVC Records	$565,366	$706,435	$1,500,000	$1,500,000	$714,923											
Grand Total	$688,194	$706,435	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,388,845	$1,135,278	$1,359,583

	2021	2022	20223	2024	2025	2026	2027	2028	2029	2030
BPI and SME Pipeline Attribute Assessment						79,000				
Distribution Data Attribute Improvement					39,000	180,000	428,000	519,000	519,000	519,000
GIS Emergency Response Zones					92,000					
GIS Pressure Systems				171,000						
AR Rejected Distribution As-Built Cleanup						539,000				
Distribution Main & Service Centerline Survey					74,000	340,000	809,000	981,000	981,000	981,000
Document Management Migration		16,000								
Gathering Centerline Survey					454,000	106,000				
GIS CP Zones						256,000	263,000			
High Pressure Distribution Centerline Survey Corrections	159,032									
Transmission/Gathering TVC Records	560,130	384,000	1,500,000	1,329,000	841,000					
Grand Total	719,162	400,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000

CERTIFICATE OF SERVICE

25-BHCG-298-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 9th day of May, 2025, to the following:

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