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August 17, 2015

Sharla Dillon
Tennessee Regulatory Authority
502 Deaderick Street
4th Floor
Nashville, TN 37243

Re: Petition of B&W Pipeline, LLC for an Increase in Rates and Charges
Docket No. 15-00042

Dear Sharla:

Please accept for filing the attached rebuttal testimony of William H. Novak in the above-captioned docket.

Sincerely,

BRADLEY ARANT BOULT CUMMINGS LLP

By: Henry Walker

HW/mkc
Enclosure
cc: Rachel Newton
Klint Alexander

7/3701259.1

BEFORE
THE TENNESSEE REGULATORY AUTHORITY

PETITION OF B&W PIPELINE, LLC FOR AN INCREASE IN ITS RATES AND CHARGES	)	Docket No. 15-00042

REBUTTAL TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
B&W PIPELINE, LLC

August 17, 2015

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Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. ARE YOU THE SAME WILLIAM H. NOVAK THAT PREVIOUSLY PRESENTED PRE-FILED DIRECT TESTIMONY IN THIS SAME DOCKET?

A2. Yes.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of B&W Pipeline, LLC ("B&W Pipeline" or "the Company").

Q4. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A4. The purpose of my rebuttal testimony is to respond to the direct testimony of the CAPD and Navitas witnesses. Specifically, the CAPD and Navitas have proposed adjustments to the Company's filed case that we disagree with. These adjustments by the CAPD and Navitas witnesses include the following categories:

I. Original Cost of the Utility Plant;

[1] State of Tennessee, Registered Accounting Firm ID 3682.

II. Cost of Non-Regulated Plant Transferred to the Company's Unregulated Affiliate;

III. Utility Operator Fee;

IV. Deferred CCN Costs;

V. Attrition Period Throughput and Usage;

VI. Rate of Return; and

VII. Rate Design.

I will be discussing each of these proposed adjustments to the Company's case.

I. ORIGINAL COST OF THE UTILITY PLANT.

Q5. MR. NOVAK, HOW DID THE COMPANY ACQUIRE THE PIPELINE ASSETS FROM THE PREVIOUS OWNER?

A5. In September 2010, the Company purchased the 48 mile gas pipeline along with 96 oil and gas wells in conjunction with the bankruptcy of the previous owner. The total price recorded for the acquisition was $2,633,085.[2] However, because these assets were purchased in conjunction with the bankruptcy of the previous owner, no original cost or continuing property records were provided with the purchase.[3]

[2] Company response to CAPD Data Request 2-1.

[3] Furthermore, because of the state of the previous owner in bankruptcy, it is doubtful that such records could have been faithfully relied upon even if they had been provided.

Q6. HOW DID THE COMPANY SEPARATE THE $2.6 MILLION ACQUISITION COST BETWEEN THE PIPELINE AND THE OIL & GAS WELLS?

A6. At the time of the pipeline and well purchase from the bankruptcy court in September 2010, the pipeline was the only viable asset acquired, since the liability associated with the existing oil and gas wells exceeded their value. Since the seller would not consider a pipeline only purchase, the Company was forced to acquire the wells if it wanted to also acquire the pipeline. As a result, none of the acquisition cost was assigned to the oil and gas wells. Also, the value of the pipeline was far in excess of its $2.6 million cost.

Specifically, the Company acquired a total of 96 wells. Of these 96 wells, only 13 were in production (6 oil wells and 7 gas wells) with the remaining 83 wells inactive. The Company calculated the value of an active producing oil well at $31,900 and the value of an active producing gas well at $29,043. However, the calculated liability associated with capping an inactive well was $5,115, resulting in a total net liability associated with the oil and gas wells of $29,845.[4] Therefore none of the acquisition cost was assigned to the wells since they had no value.

Q7. HOW DID THE COMPANY DETERMINE THAT THE VALUE OF THE PIPELINE WAS IN EXCESS OF ITS $2.6 MILLION COST?

[4] Company response to CAPD Data Request 2-1.

A7. The Company had an independent analysis conducted on the value of the pipeline by Bell Engineering. I have included a copy of the Bell Engineering Report at Attachment WHN Rebuttal-1 to my testimony.[5]

Briefly, the Bell Engineering Report values the 2013 replacement cost of the pipeline to be $12,885,858[6] and the 2013 undepreciated cost of the pipeline to be $6,559,308[7]. Therefore, the undepreciated replacement cost of $6,559,308 exceeds the acquisition cost of $2,633,085 by $3,926,223 or approximately 149%. As a result, the Company recorded its acquisition cost of $2,633,085 as a reasonable estimate for the original cost of the pipeline.

Q8. DOESN'T THE UNDEPRECIATED REPLACEMENT COST OF $6,559,308 ONLY REPRESENT THE UNDEPRECIATED VALUE IF THE PLANT WAS BUILT IN 2013?

A8. Yes. The initial portion of the pipeline was constructed around 1982 with another section constructed around 1988 as shown in the Bell Engineering Report. However, the undepreciated market value exceeds the acquisition cost by such a significant amount that even discounting this undepreciated market value by 3% per year back to its construction date to reflect changes in construction costs as shown on Attachment WHN Rebuttal-2 would still yield an acquisition cost below the market value. As a result, the Company reaffirms that its pipeline

[5] This same report was also provided in response to CAPD Data Request 2-2.
[6] Total replacement cost of $13,299,138 less $413,280 cost associated with Section 3 constructed in 2013.
[7] Total undepreciated cost of $6,972,588 less $413,280 cost associated with Section 3 constructed in 2013.

acquisition cost of $2,633,085 should be reflected as the appropriate value in rate base as an estimate of the original cost of the gas pipeline.

Q9. DOES THE UNIFORM SYSTEM OF ACCOUNTS ALLOW FOR UTILITY PLANT TO BE RECORDED BASED ON AN ESTIMATE OF ORIGINAL COST?

A9. Yes. Small utilities are often purchased with incomplete records either through bankruptcy proceedings or forced divestitures. The FERC Uniform System of Accounts recognizes this condition in its instructions for recording utility plant which reads as follows:

> C. The detailed gas plant accounts (301 to 399, inclusive) shall be stated on the basis of cost to the utility of plant constructed by it and the original cost, **estimated if not known**, of plant acquired as an operating unit or system.[8] (Emphasis added.)

As can be plainly seen, the FERC Uniform System of Accounts allows the original cost to be estimated if not known. Therefore, it is B&W Pipeline's best estimate that its acquisition cost of $2,633,085 should be properly recorded as utility plant in service on its books and reflected in the cost of service in this proceeding.

Q10. WHAT AMOUNT DID THE CAPD INCLUDE IN THEIR CASE AS THE PIPELINE ACQUISITION COST?

[8] Federal Energy Regulatory Commission, Uniform System of Accounts for Natural Gas Utilities, Gas Plant Instructions, Item 1C.

A10. The CAPD has excluded the entire pipeline acquisition cost from its calculation of rate base and instead only included additions to plant in service since the time of the acquisition. According to CAPD witness Ralph Smith,

> "As shown on Exhibit RCS-1, Schedule 2, I have excluded from Plant in Service and have treated as an Acquisition Adjustment the amount that B&W paid for the pipeline because B&W has failed to provide reliable information on the original cost of the pipeline to the previous owner, Gasco, and has failed to provide the depreciated original cost under the previous owner, Gasco, at the time of the acquisition. This adjustment also reflects that the depreciated original cost under the previous owner, Gasco, at the time of the acquisition was not able to be ascertained with reliability from any other public information that has come to my attention, including Gasco annual reports to the TRA and property tax records that were available from the State of Tennessee. The exclusion of the $2,597,285 acquisition amount leaves a cost of $437,715 for the pipeline, which relates to the pipeline safety improvement amounts that B&W invested in the pipeline after acquiring it."[9]

Q11. DO YOU AGREE WITH MR. SMITH'S ANALYSIS?

A11. Certainly not. Mr. Smith has obviously not analyzed any of the data provided to him by the Company on this issue through data requests and instead relied solely on his interpretation of the Company's "burden of proof" to justify eliminating the Company's acquisition investment. Under Mr. Smith's interpretation for "burden of proof", no entity would have ever purchased the pipeline assets in conjunction with the bankruptcy of the previous owners since there were no original cost records available. By necessity, this would have resulted in a discontinuation of service.

Further, Mr. Smith's analysis is inconsistent with the State of Tennessee's own assessment of the pipeline for taxing purposes. As shown on Attachment WHN

[9] Direct testimony of CAPD Witness Ralph C. Smith, Page 19, A 47.

Rebuttal-3, the state has appraised the utility plant of B&W Pipeline at $3,154,842 for property tax purposes. Therefore, we request and recommend that the TRA reject Mr. Smith's incomplete analysis of the utility plant acquisition cost and instead accept the Company's actual acquisition cost of $2,633,085 as the appropriate amount to include in rate base.

II. COST OF NON-REGULATED PLANT TRANSFERRED TO THE COMPANY'S UNREGULATED AFFILIATE.

Q12. MR. NOVAK, YOU STATED EARLIER THAT THE LIABILITIES OF THE OIL AND GAS WELLS EXCEEDED THEIR ASSETS VALUE. HOW WERE THESE NON-REGULATED ASSETS ACCOUNTED FOR?

A12. After the acquisition in 2010, all of the assets (both the wells and the pipeline) were recorded on the books of B&W Pipeline, LLC. During the CCN process, the Company discovered that it would be best to separate the regulated assets from the non-regulated assets. As a result, in November 2013, the Company transferred the gas and oil wells to Rugby Energy, LLC, an unregulated affiliate. Since no value was assigned to the acquisition of the wells, the only value transferred represented the system improvements of $486,216 to the wells since their acquisition.[10]

Q13. DOES THE CAPD AGREE WITH THIS TRANSFER?

[10] Company response to CAPD Data Request 2-1.

A13. No. Apparently CAPD witness Ralph Smith feels that the utility was not properly credited with the true asset value for the wells. Specifically, Mr. Smith's testimony on this point reads as follows:

> "Th[e] transfer was not made at arms' length. It was a transfer between two wholly controlled affiliates both of which have the same ownership. There are **concerns** that B&W did not receive adequate compensation for the wells that it acquired and transferred to the affiliate, Rugby Energy, LLC. There are **concerns** that B&W was not compensated by the affiliate for the market value of the oil and gas wells that were transferred to the affiliate."[11] (Emphasis added.)

Q14. DO YOU AGREE WITH MR. SMITH'S ASSESSMENT REGARDING THE TRANSFER OF UNREGULATED ASSETS TO RUGBY ENERGY, LLC.?

A14. No. First, as mentioned previously, the unregulated assets had a negative value on the date of the acquisition. Therefore, there simply was no value to record on the acquisition date. All of the information along with the supporting data related to the Company's valuation of the wells was provided to Mr. Smith through discovery.[12] However, rather than respond to the Company's analysis for any of the specific components of the valuation for the unregulated assets, Mr. Smith chose to only state that there are "concerns" about the valuations without providing any analysis to that effect.

Secondly, while in hindsight it probably would have been best to initially record the unregulated assets in a separate entity at the time of the acquisition in 2010, there would have been no resulting change to the value of the assets on the actual

[11] Direct testimony of CAPD Witness Ralph C. Smith, Page 18, A 43.
[12] Company response to CAPD Data Request 2-1.

transfer date. Therefore the assets transferred to Rugby Energy, LLC represented their total cost which was properly credited to B&W Pipeline, LLC.

Finally, while the transfer of the unregulated assets was in fact made between two wholly owned entities with common ownership, there was no preference given to the value of the assets as Mr. Smith seems to indicate. Instead, the assets were transferred at their historical cost that was properly recorded on the utility's books.

III. UTILITY OPERATOR FEE.

Q15. MR. NOVAK, WHY DOES B&W PIPELINE'S AFFILIATE CHARGE A MONTHLY OPERATOR FEE TO THE UTILITY?

A15. B&W Pipeline has no employees of its own since it would be uneconomical to have a completely dedicated staff for such a relatively small operation. Instead, the needs of the pipeline are provided by an affiliate service company (Enrema, LLC) that also provides services to other entities. In addition to labor, the service company also allocates vehicle and insurance cost to B&W Pipeline.

Q16. WHAT IS THE MONTHLY COST ALLOCATED TO B&W PIPELINE BY THE SERVICE COMPANY?

A16. As shown in the response to CAPD Data Request 1, Item 8 the service company allocates $11,375 per month to B&W Pipeline. This allocation is summarized in Table 1 below.

TABLE 1 – MONTHLY OPERATOR FEE SUMMARY			
Item	**Total Amount**	**Allocation Factor**	**Allocated Monthly**
Labor & Benefits-F. Cash, Operator	$9,198	50.00%	$4,600
Labor & Benefits-R. Ramon, Controller	9,113	10.00%	911
Labor & Benefits-M. Recchia, Manager	22,164	5.00%	1,108
Vehicle Cost (2012 Ford F150 Truck)	972	50.00%	486
Pipeline Liability & Umbrella Insurance	7,762	55.00%	4,270
Total Allocated Operator Fee			**$11,375**

The labor and benefit costs shown above are allocated to the utility based on the estimates of each individual allocating cost to the utility. Mr. Frank Cash, the local pipeline operator, splits his duties between maintaining the pipeline and supervising the oil and gas wells. Therefore only 50% of his time has been allocated to the utility operations. Mr. Ramon and Mr. Recchia, the Company's controller and general manager, split their duties between several affiliates and therefore allocate only 10% and 5% of their time respectively to the utility operations. The vehicle cost includes depreciation, maintenance and fuel for the truck to service the pipeline that is operated by Mr. Cash and therefore follows his labor and benefit allocation. The final service company cost includes the general liability and umbrella insurance policies pertaining to the pipelines and are allocated at 55% to the utility regulated operations.

Q17. DOES THE CAPD AGREE WITH THE MONTHLY OPERATOR FEE OF $11,375 ALLOCATED TO B&W PIPELINE?

A17. No. Again, CAPD witness Ralph Smith feels that B&W Pipeline has somehow not carried its "burden of proof" on the operator fee, even though he offers no analysis to prove this point. Specifically, Mr. Smith's testimony on this issue reads as follows:

> "This is an affiliated transaction and thus bears heightened regulatory scrutiny. The burden of proving the reasonableness of these affiliated fees should be on B&W. The Company has not justified the total affiliated Operator Fee cost or its proposed allocation of half the $273,000 total cost to pipeline operations."[13]

Q18. DOES MR. SMITH PROPOSE AN ALTERNATIVE TO THE COMPANY'S OPERATOR FEE?

A18. Yes. He proposes to take the combined total Operator Fee of $273,000 that is allocated to B&W Pipeline and Rugby Energy and then apply a 20% allocation factor to this amount.[14]

Q19. HOW DOES MR. SMITH CALCULATE A 20% ALLOCATION FACTOR?

A19. He provides absolutely no support for this calculation within his testimony or exhibits. He proposes to take the total Operator Fee of $273,000 that is allocated to both B&W Pipeline and Rugby Energy and then apply a 20% allocation factor to this amount.[15] That is apparently an arbitrary allocation.

[13] Direct testimony of CAPD Witness Ralph C. Smith, Page 20, A 53.
[14] Direct testimony of CAPD Witness Ralph C. Smith, Page 22, A 55.
[15] Direct testimony of CAPD Witness Ralph C. Smith, Page 22, A 55.

Again, Mr. Smith is making a recommendation without any analysis or consideration for any of the data that was provided to the CAPD through the discovery process. Therefore, we request and recommend that the TRA reject Mr. Smith's incomplete analysis of the Operator Fee and instead accept the Company's actual cost and proposed allocation methodology that produces an annual expense to B&W Pipeline of $136,500.[16]

IV. DEFERRED CCN COSTS.

Q20. MR. NOVAK, WHAT WERE THE LEGAL AND REGULATORY COSTS OF B&W PIPELINE ASSOCIATED WITH OBTAINING ITS CCN CERTIFICATE FROM THE TRA IN DOCKET 13-00151?

A20. According to the Company's 2014 financial statements, the legal and regulatory fees associated with obtaining the CCN were approximately $74,383.[17]

Q21. HOW WAS THIS COST ACCOUNTED FOR ON THE COMPANY'S BOOKS?

A21. The Company recognized the entire balance as an operating expense during the test period. This was done because deferring these expenses first requires approval from the TRA. Since no approval to defer the CCN costs was received, the Company included the entire balance in its test period expenses.

[16] Total allocated monthly cost of $11,375 from Table 1 * 12 months.
[17] Attachment 10-2 to TRA Minimum Filing Requirement #10.

Q22. DOES THE CAPD AGREE WITH INCLUDING THE CCN COSTS AS A TEST PERIOD EXPENSE?

A22. No. CAPD witness Ralph Smith proposes that the CCN costs should be capitalized and deferred with an amortization period of 20 years.[18]

Q23. WHAT IS THE BASIS OF MR. SMITH'S PROPOSED AMORTIZATION PERIOD OF 20 YEARS?

A23. Again, Mr. Smith provides no analysis or basis for his proposal to amortize these costs over 20 years.

Q24. DOES THE COMPANY AGREE WITH MR. SMITH'S PROPOSAL TO DEFER AND AMORTIZE THE TEST PERIOD CCN COSTS?

A24. The Company does not object to capitalizing and deferring the test period CCN costs if the TRA approves this. However, the Company does object to the 20 year recovery period proposed by Mr. Smith. The legal and regulatory costs included in the CCN filing are the same type of costs incurred in the preparation of this rate case and should not be amortized over a period longer than 60 months.

V. ATTRITION PERIOD THROUGHPUT & USAGE.

[18] Direct testimony of CAPD Witness Ralph C. Smith, Page 22, A 56.

Q25. MR. NOVAK, WHAT IS THE THROUGHPUT FORECAST THAT B&W PIPELINE USED IN THEIR RATE CASE FOR THE ATTRITION PERIOD?

A25. As shown on Company Exhibit, Schedule 4 that was included with our filing, B&W Pipeline forecasted the attrition period transportation throughput to be 169,861 Mcf. This attrition period throughput included the addition of two new Navitas industrial customers as well as expected transportation to one of B&W Pipeline's affiliates.

Q26. DOES THE CAPD AGREE WITH THE COMPANY'S ATTRITION PERIOD THROUGHPUT FORECAST?

A26. Only in part. The CAPD states that they agree with the Company's usage forecast to its intercompany affiliate. However, CAPD witness Ralph Smith states that he has used the forecast provided by Navitas for the existing and new customers that was provided in response to the TRA Staff's data request. [19] This produces a total CAPD throughput forecast of 212,628 Mcf. A comparison of the Company's and the CAPD's total throughput forecast, along with B&W Pipeline's updated forecast[20] is presented below in Table 2.

TABLE 2 – ATTRITION PERIOD MCF THROUGHPUT FORECAST

Item	B&W Pipeline	CAPD	B&W Update
Navitas – Existing Customers	60,411	45,178	60,411
Navitas – New Industrial Customer #1	36,000	108,000	108,000
Navitas – New Industrial Customer #2	26,000	12,000	12,000

[19] Direct testimony of CAPD Witness Ralph C. Smith, Page 7, A 17.

[20] The updated forecast retains B&W Pipeline original forecast for existing customers which was actually 32,883 Mcf in 2012, 46,187 Mcf in 2013 and 60,411 Mcf in 2014. In addition, it adjusts the intercompany transportation downward to an annualized amount based on 14,912 Mcf for the first six months of 2015.

B&W Pipeline Intercompany Transport	47,450	47,450	29,824
Total Throughput Forecast	**169,861**	**212,628**	**210,235**

Q27. WHAT IS THE BASIS OF THE THROUGHPUT FORECAST PROVIDED BY NAVITAS?

A27. We do not know. Navitas only provided total numbers in their response to the TRA's data request. No explanation or analysis was provided as to how these numbers were derived.

Q28. WHAT IS THE BASIS OF MR. SMITH'S ACCEPTANCE OF THE THROUGHPUT FORECAST PROVIDED BY NAVITAS?

A28. Once again, Mr. Smith provides no analysis or discussion as to his rationale or basis. Specifically, no reason is given in his testimony or exhibits for Mr. Smith's acceptance of the Navitas data request response as the basis for his forecast for attrition period throughput. Likewise, no reason or rationale is provided by Mr. Smith for his rejection of the Company's throughput forecast.

Q29. WHY IS THE THROUGHPUT FORECAST IMPORTANT?

A29. The acceptance by the TRA of the attrition period throughput is of critical importance to B&W Pipeline. Although the eventual throughput volumes from these new industrial customers will have no detrimental impact to Navitas since they are not included in their base rates, using these same speculative volumes for B&W Pipeline could have a damaging impact on the Company's ability to earn a fair rate of return and provide continuing service. Further, it appears that B&W

Pipeline's original forecast for its affiliate was significantly overstated. All of this points out that there is a great deal of volatility and speculation as to the projected throughput volumes forecasted on the pipeline for the attrition period. Therefore, it may be necessary for the TRA to consider other mechanisms for estimating throughput as I describe later in the Rate Design section of my rebuttal testimony.

VI. RATE OF RETURN.

Q30. MR. NOVAK, WHAT RATE OF RETURN DID YOU RECOMMEND FOR B&W PIPELINE?

A30. As shown on Company Exhibit, Schedule 6 that was included with our filing, I took the average of the approved returns on equity for the last three large gas distribution rate cases of 10.12% as a proxy for B&W Pipeline's equity return. Since B&W Pipeline is financed with 100% equity, this 10.12% return also represented the utility's overall rate of return.

Q31. DID YOUR PROXY RETURN OF 10.12% INCLUDE THE TRA'S MOST RECENT EQUITY RETURN TO ATMOS ENERGY OF 9.8% IN DOCKET 14-00146?

A31. No. The return for that particular case was adopted after B&W Pipeline filed their petition in this docket. However, that particular docket also included an alternative regulatory mechanism that allows Atmos to true-up its achieved return on an annual basis. The approval of that mechanism likely had an impact on the

rate of return that was agreed to by the parties in settlement negotiations and later adopted by the TRA. No such alternative regulatory mechanism has been requested by B&W Pipeline in this docket. Therefore, the Atmos return on equity should properly be considered an outlier for comparisons with this docket.

Q32. DID THE CAPD AGREE WITH YOUR REQUESTED PROXY RETURN OF 10.12%?

A32. No. CAPD witness Dr. Chris Klein did accept the Company's position that it was funded entirely by private equity. However, he recommends an all-equity financed return for B&W Pipeline of 8% to 9% with a midpoint of 8.5%.[21]

Q33. HOW DID DR. KLEIN DEVELOP HIS RECOMMENDED EQUITY FINANCED RETURN FOR B&W PIPELINE?

A33. Dr. Klein begins by assuming an optimal hypothetical capital structure of 50% debt and 50% equity. He then sets a benchmark equity return of 10% and debt returns of 6%, 7% and 8% to produce an overall return of 8% to 9%.

Q34. WHAT IS THE BASIS FOR DR. KLEIN'S BENCHMARK EQUITY RETURN OF 10%?

A34. We do not know. Dr. Klein provides no analysis or discussion specifically as to how the benchmark equity return of 10% was developed. However, he does note

[21] Direct testimony of CAPD Witness Christopher C. Klein, Page 10, Lines 1 – 6.

that the overall return granted to Navitas falls within the same range (8% to 9%) as his recommendation for B&W Pipeline.[22]

Q35. DO YOU AGREE WITH DR. KLEIN'S RECOMMENDED RETURN OF 8.5% FOR B&W PIPELINE?

A35. No. Dr. Klein bases his rate of return recommendation for B&W Pipeline on the assumption that it has the same risk profile as Navitas. However, this is simply not the case. B&W Pipeline has only a single unrelated customer (Navitas) for gas transportation service while Navitas has several residential, commercial and industrial customers. All other things being equal, this structure makes B&W Pipeline riskier than a typical distribution company such as Navitas.

Q36. WHAT RETURN DO YOU RECOMMEND FOR B&W PIPELINE?

A36. Admittedly, I am not an expert on recommending rates of return to utility commissions. Because of this, I used the most recent equity returns for the three large gas utilities in Tennessee which averaged 10.12% as a proxy for B&W Pipeline in order to avoid a lengthy debate on rate of return theory and methodology.[23] I believe that my recommendation of 10.12% adequately addresses the risk profile for B&W Pipeline. I therefore request and recommend that the TRA approve 10.12% as the cost of capital for B&W Pipeline.

[22] Direct testimony of CAPD Witness Christopher C. Klein, Page 11, Lines 1 – 5.
[23] By way of comparison, the TRA awarded a return on equity of 15.40% to Navitas in Docket 12-00068.

VII. RATE DESIGN.

Q37. MR. NOVAK, AFTER CONSIDERING EACH OF THE ISSUES PRESENTED ABOVE, WHAT IS THE REVENUE REQUIREMENT FOR B&W PIPELINE?

A37. The Company opposes the adjustments proposed by the CAPD and restates its request to increase revenues by $525,648, resulting in a total revenue requirement of $627,565 as shown on the Company Exhibit included with our Petition.[24]

Q38. HOW DOES THE COMPANY PROPOSE TO DESIGN RATES TO RECOVER THIS REVENUE DEFICIENCY?

A38. As mentioned in Section V of my rebuttal testimony, there is a great deal of dispute regarding the attrition period throughput and usage that is needed in order to properly design rates. Since there is no consensus on throughput and usage, and because an incorrect assumption on throughput and usage could have a material impact on the Company's earnings, I am recommending that the TRA adopt a Sales Adjustment Mechanism ("SAM") for B&W Pipeline.

A SAM is a true-up process previously used by the TRA for gas utilities when attrition period sales volumes are certain. Under a SAM, the actual sales volumes are annually trued-up to the sales volumes adopted by the TRA. The impact of

[24] Revenue Deficiency of $525,648 on Schedule 1 + Current Revenues of $101,917 on Schedule 3.

any surplus or deficiency in sales volumes is then either refunded or surcharged to the customers over the next 12 months.

For example, if the TRA were to adopt and set rates on the Company's updated sales forecast of 210,235 Mcf and the actual sales volumes turned out to be greater than this amount, then the SAM would calculate the difference, which would be refunded to the customers over the next year. Likewise if the actual sales volumes fell below the level adopted by the TRA, then the SAM would surcharge the customers over the next year. Therefore, the SAM ensures that the actual sales volumes reflect the level adopted by the TRA.

Q39. BASED ON B&W PIPELINE'S REVISED REVENUE REQUIREMENTS OF $627,565 AND THE FORECASTED THROUGHPUT AND USAGE OF 210,235 MCF WITH A SAM, WHAT RATE DESIGN DO YOU PROPOSE?

A39. I would recommend that the TRA adopt a daily demand rate structure for B&W Pipeline. A demand rate structure is how gas transmission pipeline rates are typically set since they do not have any residential, commercial or industrial customers.

Under a daily demand rate structure, the total revenue requirement of $627,565 is divided by 365 days to produce a total daily billing rate. This daily billing rate is then allocated between B&W Pipeline's two customers on the basis of their usage to the pipelines total throughput for the past year. The customer usage percentage

is then recalculated each year on the basis of each customer's total throughput to the total throughput on the pipeline.

For example, dividing the revenue requirement of $627,565 by 365 days produces a total daily demand billing rate of $1,719. Based upon the B&W Pipeline updated Throughput and Usage forecast of 210,235 Mcf from Table 2, Navitas customers will transport 180,411 Mcf (86%) of this total and B&W Pipeline's affiliates will transport the remaining 29,824 Mcf (14%). Applying these percentages to the total daily demand billing rate of $1,571 produces a daily demand charge of $1,479 (86%) to Navitas and $240 (14%) to B&W Pipeline's affiliates. The total daily demand billing rate of $1,571 will remain fixed until the Company's next rate case. However, the transportation throughput percentages will be updated on an annual basis.

This daily demand rate structure allows B&W to recover its cost of service. The daily demand rate structure also allows Navitas the opportunity to "sculpt" how it allocates this demand cost to its different customer classes through its purchased gas adjustment. I therefore request and recommend that the TRA approve a revenue requirement of $627,565 for B&W Pipeline along with a daily demand rate of $1,719 with a SAM to recover this revenue requirement.

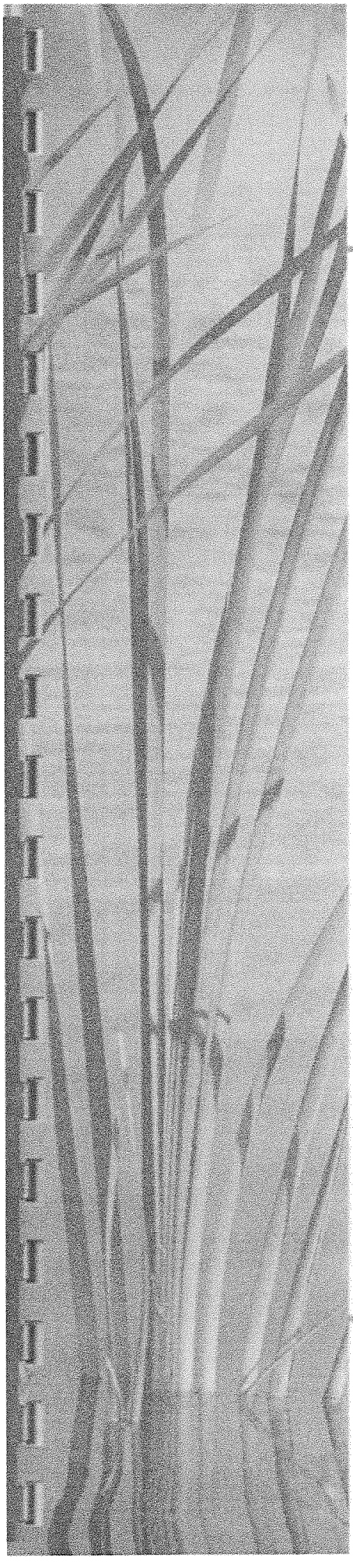
Q40. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A40. Yes it does. However I reserve the right to incorporate any new information that may subsequently become available.

ATTACHMENT

WHN REBUTTAL-1

Gas Pipeline Replacement Cost Evaluation



Gas Pipeline Replacement Cost Evaluation

B & W Pipeline, LLC

Cookeville, Tennessee

November 2013

bell engineering

bell
engineering

December 12, 2013

Mr. Rafael E. Ramon de los Rios,
Controller
ENREMA
728 South Jefferson Avenue, Unit #4
Cookeville, Tennessee 38501

Re: Gas Pipeline Replacement Cost Evaluation
B & W Pipeline, LLC
Cookeville, Tennessee

Gentlemen:

Find attached two (2) completed reports of the replacement cost analysis for the B & W Pipeline. Your comments concerning the methodology for the use of the percentage of construction cost for "Miscellaneous Construction Items" and for "Project Costs" have been incorporated into the body of the report.

It has been our pleasure to assist you in this endeavor and trust that the completed report is that which will fulfill your expectations. Should you need additional copies of the report or have other questions concerning the report, please do not hesitate to call.

Also, should you have need for engineering services for other projects, please call. We will be happy to assist.

Sincerely,
BELL ENGINEERING

Kelly G. Gillespie, President, Project Manager

Carroll R. Ramey, Associate

2480 fortune drive, suite 350, lexington, kentucky 40509
859/278-5412 phone 859/278-2911 fax www.hkbell.com

GAS PIPELINE REPLACEMENT COST EVALUATION
B & W Pipeline, LLC
728 South Jefferson Avenue, Unit #4
Cookeville, Tennessee 38501

On October 30, 2013, Bell Engineering was authorized by B & W Pipeline, LLC, to conduct a study to determine the replacement cost of their gas pipeline known as the B & W Gas Pipeline. The cost evaluation will estimate the cost to replace the entire length of pipeline from the B & W connection to the Spectra Energy transmission main, near Deer Lodge, Tennessee, to the Navitas master meter approximately one mile south of the Kentucky/Tennessee state line. The total length of this pipeline is approximately 48 miles.

It was also requested, as a part of this report, to estimate the "actual cash value" of the pipeline as it currently exists.

The methodology used for the accomplishment of these tasks is as follows:

1. Adjusting the cost of individual units of gas pipe from past projects to present day costs using the factors presented in the Engineering News Record (ENR) Index. The ENR Index is a publication of the construction industry which considers such factors as inflation, salary changes and material costs. ENR began publishing the data in this index in 1960.
2. The "Actual Cash Value" will be calculated using the present day replacement costs depreciated by the "age of the main".
3. As sections of the main were constructed in different time frames and of different materials, each section must be evaluated separately.
4. As the pipeline components are made up of both steel pipe and polyethylene pipe, and as the construction materials are different, the pipeline age used to estimate the "Actual Cash Value" will be different. For this study it was assumed the useful life of the pipe to be 50 years for steel pipe and 75 years for polyethylene pipe.
5. The study will consider the cost to replace the existing main in place. As such, the methodology used will be similar to completion of a preliminary study. In a preliminary study, the approximate length of a pipeline is known, but "miscellaneous construction items" are not known until completion of the final design. In the B & W case, the lengths of the pipeline are known, but the miscellaneous items of construction which would be necessary to replace the main are not known. These items include, but are not limited to, valves, cathodic protection, line markers, pavement replacement and similar items necessary for construction. It has been found historically, that such items can be estimated as a percentage of the main line construction cost. As the B & W pipeline crosses primarily rural areas, this percentage is estimated at 20%. Should the main be located in urban areas, for example, the percentage would be 30% to 35%.

6. Likewise, the percentage used for this report for "Project Development Costs", also 20%, covers such items as engineering fees, legal costs, company costs to administer the construction contracts, state natural gas rate regulatory soft costs, and administration costs associated with the requirements of other regulatory agencies. As the nature of the pipeline is primarily rural in nature, the percentage used would seem appropriate as compared to a location in an urban atmosphere of which the percentage would be approximately 30%.

The following table presents a list of the pipeline materials, their length and the approximate date of their installation:

PIPE	LENGTH	YEAR INSTALLED
6 Inch Medium Density Polyethylene	21,120 Ft.	1982
6 Inch Steel	79,200 Ft.	1981-1982
6 Inch High Density Polyethylene	10,250 Ft.	2013
6 Inch High Density Polyethylene	72,336 Ft.	1988-1989
6 Inch Steel	40,128 Ft.	1988
8 Inch Steel	11,088 Ft.	1986-1987
8 Inch High Density Polyethylene	20,064 Ft.	1986-1987

The individual pipe values, as adjusted to the Engineering News Record Index are as follows:

6 Inch Medium Density Polyethylene	$26.00 /L.F.
6 Inch High Density Polyethylene	$28.00 /L.F.
8 Inch High Density Polyethylene	$32.00 /L.F.
6 Inch Steel	$42.50/ L.F.
8 Inch Steel	$54.00 /L.F.

Opinion of probable replacement costs for this system, by section, is shown as follows:

Section 1 – 6 Inch Medium Density Poly.	21, 120 Ft.	@ $26.00/L.F.	$549,120.00
Pressure Regulating Station @ Spectra Connection			$ 50,000.00

Metering Station @ Spectra Connection		$ 20,000.00
Subtotal		$619,120.00
Miscellaneous Construction Items @ 20% of Subtotal		$123,824.00
Total Opinion of Construction Cost		$742,944.00
Miscellaneous Project Development Costs @ 20%		$148,589.00
Total Opinion of Probable Replacement Costs (Section 1)		$891,533.00

Section 2 – 6 Inch Steel	79,200 Ft.	@ $42.50/L.F.	$3,366,000.00
In-Line Metering Station			$ 18,000.00
Subtotal			$3,384,000.00
Miscellaneous Construction Items @ 20% of Subtotal			$ 676,800.00
Total Opinion of Probable Construction Cost			$4,060,800.00
Miscellaneous Project Development Costs @ 20%			$ 812,160.00
Total Opinion of Probable Replacement Costs (Section 2)			$4,872,960.00

Section 3 – 6 Inch High Density Poly.	10,250 Ft.	@ $28.00/L.F.	$287,000.00
Miscellaneous Construction Items @ 20%			$ 57,400.00
Total Opinion of Probable Construction Cost			$344,400.00
Miscellaneous Project Development Costs @ 20%			$ 68,880.00
Total Opinion of Probable Replacement Costs (Section 3)			$ 413,280.00

Section 4 – 6 Inch High Density Poly.	72,336 Ft.	@$28.00/L.F.	$2,025,408.00
In-Line Metering Station			$ 18,000.00
Subtotal			$2,043,408.00
Miscellaneous Construction Items @ 20% of Subtotal			$ 408,682.00
Total Opinion of Probable Construction Cost			$2,452,090.00
Miscellaneous Project Development Costs @ 20%			$ 490,418.00
Total Opinion of Probable Replacement Costs (Section 4)			$2,943,508.00

Section 5 – 6 Inch Steel	40,128 Ft.	@ $42.50/L.F.	$1,625,184.00
Miscellaneous Construction Items @ 20%			$ 325,037.00
Total Opinion of Probable Construction Cost			$1,950,221.00
Miscellaneous Project Development Costs @ 20%			$ 390,044.00
Total Opinion of Probable Replacement Costs (Section 5)			$2,340,265.00

Section 6 – 8 Inch Steel	11,088 Ft. @ $54.00/L.F.	$598,752.00
Miscellaneous Construction Items @ 20%		$119,750.00
Total Opinion of Probable Construction Cost		$718,502.00
Miscellaneous Project Development Costs @ 20%		$143,700.00
Total Opinion of Probable Replacement Costs (Section 6)		$862,202.00

Section 7 – 8 Inch High Density Poly.	20,064 Ft. @ $32.00/L.F.	$642,048.00
Byrdstown Master Meter		$ 18,000.00
Albany Master Meter		$ 18,000.00
Subtotal		$ 678,048.00
Miscellaneous Construction Cost @ 20%		$ 135,610.00
Total Opinion of Probable Construction Cost		$813,658.00
Miscellaneous Project Development Cost @ 20%		$162,732.00
Total Opinion of Probable Replacement Costs (Section 7)		$ 976,390.00

SUMMARY

TOTAL OPINION OF PROBABLE REPLACEMENT COSTS

Section 1	$ 891,533.00
Section 2	$4,872,960.00
Section 3	$413,280.00
Section 4	$2,942,508.00
Section 5	$2,340,265.00
Section 6	$862,202.00
Section 7	$976,390.00

TOTAL OPINION OF PROBABLE REPLACEMENT COST	$13,299,138.00

DEPRECIATED VALUES

The primary difference between replacement cost and actual cash value is the deduction for depreciation. There are likely several methods for calculating the depreciated value of the B & W pipeline. For the purpose of this report, the depreciation will be calculated on the basis of comparing the expected life of the pipeline materials against the amount of time since they were constructed. For this report, the expected life of steel pipe will be 50 years; the expected life of the polyethylene pipe will be 75 years. This comparison is depicted in the following table:

SECTION	PIPE	YEAR INSTALLED	AGE	DEPRECIATION AMOUNT	REPLACEMENT COST	CASH VALUE
1	Poly	1982	31 yrs.	31/75 – 41.3%	$891,533.00	$523,033.00
2	Steel	1982	31 yrs.	31/50 – 62.0%	$4,872,960.00	$1,851,725.00
3	Poly	2013	0 yrs	0%	$413,280.00	$413,280.00
4	Poly	1988	25 yrs	25/75 – 33.3%	$2,942,508.00	$1,962,653.00
5	Steel	1988	25 yrs	25/50 – 50.0%	$2,340,265.00	$1,170,132.00
6	Steel	1987	26 yrs	26/50 – 52.0%	$862,202.00	$413,857.00
7	Poly	1987	26 yrs	26/75 – 34.7%	$976,390.00	$637,908.00
TOTAL OPINION OF PROBABLE CASH VALUE						$6,972,588.00

ATTACHMENT

WHN REBUTTAL-2

Discounted Pipeline Replacement Cost Analysis

B&W Pipeline
Discounted Pipeline Replacement Cost Analysis

						Discount Rate:	3.00%
Year	Section 1 1982 Installation	Section 2 1982 Installation	Section 4 1988 Installation	Section 5 1988 Installation	Section 6 1987 Installation	Section 7 1987 Installation	Total Value
2013	$523,033	$1,851,725	$1,962,653	$1,170,132	$413,857	$637,908	$6,559,308
2012	507,342	1,796,173	1,903,773	1,135,028	401,441	618,771	6,362,529
2011	492,122	1,742,288	1,846,660	1,100,977	389,398	600,208	6,171,653
2010	477,358	1,690,019	1,791,260	1,067,948	377,716	582,201	5,986,503
2009	463,037	1,639,319	1,737,523	1,035,909	366,385	564,735	5,806,908
2008	449,146	1,590,139	1,685,397	1,004,832	355,393	547,793	5,632,701
2007	435,672	1,542,435	1,634,835	974,687	344,731	531,360	5,463,720
2006	422,602	1,496,162	1,585,790	945,447	334,389	515,419	5,299,808
2005	409,924	1,451,277	1,538,216	917,083	324,358	499,956	5,140,814
2004	397,626	1,407,739	1,492,070	889,571	314,627	484,957	4,986,590
2003	385,697	1,365,507	1,447,308	862,884	305,188	470,409	4,836,992
2002	374,126	1,324,541	1,403,888	836,997	296,032	456,296	4,691,882
2001	362,902	1,284,805	1,361,772	811,887	287,152	442,608	4,551,126
2000	352,015	1,246,261	1,320,919	787,531	278,537	429,329	4,414,592
1999	341,455	1,208,873	1,281,291	763,905	270,181	416,449	4,282,154
1998	331,211	1,172,607	1,242,852	740,987	262,075	403,956	4,153,690
1997	321,275	1,137,429	1,205,567	718,758	254,213	391,837	4,029,079
1996	311,637	1,103,306	1,169,400	697,195	246,587	380,082	3,908,207
1995	302,288	1,070,207	1,134,318	676,279	239,189	368,680	3,790,960
1994	293,219	1,038,101	1,100,288	655,991	232,014	357,619	3,677,232
1993	284,422	1,006,958	1,067,280	636,311	225,053	346,891	3,566,915
1992	275,890	976,749	1,035,261	617,222	218,302	336,484	3,459,907
1991	267,613	947,446	1,004,203	598,705	211,752	326,390	3,356,110
1990	259,585	919,023	974,077	580,744	205,400	316,598	3,255,427
1989	251,797	891,452	944,855	563,322	199,238	307,100	3,157,764
1988	244,243	864,709	**916,509**	**546,422**	193,261	297,887	3,063,031
1987	236,916	838,767	**916,509**	**546,422**	**187,463**	**288,950**	3,015,028
1986	229,808	813,604	**916,509**	**546,422**	**187,463**	**288,950**	2,982,757
1985	222,914	789,196	**916,509**	**546,422**	**187,463**	**288,950**	2,951,455
1984	216,227	765,520	**916,509**	**546,422**	**187,463**	**288,950**	2,921,092
1983	209,740	742,555	**916,509**	**546,422**	**187,463**	**288,950**	2,891,639
1982	**203,448**	**720,278**	**916,509**	**546,422**	**187,463**	**288,950**	**2,863,070**

Discounted Replacement Cost Value to Construction Date	$2,863,070
Acquisition Cost in 2010	$2,633,085
Acquisition Cost below Discounted Replacement Cost Value	$229,985

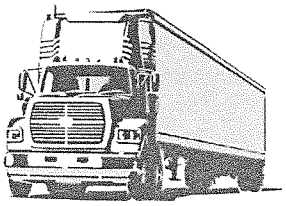
SOURCE: Attachment WHN Rebuttal-1, Page 5 of 5.

Note: Pipeline Section 3 was constructed in 2013 after the acquisition date and is therefore excluded from this analysis.

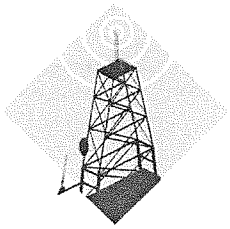
ATTACHMENT

WHN REBUTTAL-3

B&W Pipeline 2015 Ad Valorem Report



STATE OF TENNESSEE
2015
AD VALOREM TAX REPORT



COMPANY NAME B&W Pipeline, LLC

STREET 728 S. Jefferson Avenue, Unit #4 CITY Cookeville STATE TN ZIP CODE 38501
(PRINCIPLE OFFICE INFORMATION)

STREET 728 S. Jefferson Avenue, Unit #4 CITY Cookeville STATE TN ZIP CODE 38501
(PRINCIPLE OFFICE INFORMATION IN TENNESSEE)

PHONE NUMBER ( ) 931-563-0100 x 314 FAX NUMBER ( )

COMPANY WEB SITE

Visit our website at:
www.tn.gov/comptroller/sap

MAIL REPORT TO:

COMPTROLLER OF THE TREASURY
OFFICE OF STATE ASSESSED PROPERTIES
505 Deaderick Street, Suite 1700
Nashville, Tennessee 37243-1402
(615) 741-0140 FAX (615) 741-0142

1. Company Name: B&W Pipeline, LLC

2. Principal Office Location: 728 S. Jefferson Avenue, Unit #4 (Number & Street)

Cookeville (City) | TN (State) | 38501 (Zip)

3. Is Company ____ **INDIVIDUAL?** ____ **PARTNERSHIP?** ____ **CORPORATION?**

____ **COOPERATIVE?** X **OTHER?**

4. If a CORPORATION or OTHER similar enterprise, supply the following information:

Under laws of what state organized: Delaware — Date organized: 7-26-2010
Add charter of incorporation or similar enterprise. — Date dissolved:

Under laws of what state organized: Delaware — Date organized: 7-26-2010

5. Name & address of **PRESIDENT, OWNER, OR PARTNER**: Marcelo Recchia (Name)

General Manager (Position/Title) | 728 S. Jefferson Avenue, Unit #4 (Number & Street) | Cookeville (City) | TN (State) | 38501 (Zip)

6. Name & address of **GENERAL MANAGER**: Marcelo Recchia (Name)

728 S. Jefferson Avenue, Unit #4 (Number & Street) | Cookeville (City) | TN (State) | 38501 (Zip)

7. **GROSS** Investment in SYSTEM plant and property December 31, 2014 — $ 3,154,842

8. **NET** Investment in SYSTEM plant and property December 31, 2014 — $ 2,699,310

9. SYSTEM GROSS Revenue (Income) for year ended December 31, 2014 — $ 36,183

10. SYSTEM NET OPERATING Revenue (Income) for year ended December 31, 2014 — $ (94,405)

11. Amount of LOANS FROM FEDERAL AGENCIES, if any — $ 0

12. Indicate stock & debt of company:

	Amount Authorized	No. of Shares or Amount Issued	Book or Per Value	Market or Cash Value
Preferred Stock	None			
Common Stock	None			
Bonds	None			
Other Long-Term Debts	None			

13. State surplus at beginning of 2014 $ (3,002,550) End of 2014 $ (3,475,147)

14. State amount of dividends paid for the year 2014: Preferred $ 0 Common $ 0

15. State exact dollar amount of FEDERAL INCOME TAX ACTUALLY PAID OR OWED FOR 2014 as reported on your Federal Income Tax Return $ 0

16. State ACTUAL CASH or MARKET VALUE of all Tennessee plant and property as of January 1, 2015 $ 2,699,310

17. State NET additions (additions less retirements) to Tennessee plant and property for:
2013 $ 0 2014 $ 4,905

18. Total number of subscribers in Tennessee 8

19. Does your company operate solely (100%) in Tennessee? X YES _____ NO

If you checked "YES" it will not be necessary to complete questions 20-27.
If you checked "NO" **you must** complete questions 20-27.

20. GROSS Investment in Tennessee plant and property December 31, 2014 $ _____

21. NET Investment in Tennessee plant and property December 31, 2014 $ _____

22. TENNESSEE GROSS Revenue (Income) for year ended December 31, 2014 $ _____

23. TENNESSEE NET OPERATING Revenue (Income) for year ended December 31, 2014 $ _____

24. Percent of TENNESSEE GROSS Investment as compared to SYSTEM GROSS Investment in plant and property December 31, 2014 _____ %

25. Percent of TENNESSEE NET Investment as compared to SYSTEM NET Investment in plant and property December 31, 2014 _____ %

26. Percent of TENNESSEE GROSS REVENUE (Income) as compared to SYSTEM GROSS Revenue (Income) for year ended December 31, 2014 _____ %

27. Percent of TENNESSEE NET OPERATING Revenue (Income) as compared to SYSTEM NET OPERATING Revenue (Income) for year ended December 31, 2014 _____ %

28. Does your company or its parent holding company file the following? **Check all that apply:**

No	a. SEC Form 10-K	No	e. FERC Form 2
No	b. FCC Form M	No	f. FERC Form 2A
No	c. Annual report to stockholders	No	g. FERC Form 6
No	d. FERC Form 1		

File one copy of each of the items checked in item 28 with the Comptroller of the Treasury, Office of State Assessed Properties.

29. What was the date of your last rate case? N/A - Only CCN Was the case heard by a state PSC or a federal entity? _____ What was the return on equity granted? _____ %

30. Special questions regarding this report should be directed to:

NAME: Marcelo Recchia

TITLE: General Manager

ADDRESS: 728 S. Jefferson Avenue, Unit #4
Number & Street

Cookeville (City) TN (State) 38501 (Zip)

PHONE NUMBER: ( ) 931-563-0100 x 314

FAX NUMBER: ( )

E-MAIL ADDRESS: talktous@enrema.com

TOTAL INVESTMENT INSYSTEM AND TENNESSEE PLANT AND PROPERTY

PROPERTY	System Gross Investment* Dec. 31, 2014	System Net Investment* Dec. 31, 2014	Tennessee Gross Investment* Dec. 31, 2014	Tennessee Net Investment* Dec. 31, 2014
DISTRIBUTABLE:				
Pipeline & Appurtenances	$ 3,123,450	$ 2,669,559	$ 3,123,450	$ 2,669,559
LOCALIZED:				
All Other Property, Plant and Equipment	$ 11,292	$ 9,651	$ 11,292	$ 9,651
TOTAL INVESTMENT	$ 3,134,742	$ 2,679,210	$ 3,134,742	$ 2,679,210

NOTES: **(1) Gross Investment figures should be original cost before depreciation.**

(2) Net Investment figures should be original cost less depreciation reserve assignable to the property on the basis of the company's FERC approved depreciation rates.

CAPITAL STOCK

Class and Series of Stock **N/A**

	Outstanding Per Balance Sheet 12/31/2014		Market Price** Average Price Per Share			Amount of Dividend Paid Per Share		
	Shares	**Amount**	**2012**	**2013**	**2014**	**2012**	**2013**	**2014**

****AVERAGE MARKET PRICE FOUND BY AVERAGING HIGH & LOW MONTHLY SALES.**

LEASED EQUIPMENT

This schedule should include all operating equipment located in Tennessee that is leased or used by your company.

Type of Equipment	No. Of Units	Total Annual Amount of Rent	Age Of Units	Annual Depreciation Rate	Lease Expiration Date	Owner	Tax Liability Lessor or Lessee	Original Cost	Accumulated Depreciation	Depreciated Cost	Location (County & City)
		$ N/A						$	$	$	

Summary of Tennessee Property
BY COUNTIES, CITIES, AND SPECIAL SCHOOL DISTRICTS

Name of County, City & Special School District		Gross Investment in Pipeline (Inc. CWIP @ 100%)		Gross Investment in Land		Gross Investment in Structures		Personal Property CWIP @ 15% of Cost		Gross Investment/ Pumping, Storage, & Metering Stations and Equipment		Gross Investment in Furniture, Fixtures, Equipment, Automobiles, Materials & Supplies		Gross Investment
County	Cities/SSD	Outside Cities	Inside Cities	Outside Cities	Inside Cities	Outside Cities	Inside Cities	Outside Cities	Inside Cities	Outside Cities	Inside Cities	Outside Cities	Inside Cities	TOTAL
								EXAMPLE						
Williamson		$5,000,000		$500,000		$10,000,000		$2,000		$500,000		$100,000		$16,102,000
	Franklin 9th SSD		$2,000,000		$200,000		$0		$0			$50,000		$2,250,000
			$2,000,000		$1,000,000		$200,000		$2,500					$3,202,500
Fentress		1,041,150		6,700		3,764				0				1,051,614
Morgan		1,041,150		6,700		3,764				0				1,051,614
Pickett		1,041,150		6,700		3,764				0				1,051,614
GRAND TOTAL		########	$ -	$ 20,100	$ -	$ 11,292	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,154,842

(1) Please indicate the name of each City and Special School District where you have property and place them in the appropriate block under the name of the county in which they are located. SEE EXAMPLE.
(2) County figures should reflect the Gross Investment in all property located **OUTSIDE** corporate city.
(3) City figures should reflect theGross Investment in all property located **INSIDE** corporate city limits.
(4) The Special School District figures should reflect the Gross Investment in all property located therein. Figures for Special School Districts should be shown in parenthesis and should no be included in the Grand Total as these figures will be reflected in the County.

PROPERTY SHEET

NOTES: (1) One sheet should be completed for each county and include ALL property EXCEPT that located within the corporate limits of cities. (2) One sheet should be completed for each INCORPORATED CITY and include ALL property therein. (3) One sheet should be completed for each SPECIAL SCHOOL DISTRICT and include ALL Property located therein.

Fentress County | City or Special School District

DISTRIBUTABLE PROPERTY

Size of Pipeline	Miles of Pipeline	Gross Investment December 31, 2014	Cash Value Jan,. 1, 2015
4", 6" and 8"	17	1,041,150.09	889,853.07
Distributable Construction Work in Progress		-	-
Total Distributable Property		1,041,150.09	889,853.07

LOCALIZED PROPERTY

A. Land:

Acres	Location	Year Acquired	Purchased From	Deed Book	Page No.	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
	Fentress	2010	Gasco Dist Sys			$ 6,700	$ 6,700
				Total		$ 6,700	$ 6,700

B. Structures:

Kind & Type of Structure Facilities	Location	Year Constructed/Acquired	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
	Fentress County	2010	$ 3,764	$ 3,217
		Total	$ 3,764	$ 3,217

C. Pumping, Metering, & Storage:

	Gross Investment-Dec 31, 2014	Cash Value-Jan. 1, 2015
Pumping Stations	$	$
Metering Stations		
Storage Tanks		
Miscellaneous Equipment	0	0
Total	$ -	$ -

D. Furniture,Fixtures, Equipment, Automobiles,Materials & Supplies, and Other General Equipment

	$ -	$ -

E. Localized Construction Work in Progress (Gross Cost) - **Please attach a separate sheet identifying and describing the assets reported under this section**

Personal @ 15%	$	$
Real @ 100%	$	$
Total Localized Property	$ 1,051,614	$ 899,770
Total Property: County-City-SSD	$ 1,051,614	$ 899,770

PROPERTY SHEET

NOTES: (1) One sheet should be completed for each county and include ALL property EXCEPT that located within the corporate limits of cities. (2) One sheet should be completed for each INCORPORATED CITY and include ALL property therein. (3) One sheet should be completed for each SPECIAL SCHOOL DISTRICT and include ALL Property located therein.

Morgan County | City or Special School District

DISTRIBUTABLE PROPERTY

Size of Pipeline	Miles of Pipeline	Gross Investment December 31, 2014	Cash Value Jan,. 1, 2015
4", 6" and 8"	17	1,041,150.09	889,853.07
Distributable Construction Work in Progress		-	-
Total Distributable Property		1,041,150.09	889,853.07

LOCALIZED PROPERTY

A. Land:

Acres	Location	Year Acquired	Purchased From	Deed Book	Page No.	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
	Fentress	2010	Gasco Dist Sys			$ 6,700	$ 6,700
					Total	$ 6,700	$ 6,700

B. Structures:

Kind & Type of Structure	Location	Year Constructed/Acquired	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
Facilities	Fentress County	2010	$ 3,764	$ 3,217
		Total	$ 3,764	$ 3,217

C. Pumping, Metering, & Storage:

	Gross Investment-Dec 31, 2014	Cash Value-Jan. 1, 2015
Pumping Stations	$	$
Metering Stations		
Storage Tanks		
Miscellaneous Equipment	0	0
Total	$ -	$ -

D. Furniture,Fixtures, Equipment, Automobiles,Materials & Supplies, and Other General Equipment

	$ -	$ -

E. Localized Construction Work in Progress (Gross Cost) - **Please attach a separate sheet identifying and describing the assets reported under this section**

Personal @ 15%	$	$
Real @ 100%	$	$
Total Localized Property	$ 1,051,614	$ 899,770
Total Property: County-City-SSD	$ 1,051,614	$ 899,770

PROPERTY SHEET

NOTES: (1) One sheet should be completed for each county and include ALL property EXCEPT that located within the corporate limits of cities. (2) One sheet should be completed for each INCORPORATED CITY and include ALL property therein. (3) One sheet should be completed for each SPECIAL SCHOOL DISTRICT and include ALL Property located therein.

Pickett (County) _____ (City or Special School District)

DISTRIBUTABLE PROPERTY

Size of Pipeline	Miles of Pipeline	Gross Investment December 31, 2014	Cash Value Jan,. 1, 2015
4", 6" and 8"	17	1,041,150.09	889,853.07
Distributable Construction Work in Progress		-	-
Total Distributable Property		1,041,150.09	889,853.07

LOCALIZED PROPERTY

A. Land:

Acres	Location	Year Acquired	Purchased From	Deed Book	Page No.	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
	Fentress	2010	Gasco Dist Sys			$ 6,700	$ 6,700
					Total	$ 6,700	$ 6,700

B. Structures:

Kind & Type of Structure	Location	Year Constructed/Acquired	Gross Investment Dec. 31, 2014	Cash Value Jan. 1, 2015
Facilities	Fentress County	2010	$ 3,764	$ 3,217
		Total	$ 3,764	$ 3,217

C. Pumping, Metering, & Storage:

	Gross Investment-Dec 31, 2014	Cash Value-Jan. 1, 2015
Pumping Stations	$	$
Metering Stations		
Storage Tanks		
Miscellaneous Equipment	0	0
Total	$ -	$ -

D. Furniture,Fixtures, Equipment, Automobiles,Materials & Supplies, and Other General Equipment

	$ -	$ -

E. Localized Construction Work in Progress (Gross Cost) - **Please attach a separate sheet identifying and describing the assets reported under this section**

Personal @ 15%	$	$
Real @ 100%	$	$
Total Localized Property	$ 1,051,614	$ 899,770
Total Property: County-City-SSD	$ 1,051,614	$ 899,770

PURCHASES AND SALES OF TENNESSEE PROPERTY

List all purchases and sales of Tennessee real property (including Telecommunications Towers) that occurred during the year 2014. Give all applicable information for each transaction separately. (You may copy pages as needed)
Please attach a copy of the warranty deed or sales contract.

PURCHASES

Date of Purchase: N/A

County/City: _____

Assessor's Tax Map & Parcel Number: _____

Purchase Price: _____

Physical Address: _____
Number & Street

_____ _____ _____
City State Zip

Description of Property: _____

Grantor (seller): _____

Type of Improvement: _____

SALES

Date of Sale: N/A

County/City: _____

Assessor's Tax Map & Parcel Number: _____

Sale Price: _____

Physical Address: _____
Number & Street

_____ _____ _____
City State Zip

Description of Property: _____

Grantee (buyer): _____

Type of Improvement: _____

REAL PROPERTY UNDER CONSTRUCTION

Tennessee Code Annotated 67-5-503 provides that, "If after January 1 and before September 1 of any year, an improvement or new building is completed and ready for use or occupancy...the assessor of property shall make or correct the assessment of such property, on the basis of the value of the improvement at the time of its completion..."

List all real properties under construction or properties that **will be** completed by September 1, 2015.

County and City	Property Owner and Map Reference	Description of Improvement	Construction Cost
N/A			$

Date: _____

I, Marcelo Recchia, being the OWNER, PRESIDENT, SECRETARY, AND /OR PARTNER OF B&W Pipeline, LLC, do hereby swear and affirm that the foregoing Ad Valorem Tax Report for the year two thousand fifteen has been prepared from only the original books, papers, and records of said respondent under my direction in accordance with Tennessee Code Annotated, §67-5-1316, and is true and correct to the best of my knowledge and belief.

NAME

General Manager
OFFICIAL CAPACITY