Case No. 19-0468-GA-ALT

Plant in Service and Capital Spending Audit Of The East Ohio Gas Company d/b/a Dominion Energy Ohio

Submitted on April 27, 2020

Prepared by
Blue Ridge Consulting Services, Inc.
114 Knightsridge Road
Travelers Rest, SC 29690
(864) 420-8084

This report was formatted to print front and back.
Thus, this page is intentionally left blank.

TABLE OF CONTENTS

Tables

Figures

This report was formatted to print front and back.
Thus, this page is intentionally left blank.

DISCLAIMER

In this report, the word *audit* is intended, as it is commonly understood in the utility regulatory environment, to mean a regulatory review, a field investigation, or a means of determining the appropriateness of a financial presentation for regulatory purposes. It is not intended in its precise accounting sense as an examination of booked numbers and related source documents for financial reporting purposes. Neither is the term *audit* in this case an analysis of financial statement presentation in accordance with the standards established by the American Institute of Certified Public Accountants (AICPA) and the Financial Accounting Standards Board (FASB). The reader should distinguish regulatory reviews such as those that Blue Ridge performs from financial audits performed by independent certified public accountants.

This document and the opinions, analyses, evaluations, and recommendations are for the sole use and benefit of the contracting parties. There are no intended third-party beneficiaries, and Blue Ridge shall have no liability whatsoever to third parties for any defect, deficiency, error, or omission in any statement contained in or in any way related to this document or the services provided.

This report was prepared based in part on information not within the control of the consultant, Blue Ridge Consulting Services, Inc. While it is believed that the information that has been provided is reliable, Blue Ridge does not guarantee the accuracy of the information relied upon.

ORGANIZATION OF BLUE RIDGE'S REPORT

This report is organized according to the following major sections:

- *Executive Summary*: This section provides a summary of Blue Ridge's observations, findings, conclusions, and recommendations presented in more detail in the body of the report.
- *Elements of Analysis*: This section explains the following elements used in Blue Ridge's analysis: background; project purpose; project scope; audit standard; materiality; information reviewed; interviews; field observations; policies and practices; and a brief summary of the variance analyses, transactional testing, and other analyses.
- *Project Requirements and Related Summary Conclusions*: This section identifies the requirements of the Request for Proposal for this project and specifies Blue Ridge's summary conclusions regarding those requirements.
- *Detailed Analysis, Findings, and Recommendations*: This section documents Blue Ridge's analyses that led to our observations, findings, and recommendations regarding the plant-in-service balances and the Capital Expenditures Program (CEP). It includes the rationale and description of any recommended adjustments.
- *Appendices*: The appendices include information reviewed and workpapers that support recommended adjustments.

EXECUTIVE SUMMARY

On May 1, 2019, in Case No. 19-0468-GA-ALT, The East Ohio Gas Company d/b/a Dominion Energy Ohio (DEO or "Company") filed an application with the Public Utilities Commission of Ohio ("Commission" or PUCO) seeking authority to establish a rider on customer bills to collect the amounts accrued in the CEP Deferral through December 31, 2018, and a return of and a return on the underlying CEP capital assets.

The Commission issued a request for proposal seeking bids to conduct a two-part audit of DEO's CEP capital expenditures. The first part of the audit is to review and attest to the accounting accuracy and used and useful nature of DEO's non-PIR / non-automated meter reading (AMR) capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (March 31, 2007, as set in Case No. 07-829-GA-AIR et al.) through December 31, 2018. The second part of the audit is to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of DEO's non-PIR / non-AMR capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2018.[1] Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the review.

Part 1 Plant-in-Service Balances

For the first part of the audit, Blue Ridge reviewed the accounting accuracy and used and useful nature of DEO's non-PIR / non-AMR capital expenditures and related assets and corresponding depreciation reserve for investments and deferrals for the period April 1, 2007, through December 31, 2018. Blue Ridge reviewed both total Company plant in service and that recovered through the CEP mechanism. We performed our review through variance analysis, transactional testing, field observations, and analysis of the Company-provided schedules.

Based on the analysis, Blue Ridge found the Company's beginning balances not reflective of Commission-approved ratemaking adjustments from the last base rate case, issues with roll-forward-balance calculations within the Company total plant and reserve schedules, and asset retirements not recorded.

The ratemaking adjustments from the last base rate case not reflected in the Company's beginning balances are summarized below. A list by FERC account that were affected is provided in Appendix D:

- Plant in Service–$(17,319,717)
- Depreciation Reserve–$53,822,053

Blue Ridge has not reflected the effect of these Commission-approved ratemaking adjustments in its recommended Total Company net plant balances. However, Blue Ridge recommends that they be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.

The following table summarizes Blue Ridge's recommended Total Company Plant.

[1] Case No. 19-0468-GA-ALT Request for Proposal No. RA19-CSPA-2, pages 1–2.

Table 1: Recommended Total Company Net Plant as of December 31, 2018

Description	DEO Balance as of 12/31/2018	Recommended Adjustments	Revised Total Company 12/31/2018
Plant in Service	$ 4,667,116,677	(1,654,960)	$ 4,665,461,717
Depreciation Reserve	$ 1,189,439,258	$ (144,713)	$ 1,189,294,545
Net Plant in Service	$ 3,477,677,419	$ (1,510,246)	$ 3,476,167,173

Blue Ridge also recommends revisions to the net plant the Company is seeking to recover through Rider CEP, as summarized in the following table, to adjust for asset retirements not recorded and to remove Cost of Removal that was incorrectly recorded as an addition.

Table 2: Recommended CEP Net Plant as of December 31, 2018

Description	DEO Reported CEP Balance as of 12/31/2018	Recommended Adjustments	Revised CEP Balance 12/31/2018
Plant in Service	$ 614,793,531	$ (1,898,489)	$ 612,895,042
Accumulated Provision for Depreciation	(35,843,592)	(376,064)	(36,219,656)
Net CEP Plant in Service	$ 650,637,123	$ (1,522,425)	$ 649,114,698

In spite of some initial challenges related to the various systems housing the historical data of the scope period, the Company was able to provide sufficient information for Blue Ridge to reconcile the CEP filing to the plant data. The Company was able to provide detailed continuing property records to support its plant-in-service balances. Blue Ridge performed detailed transactional testing. While no gross discrepancies were found, several of Blue Ridge's account adjustments came from this analysis. All work included in the projects we sampled were capital in nature, and the scope of work and cost detail coincided with the applicable FERC 300 accounts.

In 2018, the Company implemented the PowerPlan fixed asset system to replace the SAP system. The Company believes that PowerPlan will allow it to be more efficient and, therefore, perform future reporting on a timelier basis. Blue Ridge agrees with the Company's assessment of efficiencies using PowerPlan. The system has significantly greater capability than SAP and has the ability to provide more data. Several utilities with which Blue Ridge has worked have efficiently used the PowerPlan system. The Company will need to demonstrate in future filings that a reconciliation can be more easily performed between the CEP and the fixed asset system for annual reporting on a timely basis

Blue Ridge validated the depreciation accrual rates to the Commission-approved rates. While there were several anomalies (discussed in the CEP Revenue Requirement's Schedule 8 section of this report), in conclusion, Blue Ridge's review found that the use of the rates is not unreasonable.

By the physical inspections conducted, Blue Ridge determined that the assets were used and useful and provide benefit to the ratepayer. The assets did not appear over built. Company personnel appeared knowledgeable about the projects. Desktop reviews of asset documents, performed at the Company, demonstrated adequate supporting documentation for the projects, including the appropriate engineering detail. The projects appeared to have been adequately planned with alternatives vetted.

Part 2 Capital Expenditures Prudence Audit

For the second part of the audit, Blue Ridge purposed, as the RFP instructed, "to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of DEO's non-PIR / non-AMR capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2018."

Blue Ridge examined the Company's processes and controls to ensure that they were sufficient so as not to adversely affect the balances in distribution utility net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. Furthermore, Blue Ridge examined internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances and applicable SOX and FERC audits. We were satisfied with actions taken with regard to internal and other audits reviewed. (SOX audits prior to 2011 were not available due to the DEO's Audit Service department's record retention guidelines; therefore, we were unable to review them.) Blue Ridge concluded that DEO's controls were adequate and not unreasonable.

Containing costs is key to controlling the significantly increasing costs associated with CEP-type projects. Blue Ridge reviewed both capital spending and cost containment strategies. We found that the Company is implementing sound cost containment strategies. In addition, even though capital spending has increased from 2012 through 2018, the nature of the spending does not give us cause for concern.

Blue Ridge's review of the CEP Schedule accuracy included both a review of the 2019 Annual Informational Filing (filed on April 30, 2019, in compliance with Case No. 11-6024-GA-UNC) and the Company's proposed CEP revenue requirement schedules that support its requested recovery for an alternative rate plan to establish its Capital Expenditure Program (CEP) Rider included in its application filed in Case No. 19-0468-GAL-ALT on May 1, 2019.

Blue Ridge found that the capital additions, costs of removal, and retirements reflected in the CEP revenue requirements rate base reconciled to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report and were calculated consistently with the December 12, 2012, Order in Case No. 11-6024-GA-UNC. In addition, the deferrals associated with PISCC and depreciation expense also tied to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Filing. However, it was found that the Deferred Property Taxes reported, for which the Company is seeking recovery through the CEP revenue requirements, was different from the amount reflected in the 2019 Annual Informational Filing. The difference was attributed to revisions to the effective property tax rate. Blue Ridge recommends that the deferred property taxes reflected in the CEP revenue requirements should be updated to reflect the actual tax rate and the correction for the tax rates for Tax Years 2015, 2016, and 2017, removing the lease payment reclass.

In a related issue regarding property tax expense (rather than Deferred Property Taxes), Blue Ridge found that the Company used an estimated property tax rate to calculate its annualized property taxes. Blue Ridge recommends that, in the subsequent annual filing, the property taxes based on estimated rates should be trued up using the actual rate.

Additionally, Blue Ridge recommends that the revenue collected through the CEP Rider should be reconciled to the CEP revenue requirements and a mechanism for true-up should be established.

Blue Ridge also recommends that the ADIT on Liberalized Depreciation should be updated to reflect the revisions to remove AFUDC from original cost and to reflect the actual settled balances following the tax return filing.

Other than the adjustments specified, Blue Ridge found nothing to indicate that the non-PIR / non-AMR capital expenses and assets for the period April 1, 2007, through December 31, 2018, were unnecessary, unreasonable, or imprudent. The necessity, reasonableness, and prudence of DEO's non-PIR/non-AMR capital expenditures was considered throughout the entire audit, including the variance analysis, transactional testing, and physical inspections and desktop reviews. Our work in that regard is discussed in the various sections of the report.

Blue Ridge calculated the effect of its recommended adjustments on the CEP revenue requirements as shown in the following table.

Table 3: Effect of Recommended Adjustments on CEP Revenue Requirements

	As Filed	Adjustments	Recommended
Rate Base			
Plant in Service	$ 614,793,531	$ (1,898,489)	$ 612,895,042
Less: Accumulated Provision for Depreciation	(35,843,592)	(376,064)	(36,219,656)
Net Capital Additions	$ 650,637,123	$ (1,522,425)	$ 649,114,698
Depreciation Offset	(310,120,037)	-	(310,120,037)
Net Capital Additions Less Depreciation Offset	$ 340,517,086	$ (1,522,425)	$ 338,994,661
Regulatory Deferrals	204,276,235	(181,507)	204,094,728
Accumulated Deferred Income Tax (ADIT)	(85,505,756)	841,765	(84,663,991)
Rate Base	$ 459,287,565	$ (862,167)	$ 458,425,398
Pre-Tax Rate of Return	9.91%	0.00%	9.91%
Annualized Return on Rate Base	$ 45,515,398	$ (85,441)	$ 45,429,957
Operating Expenses			
Annualized Depreciation Expense	$ 22,129,022	$ (111,455)	$ 22,017,567
Annualized Property Tax Expense	8,512,431	(36,443)	8,475,988
Amortization of Deferred PISCC	3,661,933	(3,275)	3,658,658
Amortization of Deferred Depreciation Expense	2,390,527	(12,448)	2,378,079
Amortization of Deferred Property Tax Expense	709,083	9,715	718,799
Total Operating Expenses	$ 37,402,996	$ (153,906)	$ 37,249,090
Total Revenue Requirement	$ 82,918,394	$ (239,347)	$ 82,679,047

ELEMENTS OF ANALYSIS

BACKGROUND

Since 1953, Section 4905.22 of the Ohio Revised Code (R.C.) has required utilities in Ohio to "furnish necessary and adequate service" and "provide such instrumentalities and facilities as are adequate and in all respects just and reasonable." In September 2011, R.C. 4929.111 permitted natural gas companies to apply to the Public Utilities Commission of Ohio ("Commission") for approval of a capital expenditure program (CEP) for investment related to infrastructure expansion, improvement, or replacement; programs to install, upgrade, or replace technology systems; or, programs to comply with government rules and regulations. With approval of a CEP, natural gas companies can establish a regulatory asset to defer for future recovery the post in-service carrying costs ("capitalized interest" or PISCC) and depreciation and property tax expenses associated with the CEP assets.

In Case No. 11-6024-GA-UNC et al., The East Ohio Gas Company d/b/a Dominion Energy Ohio (DEO or "Company") sought and was granted authority to create a CEP and to begin deferring the related PISCC and depreciation and property tax expenses ("the CEP Deferral") for capital investments that were not part of its accelerated infrastructure replacement program called pipeline infrastructure replacement (PIR). The Commission authorized the CEP Deferral for the period October 1, 2011, through December 31, 2012, and determined that the Company could accrue the deferral up to the point where the deferred amount would exceed $1.50 per month for the General Sales Service (GSS) class of customers if it were included in customer rates.

Subsequently, in Case No. 12-3279-GA-UNC et al., the Commission authorized the Company to continue the CEP Deferral for the period January 1, 2013, through December 31, 2013. In Case No. 13-2410-GA-UNC et al., the Commission authorized the Company to continue the CEP for the period January 1, 2014, through December 31, 2014, and beyond, up to the point where the deferred amount would exceed $1.50 per month for the GSS class of customers if it were put into rates. The Commission also restated its determination that it would consider the prudence, reasonableness, and magnitude of the CEP Deferral and capital expenditures when the Company applied for recovery.

On May 1, 2019, in Case No. 19-0468-GA-ALT, DEO filed an application with the Commission seeking authority to establish a rider on customer bills to collect the amounts accrued in the CEP Deferral through December 31, 2018, and a return of and a return on the underlying CEP capital assets.

The Public Utilities Commission of Ohio (Commission or PUCO) issued a request for proposal (RFP) seeking proposals to conduct a two-part audit of DEO's CEP capital expenditures. The first part of the audit is to review and attest to the accounting accuracy and used and useful nature of DEO's non-PIR / non-automated meter reading (AMR) capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (March 31, 2007, as set in Case No. 07-829-GA-AIR et al.) through December 31, 2018. The second part of the audit is to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of DEO's non-PIR / non-AMR capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2018.[2] Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the review.

[2] Case No. 19-0468-GA-ALT Request for Proposal No. RA19-CSPA-2, pages 1–2.

PURPOSE OF PROJECT

As defined in the RFP, the audit was to address two parts with the following scope:[3]

> Part 1 Plant In-Service Balances: Review and attest to the accounting accuracy and used and useful nature of Dominion's non-PIR / non-AMR capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (March 31, 2007, as set in Case No. 07-829-GA-AIR et al.) through December 31, 2018.
> Part 2 Capital Expenditures Prudence Audit: Simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of Dominion's non-PIR / non-AMR capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011 through December 31, 2018.

PROJECT SCOPE

The project scope, as delineated in the RFP and with clarifications as discussed with Staff, addresses the following items:

Part 1 Plant In-Service Balances

1. Determine total Company plant in service for each account and subaccount from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.
2. Audit the Company's plant in service to determine the proper value investments by account and subaccount with an emphasis on CEP expenditures and investments.
3. Determine total company depreciation reserve for each account from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.
4. Audit the Company's depreciation reserve to determine the proper value for investments by account and subaccount with an emphasis on CEP expenditures and investments.
5. Provide a determination as to the accuracy and completeness of the Company's historical plant records and continuing property record.
6. Ensure plant in service transactions were properly classified as a capital expenditure.
7. Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense.
8. Review and audit the plant and reserve balances reported on Schedule B-2 et al. and Schedule B-3 et al. provided in the Company's May 1, 2019, Application, Exhibit H.
9. Perform physical inspections to confirm the assets' used and usefulness.
10. Provide a report of findings that include rationale and description of any recommended adjustments.

Part 2 Capital Expenditure Prudence Audit

- Identify and assess the necessity, reasonableness, and prudence of the Company's non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
- Identify and assess the necessity, reasonableness, and prudence of the Company's policies and practices for plant additions, new construction, plant replacement, and plant retirements.

[3] Public Utilities Commission of Ohio Request for Proposal No. RA19-CSPA-2.

- Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in the Company's non-PIR / non-AMR capital expenditures coinciding with the CEP program.
- Identify and assess the reasonableness and prudence of the Company's cost-containment strategies and practices in the use of outside contractors for non- PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
- Identify and assess the reasonableness and prudence of the Company's cost-containment strategies and practices in the use of internal Company labor for non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
- Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of the Company's capital spending policies and practices or lack of such practices not specifically identified herein.
- Recommend and support specific adjustments to the non-PIR / non-AMR plant-in-service balance based on any findings or lack of necessity, unreasonableness, or imprudence.
- Review and audit all CEP-related schedules to ensure accuracy of the required CEP formula, including, but not limited to, Schedules 1–14 as filed on April 30, 2019, which pertain to PISCC, property tax, depreciation, and incremental revenue in Case No. 13-2410-GA-UNC.
- Recommend and support specific adjustments pertaining to the CEP schedules.

A large portion of Blue Ridge's focus was on the CEP Deferral investments and the non-PIR / non-AMR investments.

CEP Deferral: Section 4929.111(A) revised Code, provides that a natural gas company may file an application with the Commission to implement a CEP for any of the following programs:

- Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program
- Any program to install, upgrade, or replace information technology systems
- Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction[4]

The Company elaborated on what is includable in the CEP Deferral in its Application:

- *Infrastructure Expansion, Improvement, or Replacement*. Expenditures in this category include distribution system betterments; pipeline, regulating station, or other improvements or replacements, including non-billable pipeline relocations, associated with DEO's distribution, transmission, storage, production, and gathering systems that are not covered by DEO's Automated Meter Reading and Pipeline Infrastructure Replacement programs; storage well and compressor station improvements or replacements; and certain customer main line extensions and main-to-curb and curb-to meter service lines.
- *Installation, Upgrade, or Replacement of Information Technology*. This category includes capital expenditures for upgrades to or replacements of computer systems utilized for accounting, billing, and utility operations as well as communication systems. Capitalized costs may include costs for hardware, software purchases or development, installation, and associated licenses.

[4] Case No. 11-06024-GA-UNC, Finding & Order (December 12, 2012), page 13.

- *Programs Reasonably Necessary to Comply with Commission Rules, Regulations, and Orders*. Capital expenditures in this category include those for required pipeline integrity or other regulatory compliance associated with pipeline safety, environmental compliance, metering, facilities, fleet, and other general plant associated with providing DEO's regulated services.[5]

PIR Investment: To understand what is not included in Blue Ridge's review, we requested an explanation of the type of work that is recovered through the PIR. The Company provided the following information:

> The PIR Program involves the replacement of bare steel, cast iron, wrought iron, copper and ineffectively coated pipe and other items as described below.
>
> - Ineffectively coated pipe:
> - All pre-1955 pipe
> - Field-coated pipe installed in 1955 or after that is determined to be ineffectively coated after testing
> - Governmental relocations that include target pipe if plastic pipe associated with the relocation is less than or equal to 25% of the total footage relocated
> - The cost of system improvements can be included only if the improvements replace the role of the target pipe and cost no more than an in-kind replacement of target pipe
> - Replacement, modification, or removal of district regulating stations if needed due to age or condition or if the work is directly associated with the replacement of target pipe
> - Relocation of inside meters to outside the premises if a) the Company plans to increase the pressure in the pipeline associated with the meter to operate that pipeline at regulated pressure (greater than 1psig); b) the meter is connected to a segment of target pipe; and c) the Company operates the replacement mains and associated service lines at regulated pressure within two years of relocating the first meter on the project
> - Replacement of steel main-to-curb service lines, regardless of whether in conjunction with a PIR project
> - Repair or replacement of leaking service lines
>
> Prior to the 2011 reauthorization of the PIR program by the Commission, the program included the following:
>
> - The cost of moving inside meters to outside locations could be recovered if agreed upon with Staff after the presentation by DEO of a meter relocation plan at the time of the annual cost recovery filing.
> - Ongoing infrastructure investment could be included in cost recovery provided that it would not cause the PIR Cost Recovery Charge to exceed the annual increase cap of $1.00 per customer per month.[6]

AMR Investment: To understand what is not included in Blue Ridge's review, we requested an explanation of the type of work that is recovered through the AMR. The Company stated,

> The AMR program involved the installation of Encoder-Receiver-Transmitters (referred to both as "ERT devices" and "AMR devices") on all customer meters other

[5] Case No. 19-0468-GA-ALT, Direct Testimony of Vicki H. Friscic, page 2, line 14: page 3, line 10.
[6] DEO Response to data request BRDR-21.

than those meters already equipped with electronic gas measurement (i.e., accounts on the Daily Transportation Service rate schedule). The program also included associated hardware installed in trucks, handheld devices needed to read the AMR devices, as well as software and programming required to incorporate the AMR meter reads into the billing system. The installation of AMR devices on production meters were not recovered under the AMR program. Capital investment in the AMR program ended in 2012. Annual cost recovery filings continue to recover depreciation expense, property tax expense, and the return on investment, with an offset for certain O&M savings associated with the program.[7]

Blue Ridge's analysis and recommendations did not include the following items:

11. Disallowances based on prior Commission precedents or policy
12. Review of the appropriateness of jurisdictional allocation factors
13. Appropriateness and accuracy of Company overhead allocations applied to capital work orders

AUDIT STANDARD

Blue Ridge's focus is on the accounting accuracy; used and useful nature; and the necessity, reasonableness, and prudence of the non-PIR, non-AMR capital expenditures. Blue Ridge used the following standards during the course of the audit when assessing the attributes required in the project scope:

Accounting Accuracy: The stated value is supported by accurate and complete plant accounting property records. Transactions are properly recorded as capital expenditures in the appropriate FERC account(s).

Used and Useful: The assets are used in providing services and are useful to the ratepayer.

Necessity, Reasonableness, and Prudence: The decision to make the investment was reasonable at the time the decision was made and based on information then available. The decision is one that a reasonable person could have made in good faith, given the information and decision tools available at the time of the decision.

MATERIALITY

Materiality relates to the importance or significance of an amount, transaction, or discrepancy. The assessment of materiality depends on certain factors, such as an organization's revenues and expenses. For a regulated utility, the impact on a company's ratepayer should also be considered.

Under traditional cost-of-service ratemaking, revenue requirements, or cost of service, equates to the total of operating expenses, depreciation, taxes, and a rate-of-return allowance on the utility's investment in rate base. Blue Ridge used the traditional cost-of-service concept to identify materiality as it relates to changes in the plant-in-service component of rate base. Materiality was calculated by backtracking through the Company's CEP revenue requirements calculation to determine the amount of change in gross plant in service that would result in a five percent change in the CEP Rider on an average residential customer's monthly bill. Blue Ridge found that a $25.196 million change in gross

[7] DEO Response to data request BRDR-22.

plant in service would result in five percent change in the CEP Rider on an average residential customer's monthly bill.[8]

The resultant materiality threshold was used to determine the *tolerable error* in the calculation of the sample size for detailed transactional testing. Blue Ridge's findings were not limited by the tolerable error. We reported on all our findings regardless of amount.

INFORMATION REVIEWED

Blue Ridge reviewed or is familiar with the following information as required by the RFP:

14. Case documents, including applications, testimony, work papers, stipulations (if any), and orders in Cases 11-6024-GA-UNC and 12-3279-GA-UNC, Case No. 13-2410-GA-UNC et al., and Case No. 19-0468-GA-ALT
15. Generally accepted accounting principles (GAAP)
16. Federal Energy Regulatory Commission (FERC) Uniform System of Accounts
17. Various accounting and tax changes or decisions issued during calendar year 2018
18. The operations and regulatory environment of natural gas distribution utilities
19. The capital-spending practices and requirements of natural gas distribution utilities
20. The Pipeline and Hazardous Materials Safety Administration's (PHMSA) Pipeline Safety Regulations (49 CFR, Parts 190–199)

During the audit process, Blue Ridge requested and was provided additional information. A list of the data requested is included as Appendix B. Electronic copies of the information obtained were provided to Staff.

INTERVIEWS

Blue Ridge conducted interviews of Company personnel and performed field inspections and desktop reviews.

The interview notes are included within the electronic appendices to this report. Blue Ridge's interviews focused on the following areas:

1. Plant Accounting functions related to CEP and non-CEP additions (Base Rate), retirements, cost of removal, salvage, unitizations, and the 2018 PowerPlan software implementation
2. Major Events from April 1, 2007, through December 31, 2018, that could have had an impact on Plant Accounting records
3. Engineering and WMIS, including system planning and load growth
4. Work Order accounting (CEP and non-CEP)
5. Capital Budgeting, including cost containment strategies and capital budget selection and prioritization

FIELD OBSERVATIONS

The objectives of the field inspections focused on (1) Used and Usefulness—whether the Company assets were used and useful, providing service to the customer and, therefore, properly included in utility plant in service—and (2) Necessity, Reasonableness, and Prudence—whether the decision to make the investment was reasonable at the time the decision was made and based on information then available. The field inspections included on-site visits to review the overall

[8] WP-19-0468-GA-RDR Sensitivity and Sample Size. The calculation used the Company's CEP Revenue Requirement model and assumes no other adjustments were made to the Company's revenue-requirement calculation.

construction at each site to determine whether the assets appeared to be in use and, therefore, used and useful. The review also determined whether the assets appeared overbuilt (gold plated) and whether the Company selected a reasonable option to execute the work. The reviews included inspection of drawings, schematics, notes, and other documentation that supported the reasonableness of the decision to execute the work. Where on-site visits were not practical, as in the case of work that could not be seen, a desk-top review was conducted to examine the supporting documentation for the work performed.

Additional discussion on the team's observations is included in the section labeled Physical Inspections and Desktop Reviews. The field observation notes and photos are included within the electronic appendices to this report.

POLICIES AND PRACTICES

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as to not adversely affect the balances in distribution utility net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. Blue Ridge also reviewed internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits.

VARIANCE ANALYSIS, TRANSACTIONAL TESTING, AND OTHER ANALYSIS

To identify, quantify, and explain any significant net plant increases within the individual accounts, Blue Ridge performed account variance analyses. The Company was asked to explain any significant changes. The results of the analyses are included in this report under the section labeled Variance Analysis.

In addition, Blue Ridge selected a sample number from the population of work orders that support the gross plant in service for detailed transactional testing. The sample was selected using a statistically valid sampling technique. Additional work orders were selected based on professional judgment. The results of the transactional testing are included in the section labeled Detailed Transactional Testing.

Blue Ridge also performed other various analyses, including mathematical verifications and source data validation of the schedules that support the application filing.

PROJECT REQUIREMENTS AND RELATED SUMMARY CONCLUSIONS

The Request for Proposal (RFP) included general project requirements for the auditor investigation that were separated into two parts: (1) Plant in Service and (2) Capital Expenditures Prudence. The two parts are interrelated and the findings in each part are used to support Blue Ridge's ultimate recommendations. To ensure that we have addressed the specific requirements in the RFP, we have maintained the integrity of the work scope by part. The following lists include the subject areas of the RFP's required audit components and how this section of the report is organized.

Part 1 Plant In-Service

The RFP stated that the purpose for the first part of the audit was to "review and attest to the accounting accuracy and used and useful nature of the [Company's] non-PIR / non-automated meter reading (AMR) capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (March 31, 2007, as set in Case No. 07-829-GA-AIR et al.) through December 31, 2018." Specific scope included the following items:

1. Plant-in-Service Balances
    - Determine total Company plant in service for each account and subaccount from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.
    - Audit the Company's plant in service to determine the proper value investments by account and subaccount with an emphasis on CEP expenditures and investments.
2. Depreciation-Reserve Balances
    - Determine total Company depreciation reserve for each account from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.
    - Audit the Company's depreciation reserve to determine the proper value for investments by account and subaccount with an emphasis on CEP expenditures and investments.
3. Historical Records
    - Provide a determination as to the accuracy and completeness of the Company's historical plant records and continuing property record.
4. Classification—Capital vs. Expense
    - Ensure plant-in-service transactions were properly classified as a capital expenditure.
5. Subaccounts—Allocations and Depreciation
    - Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense.
6. Physical Inspections
    - Perform physical inspections to confirm the assets' used and usefulness.
7. Total Company Plant and Reserve Schedules
    - Review and audit the plant and reserve balances reported on Schedule B-2 et al. and Schedule B-3 et al. provided in the Company's May 1, 2019, Application, Exhibit H.

Part 2 Capital Expenditures Prudence Audit

For the second part of the audit, the RFP stated the purpose as "to simultaneously assess and form an opinion on the necessity, reasonableness, and prudence of the [Company's] non-PIR / non-AMR capital expenditures and related assets, with an emphasis on the CEP expenditures and assets from October 2011, through December 31, 2018." Specific scope included the following items:

8. Necessity, Reasonableness, and Prudence
    - Identify and assess the necessity, reasonableness, and prudence of the Company's non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
9. Policies and Practices
    - Identify and assess the necessity, reasonableness, and prudence of the Company's policies and practices for plant additions, new construction, plant replacement, and plant retirements.
    - Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of the Company's capital spending policies and practices or lack of such practices not specifically identified herein.
10. Causes for Increased Non-IRP / Non-AMR Spending
    - Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in the Company's non-PIR / non-AMR capital expenditures coinciding with the CEP program.
11. Cost Containment
    - Identify and assess the reasonableness and prudence of the Company's cost- containment strategies and practices in the use of outside contractors for non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
    - Identify and assess the reasonableness and prudence of the Company's cost- containment strategies and practices in the use of internal Company labor for non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.
12. CEP Schedule Accuracy
    - Review and audit all CEP-related schedules to ensure accuracy of the required CEP formula, including, but not limited to, Schedules 1–14 as filed on April 30, 2019, which pertain to PISCC, property tax, depreciation, and incremental revenue in Case No. 13-2410-GA-UNC.
    - Recommend and support specific adjustments pertaining to the CEP schedules.
13. Adjustments and Other Recommendations
    - Recommend and support specific adjustments to the non-PIR / non-AMR plant-in-service balance based on any findings or lack of necessity, unreasonableness, or imprudence.

The following subsections address the RFP requirements delineated above and Blue Ridge's summary conclusions based on our analysis. Additional information related to the analysis is provided in the next section of this report: Detailed Analysis, Findings, and Recommendations.

1. PLANT-IN-SERVICE BALANCES

Requirements: Determine total company plant in service for each account and subaccount from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.

Requirement: Audit the Company's plant in service to determine the proper value investments by account and subaccount with an emphasis on CEP expenditures and investments.

Blue Ridge's investigation included a review of (1) total Company plant in service for each account/subaccount from the date certain balance and (2) plant in service recovered through the CEP mechanism.

Blue Ridge's investigation included data requests, interviews, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service schedules. These adjustments are addressed throughout the report and listed in Section 13 Adjustments and Other Recommendations.

Total Company Plant-in-Service Recommended Balance

Blue Ridge's analysis results in the following recommended revisions to the total Company plant-in-service balance.

Table 4: Total Company Plant in Service as of 12/31/2018 Recommended Balance

Description	DEO Balance as of 12/31/2018	Recommended Adjustments	Revised Total Company 12/31/2018
Plant in Service	$ 4,667,116,677	(1,654,960)	$ 4,665,461,717

The revised Total Company plant shown above does not reflect the Commission-approved ratemaking adjustments, totaling $(17,319,717), that were not reflected in the Company's beginning plant-in-service balances. Blue Ridge recommends these adjustments should be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.

Blue Ridge's recommended adjustments have been included in the recast Schedule B-2 provided in Appendix D.

CEP Plant-in-Service Recommended Balance

Blue Ridge's analysis results in the following recommended revisions to the Company CEP plant-in-service balance.

Table 5: CEP Plant-in-Service Recommended Balance

Description	DEO Reported CEP Balance as of 12/31/2018	Recommended Adjustments	Revised CEP Balance 12/31/2018
Plant in Service	$ 614,793,531	$ (1,898,489)	$ 612,895,042

Blue Ridge's recommended adjustments have been included in the recast CEP Revenue Requirements schedules that are provided in Appendix E.

2. DEPRECIATION RESERVE BALANCES

Requirement: Determine total company depreciation reserve for each account from the date certain balance approved in the Company's previous application to increase rates forward through December 31, 2018.

Requirement: Audit the Company's depreciation reserve to determine the proper value for investments by account and subaccount with an emphasis on CEP expenditures and investments.

Blue Ridge reviewed the (1) the total Company depreciation reserve for each account/subaccount from the date certain balance and (2) the depreciation reserve recovered through the CEP mechanism.

Blue Ridge's investigation included data requests, interviews, field inspections, and analyses, including, variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service schedules and their associated depreciation reserve balances. These adjustments are addressed throughout the report and are listed in Section 13 Adjustments and Other Recommendations.

Total Company Depreciation-Reserve Recommended Balance

Blue Ridge's analysis results in the following recommended revisions to the total company depreciation-reserve balance.

Table 6: Total Company Depreciation Reserve as of 12/31/2018 Recommended Balance

Description	DEO Balance as of 12/31/2018	Recommended Adjustments	Revised Total Company 12/31/2018
Depreciation Reserve	$ 1,189,439,258	$ (144,713)	$ 1,189,294,545

The revised Total Company reserve shown above does not reflect the Commission-approved ratemaking adjustments, totaling $53,822,053, that were not reflected in the Company's beginning reserve balances. Blue Ridge recommends these adjustments should be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.

Blue Ridge's recommended adjustments have been included in the recast Schedule B-3 provided in Appendix D.

CEP Depreciation Reserve Recommended Balance

Blue Ridge's analysis results in the following recommended revisions to the CEP depreciation-reserve balance.

Table 7: CEP Depreciation-Reserve Recommended Balance

Description	DEO Reported CEP Balance as of 12/31/2018	Recommended Adjustments	Revised CEP Balance 12/31/2018
Accumulated Provision for Depreciation	$ (35,843,592)	$ (376,064)	$ (35,467,528)

Blue Ridge's recommended adjustments have been included in the recast CEP Revenue Requirement schedules provided in Appendix E.

3. HISTORICAL RECORDS

Requirement: Provide a determination as to the accuracy and completeness of the Company's historical plant records and continuing property record.

Through our analysis, Blue Ridge found that the Company was able to provide detailed continuing property records to support its plant-in-service balances. However, certain system changes the Company had undergone through the years created some difficulties in gathering the data needed for the audit.

SYSTEM CHANGES

In 2013 the Company converted its work management system from WMIS to the Plant Maintenance Order Operation module (PMOO). PMOO includes data identifying recovery programs and massed asset in-service dates; however, that data did not flow to the then SAP Fixed Asset system. PMOO and the SAP fixed asset system data were exported to BW where it was combined to facilitate tracking and cost reporting for both the PIR and CEP annual filings. In summary, PMOO contained detailed construction and cost information, the SAP fixed asset system was the system of record, and BW facilitated tracking and reporting.

In 2018, the Company implemented the PowerPlan fixed asset system to replace the SAP system. The Company believes that PowerPlan will allow it to be more efficient and, therefore, perform future reporting on a timelier basis. Blue Ridge agrees with the Company's assessment of efficiencies using PowerPlan. The system has significantly greater capability than SAP and has the ability to provide more data. Several utilities with which Blue Ridge has worked have efficiently used the PowerPlan system. The Company will need to demonstrate in future filings that a reconciliation can be more easily performed between the CEP and the Fixed Asset system for annual reporting on a timely basis.

AUDIT DIFFICULTIES

At the inception of the audit in September 2019, Blue Ridge explained to the Company that in order for us to create a statistically valid work order sample for testing, we would need to make sure the Plant Records reconciled to the CEP as filed by the Company. The Company explained, however, that due to the various systems housing the historical data of the scope period, they were finding it difficult to reconcile the plant records to the data included in the CEP filing. They were well aware of the problem and had previously informed Staff and Blue Ridge of the problem before the audit even began.

Over the course of the next 60 days, the Company was able to provide sufficient information for Blue Ridge to reconcile the CEP filing to the plant data, so we were confident that we had the entire work order population to produce a statistically valid work order sample for testing.

However, due to the time necessary to provide reconciliations and project data, the core work of the audit was delayed by 60 days. In addition, it took a considerable amount of time for analysis and communication with the Company to be satisfied that the reconciliations were proper so that we could pull the statistical sample we needed that included the entire population of work orders.

The Company also had a difficult time providing work order information since the data came from various sources, such as BW and plant records for base rates. As a result of having the information coming from these various systems, SAP was unable to allocate certain standard core charges when work orders were closed. That situation resulted in several massed asset reallocation entries to distribute those core costs, all of which required review by Blue Ridge. The Fixed Asset

system performs that function as work orders are closed. In addition, BW did not contain the accumulated reserve for depreciation for the CEP. That information had to be manually calculated.

The delays and significant work required on the part of the Company and Blue Ridge resulted in the Company asking for an extension of time to complete the audit and for Blue Ridge to request a Change Order to cover the time spent on this issue. However, once the Company was able to reconcile, DEO began to provide a steady stream of information, and the work proceeded on a more regular schedule.

Timing differences also occurred between the Company's books and annual filings. Monthly massed asset costs for AMR and PIR programs are included within the annual filings as long as the projects are placed in service by the end of the year. However, CEP does not include costs for deferral until the asset is placed in service, even though monthly costs were recorded on the books.

Ultimately, Blue Ridge found that the Company was able to provide detailed continuing property records to support its plant-in-service balances.

4. CLASSIFICATION—CAPITAL VS. EXPENSE

Requirement: Ensure plant in service transactions were properly classified as a capital expenditure.

Through our transactional detail testing (Step T3), Blue Ridge found that all the work included in the projects sampled are capital in nature and the scope of work and cost detail coincided with the applicable FERC 300 accounts to which the work applies in accordance with the FERC Uniform System of Accounts (CFR 18). The projects were classified to the proper production and gathering, transmission, intangible, distribution, and general equipment FERC accounts.

5. SUBACCOUNTS—ALLOCATIONS AND DEPRECIATION

Requirement: Identify subaccounts and/or functions for the determination of allocation factors and/or depreciation expense.

The depreciation accrual rates are based on the depreciation rates approved by the Commission in Case No. 13-1988-GA-AAM. The Commission's Finding and Order (October 23, 2013) stated that the Company should apply the approved depreciation accrual rates to investments made in 2013 and thereafter under its AMR, PIR, and CEP Programs. The Company was also ordered to submit a new deprecation study for all gas plant accounts no later than September 1, 2019, with a study date of December 31, 2018.[9] The Company stated that no new FERC 300 accounts and/or subaccounts were added since the most recent Commission-approved depreciation accrual rates.[10]

Blue Ridge validated the depreciation accrual rates to the Commission-approved rates. There were several anomalies discussed in the CEP Revenue Requirement's Schedule 8 section of this report. Blue Ridge found that the Company has used depreciation accrual rates for several FERC accounts (357.00-Storage Other Equipment, 380.00-Distribution Services-LP & RP, and 380.00-Distribution-New Customer Facilities) that were not reflected in the approved rates. The Blue Ridge review concluded that the use of the rates is not unreasonable and had no impact on depreciation expense. However, these rates have not been approved by the Commission. Blue Ridge recommends that the Company correct this issue, if not already addressed, prior to the Commission approving the

[9] DEO Response to Data Request BRDR-31 (Depreciation), Case No. 13-1988-GA-AAM, Finding and Order (October 23, 2013), page 2.
[10] DEO Response to Data Request BRDR-31 (Depreciation).

new deprecation study for all gas plant accounts that was presumably filed Blue Ridge recommends that the Company have the FERC account accrual rates approved.

Blue Ridge also reviewed allocation factors and found that all DEO's plant investment is jurisdictional to its gas distribution service customers.

6. PHYSICAL INSPECTIONS

Requirement: Perform physical inspections to confirm the assets' used and usefulness.

By the physical inspections conducted, Blue Ridge determined that the assets were used and useful and provide benefit to the ratepayer. The assets did not appear over built. Company personnel were knowledgeable about the projects.

Desktop reviews performed revealed that the Company had adequate supporting documentation for the projects, including the appropriate engineering detail. The projects appeared to have been adequately planned with alternatives vetted. As a result, the projects are used and useful and providing benefit to the ratepayers.

We did not find anything in either the physical inspections or desktop reviews that is unreasonable.

Additional details of the field reviews are included in this report's Field Inspections and Desktop Review subsection. The inspection forms and photos are included in Blue Ridge's workpapers.

7. TOTAL COMPANY PLANT AND RESERVE SCHEDULES

Requirement: Review and audit the plant and reserve balances reported on Schedule B-2 et al. and Schedule B-3 et al. provided in the Company's May 1, 2019, Application, Exhibit H.

In Case No. 07-829-GA-AIR et al. (the Company's last base rate case), the Commission approved rate base of $1,404,744,493 (as of March 31, 2007). The Company provided Section A and B Schedules (as of December 31, 2018) of Standard Filing Requirement in accordance with Ohio Adm Code 4901-7-01 in its application seeking approval of an alternative form of regulation in Case No. 19-0468-GA-ALT. The following table compares the rate-based approved at date certain and the balance reflected in the schedules provided with the Company's application in this docket.

Table 8: Comparison of Total Company Rate Base at Date Certain 3/31/2007 to Reported Total Company Rate Base Balances as of 12/31/2018[11]

Description	Approved as of 3/31/2007	DEO Balance as of 12/31/2018	Change
Plant in Service	$ 1,916,133,980	$ 4,667,116,677	$ 2,750,982,697
Depreciation Reserve	(849,347,745)	(1,189,439,258)	(340,091,513)
Net Plant in Service	$ 1,066,786,235	$ 3,477,677,419	$ 2,410,891,184
Construction Work in Progress	-	-	-
Working Capital Allowance	131,898,359	23,641,487	(108,256,872)
Other Rate Base Items	206,059,899	359,260,975	153,201,076
Rate Base	$ 1,404,744,493	$ 3,860,579,881	$ 2,455,835,388

[11] WP BRDR-4 Attachment Staff Report Last Rate Case and Case No. 19-0468-GA-ALT, Application, May 1, 2019, Exhibit H, Schedule B-1.

The Company's application included roll-forward balances for each year from March 31, 2007, through December 31, 2018.[12] Blue Ridge compared the beginning plant-in-service balances as of March 31, 2007, to what was approved in the last base rate case and also reviewed the roll-forward Schedule B-2.3a and B-3.3a for mathematical accuracy. We also compared each year's FERC account balances, as reported in the Company's application, to the balances reported in the PUCO annual reports. As discussed in the section labeled Validation and Verification of Plant Schedule B-2 et al. and B-3 et al., Blue Ridge identified the following items that would impact the balances.

- Beginning balances for plant in service and the reserve did not match balances approved in the last base rate case. The differences were identified as Commission-approved ratemaking adjustments that were not reflected in the beginning balances for plant in service ($17,319,719) and the reserve ($53,822,053), resulting in net plant being overstated by $71,141,772. Blue Ridge recommends that these adjustments should be considered in the Company's next base rate case to ascertain their rolled forward impact and relevance at that time.
- Formulas used in the roll-forward schedules (B-2.3a and B-3.3a) included errors and inconsistencies. The following two errors included hard-coded numbers, where a formula should have reflected the plant-in-service and reserve balances, that caused the plant and reserve balances to be overstated.
    - 2007 Additions for General Plant was overstated by $64,210. This overstated amount rolled forward through to the December 31, 2018, balance. Blue Ridge recommended an adjustment be made to the plant-in-service balance.
    - 2016 FERC account 375.03 Structures & Improvements-Leasehold Improvements Reserve reported a hard-coded ending balance of zero when the calculated amount was $83,095. The amount was rolled forward to the December 31, 2018, balance, resulting in understated reserve. Blue Ridge recommends an adjustment be made to the reserve balance.
- In 2018, a performance issue with PowerPlan resulted in approximately $50 million massed assets that are typically recorded to FERC 101 as costs are incurred monthly to be recorded to FERC account 106 Construction Completed but not Classified. Blue Ridge found that the assets in both FERC account 101 and FERC account 106 are in service and the impact was related only to where the assets are reported in the PUCO Annual Report and the B Schedules. However, due to the magnitude of the issue in 2018, Blue Ridge recommends that the Company evaluate the performance issue that occurred and develop a plan to identify and rectify the issue should it occur again in the future.

In addition, Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service, depreciation-reserve, and annualized depreciation expense schedules. Blue Ridge's recommended adjustments are summarized in Section 13 Adjustments and Other Recommendations. The recommended revised Schedules B-2 and B-3 are provided in the attached Appendix D.

[12] Case No. 19-0468-GA-ALT, Application, May 1, 2019, Exhibit H, Schedules B-2.3a and B-3.3a.

8. NECESSITY, REASONABLENESS, AND PRUDENCE

Requirement: Identify and assess the necessity, reasonableness, and prudence of the Company's non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.

Other than the adjustments specified, Blue Ridge found nothing to indicate that the non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, were unnecessary, unreasonable, or imprudent. The necessity, reasonableness, and prudence of DEO's non-PIR / non-AMR capital expenditures were considered throughout the entire audit, including the variance analysis, transactional testing, and physical inspections and desktop reviews. Our work in that regard is discussed in the various sections of this report.

9. POLICIES AND PRACTICES

Requirement: Identify and assess the necessity, reasonableness, and prudence of the Company's policies and practices for plant additions, new construction, plant replacement, and plant retirements.

Requirement: Utilize the auditor's and/or retained subcontractor's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of the Company's capital spending policies and practices or lack of such practices not specifically identified herein.

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as not to adversely affect the balances in distribution utility net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. Blue Ridge also reviewed internal audit reports conducted on various areas of the Companies' operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits. SOX audits prior to 2011 were not available due to the DEO's Audit Service department's record retention guidelines; therefore, we were unable to review them.[13] In addition to a review of the Company's formal policies and procedures, Blue Ridge conducted interviews with a focus on understanding the processes and any changes that have been made since April 2007.

A few significant events occurred during the scope period of this audit.

1. December 2012–March 2014: Conversion of Assets to Wet Gathering Service—The Company converted certain assets to Wet Gas and sold those assets to Blue Racer Midstream LLC, a joint venture to which DEO was not a party. The sale did not impact asset recording and tracking.
2. 2013: WMIS to SAP/PMOO conversion—This conversion did not impact the fixed asset system. Both systems are work order management systems and fed into the fixed asset systems in SAP.
3. 2014–2016: Western Access I and II Projects—These two phases were undertaken to provide access to DEO's Market for Utica producers as well as to provide off-system transportation service. This project could generate revenue but would not impact the fixed asset system.
4. 2017: Lordstown Energy Center—This asset comprises facilities constructed to provide gas to a customer-owned 800 MW gas-fired combined-cycle power plant.

[13] DEO Response to Data Request BRDR-48 (SOX Reports) Confidential.

5. 2018: PowerPlan Conversion[14]—In August 2018, the Company converted to the PowerPlan projects and assets module. Plant balances were transferred from SAP. This event could affect asset recording and tracking. However, an internal audit of the conversion did not find any issues.

Blue Ridge concluded that DEO's controls were adequate and not unreasonable. Furthermore, we were satisfied with actions taken with regard to internal and other audits reviewed.

Additional details of the policies and practices reviews are included in this report's Review of Company's Processes and Controls subsection.

10. CAUSES FOR INCREASED NON-PIR / NON-AMR SPENDING

Requirement: Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in the Company's non-PIR / non-AMR capital expenditures coinciding with the CEP program.

Capital spending has increased 115% from the first full year of the CEP in 2012 through 2018. Relocation work and new business accounted for approximately 26% of the total spending during that period. Relocation work is a required activity and frequently cannot be budgeted. New Business falls under the Company's obligation to serve. Transmission Storage and Gathering accounted for 24% of the total spending, and Facilities accounted for 12%. The highest spending year was 2018. During that year, the Company spent $147 million. However, 22% of that represents Relocation and New Customer work. Besides 2018, the highest spending years were 2015 and 2016. During those years, the primary spending was on consolidating facilities and again on Relocation and New Customer work. Our review found that the principal causes for the increase in the Company's non-PIR / non-AMR capital expenditures were based on necessity, were not unreasonable, and did not indicate imprudence. We are satisfied that the Company is taking appropriate measures to control labor and contractor costs, which in turn control spending. We did not see anything during field testing that would indicate the Company is "gold plating" construction.[15]

11. COST CONTAINMENT

Requirement: Identify and assess the reasonableness and prudence of the Company's cost-containment strategies and practices in the use of outside contractors for non- PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.

Requirement: Identify and assess the reasonableness and prudence of the Company's cost-containment strategies and practices in the use of internal company labor for non-PIR / non-AMR capital expenditures and assets for the period April 1, 2007, through December 31, 2018, with an emphasis on CEP expenditures and assets.

Containing costs is key to controlling the significantly increasing costs associated with CEP-type projects. The Company hires outside contractors to perform capital work, leaving most of the maintenance work to in-house labor. Over 80% of the capital activities are performed by contractor labor. From 2011 through 2019, contractor labor ranged from 81% to 86% of the total labor used on capital projects.

[14] DEO Response to Data Request BRDR-12 (Timeline) Revised 11.26.2019.
[15] DEO Response to Data Request BRDR -49, Attachment 1.

To help achieve the most cost-effective outcomes in utilizing contractor labor, DEO has employed a competitive bid process. This process has been utilized both with respect to PIR and non-PIR projects. The strategy that has emerged is to balance the use of contractors with internal labor and determine the areas of specialization that are best performed internally, areas that are best suited to contracting, and areas in which a blend is necessary due to the scope and/or pace required.

Large projects generally are performed by contractors that may be outside the state. Smaller projects tend to be done by local or state-wide contractors. Many of the projects have onsite inspectors, and the smaller projects are monitored periodically in the field. Putting on more full-time staff or staffing up would not appear to be a viable alternative. The construction season in the gas business is finite, and therefore, the Company would be overstaffed in non-construction months. Since the ability to perform maintenance also depends on weather conditions, the same would hold true for hiring additional maintenance staff. The Company is taking steps which appear to be not unreasonable to try to control costs.

12. CEP SCHEDULE ACCURACY

Requirement: Review and audit all CEP-related schedules to ensure accuracy of the required CEP formula, including, but not limited to, Schedules 1–14 as filed on April 30, 2019, which pertain to PISCC, property tax, depreciation, and incremental revenue in Case No. 13-2410-GA-UNC.

Requirement: Recommend and support specific adjustments pertaining to the CEP schedules.

Blue Ridge's review of the CEP Schedule accuracy included both a review of the 2019 Annual Informational Filing (filed on April 30, 2019, in compliance with Case No. 11-6024-GA-UNC) and the Company's proposed CEP revenue requirement schedules that support its requested recovery for an alternative rate plan to establish its Capital Expenditure Program (CEP) Rider included in its application filed in Case No. 19-0468-GAL-ALT on May 1, 2019.

The Company is seeking recovery of $82,918,394 through the CEP Rider. The CEP Rider revenue requirements summary schedule is provided on Schedule 2. The summary schedule pulls together the various components of CEP deferrals for which the Company seeks recovery through the CEP Rider and calculates the resultant revenue requirements as summarized in the following table.

Table 9: CEP Revenue Requirements Calculated by Company

Rate Base	
Plant in Service	$ 614,793,531
Less: Accumulated Provision for Depreciation	(35,843,592)
Net Capital Additions	$ 650,637,123
Depreciation Offset	(310,120,037)
Net Capital Additions Less Depreciation Offset	$ 340,517,086
Regulatory Deferrals	204,276,235
Accumulated Deferred Income Tax (ADIT)	(85,505,756)
Rate Base	$ 459,287,565
Pre-Tax Rate of Return	9.91%
Annualized Return on Rate Base	$ 45,515,398
Operating Expenses	
Annualized Depreciation Expense	$ 22,129,022
Annualized Property Tax Expense	8,512,431
Amortization of Deferred PISCC	3,661,933
Amortization of Deferred Depreciation Expense	2,390,527
Amortization of Deferred Property Tax Expense	709,083
Total Operating Expenses	$ 37,402,996
Total Revenue Requirement	$ 82,918,394

As discussed in the sections labeled Validation and Verification of Schedules, Blue Ridge found issues with the 2019 Annual Informational Filing and the Company's proposed CEP revenue requirements schedules.

Blue Ridge performed various validations and verification checks on the schedules included in the 2019 Annual Informational Filing. Blue Ridge found that the Company calculated the deferral balances consistently with the December 12, 2012, Order in Case No. 11-6024-GA-UNC.

Blue Ridge also performed various validations and verification checks on the schedules reflected in the calculation of the CEP revenue requirement. Blue Ridge found that the capital additions, costs of removal, and retirements reflected in the CEP revenue requirements rate base reconciled to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report. In addition, the deferrals associated with PISCC and depreciation expense also tied to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Filing. However, it was found that the Deferred Property Taxes reported, for which the Company is seeking recovery through the CEP revenue requirements, was different from the amount reflected in the 2019 Annual Informational Filing. Further analysis resulted in two recommended adjustments to Deferred Property Taxes. The estimated tax rate should be trued up to actual, and the deferred property taxes for Tax Years 2015 through 2017 should be corrected to remove the lease payment reclass. These adjustments increase Deferred Property Taxes by $293,515.

During discovery, the Company updated its ADIT on Liberalized Depreciation balance. Blue Ridge recommends that the ADIT on Liberalized Depreciation be adjusted to reflect the revision. The Company's ADIT on Liberalized Depreciation in rate base is $56,915,425, as updated, compared to $57,774,229, as filed.

Blue Ridge found that the Company has used depreciation accrual rates for several FERC accounts (357.00-Storage Other Equipment, 380.00-Distribution Services-LP & RP, and 380.00-Distribution-New Customer Facilities) that have not technically been approved by the Commission. From a

practical standpoint, there is no impact on the CEP revenue requirements. However, Blue Ridge recommends that the Company have the FERC account accrual rates approved.

The Company used an estimated property tax rate to calculate its annualized property taxes. Blue Ridge recommends that the property taxes based on estimated rates should be trued up using the actual rate in the subsequent annual filing and that the use of any estimates in the future be subject to true-up.

Blue Ridge found that the Company's CEP revenue requirement reports no incremental revenue related to CEP investments. The Company stated that it does not believe that there are any revenue-generating investments reflected in CEP plant through December 31, 2018. As part of Blue Ridge's transactional testing and field work, we considered whether the projects included within the CEP for recovery could generate incremental revenue. Blue Ridge questioned three projects. The Company was able to adequately explain why the projects would not generate incremental revenue. Based on the Company explanation, Blue Ridge did not find any projects that could generate incremental revenue.

Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service, depreciation-reserve, and annualized depreciation expense reflected in the CEP Revenue Requirements.

The following table summarizes the effect of Blue Ridge's recommended adjustments on the CEP Revenue Requirement. The recast CEP revenue requirement schedules are provided in Appendix E.

Table 10: Recommended Adjustments to CEP Revenue Requirements

	As Filed	Adjustments	Recommended
Rate Base			
Plant in Service	$ 614,793,531	$ (1,898,489)	$ 612,895,042
Less: Accumulated Provision for Depreciation	(35,843,592)	(376,064)	(36,219,656)
Net Capital Additions	$ 650,637,123	$ (1,522,425)	$ 649,114,698
Depreciation Offset	(310,120,037)	-	(310,120,037)
Net Capital Additions Less Depreciation Offset	$ 340,517,086	$ (1,522,425)	$ 338,994,661
Regulatory Deferrals	204,276,235	(181,507)	204,094,728
Accumulated Deferred Income Tax (ADIT)	(85,505,756)	841,765	(84,663,991)
Rate Base	$ 459,287,565	$ (862,167)	$ 458,425,398
Pre-Tax Rate of Return	9.91%	0.00%	9.91%
Annualized Return on Rate Base	$ 45,515,398	$ (85,441)	$ 45,429,957
Operating Expenses			
Annualized Depreciation Expense	$ 22,129,022	$ (111,455)	$ 22,017,567
Annualized Property Tax Expense	8,512,431	(36,443)	8,475,988
Amortization of Deferred PISCC	3,661,933	(3,275)	3,658,658
Amortization of Deferred Depreciation Expense	2,390,527	(12,448)	2,378,079
Amortization of Deferred Property Tax Expense	709,083	9,715	718,799
Total Operating Expenses	$ 37,402,996	$ (153,906)	$ 37,249,090
Total Revenue Requirement	$ 82,918,394	$ (239,347)	$ 82,679,047

Additionally, Blue Ridge recommends that the revenue collected through the CEP Rider should be reconciled to the CEP revenue requirements and a mechanism for true-up should be established.

In conclusion, the effects of Blue Ridge's recommended adjustments are summarized in Section 13 Recommended Adjustments and have been reflected in the adjustments of the recast CEP schedules, provided in Appendix E.

13. ADJUSTMENTS AND OTHER RECOMMENDATIONS

Requirement: Recommend and support specific adjustments to the non-PIR / non-AMR plant in-service balance based on any findings or lack of necessity, unreasonableness, or imprudence.

Blue Ridge's recommends the following adjustments:

Adjustment #1: Variance analysis identified amounts in CEP FERC Accounts 390, 394, and 398 that were not retired timely. As of December 31, 2018, Utility Plant-in-Service was overstated by $1,397,319 and the accumulated reserve was overstated by $206,500 as a result of over accrued depreciation. Blue Ridge recommends that CEP plant in service be reduced by $1,397,319 and the CEP reserve reduced by $206,580, resulting in a reduction to CEP net plant in service of $1,190,739. This adjustment flows through the recast CEP revenue requirements.

Adjustment #2: IT DEO.RATE CASE.2 - DEO RATE CASE was a project that was completed before initiation of CEP and should be removed from CEP plant. CEP plant in service should be reduced by $306,807, and the CEP reserve should be adjusted by $(148,364), resulting in a reduction to CEP net plant in service of $148,443. This adjustment flows through the recast CEP revenue requirements.

Adjustment #3: Not used.

Adjustment #4: P400090072.001 - LN1745 PIGGABILITY. Posted charges exceed overall actual project costs. A journal entry to move charges was not fully posted in the BW system. CEP plant in service should be adjusted to reflect the direct charges by $7,330, the 2018 costs should be adjusted by $4,996, and the Journal Entry should be corrected by $(61,094), for a total adjustment to CEP plant of $(48,768). In addition, the CEP reserve should be adjusted by $(2,743), resulting in a net reduction to CEP net plant in service of $46,025. This adjustment flows through the recast CEP revenue requirements.

Adjustment #5: DEO.LEAK.2 - LEAK SURVEY IN SAP. Direct charge not included in CEP plant in service. While the amount is immaterial, Blue Ridge recommends that CEP plant in service be increased by $1,042 and the CEP reserve should be adjusted by $425, resulting in an increase to CEP net plant in-service of $616. This adjustment flows through the recast CEP revenue requirements.

Adjustment #6: FCDEO.16.GAS.8D. Cost of removal was recorded as an addition. CEP plant in service should be reduced by $81,636 and the CEP reserve should be adjusted by $(2,823) because of the over accrual of depreciation. This results in a reduction to CEP net plant in service of $78,813. This adjustment flows through the recast CEP revenue requirements.

Adjustment #7: FCDEO.13.GAS.7B - CPY RENOVATIONS. Cost of removal was recorded as an addition. CEP plant in service should be reduced by $65,000, and the CEP reserve should be adjusted by $(15,979) because of the over accrual of depreciation. This results in a reduction to CEP net plant in service of $49,021. This adjustment flows through the recast CEP revenue requirements.

Adjustment #8: Update ADIT on Liberalized Depreciation reflected in the CEP rate base to remove AFUDC from tax basis and true up to actual settled tax balances following end of year reconciliation;

reflect impact of Adjustments #1 through #7 on ADIT. The adjustment reduces ADIT in the CEP revenue requirements calculation by $882,622.

Adjustment #9: CEP Deferred Property Taxes reflected in the CEP revenue requirements should be changed from $21,422,462 to $21,715,977, for an increase of $293,515, to reflect the update of adjusted estimated effective tax rates to actual rates and to remove the lease payment reclass.

Adjustment #10: Approved ratemaking adjustments to plant in service, totaling $17,319,717, from last base rate case were not reflected in beginning balances in the Company's rolled-forward Schedule B-2. While we believe these Commission approved adjustments, totaling $(17,319,717), should have been reflected in the Company's beginning balance as reported on Schedule B-2, and have labeled the finding as an adjustment, we are not recommending that the December 31, 2018, plant balance should be adjusted at this time. Instead, Blue Ridge recommends that the adjustment be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.

Adjustment #11: Approved ratemaking adjustments to the depreciation reserve of $53,822,053 from last base rate case were not reflected in beginning balances in the Company's rolled-forward Schedule B-3. While we believe these Commission-approved adjustments, totaling $53,822,053, should have been reflected in the Company's beginning balance as reported on Schedule B-3, and have labeled the finding as an adjustment, we are not recommending that the December 31, 2018, reserve should be adjusted at this time. Instead, Blue Ridge recommends that the adjustment be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.

Adjustment #12: Incorrect value hard coded in lieu of formula on Schedule 2.3a–2007 Additions for General Plant. Plant was thus overstated by $64,210. This adjustment flows through the recast Schedule B-2

Adjustment #13: Incorrect value hard coded in lieu of formula on Schedule 3.3a–2016, FERC account 375.03 Structures & Improvements-Leasehold Improvements. The adjustment increases the reserve by $83,095 (reducing net plant by the same amount). This adjustment flows through the recast Schedule B-3.

Adjustment #14: P400002271 (.006 and .039) -Install Johnston Compressor Station. CIAC booking was delayed, resulting in ADFUC inadvertently booked as a credit. Plant is understated by $1,974. Blue Ridge recommends that total Company plant in service be increased by $1,974 and the reserve should be adjusted by $(317), resulting in an increase to net plant in service of $1,657. This adjustment flows through the recast Schedules B-2 and B-3.

Besides the above adjustments, Blue Ridge provides the following recommendations based on its audit:

1. As discussed in Adjustment #10 and #11 above, Blue Ridge is not recommending at this time that the December 31, 2018, plant and reserve should be adjusted to recognize the Commission-approved rate making adjustments from the last base rate case that were not reflected within the Company's beginning balances on Schedules B-2 and B-3. Instead, Blue Ridge recommends that the adjustments be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time.
2. Blue Ridge recommends the Company review and comply with their approval process to ensure that it is applied on a consistent uniform basis. Blue Ridge found that in some instances the Company did not update the CRF when the projects changed. The purchase

order requisition was used instead. For blanket projects, it is appropriate that the approvals are at the Board of Director level. Because of the various types of approvals that take place based on the nature of the project, it is important for the Company to apply a consistent procedure. (page 56)

3. Blue Ridge found that several factors contributed to the cost overrun for DEO PLNT MAINT.2.BA and DEO PLNT MAINT.2. Scope changes and time delays contribute to some extent. Also contributing is the additional testing as a result of the initial tests not meeting performance goals. It is our opinion that while we understand projects such as this contain many variables, the Company should have been able to control the project to a certain extent regarding meeting testing performance goals. Blue Ridge recommends that the Company put more emphasis on monitoring the projects so the testing phase would yield positive results. (pages 61–62)
4. Blue Ridge recommends that the Company make a more concerted effort to ensure project budgets include the routine type project costs. Doing so may help avoid cost overruns and provide savings to the ratepayer. (page 68)
5. Blue Ridge recommends that the Company conform to FERC guidelines as to what purchases of General Equipment can be capitalized at point of purchase and what should be considered inventory until deployed in the field. (page 73)
6. Blue Ridge recommends that the Company evaluate the performance issue that occurred with PowerPlan in 2018 and develop a plan to identify and rectify the issue should it occur again in the future. (page 92)
7. Blue Ridge recommends that the estimated property tax rates used should be trued up to actual rates. Going forward, because actual property tax rates will likely not be known until after the Company makes its annual rider filing, the Company suggested, and Blue Ridge recommends, that it use an estimated rate in its filing and true up that year's expense to the actual rate in the subsequent annual filing. (pages 102–103)
8. Blue Ridge recommends that, in the future, the Company provide an explanation and reconciliation of any differences between what is reported in the Annual Informational Filings to the amounts it requests through the CEP. (page 108)
9. Blue Ridge recommends that the Company correct the issue of using depreciation accrual rates not approved by the Commission, if not already addressed, prior to the Commission approving the new deprecation study for all gas plant accounts that was presumably filed on or before September 1, 2019. (page 111)
10. Blue Ridge recommends that the revenue collected through the CEP Rider be reconciled to the CEP revenue requirements and a mechanism for true-up should be established. (page 114)

DETAILED ANALYSIS, FINDINGS, AND RECOMMENDATIONS

Blue Ridge's review was focused on determining whether DEO has accurately accounted for its non-PIR/non-AMR plant in service and depreciation reserve as of December 31, 2018, and whether those investments were used and useful, necessary, reasonable, and prudent. Our investigation covered all capital assets from its most recent base rate case (March 31, 2007, as set in Case No. 07-829-GA-AIR et al.) through December 31, 2018, with a focus on CEP expenditures from October 2011 through December 31, 2018. In addition, we focused on the accuracy of the roll-forward balances from the last base rate case (2007–2018) as reported in Schedule B-2 et al. and Schedule B-3 et al. We also verified and validated the CEP Revenue Requirement Schedules that support the Company's CEP deferral.

The following sections discuss Blue Ridge's review of the Company's processes and controls, external and internal audit reports, variance analysis, capital spending and cost containment, detailed transactional testing, work order backlog, field inspections and desktop reviews, plant-related Schedules B-2 and B-3, and the CEP deferral schedules. We have also included a summary of our findings and our recommendations.

PROCESSES AND CONTROLS

POLICIES AND PROCEDURES

Blue Ridge did not perform a management audit but did review the Company's processes and controls to ensure that they were sufficient so as to not adversely affect the balances in net plant in service. Based on the documents reviewed, Blue Ridge was able to understand the Companies' processes and controls that affect each of the plant balances. In addition to a review of the Company's formal policies and procedures, Blue Ridge conducted interviews with a focus on understanding the processes and any changes that have been made since 2007.

SUMMARY OF POLICIES AND PROCEDURES

The audit of DEO's plant-in-service balances did not call for a regulatory management audit (i.e., a diagnostic examination purposed to assess the effectiveness and efficiency of operation of a specific regulated utility). However, while Blue Ridge did not perform a management audit, we did review the Company's processes and controls to obtain an understanding of their impact on the plant balances. In particular, Blue Ridge reviewed the following policies and procedures:

1. Plant Accounting:
    a. Capitalization vs Expense
    b. Preparation and approval of work orders
    c. Recording of CWIP, including the systems that feed the CWIP trial balance
    d. Application of AFUDC
    e. Recording and closing of additions, retirements, cost of removal, and salvage to plant
    f. Unitization process based on the retirement unit catalog
    g. Application of depreciation
    h. Contributions in Aid of Construction (CIAC)
    i. Damage Claims
2. Purchasing/Procurement
3. Accounts Payable/Disbursements
4. Accounting/Journal Entries

5. Payroll (direct charged and allocated)
6. Insurance recovery
7. Allocations
8. Work Management System
9. Information Technology
10. Capital Project selection and prioritization
11. System planning and load growth

Current Policies and Procedures

Blue Ridge reviewed current policies and procedures in the areas that provide input into distribution plant. Documentation and detailed responses were provided regarding the Work Management System and capital project selections,[16] the Level of Signature Authority,[17] and for the following policies and processes[18]:

Capitalization: The Company's capitalization policy provides compliance and guidance with respect to the accounting classification for addition, replacement, and betterment of property, plant, and equipment. The policy provides asset definition and capitalization guidelines for additions and replacements.

AFUDC: The AFUDC policy provides guidance for the computation, application, and capitalization of allowance for funds used during construction. It identifies construction projects for which AFUDC is to be computed and explains rates and accounting, including the rules for application of rates and the calculation of the AFUDC rate.

Disposal of Assets: This policy defines areas of responsibility when property, plant, and equipment is retired or removed from service with or without replacement. It provides discussion of business segment responsibilities, associated costs, reporting exceptions for asset retirements, and fixed asset accounting responsibilities.

Acquiring and Developing Assets: This fixed asset policy defines the responsibilities of project owners and the Fixed Asset accounting group with regard to administering the life cycle of a capital project from creation to close. Areas discussed include project owner responsibilities and fixed asset accounting responsibilities.

Intangible Assets: This policy points to Accounting Standards Codification 350-30 as providing accounting guidance on intangible assets (other than goodwill). The accounting approach is detailed in the policy, including providing application examples in its appendix.

Supply Chain Management: Separate procedures listed below provide information regarding supply chain:

Definitions: Supply Chain Management offers a list of definitions for key terms and provides locational detail for other underlying procedures.

Roles and Responsibilities: This document provides the division of roles and responsibilities among supply chain groups.

[16] DEO Response to Data Request BRDR-51.
[17] DEO Response to Data Request BRDR-30, Attachments 1–3, Confidential.
[18] DEO Response to Data Request BRDR-13 (Policies and Procedures) Attachments 1–23, Confidential.

Procedure Control: This document establishes the process by which SCM procedures are developed, formatted, revised, authorized, and controlled.

Supply Chain: This document provides the detail of the procurement process, including such areas as objectives, ethics, applicability, deviations and revisions, signature authority, requirements of requisitioning and leasing, methods of procurement, communication with suppliers, bidding process, exemptions, compliance requirements, and other legal- and insurance-related reviews.

Corporate Disbursements: This policy provides guidance on processing miscellaneous and purchase-order-related invoices for payment. A separate procedure details the process review.

Manual Journal Entries: This policy provides guidance on the acceptable level of documentation required to validate manual journal entries. The policy defines *significant* entries, processor and approver assignments, workflow approval, month-end closing, and substitutions.

Design Notifications: The policy provides the steps necessary for releasing and approving notifications.

Construction Work Order: This policy discusses working in a construction work order. Included are material ordering, releasing the work order, generating and printing bills of material, and adding, modifying, and deleting component units.

Notification Creation: This process provides detail in working with notifications.

Claim Collection: The Company provided a flow diagram regarding claim collections from invoicing through receipt or, conversely, through litigation.

Application of Surcharges: This policy provides guidance for areas of responsibility when surcharges are applied to capital and expense projects. It provides definitions and responsibilities for segment accounting, project owners, corporate and fixed asset accounting, and the IT SAP finance team.

Contractor Defect Process: The Company provided a flowchart showing the process from leak identification through defect identification, repair, invoicing, and settlement if necessary.

Liability Claims: The Company provided a flowchart showing the process from occurring incident through claim resolution.

Gas Line Damage Claims: Similar to the Liability Claims flowchart, this damage claim chart shows the process through claim resolution.

Reporting Third Party Liability Claims: The purpose of this guideline is to define the existing DEO reporting requirements for third party property damage and/or personal injury claims against the Company and to provide employees with an understanding of the claims process and their related responsibilities.

Information Technology: This process involves IT providing input to distribution plant through the creation of IT capital projects that create a software or hardware asset added to distribution plant at project closing.

Insurance: This document describes the comprehensive and worldwide property and liability insurance programs covering all assets and entities involved in the Company's businesses.

Retirements: The Company's policies and procedures state that Fixed Asset Accounting is notified in writing when an asset is taken out of service. When notified in writing, Fixed Asset

Accounting retires the asset(s) from the Asset Management System. There are some assets that are automatically retired from plant after a specified number of years and do not need to be communicated to Fixed Asset Accounting unless a facility of office is closed or sold. The Company provided a list of those assets.[19]

The Company further explained the Retirement Process:

> On a monthly basis, assets are flagged in the system for retirement. Retirements are processed without indication of its recovery mechanism. Rather, the retirement is processed based on general asset information such as location code, FERC, and WBS. A list of CEP capital projects placed in service are then matched to the list of retirements to determine which retirements are associated with CEP projects. Except for FERC accounts that are subject to systematic retirements, the matched retirements are then included in the retirement value used to calculate rate base and deferrals. For the treatment of systematic retirements, please see BRDR-45 Attachment 1.[20]

Massed Asset Reallocation

The Company's Business Warehouse (BW) software product holds the capital additions and cost of removal data that is included in the CEP. Retirement data are generated from SAP. For purposes of the CEP, depreciation is manually calculated versus the automated depreciation calculation used in FA for all assets. The FA system does not track assets by regulatory program. Therefore, the support for the CEP Rider is retrieved from BW and SAP and the support for Base Rates is retrieved from the FA. As with any other manual calculation, the possibility exists that depreciation-calculation errors could be made. However, since the CEP uses a composite depreciation rate, the likelihood for errors is greatly diminished.

Because of how the Company's PMOO system operates, certain types of common costs are charged to a single operation and, therefore, to a single asset type. Costs, such as design, traffic control, and inspection, are basically charged to one asset and require reallocation to the various massed assets to which they relate. A journal entry is made to reallocate common costs to various assets based on the project's final asset mix. The CPR is not affected since the settlement represents a reclassification and nets to zero. Journal entries were made in January 2018 to reallocate common costs for 2013 through 2017. The Company has been reviewing this process for improvements going forward.

As a result of these settlement entries, the possibility exists that depreciation was either over- or understated for massed assets. However, because the massed assets in general represent a limited number of retirement units, the prospect that net plant for the CEP massed assets was over- or understated by any material amount is unlikely.

Changes to Capitalization Policy

Any major changes to the Capitalization Policy can directly affect plant balances. Blue Ridge requested a list of major changes for the scope period. The Company reported that no major changes

[19] DEO Response to Data Request BRDR-13 (Policies and Procedures) Confidential, Attachment 3 (Disposal of Assets) Confidential.
[20] DEO Response to Data Request BRDR-45 (CEP Revenue Requirements Cost of Removal and Retirements).

have been implemented in its capitalization policy from March 31, 2007, through December 31, 2018.[21]

SIGNIFICANT EVENTS BETWEEN APRIL 1, 2007, AND DECEMBER 31, 2018

The Company has undergone several events that could affect its asset recording and tracking. The effects of these events were examined in conjunction with the other reporting detail of this report:

1. December 2012–March 2014: Conversion of Assets to Wet Gas Gathering Service—The Company converted certain assets to Wet Gas Gathering and sold those assets to Blue Racer Midstream LLC, a joint venture to which DEO was not a party. The sale did not impact asset recording and tracking.
2. 2013: WMIS to SAP/PMOO conversion—This conversion did not impact the fixed asset system. Both systems are work order management systems and fed into the fixed asset systems in SAP.
3. 2014–2016: Western Access I and II Projects—These two phases were undertaken to provide access to DEO's Market for Utica producers as well as to provide off-system transportation service. This project could generate revenue but would not impact the fixed asset system.
4. 2017: Lordstown Energy Center—This asset comprises facilities constructed to provide gas to a customer-owned 800 MW gas-fired combined-cycle power plant.
5. 2018: PowerPlan Conversion[22]—In August 2018, the Company converted to the PowerPlan projects and assets module. Plant balances were transferred from SAP. This event could affect asset recording and tracking. However, an internal audit of the conversion did not find any issues.

CONCLUSION—PROCESSES AND CONTROLS

Blue Ridge concluded that DEO's processes and controls were adequate and not unreasonable.

EXTERNAL AND INTERNAL AUDIT REPORTS

Blue Ridge reviewed 26 internal audit reports conducted on various areas of the Company's operations that could impact utility plant-in-service balances. Blue Ridge also reviewed applicable SOX and FERC audits.

INTERNAL AUDITS

Blue Ridge requested and reviewed a list of the completed and on-going audits performed by the internal audit group during the period April 1, 2007, through December 31, 2018,[23] and selected 26 internal audit reports[24] to examine further regarding potential findings that could have had an impact on the internal controls of the feeder systems that charge distribution work orders or feed CWIP, including those affecting payroll, materials and supplies, transportation, overheads, and contractors.

Based upon our review, conclusions for the examined audits did not engender a level of concern that the Company's controls were less than adequate.

[21] DEO Response to Data Request BRDR-15 (Policies and Procedures).
[22] DEO Response to Data Request BRDR-12 (Timeline) Revised 11.26.2019.
[23] DEO Response to Data Request BRDR-33.
[24] DEO Response to Data Request BRDR-50 (Internal Audits) Confidential.

EXTERNAL AUDITS

The Company could be subject to various external audits, particularly of FERC. Blue Ridge requested a copy of all FERC audit reports issued during the scope period; however, there were no FERC audits during the scope period (March 31, 2007, through December 31, 2018).[25]

SOX COMPLIANCE AUDITS

Blue Ridge reviewed the SOX compliance audits that feed CWIP that were performed from 2011–2018 and found that while some of the control tests failed, the Company reported that there were no significant financial reporting impacts to CWIP accounting figures as a result.[26] Blue Ridge examined the remediation and mitigation performed by the Company regarding the failures and was satisfied that actions taken were satisfactory. Blue Ridge was informed by the Company that SOX compliance audits performed prior to 2011 were not retained because they exceeded the Audit Service's record retention guidelines.[27] Therefore, Blue Ridge was unable to review them and cannot render an opinion regarding SOX controls for the years 2007–2010.

CONCLUSION—EXTERNAL AND INTERNAL AUDIT REPORTS

Blue Ridge concluded that Company actions taken with regard to DEO's internal and external audits reviewed were adequate and not unreasonable.

VARIANCE ANALYSIS

Blue Ridge's variance analysis focused on three areas. The first was to compare the balances reflected in Schedules 2.3 Plant Gross Additions, Retirements, and Transfers and Schedule B-3.3 Depreciation Reserve to the balances in the annual reports filed with the Commission. We prepared spreadsheet tables for plant balances[28] and reserve balances[29] for each asset group and year, which showed the calculated differences and requested from the Company explanations for those differences. The Company provided reconciliations and explanations for the differences.[30] Blue Ridge found the explanation of the differences not unreasonable. Therefore, Blue Ridge was satisfied with the account comparison.

The second area of focus for variance analysis concerned identifying, quantifying, and explaining significant net plant changes, transfers, and adjustments within the individual distribution, general, and intangible plant accounts for each year from 2007 through 2018. Blue Ridge took note of anomalous or undefined changes in balances and asked the Company for explanations. Based on its investigative and analytical evaluation of the causes and details included in the Company's explanations, Blue Ridge attempted to determine the reasonableness of those changes.

[25] DEO Response to Data Request BRDR-32 (FERC Audits).
[26] DEO Response to Data Request BRDR-34 (SOX Compliance Audits).
[27] DEO Response to Data Request BRDR-34 (SOX Compliance Audits) and BRDR-48 (SOX Reports) Confidential.
[28] WP Schedule B-2.3a Reconcile to Annual Report-Plant and WP Staff DR 1 Exhibit H Schedule B-2.3a Tie to Annual Report.
[29] WP Schedule B-3.31 Reconcile to Annual Report-Reserve and WP Staff DR 1 Exhibit H Schedule B-3.3a Tie to Annual Report.
[30] DEO Responses to Data Request BRDR-163 (Schedule 2.3a Tie Out to Annual Report) and Data Request BRDR-168 (Schedule B-3.31 Tie Out to Annual Report).

Blue Ridge submitted questions to the Company for explanation, regarding such items as detail behind significant additions over retirements, significant retirements over additions, negative additions, positive retirements, and transfers and adjustments. The Company responded with explanations for each instance,[31] from which Blue Ridge asked an additional set of questions to ensure our understanding. In the follow-up discussion,[32] the Company stated that further review of the facilities projects in FERC account 390.01 and existing shop location assets in FERC accounts 390.01, 375, and others revealed that $1,397,319 of assets likely should have been retired. Therefore, as of December 31, 2018, Utility Plant-in-Service was overstated by $1,397,319. Blue Ridge recommends that CEP plant in service be reduced by $1,397,319 and the CEP reserve reduced by $206,580, resulting in a reduction to CEP net plant in service of $1,190,739. This adjustment flows through the recast CEP revenue requirements. **[ADJUSTMENT #1]**

The chart below shows the specific retirements that had not been made.

Table 11: Building Renovation Retirements Not Recorded

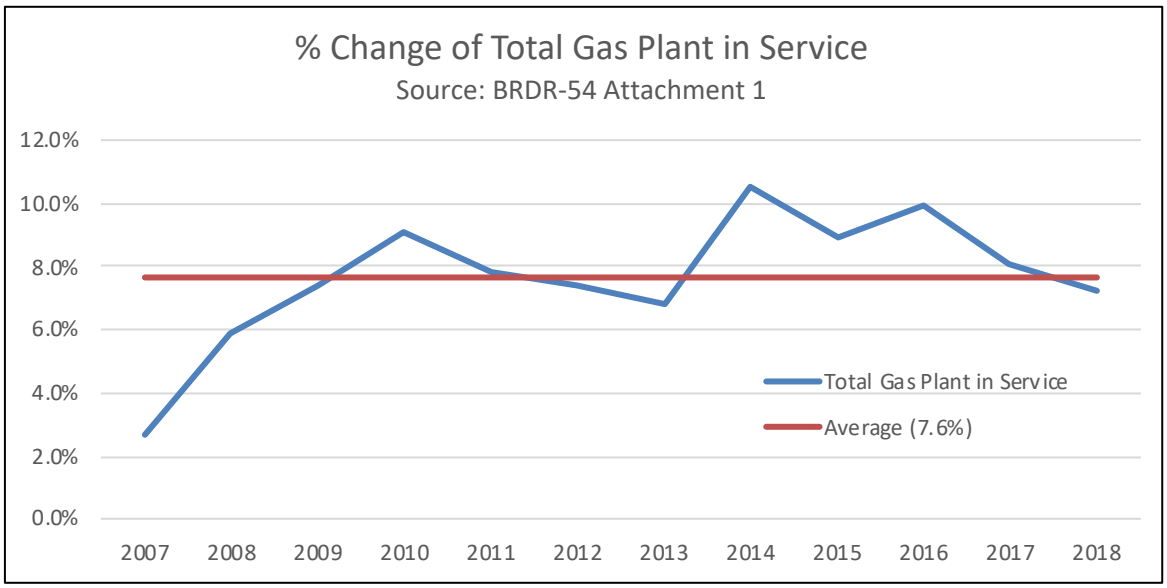
WBS Element	Description	Value of Retirement	Notes
FCDEO.15.GAS.8A	Ashtabula HVAC Building Management System	$ 110,681.72	
FCDEO.14.GAS.12A	Belmont - Building renovation	$ 109,612.58	
FCDEO.14.GAS.11A	Cambridge - Building renovation	$ 49,484.59	Most of the project costs related to construction of new building.
FCDEO.13.GAS.7B	Canton Perry Yard Renovations	$ 374,585.70	
FCDEO.16.GAS.5D	Eastwood Back Entrance Vehicle Gate/Operator/Camera	$ 262,684.12	Most costs associated with this WBS element settled in another year.
FCDEO.16.GAS.3C	Eastwood HVAC RTU #2 & #3		
FCDEO.15.GAS.3J	Eastwood-Management Area reconfiguration		Eastwood Renovation. Most costs associated with this WBS element settled in another year.
FCDEO.16.GAS.1D	E 55th - Cafeteria equipment/upgrade	$ 200,130.56	
FCDEO.16.GAS.6A	E 55th - Gas Control Offices		
FCDEO.16.GAS.10A	E 55th Street cooling tower replacement main bldg		
FCDEO.16.GAS.9D	E 55th - Drainage System		
FCDEO.15.GAS.5A	E55th - Conf Rm Technology Upgrade - Various		
FCDEO.15.GAS.2H	E55th Street Microturbines		
FCDEO.15.GAS.3K	E 55th - Northern Storage (Vehicle) Building		
FCDEO.16.GAS.9B	Eastern (Randall) Parking Lot	$ 113,584.63	Asphalt Replacement
FCDEO.16.GAS.5C	New Philly Annex Light fixtures/tube heaters	$ 17,501.00	
FCDEO.16.GAS.9C	Western (West Park) Parking lot	$ 29,450.05	
FCDEO.14.GAS.11E	Wooster - Build Meter Storage Building	$ 76,913.76	Renovation to Building.
FCDEO.16.GAS.3D	Youngstown Fence/Card Readers	$ 52,690.22	
Total		**$ 1,397,318.93**	

Besides the missing retirements from the table above, Blue Ridge was satisfied that the rest of the activity was not unreasonable.

The third area of focus reviewed year-over-year total plant in service. The trend showed increase each year at an average rate of about 7.6%, which Blue Ridge determined was not unreasonable.

[31] DEO Response to Data Request BRDR-54 (Variance Analysis).
[32] DEO Response to Data Request BRDR-73 (Variance Analysis) and BRDR-73 (Revised).

Figure 1: Percent Change in Total Plant in Service[33]



CONCLUSION—VARIANCE ANALYSIS

Based on the variance analyses performed, Blue Ridge was satisfied that the activity was not unreasonable.

CAPITAL SPENDING AND COST CONTAINMENT

CAPITAL SPENDING

Capital spending has increased 115% from the first full year of the CEP in 2012 through 2018. Relocation work and new business accounted for approximately 26% of the total spending during that period. Relocation work is a required activity and frequently cannot be budgeted. New Business falls under the Company's obligation to serve. Transmission Storage and Gathering accounted for 24% of the total spending, and Facilities accounted for 12%. The highest spending year was 2018. During that year, the Company spent $147 million. However, 22% of that represents Relocation and New Customer work. Besides 2018, the highest spending years were 2015 and 2016. During those years, the primary spending was on consolidating facilities and again on Relocation and New Customer work. Our review found that the principal causes for the increase in the Company's non-PIR / non-AMR capital expenditures were based on necessity, were not unreasonable, and did not indicate imprudence. We are satisfied that the Company is taking appropriate measures to control labor and contractor costs, which in turn control spending. We did not see anything during field testing that would indicate the Company is "gold plating" construction.[34]

COST CONTAINMENT

Containing costs is key to controlling the significantly increasing costs associated with CEP-type projects. The Company hires outside contractors to perform capital work, leaving most of the maintenance work to in-house labor. Over 80% of the capital activities are performed by contractor

[33] WP BRDR-54 Attachment 1 Variance Analysis.xlsx.
[34] DEO Response to Data Request BRDR -49, Attachment 1.

labor. From 2011 through 2019, contractor labor ranged from 81% to 86% of the total labor used on capital projects.

To help achieve the most cost-effective outcomes in utilizing contractor labor, DEO has employed a competitive bid process. This process has been utilized both with respect to PIR and non-PIR projects.

In DEO's most recent PIR reauthorization case (No. 15-362-GA-ALT), DEO's competitive bidding process regarding the PIR Program was extensively reviewed by the PUCO, along with other factors affecting PIR costs. Even though not specifically reviewed by Staff, the CEP projects use the same competitive bidding process as do the PIR projects. Staff investigated DEO's contractor bidding and selection processes to ensure that the Company is not establishing unreasonable qualification standards on contractors or erecting any other sort of barriers that would prevent contractors from participating in DEO's program or submitting project bids. Staff did not find such barriers. In fact. Staff found that DEO has a large number of eligible contractors in its bid solicitation pool and, on average, more contractors are submitting bids on projects now than in the past. In Staff's opinion, DEO has a robust competitive contractor bidding-and-selection process and an effective program for recruiting contractors and assisting them to become qualified to submit bids on PIR projects. While cost is a primary input into the consideration of bids, DEO focuses on "best value," which comprises other elements beyond cost, such as a contractor's ability to complete the project by the required date, the contractor's construction schedule, and the corresponding impact on inspection, traffic control resources, and relationships with cities and customers.

The strategy that has emerged from this process is to balance the use of contractors with internal labor and determine the areas of specialization that are best performed internally, areas that are best suited to contracting, and areas in which a blend is necessary due to the scope and/or pace required.[35]

Regarding cost containment, the Company has essentially four options:

- Pay what the market will bear
- Defer or eliminate work
- Negotiate prices and lock in longer-term contracts
- Hire and train in-house resources

The larger pool of qualified outside labor allows the Company to negotiate from a more advantageous position. The Company is taking steps to control contractor costs. The pool of outside contractors has increased over the years. The Company uses a bidding process for work. Large projects generally are performed by contractors that may be outside the state. Smaller projects tend to be done by local or state-wide contractors. Many of the projects have onsite inspectors, and the smaller projects are monitored periodically in the field. Putting on more full-time staff or staffing up would not appear to be a viable alternative. The construction season in the gas business is finite, and therefore, the Company would be overstaffed in non-construction months. Since the ability to perform maintenance also depends on weather conditions, the same would hold true for hiring additional maintenance staff. The Company is taking steps which appear to be not unreasonable to try to control costs.

[35] DEO Response to Data Request BRDR-42 (Labor Costs).

CONCLUSION—CAPITAL SPENDING AND COST CONTAINMENT

Blue Ridge concludes that the Company is implementing sound cost containment strategies. In addition, even though capital spending has increased from 2012 through 2018, the nature of the spending does not give us cause for concern.

DETAILED TRANSACTIONAL TESTING

The Company provided a list of 202,655 work orders / projects that support gross plant in service from April 1, 2007, through December 31, 2018. The list was compiled of 76,329 CEP-related work orders and 135,300 non-CEP-related work orders. These work orders / projects included $2,824,374,721 in assets.

In addition, the Company provided a list of major additions or replacements from October 1, 2011, through December 31, 2018:

- Support pipeline integrity, involving replacing transmission pipe and valves as well as installing a pig launcher and receiver
- Increase reliability of storage injections and provide added storage flexibility
- Replace aging equipment that required difficult-to-acquire replacement parts to increase reliability on the supported systems and to reconfigure station layout to increase operational efficiency
- Construct a new training center to offer comprehensive, classroom and hands-on learning experiences for DEO field personnel and emergency responders
- Construct a new facility to replace former company operations building in Lima, Ohio.[36]

Blue Ridge considered the following information when selecting projects for transactional testing.

1. Developed an understanding of CEP and non-regulatory-recovered projects (non-CEP, non-PIR, and non-AMR projects)

   Blue Ridge developed an understanding of the difference between CEP and non-regulatory-recovered projects.

2. Reconciliation of Work Order / Annual Informational Reports and Plant-in-Service Schedules

   To ensure that Blue Ridge was provided a comprehensive list of work orders / projects for review and testing, we compared the lists of work orders / projects ("work order population") to the totals in the annual report of utility plant in service filed with the Commission. With the help of the Company, Blue Ridge was able to reconcile the total additions in the work order population for CEP and non-regulatory-recovered additions to the 2007 through 2018 annual reports.

3. Determining Work Order Sample

   Blue Ridge selected 93 CEP and 117 Base Rate work orders / projects reflecting thousands of cost line items using the probability-proportional-to-size (PPS) sampling technique and professional judgement. The work orders selected based on professional judgment focused

[36] DEO Response to Data Request BRDR-11 (Major Additions or Replacements).

on individual (rather than blanket) work orders that have a high-dollar value and occurred from April 1, 2007, through December 2018.

To satisfy the review of these areas of focus, Blue Ridge formulated the objective criteria into the following transactional testing steps, labeled T1 through T12. Blue Ridge's observations and findings against the criteria follow.

- T1: Project Type
  - T1A: Is the work related to DEO?
  - T1B: Is the work order / project CEP, PIR, AMR, or "other capital investments"? [Label as appropriate]
  - T1C: Is the work order / project specific, blanket, multi-year, or other (provide description)?
  - T1D: Is the work order / project an addition, replacement, non-project allocation, or other (provide description)?
- T2: Project Category (CEP Inclusion October 1, 2011–December 31, 2017)
  - T2A: Is the work order / project Infrastructure Expansion, Improvement or Replacement?
  - T2B: Is the work order / project Installation, Upgrade or replacement of Information Technology?
  - T2C: Is the work order / project a Program Reasonably Necessary to comply with Commission Rules, Regulations, and Orders?
- T3: Capital Scope
  - T3A: Is the scope of work properly classified as capital and charged to the proper FERC 300 account(s) as dictated by the FERC code of accounts (CFR 18)?
- T4: Justification
  - T4A: For specific or multi-year work orders / projects (i.e., not blankets), does the project have detailed justification that supports that it was necessary and not unreasonable?
- T5 Approval
  - T5A: Did the work order / project have proper level of approval?
- T6: Budget
  - T6A: Does the work order / project have an approved budget?
  - T6B: Are the work order / project costs +/- 20% of the approved budget?
  - T6C: Are explanations and approvals provided for cost overruns 20% and greater over the approved budget?
- T7: In-Service Dates
  - T7A: Is the actual in-service date in line (at or before) with the estimated in-service date.
  - T7B: Was the work order / project in service and closed to UPIS within a reasonable time period from project completion, and if not, was AFUDC stopped?
- T8: Continuing Property Records
  - T8A: Do the Continuing Property Records support the asset completely and accurately?
- T9: Cost Categories
  - T9A: For work orders / projects, are the cost categories (Payroll, M&S, etc.) not unreasonable and support the work order total?
  - T9B: For "other" (referring to T1d above), are the description and costs not unreasonable?
- T10: Revenue-Generating
  - T10A: For CEP additions, will the work order / project generate revenue? If so, how has the revenue been quantified?

T11: Replacement projects
- T11A: Were assets retired?
- T11B: Was the date of retirement and cost of removal in line with the asset replacement date?
- T11C: Is the amount of the retired asset not unreasonable?
- T11D: Was salvage recorded?
- T11E: Was cost of removal charged? Is the amount not unreasonable?

T12: Field Verification
- T12A: Is the project a candidate for field verification?

The results of the detailed transactional testing performed on the work-order sample are included in the workpapers. Specific observations and findings about the testing are listed below.

T1: Project Type

T1A: Is the work related to DEO?

Based on single-line-item description of the scope provided for massed (blanket) projects and the detailed scope provided for fixed (specific) projects, the work does appear to be attributed to DEO.

T1B: Is the work order / project CEP, PIR, AMR, or "other capital investments"?

Blue Ridge tested 210 work orders / projects (WBS [Work Breakdown Structure] elements), in which each of the WBS elements fit into one or more of the following capital investment categories.

CEP: CEP related capital investments involve the follow three categories of work:

- HB95-1: Infrastructure Expansion, Improvement, or Replacement.
- HB95-2: Installation, Upgrade, or Replacement of Information Technology
- HB95-3: Programs Reasonably Necessary to Comply with Commission Rules, Regulations, and Orders[37]

PIR: The PIR program involves the replacement of bare steel, cast iron, wrought iron, copper, and ineffectively coated pipe and other items as described below previously in the Project Scope section of this report.[38]

AMR: The AMR program involved the installation of Encoder-Receiver-Transmitters (referred to as both *ERT devices* and *AMR devices*) on all customer meters other than those meters already equipped with electronic gas measurement (i.e., accounts on the Daily Transportation Service rate schedule). Capital investment in the AMR program ended in 2012. Annual cost recovery filings continue to recover depreciation expense, property tax expense, and the return on investment, with an offset for certain O&M savings associated with the program.[39] More discussion of the AMR program can be found previously in the Project Scope section of this report.

[37] Case No. 19-0468-GA-ALT, Direct Testimony of Vicki H. Friscic, page 2, line 14–page 3, line 10.
[38] DEO Response to Data Request BRDR-21 (PIR Investments).
[39] DEO Response to Data Request BRDR-22 (AMR Investment).

Other Capital Investments (Base Rates): Capital investments not included in the above regulatory programs.[40]

Hybrid: Where it made sense from a construction perspective, some projects, identified as *Hybrid*, included both PIR-eligible and CEP-eligible portions. Common costs incurred for these projects were allocated between PIR and CEP based on the initial project design. Allocations would be later adjusted based on the final project "as-built" entered into the system.[41]

Blue Ridge sampled 210 work orders / projects; 101 of the work orders / projects were found to be includable as CEP deferrals (100% HB95 or Hybrid projects). Seventeen of the 101 work orders / projects were Hybrid.[42] Blue Ridge found that, for the projects identified as Hybrid, the reasons the Company provided for the scope of work being split between CEP and PIR is not unreasonable. The remaining 109 work orders / projects were found to be non-CEP, non-PIR, and non-AMR capital investments within Base Rates.

T1C: Is the work order / project specific (fixed), blanket (massed), multi-year, or other?

Specific (Fixed) Projects

- Fixed Projects (specifics) are created in SAP as capital projects and are manually closed as individual projects.
- Unless the projects are direct purchases of equipment, they usually have longer construction periods (over 30 days) and typically accrue AFUDC.
- Costs on this type of project are recorded to CWIP monthly and, when declared ready for service, are closed to either completed construction not classified or Utility Plant in service.[43]

Blanket (Massed) Projects

- Projects within this classification are typically recurring work that is done throughout the year, contain work similar in nature, and consist of one or two retirement units of property. Each individual project within a blanket massed assets project are typically of smaller dollar value. Massed asset projects are of a short-term duration and a portion of massed assets is placed in service and closed every 30 days.
- Most distribution system projects are considered Massed Projects. Examples include service line projects and meters.
  Massed projects are typically created in SAP as O&M project types (for identification only) so that they can settle automatically (close) up through capital roll-up projects, assets accounted for by vintage year.
- Costs on this type of project are closed to Plant each month as permitted by the FERC Uniform System of Accounts.

[40] Capital Project Process Overview 7-17-19, page 1. Provided for review during Kick-Off Meeting on 9/20/19).
[41] Capital Project Process Overview 7-17-19, page 3. Provided for review during Kick-Off Meeting on 9/20/19).
[42] Workpaper DEO Detailed Transactional Testing Matrix.
[43] Capital Project Process Overview 7-17-19, page 1. Provided for review during Kick-Off Meeting on 9/20/19).

- AFUDC is not applied to Massed Projects since the projects are short in duration (fewer than 30 days).[44] AFUDC is calculated monthly based on CWIP. Therefore, projects that close monthly are not subject to the calculation.

Of the 210 work orders / projects in the sample that Blue Ridge tested, 153 (73%) were fixed, 55 (26%) were massed assets, and 2 (1%) were either transfers or capital projects.

Table 12 Number of work orders / projects that are Fixed or Massed

	CEP	%	Base Rates	%	# of WBS Elements	%
Fixed	75	81%	78	67%	153	73%
Massed	18	19%	37	32%	55	26%
Transfers/Capital	0	0%	2	2%	2	1%
Total	**93**	**100%**	**117**	**100%**	**210**	**100%**

T1D: Is the work order / project an addition, replacement, non-project allocation, or other?

Blue Ridge identified the following breakdown:

Table 13 Breakdown of number of additions, replacements, etc. sampled

	CEP	Base Rates	Total
Additions	4	41	45
Replacements	43	15	58
Additions / Replacement	9	29	38
Retirements	1	0	1
Reinstatement	0	0	0
Replacement / Retirement	1	0	1
Non-Project Allocations	0	17	17
Other (Facilities, Metering, IT, Transfers, Accounting, and Conversion)	35	15	50
Total	93	117	210

T2: Project Category (CEP Inclusion October 1, 2011–December 31, 2017)

Blue Ridge identified the project recovery category for each work order / project sampled. Of the 210 work orders / projects sampled, the following table records their alignment.

Table 14: Project Recovery Category

	CEP-HB95	PIR	AMR	Base Rate
CEP-HB95	84	9	0	8
PIR				0
AMR				0
Base Rate				108

T2A: Is the work order / project Infrastructure Expansion, Improvement or Replacement?

HB95-1: Expenditures in this category include distribution system betterments; pipeline, regulating station, or other improvements or replacements, including non-billable pipeline relocations, associated with DEO's distribution, transmission,

[44] Capital Project Process Overview 7-17-19, page 1. Provided for review during Kick-Off Meeting on 9/20/19).

storage, production, and gathering systems that are not covered by DEO's Automated Meter Reading and Pipeline Infrastructure Replacement programs; storage well and compressor station improvements or replacements; and certain customer main line extensions, main-to-curb and curb-to-meter service lines.[45]

Blue Ridge identified 60 of the 93 CEP-related work orders / projects were associated with infrastructure, improvement, or replacement.

T2B: Is the work order / project Installation, Upgrade or replacement of Information Technology?

HB95-2: This category includes capital expenditures for upgrades to or replacements of computer systems utilized for accounting, billing, and utility operations as well as communication systems. Capitalized costs may include costs for hardware, software purchases or development, installation, and associated licenses.[46]

Blue Ridge identified 13 of the 93 CEP-related work orders / projects were associated with installation, upgrade, or replacement of information technology. For those 13 IT projects found in the CEP sample, seven of the projects split charges between the Company and a subsidiary. The remaining six IT projects were entirely the Company.

Blue Ridge identified seven additional IT-related projects within the Base Rate sample. Four of the seven Base Rate IT projects were split, while the other three were not split between other subsidiaries.[47]

T2C: Is the work order / project a Program Reasonably Necessary to comply with Commission Rules, Regulations, and Orders?

HB95-3: Capital expenditures in this category include those for required pipeline integrity or other regulatory compliance associated with pipeline safety, environmental compliance, metering, facilities, fleet, and other general plant associated with providing DEO's regulated services.[48]

Blue Ridge identified 19 of the 93 CEP-related work orders / projects were associated with project infrastructure improvement, or replacement.

T3: Capital Scope

T3A: Is the scope of work properly classified as capital and charged to the proper FERC 300 account(s) as dictated by the FERC code of accounts (CFR 18)?

The Company provided descriptions of the type of work included in specific work orders / projects in the sample. Blue Ridge evaluated the information to determine whether the work orders / projects in the sample were appropriately classified as capital and charged to the proper Intangible, Distribution, and General Equipment FERC 300 accounts. Blue Ridge found seven items that warranted further review,[49] and Blue Ridge recommends the following two adjustments:

[45] DEO Response to Data Request BRDR-8 Attachment 2.
[46] DEO Response to Data Request BRDR-8 Attachment 2.
[47] DEO Response to Data Request BRDR-120 (WBS Testing).
[48] DEO Response to Data Request BRDR-8 Attachment 2.
[49] Workpaper DEO Detailed Transactional Testing Matrix.

1. CEP: IT DEO.RATE CASE.2 - DEO RATE CASE
   a. Capital Scope Initial Concern: *Costs charged to FERC 399.01 (General Plant other tangible property) not FERC 303 (Misc. Tangible Plant)*
   b. The Company provided the following explanation for the FERC charges: This project relates to modifications made to the company's CCS/SBS billing systems. The Commission approved reclassification of the company's CCS and SAP system-related costs to FERC Account 399, Other Tangible Property.

      DEO has determined that this project should not have been included in the CEP. On further review, DEO determined that the project was completed prior to the initiation of the CEP. DEO would not object to the removal of this project from the CEP Rider.[50]

   Blue Ridge agrees with the Company that this project does not belong in the CEP since the project was completed prior to the initiation of the CEP. Blue Ridge recommends that CEP plant in service be reduced by $306,807 and the CEP reserve should be adjusted by $(148,364), resulting in a reduction to CEP net plant in service of $148,443. This adjustment flows through the recast CEP revenue requirements. **[ADJUSTMENT #2]**

   CEP: P400422422.001 – Huskey M&R Station:

   c. Capital Scope Initial Concern: This project was in CWIP as of December 31, 2018.
   d. The Company explained that the project was originally closed December 3, 2018. The project was reopened to post a contractor payment on December 28, 2018 and was not properly re-closed. The Company believes this project was appropriately included as a CEP capital addition for 2018. The project cost, including cost of removal, was $760,056.35.[51].

   Blue Ridge found that this project was in CWIP as of December 31, 2018, and therefore, should not be included in the CEP for this scope period. Upon further review, Blue Ridge found that although closed and put in service on December 3, 2018, the asset was reopened to post a contractor payment on December 28, 2018, and was not properly reclosed. The project was in service as of the CEP date certain and the correction was made to reclose the project (and remove it from CWIP) in January 2019. Thus, Blue Ridge found that it is not unreasonable to allow this project to be recovered through the CEP as of December 31, 2018.

T4: Justification

T4A: For specific or multi-year work orders / projects (i.e., not blankets), does the project have detailed justification that supports that it was necessary and not unreasonable?

The Company provided detailed documentation that supported the specific (fixed) work orders / projects for 153 of the 210 work orders in the sample. The documentation defined the scope of the project and, for the most part, the necessity of the project.

Of the 210 work orders / projects sampled, 38 are blanket (massed asset) projects. Blanket projects do not have detailed justification, as projects within this classification are similar, typically of a smaller dollar value, and are constructed and put into service quickly (i.e. projects

[50] DEO Response to Data Request BRDR-137.
[51] DEO Response to Data Request BRDR-160.

of fewer than 30 days).[52] These projects represent normal recurring utility work.

Seventeen of the 210 work orders / projects sampled are massed asset reallocation entries. They are not massed projects per se but are the reallocation of certain massed project core costs and, therefore, considered transfers. The Company explained that these were necessary to reallocate massed asset common costs because of how the PMOO system works.[53] Blue Ridge is satisfied with the Company's response and the detail provided to support that response.

The remaining two work orders / projects were either Conversions or Transfers. The net impact of those entries did not change utility plant.

T5 Approval

T5A: Did the work order / project have proper level of approval?

The Company provided the Expenditure Control Policy, effective August 2014 and updated April 2016, as well as a list of the Company's Signature Authorities that Support the Approval of Capital Projects.[54]

Early on, the business process had a manager level approve each project/process from the PPT group, but in 2015, the Company realized that they should be following the appropriate R-level approval based on estimated project amounts. After 2015, the approvals are based on R-levels, and they are going higher up the food chain than just the PPT group.[55]

T6: Budget

The Company's Expenditure Control Policy notes that strict control must be exercised over the expenditure of Company funds. An essential element of control is adherence to budgeting, procurement, and expenditure policies. Employees who have been assigned requisition and payment approval authority are responsible for monitoring and exercising control over expenditures of Company funds included in their authorized budgets and are accountable for adherence to Company policies and procedures. Employees may exercise only the approval authority assigned to them.[56]

Blue Ridge asked the Company to provide budgets supporting the CEP capital expenditures and related assets for 2011 through 2018 as well as the assumptions supporting the budget/ projected data. The Company's response indicated that there is a wide range of potential data and assumptions at issue in each budget and that, given the number of years in scope, it is not practical to provide all supporting assumptions. Instead, the Company gave a general response indicating that the Company's budgets are based on expenditures needed for the Company to manage its business and provide safe and reliable utility service to its customers. CEP budgets are constructed based on both previous capital budget and usage and known and projected future capital needs.[57]

[52] Capital Project Process Overview 7-17-19, page 1. Provided for review during Kick-Off Meeting on 9/20/19).
[53] DEO Response to Data Request BRDR-66.
[54] DEO Response to Data Request BRDR-30 (Approval Signatures) Confidential, Attachments 1, 2, and 3.
[55] Notes from Various Calls – December 17, 2019 Call.
[56] DEO Response to Data Request BRDR-30 (Approval Signatures) Attachment 1 Confidential.
[57] DEO Response to Data Requests BRDR-41 (Budget) and BRDR-162 (Approvals).

T6A: Does the work order / project have an approved budget?

Of the total work orders / projects in the sample, approximately 83 of 210 were properly approved. According to the Company, prior to 2015, DEO CRF (Capital Requisition Form) approval process required only a manager-level approval, no matter the estimate of the project on the CRF.[58] Blue Ridge found that 115 of the 210 work orders / projects sampled were properly approved based on DEO's historical process.

Post mid-2015, the Company changed their approval process by following appropriate R-level approval based on estimated project amounts.[59] Blue Ridge found that 65 of the 95 work orders / projects were approved at the proper level of approval based on estimated project amounts. While seven projects were questionable the Company provided the following explanations:

- Per DEO process, the CRF approval level is obtained for the original estimate value. Estimates may be refined after the scope has been approved; however, DEO's current process is to not renew the CRF approval. Per DEO process, the purchase order requisition would follow the LOSA for the refined estimate. The director-level approval on the CRF, based on the CRF estimate, met DEO's process.
- The project spending was approved as part of the capital budgeting process and was ultimately approved by the Board of Directors when it approved the DEO capital budget.
- This project has multiple components (labor and material). Each component follows the appropriate R-value approval process. The majority of costs for the project were from the contractor and the R-3 Director level value shown meets the R-level process.

  Requisitions for materials are created by line item with Stock ID and/or description of what material is required for the job. A requisition may have multiple lines. Each line item is approved based on the net value of the item. For example, quantity of six valves at $100.00/EA is approved at a $600 value and approved in SAP to the appropriate R-value approver.[60]

The remaining 18 of the 210 work orders / projects were approved by the Board of Directors during the Capital Budgeting Process.

Blue Ridge found that the Company did use the CRF but did not do so consistently when the projects changed; instead, the PO requisition was used. For blanket projects, it is appropriate that the approvals are at the Board of Director level. Because of the various types of approvals that take place based on the nature of the project, it is important for the company to apply a consistent procedure. Blue Ridge recommends the Company review and comply with their approval process to ensure that it is applied on a consistent uniform basis.

Projects that are Board Approved or without Budgets

The 20 work orders / projects were approved at the Board of Directors level within the total capital budget and, therefore, did not have individual budgets. The capital budget includes the following type projects:

- Growth

[58] DEO Response to Data Request BRDR-161.
[59] Various Call Notes: December 17 Call.
[60] DEO Response to Data Request BRDR-161.

  - New Customer Faculties excluding meters
  - OH HCA (Heat Content Agreement)
  - Strategic Growth
  - Pipeline Infrastructure Replacement (PIR)
- Maintenance
  - Distribution Infrastructure – Non-PIR
  - Gathering Production Infrastructure
  - Storage Infrastructure
  - Transmission Infrastructure
  - General Infrastructure – Training Center, Lima
  - IT / Telecomm
  - Metering Capital – Non-AMR
  - Pipeline Integrity – Non-PIR
- Environmental[61]

Twenty-three work orders / projects did not have budgets.

- Massed Reallocations
- Conversion
- Accounting/Transfers

T6B: Are the work order / project costs +/- 20% of the approved budget?

In summary, Blue Ridge found the following calculated results:

Table 15 Cost overrun analysis

% of Sample	# in Sample	Description
15%	32	Projects over budget greater than 20%
3%	6	Projects under budget by less than 20%
58%	121	Projects over/under budget by less than 20%
3%	7	Projects over/under budget by less than 20% as long as Change Orders are accounted for
21%	44	Projects did not have budgets (100% Billable (Base Rates only), Budget not built at individual WBS element level or Board of Director Approved, Massed Reallocations, accounting work orders (transfers / conversions), etc.)
100%	**210**	**Total**

T6C: Are explanations and approvals provided for cost overruns 20% and greater over the approved budget?

Of the total work orders / projects in the sample, approximately 32, or 15%, were over budget by 20% or greater. The Company provided explanations for those 32 projects. Explanations for 14 of the 32 work orders / projects indicated that the budget variance occurred due to either unforeseen events or were outside the Company's direct control. The

[61] Informal Response for 2018 Board Capital Budget Approval and DEO Response to Data Request BRDR-162 (Approvals).

remaining 18 work orders / projects needed a closer look.[62] Blue Ridge found that the Company's explanations for 4 of 19 work orders / projects were not unreasonable. Further discussion regarding the other 15 work orders is included below.

1. WBS: OC.P.DI.M.000305 / Project ID: P400039662
   a. Actual Spend: $533,537
   b. CEP Spend: $533,537
   c. Budget: $224,456
   d. Change Order / Additional Funds Requested: $41,941
      i. Blue Ridge's initial concern regarding Change Order: Summary Notes on variance indicate that "the original project estimate was too low. Estimate included the cost of a heater, and the installations costs"; however, the Change Order Agreements explained only $41,941 for materials of the $309,081 variance.
      ii. Company's Reason for the Change Order not covering the variance: The scope of this project did not change; therefore, a Change Order would not have been initiated. The project baseline included only the cost of the heater and the glycol, not any installation or internal costs. This was an oversite when the project baseline was created. Typically, material and labor are included in project baselines. Please see BRDR-105 Attachment 4, which shows the project material was installed by a contracting company that was under a blanket contract. That blanket contract was approved by the appropriate level of signature authority.[63]
   e. Over budget by 58% or $309,081
   f. Project Description:
      Project Driver: The existing unit is undersized, operations has been having trouble maintaining an adequate temperature with this unit.
      Scope of Work: Replace the Indirect fired natural gas heater.
      Project Location: S Youngstown Station near 1558 Walker Mill Rd
   g. Reason for cost overrun: The original project estimate was too low. Estimate included the cost of the heater and not the installation costs.

   Blue Ridge found that the Company should have included the installation costs in the original estimate since it is a routine cost.

   Blue Ridge found the Company's explanation unusual that the costs were split between a fixed project and a blanket contract, but we did not see anything in the overall explanation that would be a cause for concern.

2. WBS: OC.P.REL.000383 / Project ID: P400059460
   a. Actual Spend: $1,211,197
   b. CEP Spend: $1,157,936
   c. Budget: $890,209
   d. Change Order / Additional Funds Requested: $31,044
   e. Company's reason for the Change Order not covering the variance: Increased costs not included in the values shown on the change order agreements occurred for two reasons. First, additional costs were associated with material types for which pricing was already established with the project's contractor. In this instance, the change order quantity was included on the change order, but with no associated

[62] WP – DEO Scope against Variance Explanations (BRDR-61, 64-66) and Workpaper DEO Detailed Transactional Testing Matrix.
[63] DEO Response to Data Request BRDR-105 REVISED.

cost. The Company terms these change orders as "Reference Only." Please see documents b126 10-13-16 6335910-COA-25381 and b126 10-12-16 63359120-COA-25383, which were provided in support of this project, to see the reference only material quantities. Second, additional traffic control was not part of DEO's change order process because it was not related to a change in the scope of the project. Safety of the workers on the job, along with the traffic patterns and the presence of students near Kent State's campus required additional traffic control throughout the duration of the project that was not anticipated. The estimated cost for traffic control at the beginning of the project was $27,672. At the end of the project, a total of $139,296 was spent on traffic control. This additional spend of $111,624 did not require a change order per DEO's Change Order process. Typically for this type of project, prices for potential unforeseen conditions are established with the contractor at the beginning of the project and executed as necessary, not requiring a change order.[64]

f. Overbudget by 27% or $320,988
g. Project Description: Relocate 1,100' of gas main due to Roadway and Drainage improvements.
h. Reason for Cost overrun: Additional mainline installed due to related utility and design conflicts at tie-in locations. Additional time and equipment added to project due to temporary restoration required by city of Kent and Kent State during the project.

Blue Ridge found that the Company should have realized traffic control was going to be an issue since they were working near a college during school. Blue Ridge would have been willing to accept the Company's explanation if the traffic control had not exceeded five times the original budget.

3. WBS: P400090072.001 / Project ID: P400090072
   a. Actual Spend: $1,992,960
   b. CEP Spend: $2,041,729
   c. Budget: $1,472,264
   d. Change Order / Additional Funds Requested: $105,775
   e. Company's reason for the Change Order not covering the variance: Typically, internal labor and internally purchased material do not require inclusion in a change order, per DEO's established process. Dominion purchases all steel pipe material required. As the scope for this project was to make L#1745 piggable, assessments to the existing pipe took place once construction started and determined that the replacement of additional steel pipe was required. This additional pipe footage increased the cost of the project but was not required to be reflected in a change order per process. Additional restoration material was also required to install a new access road at the station, but it was not captured on a change order because pricing was already established with the project's contractor. The project duration was increased due to both the additional pipe installation and restoration mentioned above. The increased project duration, in turn, increased internal labor, which per DEO process, is not typically captured on change orders. There were also some necessary costs associated with land and right-of-way acquisitions required to complete the project, which were not reflected in the

[64] DEO Response to Data Request BRDR-105 REVISED.

estimate but did not change the scope of the project. For this project, prices for potential unforeseen conditions were established with the contractor at the beginning of the project and executed as necessary, not requiring a change order.[65]

f. Overbudget by 26% or $520,697
g. Project Description: Project Driver/Goal: Most of L#1745 is 12in mainline(~7300ft). Replacing the remaining mainline could potentially allow the entire line to be made piggable (~1650ft).
   Project Scope: Replace mainline/assess options to make L#1745 piggable
   Project Location: L#1745, between Franklin Station and valve#4853, Lawrence Township
h. Reason for Cost overrun: A new access road was installed at Franklin Station, which was not part of the originally planned project. It was required in order to allow continued access to other facilities at the station, which was missed during the initial design. Labor cost was included in the Change Orders; however, the material (gravel and environmental CU's) was not.

   There was significantly more land and legal cost on this project to settle unforeseen land disputes. During construction, operations requested a scope change to bring branch tie-ins above ground for future operational safety. Additional restoration costs due to grading issues.

Blue Ridge found the Company's explanation confusing. Pricing established with a contractor should not change unless a change order is needed. If it were to change then the pricing should have been in the original estimate.

COMPANY FACT CHECK COMMENT: DEO stated that it did not consider contractor pricing to have changed and that a change order was not required for reasons stated.

BLUE RIDGE REPLY: The Company stated part of the reason for the variance was that "additional restoration material was also required to install a new access road at the station, but it was not captured on a change order because pricing was already established with the project's contractor." Blue Ridge believes that even if a per unit cost is established with a contractor, significantly changing the amount of material purchased from the estimate should require a change order.

4. WBS: 400239583.001 / Project ID: P400239583
   a. Actual Spend: $1,593,664
   b. CEP Spend: $1,387,393
   c. Budget: $1,095,297
   d. Change Order / Additional Funds Requested: $70,021
   e. Company's reason for the Change Order not covering the variance: Cost increases were incurred on this project for the following expenses: legal fees, legal settlement, additional security needed due to legal issues, and additional inspector time. These additional costs were in response to an easement dispute with a landowner. Although these changes cannot be forecasted at the beginning of every project, they do occur from time to time on projects. The scope of the project did not change, and a change order agreement was not required to be initiated. DEO did review these

[65] DEO Response to Data Request BRDR-105 REIVSED.

costs in advance and approve as reasonable prior to proceeding. Please see BRDR-105 Attachments 2 and 3 for invoices detailing legal charges.[66]

f. Overbudget by 31% or $70,021
g. Project Description: Project Driver: Internal Corrosion Issues and Heavy debris inside of the pipeline.
   Project Description: Due to recent pig runs and remediation projects showing heavy debris and internal corrosion occurring in this pipeline. Because of these findings, we are going to replace this pipe in a four-phase project. This project is the first phase. In this phase, we will need to replace around 5400' of 8" steel with new 8" steel pipe. This project will be between these two segments: 8344477369956025723 and 459744574.
   Location: L#2925 Lawrence Township, Ohio 44614
h. Reason for Cost overrun: There were multiple unforeseen costs added during construction. The breakdown of the costs consisted of various change orders, tree clearing associated with legal, BJ Inspection time, Traffic Control, and legal costs associated with a right of way dispute with a property owner.

Blue Ridge found that increased costs should have triggered a change order in accordance with procedure.

COMPANY FACT CHECK COMMENT: The Company clarified that it did not consider a change order to be necessary per its change-order procedures. The Company had provided a decision tree to explain the process.

5. WBS: DEO PLNT MAINT.2. and DEO PLNT MAINT.2.BA / Project ID: DEO PLNT MAINT
   a. Actual Spend: $4,039,317
   b. CEP Spend: 100% of project is CEP
   c. Budget: $2,888,675
   d. Over budget by 28% or $1,150,642
   e. Project Description: SAP will replace the current functionality provided by Logica's Work Management System for the Gas Delivery Business by implementing Enhancement Pack 5 which includes Compatible Unit's and Operational Level Cost Accounting Functionality.
      i. Streamline the Process "Initiate to Close"
      ii. Assure Fixed Asset Accounting Functionality
      iii. Integrate to Business Warehouse
      iv. Leverage and Optimize SAP Integration
      v. Align with Portfolio Project Management Tool
   f. Reason for cost overrun DEO PLNT MAINT.2.BA: Budget estimates for business labor are assumed to be 5% additional to project costs which would be $137,556 based on the original forecast of the project of $2,751,119. The largest factor in the increased project cost is functional scope increases and time extensions with the vendor. The original plan was to implement in August with two weeks of post implementation support from the vendor. Additional scope was added for a single point of entry for new projects based on the capital request form, project profiles to properly account for fixed and massed assets on a single project and automatic creation assets. Time extensions were the result of a delay in the Dominion schedule to implement Ehp5, and a need for extended vendor support through the end of

[66] DEO Response to Data Request BRDR-105 REVISED.

2012 based on a phased roll out to user groups based on their role. Also contributing to the increased cost is the internal effort required for additional testing and support related to the additional scope, adding a training specialist to the team, and for the SAP team to perform volume testing on the monthly accounting close. The DEO SAP team has been working on the volume testing in September, October, and November. Initial tests did not meet performance goals and improvements were needed. This effort was not planned and increased the cost of internal SAP resources.

g. Reason for cost overrun DEO PLNT MAINT.2: The largest factor in the increased project cost is functional scope increases and time extensions with the vendor. The original plan was to implement in August with two weeks of post implementation support from the vendor. Additional scope was added for a single point of entry for new projects based on the capital request form, project profiles to properly account for fixed and massed assets on a single project, and automatic creation assets. Time extensions were the result of a delay in the DEO schedule to implement Ehp5 and a need for extended vendor support through the end of 2012 based on a phased roll out to user groups based on their role. Also contributing to the increased cost is the internal effort required for additional testing and support related to the additional scope, for adding a training specialist to the team, and for the SAP team to perform volume testing on the monthly accounting close. The DEO SAP team has been working on the volume testing in September, October, and November. Initial tests did not meet performance goals and improvements were needed. This effort was not planned and increased the cost of internal SAP resources.

Blue Ridge found that several factors contributed to the cost overrun for DEO PLNT MAINT.2.BA and DEO PLNT MAINT.2. Scope changes and time delays contribute to some extent. Also contributing is the additional testing as a result of the initial tests not meeting performance goals. It is our opinion that while we understand projects such as this contain many variables, the Company should have been able to control the project to a certain extent regarding meeting testing performance goals. Blue Ridge notes this and recommends that the Company put more emphasis on monitoring the project so the testing phase would yield positive results.

6. WBS: O7300.12.GAS.5B / Project ID: O7300.12
   a. Actual Spend: $181,302
   b. CEP Spend: 100% of project is CEP
   c. Budget: $60,000
   d. Over budget by 67% or $121,302
   e. Project Description: Replace Harris-Farinon MW radios with Alcatel 8000 MW radios at Thompson, Chardon and Saybrook.
   f. Reason for cost overrun: Original Budget amount did not include site work or installation charges for the hardware. The equipment was budgeted at $60,000 for 3 microwave radios. The implementation of the project also included additional charges for labor for vendor consulting, site preparation, and installation.

   Blue Ridge found that the Company should have included site work and installation charges should have been included in the budget. A more comprehensive budget could have, in our opinion, helped to avoid the cost overrun for the most part. We recommend

that the Company perform a more comprehensive review to make sure normal activities, such as site work, are included in the initial project estimate.

7. WBS: FCDEO.15.GAS.3J / Project ID: FCDEO.15
   a. Actual Spend: $395,599
   b. CEP Spend: $395,599
   c. Change Order / Additional Funds Requested: $62,000
   d. Company's reason for the Change Order not covering the variance: The baseline budget of $50,000 was not the approved total project value; it represented only the costs associated with the architectural design. The total project baseline should have been $270,000. A project requisition was initially approved at $209,555. Additional funds were requested for added electrical service work and was approved for $62,000. The approval of $62,000 was shown in the documentation provided in response to BRDR-61. The difference between $270,000 and project actuals is related to the purchase of furniture. After the project was initiated, it was determined new furniture would be purchased. Verbal approval was given to purchase new furniture during a monthly project meeting. Please see BRDR-105 Attachments 5, 6 and 7 for the furniture invoices.[67]
   e. Budget: $50,000
   f. Over budget by 87% or $345,599
   g. Project Description: Construct 1 office and 1 conference room using drywall and metal studs. Remove and replace all ceiling tile and carpet and rubber base (carpet to be provided by DEO). Move 3 doors to new locations and patch walls as needed. Paint entire designated area. Provide HVAC work to properly condition the space. Remove and replace all florescent light fixtures with new LED fixtures.
   h. Reason for cost overrun: The Eastwood renovation had a project baseline of $50,000, however, the project request was $270K. The $50,000 baseline was the estimated architectural design dollars. The requested project amount of $270K did not include the furniture spend of $114K.

Table 16 Cost Detail for FCDEO.15.GAS.3J—(Highlights are the costs to move three doors)[68]

Asset description	Amount posted
CARPETING	$644.58
SUPERSTRUCTURE- PARTITIONS/ DRYWALL WALLS,	$2,578.30
LIGHTING SYSTEM	$1,933.73
ARCHITECT FEES- EASTWOOD	$322.29
HVAC SYSTEM- EASTWOOD	$966.87
CARPETING	$122.10
CARPETING	$38,743.55
SUPERSTRUCTURE- PARTITIONS/ DRYWALL WALLS,	$488.42
SUPERSTRUCTURE- PARTITIONS/ DRYWALL WALLS,	$154,974.20
LIGHTING SYSTEM	$366.31
LIGHTING SYSTEM	$116,230.64
ARCHITECT FEES- EASTWOOD	$61.05

[67] DEO Response to Data Request BRDR-105 REVISED.
[68] DEO Response to Data Request BRDR-8 Attachment 6 (2015 Addition Summary).

Asset description	Amount posted
ARCHITECT FEES- EASTWOOD	$19,371.77
HVAC SYSTEM- EASTWOOD	$183.16
HVAC SYSTEM- EASTWOOD	$58,115.32
Total Actual Spend for FCDEO.15.GAS.3J	**$395,102.29**

Blue Ridge found the project cost should have included furniture since the office and conference room would need to be made functional. Therefore, we conclude that a portion of the variance should have been budgeted.

COMPANY FACT CHECK COMMENT: The Company stated the reason the original budget did not include furniture was that the Company had planned to use existing furniture and only later in the process was it determined that new furniture was necessary.

8. WBS: P400120518.001 / Project ID: P400120518
   a. Actual Spend: $1,346,964
   b. CEP Spend: $1,114,446
   c. Change Order / Additional Funds Requested: $19,650
   d. Company's reason for the Change Order not covering the variance: The scope of this project did not change; therefore, a change order would not have been initiated. The project baseline did not include any internal costs associated with the project. This was an oversight when the project baseline was created. Typically, internal costs are included in project baselines.[69]
   e. Budget: $1,031,252
   f. Over budget by 23% or $315,712
   g. Project Description: Project Goal: To protect the gathering line and TPL 1 from over pressure due to high possible well pressures. These wells are in an area adjacent to active injection wells. Historically there has been observed a rapid pressure response when injecting nearby. During inventory verification shut-in tests, these wells can #rock up# to fairly high pressures (1375# observed). MAOP of the gathering system is 400#. As a secondary benefit, using these wells as a pilot project in a controlled area should also result in a modular solution that can be duplicated and used for other B-Wells that need this issue addressed.

      Another goal is to address a safety issue with the location of the tank batteries of two wells (Costello and Flower). These wells have a tendency to #load up# with produced fluid, which necessitates blowing or swabbing of the wells. These activities result in venting gas through the tanks. Both tank batteries are located under or nearly under power lines and transformers.

      Project Scope: Install over pressure protection (regulation) on 5 Group 6 B-Wells. Consolidate and relocate tank batteries for the Costello and Flowers wells.

      Project Location: Wells#1884(Smith), 1287(Costello), 1650(Flowers), 1288(S&S Condo), and 3842 (Turkeyfoot).

      Reason for cost overrun: Scope for project did not change. Upon analysis, it was determined that loaded figures were not used as part of the original baseline estimate.

[69] DEO Response to Data Request BRDR-105 REVISED.

Blue Ridge found that the internal costs of the project are routine budget items and should have been included in the original budget and that if the Company uses loaded figures for budgeting purposes, they should have included them in the original estimate. Again, it is important to include what would be considered routine costs in the project estimates.

9. WBS: P400161431.001 / Project ID: P400161431
   a. Actual Spend: $236,175
   b. CEP Spend: $236,039
   c. Budget: $180,000
   d. Change Order / Additional Funds Requested: $6,488
   e. Company's reason for the Change Order not covering the variance: The scope of this project did not change; therefore, a change order would not have been initiated. The project baseline did not include all material costs. This was an oversight when the project baseline was created. Typically, labor and material costs are both included in project baselines.[70]
   f. Over budget by 24% or $56,175
   g. Project Description: Project Driver: The current Phoenix I/O modules are obsolete and are a regular and troublesome point of failure. Upgrading to Modicon modules and Unity Processors at multiple locations will allow for improved safety, reliability, and a reduction in maintenance calls.

      Project Scope: Replace/upgrade the existing Phoenix I/O modules to Modicon modules and Unity Processors at eight DEO locations

      Project Locations at the following locations: Middle Road, Willow, Chardon, Gross, Price, Twinsburg, Chippewa, and Brush
   h. Reason for cost overrun: Project estimate did not include all material costs required for project completion (transmitters were not included in project estimate). In addition, design modifications were reflected in total project cost that were not in initial project baseline estimate.

   Blue Ridge found that internal costs and the transmitters should have been included in the original budget. Internal costs are part of a normal project budget (for example, labor), and transmitters are routing costs.

10. WBS: 52070.8.7 / Project ID: LL WELLS
    a. Actual Spend: $160,270
    b. CEP Spend: $160,270
    c. Change Order / Additional Funds Requests: $69,711
    d. Budget: $90,000
    e. Over budget by 44% or $70,270
    f. Project Description: Replug/retire well#1270 0 Nichter-Parker: Well Clean Out and Plugging:
    g. Reason for cost overrun: Initial baseline estimate based on turnkey price. When the scope was outlined, potential contingencies were identified and priced out based on unknown conditions in well. These contingencies were purposefully not included in project baseline and were enacted as necessary as conditions in field dictated. In addition, the initial estimate did not include overhead costs.

[70] DEO Response to Data Request BRDR-105.

Blue Ridge found that if the Company budgets with overhead costs, they should have done so here. Neither the Company nor the contractor would know the conditions in the well until the work started. Therefore, that part of the explanation is not unreasonable.

11. WBS: P400136758.001 / Project ID: P400136758
    a. Actual Spend: $177,793
    b. CEP Spend: 100% CEP Spend
    c. Budget: $132,600
    d. Over budget by 25% or $45,193
    e. Project Description: INSTALL APPROX 2600' ML #107 FOR 67 SINGLE FAMILY HOMES
    f. Reason for cost overrun: High level cost per foot used to create project baseline was less than actual cost per foot once installed.

    Blue Ridge found that determining cost per foot should be a routine budget activity and for the most part in the direct control of the Company.

12. WBS: OC.TSG.000584 / Project ID: P400073192
    a. Actual Spend: $353,561
    b. CEP Spend: $353,561
    c. Budget: $175,000
    d. Change Order / Additional Funds Requested: $776
    e. Company's reason for the Change Order not covering the variance: During construction, the president for one of the contractors unexpectedly passed away causing additional communication complications. Due to these unfortunate circumstances, not all change orders normally processed, were processed.[71]
    f. Over budget by 51% or $178,561
    g. Project Description: Project Driver: Replacement is needed due to the deteriorating state of the meter house building
       Project Scope: Replace meter houses
       Project Location: Strausser Station, Jackson Township
    h. Reason for cost overrun: Project was scoped to replace the meter building based off historical estimates for similar projects. After talking with operations, there were additional requests to move the buildings further apart. Extra conduit was required, 2 poles needed moved, and foundations needed moved. There were performance issues with the building contractor, delaying completion. DEO worked with contractor to correct delays, ultimately changing out contractor crews. These delays required DEO inspectors/GM&R employees to be onsite longer than originally anticipated.

    Blue Ridge found that, given the unusual circumstances, the Company's explanation is not unreasonable.

13. WBS: P400142569.001 / Project ID: P400142569
    a. Actual Spend: $7,955,187
    b. CEP Spend: $7,838,180
    c. Budget: $6,350,186
    d. Change Order / Additional Funds Requested: $244,020

[71] DEO Response to Data Request BRDR-105 REVISED.

e. Over budget by 20% or $1,605,001
f. Project Description: Project Driver: Austintown Station as it currently stands requires a significant rebuild due to the following reasons:
    1. Existing regulator runs are oversized
    2. Reliability concerns
    3. Corrosion concerns and atmospheric leaks
    4. Controls and actual equipment is antiquated, outside of its service life, and requires spare parts that are often difficult to attain

    ii. Project Scope:
    1. Replace current building for station
    2. Replace current heater with larger heater
    3. Replace current cleaners
    4. Cut and cap 10in warren line
    5. Existing runs 14, 15, and 16 should be cut to valve#6229
    6. Install 4 runs for Warren (1 Bypass, 1 Winter Run, 1 Summer Run, 1 Auxiliary Backup Run)
    7. Install 3 runs for Youngstown (1 Bypass, 1 Winter Run, 1 Summer Run)
    8. Install run for GA Fee
    9. Install metering for Warren and Youngstown Feeds.
g. Reason for cost overrun: Per PM there were multiple changes that occurred in the field. These changes resulted in a longer project duration that increased inspection time, overheads, etc. These changes include the following:
    i. Building foundation changes due to over-excavation of the regulation area required due to adverse weather conditions.
    ii. Unplanned valve replacements were required for safety and compliance purposes.
    iii. Installing two (2) 26-inch stopples that we did not originally plan on installing due to weather. At the time, we did not have stopple equipment that could handle stopples this large. We had to subcontract T.D. Williamson
    iv. Valve isolation issues that prevented us from a double block and bleed for welding.

Blue Ridge found that most of the cost overrun was due to changes in the field or problems that arose during construction. The Company's explanations are not unreasonable.

14. WBS: 6T07371814 / Project ID: P80026
    a. Actual Spend: $1,283,323
    b. CEP Spend: $1,220,924
    c. Budget: $700,000
    d. Change Order / Additional Funds Requested: $21,000
    e. Company's reason for the Change Order not covering the variance: A change order was not required because the scope of the project did not change. The project baseline was created using past project examples of various similar projects, knowing each project has unique conditions and obstacles. At the time of construction, contractor demand for this type of work was higher, causing construction costs to exceed past project examples. DEO did review and determine in advance of awarding a contract that the cost increases for the project were prudent given the size of the coolers, number of coolers, and current market pricing

of similar labor. The typical DEO process is to update project baseline post contract award as necessary, however, the project baseline was not updated on this project.[72]

f. Over budget by 45% or $583,323
g. Project Description: Replace deteriorating Cooper Aftercoolers. Remove existing aftercoolers and intercooler.
h. Reason for cost overrun: Initial baseline estimate was based on other similar projects with 'pre-design' assumptions. In addition, material costs for coolers were higher than anticipated and bidding costs were higher than expected due to timing of construction.

Blue Ridge found the initial base line estimates that were based on similar projects to be unreliable, which resulted in increased material and bidding costs.

15. WBS: P400194684.007 / Project ID: P400194684
    a. Actual Spend: $656,021
    b. Base Rate Specific WBS Element Spend: $308,277
    c. Budget: $465,272
    d. Change Order / Additional Funds Requested: $46,355
    e. Company's reason for the Change Order not covering the variance: This project had a tight timeline due to required supply commitments to a nearby power plant. Additional internal labor and materials including additional pipe and employee overtime were required to complete the job within the timeline. The additional work required consisted of demagnetizing the pipeline prior to construction, and additional pipe replacement due to an unplanned pipe section needing to be cutout and replaced.[73]
    f. Over budget by 29% or $190,749
    g. Project Description: Project Driver: Class location studies show inadequate valve spacing per current industry practice.

       Project Scope: Install in-line valve (30 inch) and associate appurtenances. Current distance between valves is 11.64 miles.

       Project Location: L#258/M (TPL-12), between Maumee Station and Garling Station, Wood County
    h. Reason for cost overrun: Unexpected field issues led to increased project costs not included in baseline estimate. These unexpected occurrences included demagnetizing the pipe and an unplanned cut-out required due to multiple failed welds. There was also a tight timetable due to required supply commitments to a nearby power plant which increased overtime requirements on the project.

    Blue Ridge found that the expected field issues cannot be reasonably foreseen. However, supply commitments to nearby power plant would have, or should have, been known since it was a requirement.

Overall Recommendations: Of the 19 projects that had variances that required follow-up, Blue Ridge found that 10 of those projects had variance explanations that were either in whole

[72] DEO Response to Data Request BRDR-105 REVISED.
[73] DEO Response to Data Request BRDR-105 REVISED.

or in part not unreasonable.[74] It is Blue Ridge's opinion that the remaining project cost overruns could have been controlled to a certain extent by the Company.

- Installation costs should have been included in the original estimate since it is a routine cost.
- It is Blue Ridge's opinion that while we understand projects contain many variables, the Company should have been able to control the project to a certain extent regarding meeting testing performance goals.
- The Company should have included site work and installation charges should have been included in the budget.
- The project cost should have included furniture since the office and conference room would need to be made functional.
- Internal costs of the project are routine budget items and should have been included in the original budget
- If the Company uses loaded figures for budgeting purposes, they should have included them in the original estimate.
- Transmitters should have been included in the estimate since this is a routine cost
- If the Company budgets with overhead costs, they should have done so here
- Determining cost per foot should be a routine budget activity and for the most part in the direct control of the Company.
- Ratepayers should not be required to pay for the increased costs of inefficient contractors.
- supply commitments to nearby power plant would have, or should have, been known since it was a requirement.

Blue Ridge recommends that the Company make a more concerted effort to ensure project budgets include the routine type project costs. Doing so may help avoid cost overruns and provide savings to the ratepayer.

T7: In-Service Dates

T7A: Is the actual in-service date in line (at or before) with the estimated in-service date.

Blue Ridge found that 57 work orders / projects in the sample were blanket (massed) or other types of work orders, such as massed reallocations, transfers, and adjustments, that would not typically have estimated in-service dates.

Of the 153 work orders / projects with estimated in-service dates, 68, or approximately 44%, had in-service dates that were over 90 days delayed from the estimates. Fifty-seven, or approximately 83%, accrued AFUDC.[75] The following 3 work orders / projects Blue Ridge wanted to highlight based on the Company's explanations to their greater than 90-day delay in placing the work order / project in-service.

1. WBS EOG-2295.2
   a. In-Service Date: 3/31/18
   b. Estimate: 2015
   c. In-Service months after estimated date: 27
   d. AFUDC Charged: $31,854

[74] Workpaper DEO Detailed Transactional Testing Matrix.
[75] Workpaper DEO Detailed Transactional Testing Matrix.

e. Project Description: Service Line Data Model Create the Service Line Data Model in SAP. Allow the SLDM to store all data related to assets from the Mainline to the manifold. Create the necessary interfaces between the new SLDM in SAP and the systems that need that information (CCS and GIS).
f. Reason for greater than 90-day delay: The original scope of the project was changed. Contributing factors to the extended duration included (1) additional functionality added due to tracer wire and wall head adaptor, (2) vendor assistance for MapFrame changes, and (3) personnel resource constraints.

Blue Ridge found that the Company's explanations that (1) additional functionality added due to tracer wire and wall head adaptors and (2) vendor assistance for MapFrame changes are not unreasonable. However, Blue Ridge is unsure of how item (3) personnel resource constraints would have contributed to a delay.

2. WBS IT SW DEO.ARM_C.2
   a. In-Service Date: 10/29/09
   b. Estimate: 2004
   c. In-Service months after estimated date: 59
   d. AFUDC Charged: $91,561
   e. Project Description: IT Software -EOG-ARM Track C-In-House
   f. Reason for greater than 90-day delay: The ARM series of projects delivered multiple work management software solutions. It included multiple tracks A, B, and C. There were delays from failures to successfully pass user acceptance testing and the need for the vendor, Logica, to complete software upgrades.[76]

   Blue Ridge found that user acceptance testing is routine for software projects. Software upgrades are also normal. There are various reasons acceptance testing fails; they can include less than adequate product development or failure on the part of the Company to adequately monitor activities or various other reasons. The explanations for the delay in completing the project are not unreasonable.

3. WBS SW DEO.ARM_B LEAK.3
   a. In-Service Date: 12/12/08
   b. Estimate: 2004
   c. In-Service months after estimated date: 48
   d. AFUDC Charged: $126,641
   e. Project Description: Software -EOG-ARM B Leak Survey-In-House
   f. Reason for greater than 90-day delay: All charges on this project were transferred from IT SW DEO.ARM_B.3 to SW DEO.ARM_B LEAK.3. SW DEO ARM_B.3 was created for multiple WMIS work management features including Leak Survey. Only the leak survey portion was implemented. A total of $1,225,035.15 was transferred to SW DEO ARM_B LEAK.3 for contractor services and software purchases related to the Leak Survey asset. The rest of the charges were written off as an expense. To clarify, the in-service date was December 31, 2006. The financial transaction to the separate the WBS was made in December 2008. The ARM series of projects included multiple tracks A, B, and C. These projects were combined with projects at Virginia Power and Hope Gas. There were delays from failures to successfully pass user

[76] DEO Response to Data Request BRDR-140.

acceptance testing and the need for the vendor, Logica, to complete software upgrades.[77]

Blue Ridge found again that user acceptance testing is normal in a software project as is software upgrades. The Company's explanation for the delays is not unreasonable, but Blue Ridge has concerns that this project and another software project, identified as item 2 above, both had user acceptance testing issues and both used the same vendors. The Company should consider the problems that both projects had and make a determination whether the vendor being used (Logica) is the best choice.

T7B: Was the work order / project in service and closed to UPIS within a reasonable time period from project completion, and if not, was AFUDC stopped?

As discussed and identified in T7A, Blue Ridge found 57 work orders / projects that were not closed timely after the work was complete. Blue Ridge does not recommend any adjustments for this section.

T8: Continuing Property Records

T8A: Do the Continuing Property Records support the asset completely and accurately?

The Company uses a current version of PowerPlan for its plant accounting records. The system has the ability to provide detailed information by account, activity, and amount for all work orders / projects, including blankets (massed projects) down to the unit level.[78]

Blue Ridge's initial concern regarding the CPR was that amounts for work orders / projects representing Massed Asset Reallocation entries did not tie back to the detail provided by the Company. The Company provided the following clarifications. The Massed Asset Reallocation entries are mainline and service roll-up projects. The selections made by Blue Ridge were a portion of the costs associated with the projects in specific years. Generally, the sample selected represented massed asset reallocation entries. Blue Ridge found that the Company's explanations for the variances from the sample selected and the submission from the Company for the massed asset reallocation entries are not unreasonable.[79]

Blue Ridge identified three work orders / projects with CEP spend greater than overall spend, and the Company provided the following explanations. Blue Ridge found two of the three explanations not unreasonable.[80] However, Blue Ridge recommends CEP be adjusted due to the following:

- P400090072.001 - LN1745 PIGGABILITY - P400090072 *Posted charges $2,041,729 are greater than Overall Actual Charges $1,992,960.* The entire difference relates to charges and credits included in the overall project dollars but not in the CEP Actuals. The total variance between the CEP Actuals and overall project costs are attributable to the following: (1) Direct charges to the high-level "P" number in SAP are not included in the CEP BW Report, (2) certain 2018 costs were not picked up in the BW Report because they related to a project placed in service in 2016 (The report picks up only costs incurred on projects for which the construction complete date falls in the current or prior CEP filing year.), and (3) the credit side of a journal entry was inadvertently not

[77] DEO Response to Data Request BRDR-140.
[78] DEO Interview – Plant Accounting. Page 3 of 7.
[79] Workpaper DEO Detailed Transactional Testing Matrix.
[80] Workpaper DEO Detailed Transactional Testing Matrix.

included when the BW CEP Report was run. This journal entry was made at the order operation level in the SAP general ledger to move costs from one compatible unit (CU) to another within the project. The debit side of the entry was included in the BW Report. After reviewing, the Company is unable to determine why the BW Report did not pick up both sides of the journal entry. The following table reconciles the CEP Actuals to Overall Project Actuals.[81]

Table 17 Reconciliation of Costs for P400090072

	Spend
CEP Actuals	**$ 2,041,728.59**
Direct Charges	$ 7,330.24
2018 Costs	$ 4,995.78
Journal Entry	$ (61,094.40)
Overall Project Dollars	**$ 1,992,960.21**

Blue Ridge recommends that CEP plant in service be adjusted to reflect the direct charges by $7,330, the 2018 Costs by $4,996, and the Journal Entry corrected by $(61,094), for a total adjustment to CEP plant of $(48,768). In addition, the CEP reserve should be adjusted by $(2,743), resulting in a net reduction to CEP net plant in service of $46,025. This adjustment flows through the recast CEP revenue requirements. **[ADJUSTMENT #4]**

Blue Ridge identified three work orders / projects whose cost provided within the population (BRDR-8) did not agree to the cost summary provided for the sample (BRDR-61) Two of the three work orders / projects were WBS elements that rolled up to a larger project and therefore no variance existed. While the third work order / project included costs from the full year of 2011-2018 for the Cost Detail instead of the scope period, Q4 2011-2018.[82] Blue Ridge found that the costs should not have been included in the cost detail provided in the sample and that since the costs were not in the population the CEP is correct and Blue Ridge does not recommend an adjustment

Blue Ridge identified six work orders / projects that were identified as "100%HB95" (100% CEP within the project documentation provided by the Company); however, the CEP spend was significantly less than Overall spend. Blue Ridge found that the Company's various explanations that follow were not unreasonable.[83]

- The project was a hybrid project, so a portion of the overall project costs are in PIR.
- The project costs were in CWIP and therefore not included in the CEP informational filing value.
- Direct charges to high-level "P" number were not included in the CEP BW Report.[84]

T9: Cost Categories

The Company has two cost allocation methods for work orders / projects: Cost allocations for fixed assets and cost allocations for massed assets.

[81] DEO Response to Data Request BRDR-106.
[82] DEO Response to Data Request BRDR-144.
[83] Workpaper DEO Detailed Transactional Testing Matrix.
[84] DEO Response to Data Request BRDR-122.

- Cost allocations for fixed assets: Allocation percentages determined only once at the time the as-built is finalized, as costs sit in CWIP until this process is completed.[85]
- Cost allocations for massed assets: Allocation percentages initially determined when the construction work order is generated and then updated as changes are made throughout the life of the project. This is needed since Massed dollars settle monthly. Final allocation percentages are determined when the as-built is final-final. Prior month costs, although in total will not change, could change by category (i.e.: pipe replacement low pressure, pipe replacement regulated pressure, etc.) as the make-up of the project could change during its life cycle.[86]

T9A/B: For work orders / projects, are the cost categories (Payroll, M&S, etc.) not unreasonable and support the work order total? For "other" (referring to T1d above), are the description and costs not unreasonable?

The Company provided a list of all overheads (labor loading, etc.) and any other indirect items charged to DEO work orders / projects, including descriptions of the type of charge and how that charged item is applied. The following is a list the Company provided of surcharges applied to DEO's capital projects as well as a list several charges, although not surcharges per se, that may be applied to DEO work orders or WBS elements.

- Material Overhead
- Bin Stock (under 2" Fittings & Small Tools)
- DES Billing
- Supervision
- Project Management (A&G)
- Pension Credit
- ClearingCap DRS ICO Expense (These charges represent intercompany costs incurred for specified DEO capital projects.)
- PIR Incremental O&M (Incremental costs directly attributable to the PIR program are capitalized and recovered through the PIR Cost Recovery Charge as permitted by the Commission.[87] Such costs are incurred for PIR project reporting, data preparation, and map generation. DEO has established specific WBS elements for purposes of tracking and reporting these costs.[88])

Blue Ridge reviewed the cost categories and charges for each work order / project sampled. While most of the categories and charges appeared not unreasonable, 29 work orders / projects required additional information and review. Blue Ridge had specific recommendations or adjustments on only the following four work orders / projects regarding cost categories. The remaining detail can be found in Blue Ridge's workpapers.[89]

1. DEO.LEAK.2 - LEAK SURVEY IN SAP
   a. Initial Cost Category Concern: *CEP Actuals do not Agree with Cost Detail*

[85] SAP Project Structure, page 3. Provided during Kick-off Meeting on 9/20/19.
[86] SAP Project Structure, page 3. Provided during Kick-off Meeting on 9/20/19.
[87] See Opinion and Order in Case No. 09-458-GA-RDR, page 9.
[88] DEO Response to Data Request BRDR-39 (Overhead and Indirect Cost Summary Confidential).
[89] Workpaper DEO Detailed Transactional Testing Matrix.

b. The Company provided the following explanation for the charges: The variance is $(1,041.63). The variance is attributable to direct charges to the high-level "P" number in SAP that are not included in the CEP BW Report.[90]

Blue Ridge found that the Company missed the direct charges to the high-level "P" number in SAP, and they indicated that it can be fixed in the 2020 CEP. The CEP as of December 31, 2018, is understated by $1,041.63. While the amount is immaterial, Blue Ridge recommends that CEP plant in service be increased by $1,042 and the CEP reserve should be adjusted by $425, resulting in an increase to CEP net plant in service of $616. This adjustment flows through the recast CEP revenue requirements **[ADJUSTMENT #5]**

2. O7000.15.GAS.6B – TOUGHBOOKS
   a. Initial Cost Category Concern: *Software / Hardware / Spares*
   b. The Company provided the following explanation for the charges: Project O7000.15.GAS.6B includes the purchase of Toughpads and related accessories. Please see BRDR- 170 Attachment 1 for the quantity purchased and unit costs of each item.

      The Toughpads were assigned to shop locations based on the number of employees in each shop. Spares are not kept in a central storage facility. A small number of machines to be used as spares were assigned to the supervisor of a shop location; this allows for immediate replacement of any equipment which needs maintenance performed. Below is a chart of the number of employees and number of Toughpads deployed at each shop. Please see BRDR-170 Attachment 2 for the closing form which supports the Toughpad deployment.

Office / Shop	Panasonic Toughpads Deployed	Field Employees Dec 2015[1]
Ashtabula	18	15
Eastern	80	71
Lima (West OH)	14	31
Youngstown	50	47
West Park	68	69
Wilbeth – Akron	80	69
Canton Perry Yard	42	36
Total	**352**	**338**

      To note, the response to BRDR-61 included the statement "Order increased to 396 Toughbooks to accommodate additional training units. Scope increase described in capital request form document." The details of the purchasing documents support a final count of 352 for O7000.15.GAS.6B. The additional training units were recorded in a separate WBS element.[91]

Blue Ridge found that the Company purchased a total of 396 Toughpads. Of those, 352 Toughpads were applicable to this WBS element, and of those 352, 338 were put into service, whereas 14 were considered spares. The cost for each Toughpad is $3,612.

[90] DEO Response to Data Request BRDR-143, part c.
[91] DEO Response to Data Request BRDR-170.

The cost for each Toughpad is $3,612. The Company capitalized the entire amount. The units used in the field are considered used and useful and capital. The training units would be considered capital if the technology is new to the Company, which appears to be the case in this instance. The costs of the spare units should not have been charged to capital. They are considered inventory until used in the field and should not be capitalized at the point of purchase as meters are. Blue Ridge found that the Company overbooked $50,568 (14 units at $3,612). Blue Ridge is not, however, recommending an adjustment in this case since the charges were booked five years ago and the units would have been used by now. Blue Ridge does recommend that the Company conform to FERC guidelines as to what purchases of General Equipment can be capitalized at point of purchase and what should be considered inventory until deployed in the field.

3. P400002271 (.006 and .039) -Install Johnston Compressor Station—
   a. Initial Cost Category Concern: *Negative COR, CIAC*.
   b. The Company provided the following explanation for the charges: There was no cost of removal on this project. The value was inadvertently labeled cost of removal. The ($119,805) consisted of: 1) CIAC in the amount of ($117,830.93) which was credited to the project in September 2014, and 2) AFUDC in the amount of ($1,974.03) which was charged from October 2014 through November 2016. The project was in-service on November 8, 2013, not November 3. The project was technically closed on August 22, 2014, due to a delay in receiving paperwork. CIAC of ($117,830.93) was posted on September 30, 2014. The Company inadvertently accrued post in-service AFUDC of ($1,974.03). The entire value of ($119,805) was inadvertently not closed to the Company's fixed asset system until assets were converted to PowerPlan in 2018, which is the reason a 2018 in-service date is associated with the CIAC. Construction was complete on November 8, 2013.[92]

   Blue Ridge found that the Company did not book CIAC until September 2014. The project was in service August 2013. The Company claims that AFUDC was inadvertently booked as a credit of $1,974. Between August 2013 and September 2014, the Company would have over accrued depreciation. Since the project was in service as of December 2018, plant is not materially impacted. Plant is understated by $1,974. Blue Ridge recommends that total Company plant in service be increased by $1,974 and the reserve be adjusted by $(317), resulting in an increase to net plant in service of $1,657. This adjustment flows through the recast Schedules B-2 and B-3. **[ADJUSTMENT #14]**

4. 27511.1.3-Cuernsey Control Panel Comp Equipment
   a. Initial Cost Category Concern: *Postage / Shipping.*
   b. The Company provided the following explanation for the significant amount of postage / shipping charges found in the Cost Detail. Of the amount listed above, $82.80 was a postage charge. The remaining value of $293,207.00 was incorrectly posted in the Postage/Shipping Freight Cost Element. This charge should have been posted to Contractor Services Cost Element.[93]

   Blue Ridge found that the incorrect cost element does not change the project cost. The error is not financial, and therefore, we do not recommend an adjustment or reclassification.

[92] DEO Response to Data Request BRDR-141.
[93] DEO Response to Data Request BRDR-85.

T10: Revenue-Generating

T10A: For CEP additions, will the work order / project generate revenue? If so, how has the revenue been quantified?

The Project Prioritization Team (PPT) or Design Engineering technicians determine the relevant mechanism (PIR, CEP, etc.) during the design process. Projects falling within the recovery categories set forth in R.C. 4929.111 are designated as CEP when they are not eligible for the PIR program and are not expected to generate incremental income for the Company. Revenue generating projects are deemed to "stand on their own" and are not proposed for deferral and recovery via the CEP mechanism.[94]

The Company identifies CEP plant that will generate additional revenue by noting whether the projects fall include either of the following conditions:

- New business additions or other additions, such as mainline extensions requested by an existing customer, that will generate additional revenue
- An economic analysis of the project considers revenues to be generated and associated expenses to ensure that the project yields a return that is at least the Company's authorized return

The Company generally does not include revenue generating projects in the CEP, as the support provided by the CEP mechanism is not considered necessary for such projects. The Company does not believe that there are any revenue generating investments reflected in CEP plant through December 31, 2018.[95]

Blue Ridge identified three CEP work orders / projects that warranted further review and understanding on whether additional revenue was generated. The Company was able to adequately explain why the projects would not generate incremental revenue. Blue Ridge found the Company's explanations were not unreasonable.[96]

T11: Replacement projects

Systematic fixed asset retirements are processed automatically in the fixed asset system when assets reach the end of their useful life. The same entries are created and passed to SAP[97] for recording in the general ledger.

Non-systematic fixed asset retirements are identified in SAP each month by field personnel. The retirement is entered manually into the fixed asset system, which creates an entry to debit Accumulated Depreciation (FERC 108) and credit Gas Plant in Service (FERC 102). Those entries are passed back to SAP to update the general ledger.

Retirements for massed assets are done automatically in the fixed asset systems based on information provided by field personnel. The entries are passed back to SAP in the same manner as fixed and systematic retirements.[98]

[94] DEO Response to Data Request BRDR-14 (Work Order Accounting).
[95] DEO Response to Data Request BRDR-25 (Revenue Generating CEP Investments).
[96] Project WBSs P400096569-001 and P400136758.001. DEO Response to Data Request BRDR-109 (WBS Testing) and Project WBS 09200_FA.2A.1.8 DEO Response to Data Request BRDR-174.
[97] SAP is financial software with modules that typically cover the General ledger, Fixed Assets, and other relevant financial recording and reporting areas
[98] DEO Response to Data Request BRDR-14 (Work Order Accounting).

Assets are flagged on a monthly basis in the system for retirement. Retirements are processed without indication of its recovery mechanism. The retirement is processed based on general asset information, such as location code, FERC account, and WBS. CEP capital projects placed in service are then matched to the list of retirements to determine which retirements are associated. Except for FERC accounts that are subject to systematic retirements, the matched retirements are then included in the retirement value used to calculate rate base and deferrals.[99]

Table 18 Fixed assets automatically retired from plant[100]

FERC	FERC Description	FA Policy	Asset Life	Depr Rate	Recovery/Deferral Treatment
303	Intangible Plant Computer Software	Retired when Software is Fully Amortized	10	10%	Where possible, match with a replacement capital addition included in CEP deferrals and include retirement dollars up to the level of CEP additions for the year in which the retirements occur
332	Production - Other Equipment - Reads "Field Lines in Depr Study"	Automatically retired based on asset life			Recognize retirements up to level of additions for that year
347	Extraction - Other Equipment	Automatically retired based on asset life			Recognize retirements up to level of additions for that year
357.03	Storage - Other Equipment	Automatically retired based on asset life	15	6.67%	Recognize retirements up to level of additions for that year
371.03	Transmission - Other Equipment	Automatically retired based on asset life	60	1.67%	Recognize retirements up to level of additions for that year
387.01	Distribution - Other Equipment	Automatically retired based on asset life	22	4.55%	Recognize retirements up to level of additions for that year
391.01	Office Furniture and Equipment - Furniture	Automatically retired based on asset life	20	5%	Recognize retirements up to level of additions for that year
391.02	Office Furniture and Equipment - Computer Hardware	Automatically retired based on asset life	5	20%	Recognize retirements up to level of additions for that year
FERC	FERC Description	FA Policy	Asset Life	Depr Rate	Recovery/Deferral Treatment
391.03	Office Furniture and Equipment - Equipment	Automatically retired based on asset life	10	10%	Recognize retirements up to level of additions for that year
393.01	Stores Equipment	Automatically retired based on asset life	20	5%	Recognize retirements up to level of additions for that year
394.01	Tools, Shop, and Garage Equipment - Tools & Equipment	Automatically retired based on asset life	20	5%	Recognize retirements up to level of additions for that year
395.01	Laboratory Equipment	Automatically retired based on asset life	20	5%	Recognize retirements up to level of additions for that year
397.01 397.02	Communication Equipment – Radio, Comm., & Telephone	Automatically retired based on asset life	10	10%	Where possible, match with replacement capital addition of the same type of equipment at the same physical location and include retirement dollars up to the level of CEP additions for the year in which the retirements occur
398.01	Miscellaneous Equipment	Automatically retired based on asset life	15	6.67%	Recognize retirements up to level of additions for that year

T11A: Were assets retired?

Of the 210 work orders / projects selected for testing, approximately 139 were of the type of work for which retirements would not be expected (such as main and service line addition, reclassifications, massed asset reallocations, and other adjustments and transfers). The remaining 71 work orders / projects represented replacement work, such as service line replacements, pubic improvement, and replacements for age and condition. Typically, when assets are retired, cost of removal will be charged. Even in instances where pipe is retired in

[99] DEO Response to Data Request BRDR-45 (CEP Revenue Requirements COR and Retirements).
[100] DEO Response to Data Request BRDR-45, Attachment 1.

place, the Company may perform some functions to relieve the pipe of gas and make it safe, resulting in a cost of removal charge. Cost of removal represents a decrease to the accumulated reserve for depreciation (debit to a contra-asset) and increases net plant.

The following work order / project had no retirement nor Cost of Removal charges and the Company has overstated net plant.

Blue Ridge identified 12 replacement work orders / projects that had no retirement nor cost of removal charges. Blue Ridge found the Company's various explanations that follow were not unreasonable for eleven of the twelve:[101]

- Project was for the overhaul of a compressor station. The compressor was initially installed as a singular asset, not individual parts. When overhaul maintenance occurs the entire compressor station is not replaced, and there are no specific assets to retire
- No retirements or cost of removal associated with this project could be identified.
- The projects spanned over multiple WBS elements. There was cost of removal associated with this project. It was charged to a separate WBS element.
- This WBS element related to the purchase of new equipment for the Company's Springside location. There were no related retirements or removals.
- This project was a new install; no removals or retirements took place.
  The cost of removal for this project was charged to a different WBS Element.[102]

Work order / project FCDEO.16.GAS.8D should have had cost of removal charged. After further review, the Company determined that there was cost of removal in the amount of $81,636.25 related to this project. The cost of removal was inadvertently charged to plant additions and will need to be adjusted.[103] Blue Ridge found that the Company should have charged $81,636.25 to cost of removal. CEP plant in-service is overstated as of 12/31/18. Blue Ridge recommends that CEP plant in service be reduced by $81,636 and the CEP reserve should be adjusted by $(2,823) because of the over accrual of depreciation. This results in a reduction to CEP net plant in service of $78,813. This adjustment flows through the recast CEP revenue requirements **[ADJUSTMENT #6]**

It is not unusual in the Gas Distribution industry to not remove pipe from the ground. In several instances, unless necessary for safety or mandated, Gas Distribution companies frequently leave pipe in the ground and purge the gas from the pipe and cap the ends to make it safe, thereby avoiding the cost to remove the pipe. In those instances, cost of removal is minimal and, depending on the category of work order, could be charged to a blanket work order or a retirement work order that would not have been picked up in the sample. Service line replacements are an example because they are blanket projects.

T11B: Was the date of retirement and cost of removal in line with the asset replacement date?

Massed Asset projects (Blanket projects) are closed every month. Blue Ridge reviewed the asset replacement and asset retirement dates for Fixed Projects (Specific projects). Several work orders /projects required additional information and review.

[101] Workpaper DEO Detailed Transactional Testing Matrix.
[102] DEO Response to Data Request BRDR-103.
[103] DEO Response to Data Request BRDR-103.

Table 19 Work orders / projects that required additional information pertaining to retirement dates[104]

WBS Element	In-Service	Retirement Date	Company Explanation
25633.1.1.1	12/29/05	12/30/13	The actual in-service date shown for WBS element 25633.1.1.1 reflects the original in-service date for assets retired upon the sale to Blue Racer Midstream on December 30, 2013.
6T07179411	12/10/09	1/26/15	Project 6T07179411 was for the installation of a new transmission main line with an in-service date of December 10, 2009. The retirement on January 26, 2015 was not associated with the installation of that project. It was associated with the installation of another project in which 7' of 20" pipe that was installed as part of Project 6T07179411 were retired.
IT SW DEO.ARM_C.2	10/29/09	9/30/16	This was a software project placed in service in 2009 that was fully amortized and retired on September 30, 2016.
OH13335	10/12/10	10/7/14	OH13335 is not a WBS Element; it is a tax jurisdiction code. The WBS element is 6T07243139. This was for the installation of Austintown Compressor #3. The retirements on October 7, 2014 were not associated with this project. They were associated with the installation of another project in which two valves (8"and 4") that were installed as part of Project 6T07243139 were retired.
OH14616	12/18/09	12/30/13	OH14616 is not a WBS Element; it is a tax jurisdiction code. The WBS element is 35270. The assets underlying the retirements recorded on December 30, 2013 for WBS element 35270 were sold to Blue Racer Midstream.
OH14852	12/13/11	11/30/16	OH14852 is not a WBS element; it is a tax jurisdiction code. The WBS Element is 49837. This project was for the Stryker Acquisition, which included the purchase of Lawrence compressor station. The assets underlying the retirements recorded on November 30, 2016 are associated with Lawrence station, which was decommissioned and retired in 2016
SW DEO.ARM_B LEAK.2	12/12/08	12/18/13	Project SW DEO.ARM_B LEAK.2 was a software project (ARM Track B Leak Survey) that was fully amortized over 5 years and was retired on December 18, 2013.
SW DEO.ARM_B LEAK.3	12/12/08	12/18/13	Project SW DEO.ARM_B LEAK.3 was a software project (ARM Track B Leak Survey) that was fully amortized over 5 years and was retired on December 18, 2013.

Blue Ridge found that the Company's responses are not unreasonable.

Blue Ridge identified 15 work orders with cost of removal that appeared to have cost of removal dates significantly later than in-service dates. The Company provided this explanation: the cost of removal date does not indicate the date which the removal occurred. The projects listed above incurred costs after the in-service date. The WBS element to which these costs were charged had settlement rules indicating some of the charges would settle to cost of removal.

[104] DEO Response to Data Request BRDR-167.

Examples of why costs may be incurred post in-service include:

1. Approved work performed after the project was closed (e.g. restoration work, environmental inspections, etc.)
2. Journal entries made to correct project costs
3. Delay in receipt of project folder or other documentation
4. Costs related to closing or geographical information system (GIS) activities
5. Disputed contractor payment or change order

These explanations account for costs coming into the projects listed above after the in-service dates. The following is the Company's explanation for cost of removal date significantly later than the in-service date.

> WBS OC.TSG.000028—Actual in-service date: 11/3/13, Cost of removal date: 9/3/14, Cost of removal date is 10 months post in-service date. Due to the WMIS to SAP conversion, there was a delay in technically closing the project.[105]

The Company explained that cost of removal dates provided in the cost detail are not the dates cost of removal is booked. Blue Ridge found that the Company allows work orders / projects to remain open to collect other charges, and once that is done, some of the work order / project costs are settled to cost of removal this explanation is not unreasonable.

T11C: Is the amount of the retired asset not unreasonable?

Retired assets are based on the original cost of the asset retired. We were satisfied that assets were retired for replacement work orders.

T11D: Was salvage recorded?

Dominion Energy Services' Investment Recovery group handles DEO's scrap materials. In order to be credited to a project as salvage, a WBS element that settles to the salvage component of accumulated depreciation must be provided to Investment Recovery with the material to be scrapped. This is true for both massed asset projects and fixed projects. If scrap materials are stockpiled at a shop location with material from other jobs, when salvage proceeds are received, they will be credited to the shop location's cost center.[106]

Blue Ridge found that the Company's explanation about salvage is not unreasonable for salvage that can be specifically identified to a project. Blue Ridge also finds that as long as stockpiled scrap ends up charged as a credit to the accumulated reserve for depreciation (FERC account 108), it does not matter if the credit goes to the shop location.

T11E:Was cost of removal (COR) charged? Is the amount not unreasonable?

Starting in 2003, prior to the last rate case, the Company moved away from direct charging COR on small dollar, high volume (massed) pipeline replacement projects. That decision eliminated the Company's ability to distinguish, on an individual project basis, costs related to new pipeline installations or COR for retired pipe. Fixed Asset Accounting developed allocation factors based on historical direct charge data in order to develop an average COR rate to be used in allocating project costs between the new pipeline asset and COR on the retired asset. In 2003, an allocation factor of 2.91% was established. That factor was used until 2014 when an

[105] DEO Response to Data Request BRDR-118.
[106] DEO Response to Data Request BRDR-126 (Salvage).

internal audit was performed recommending a changed to the current rate of 1.11%.[107] The audit also recommended that the rate be reviewed every three to five years. However, the Company has stated that they intend to review the rate again in 2020.[108]

From 2003 to 2014, the allocation rate dropped over 50%. The Company explained that the drop in the rate was primarily due to the change in the size of the projects. Prior to 2014, the Company indicated that the projects were, in general, much smaller in scope. Subsequent to the implementation of the PIR program, the projects tend to be larger, which translates to more feet of pipe installed. This means the ratio of pipe installed to pipe removed was larger and, therefore, the percentage of COR was smaller. The Company abandons pipe in place whenever possible.[109]

Specific, fixed projects can receive COR directly. Common costs are allocated between installation and abandonment/retirement (COR) components of the project on the basis of internal logic (a calculated percentage based on standard cost and actual quantity). During the settlement process in SAP, the total costs for the installation and for the abandonment/retirement are passed to the respective plant asset and COR accounts.[110]

Blue Ridge believes the percentage of COR charged to the accumulated reserve for depreciation has a direct impact on net plant. Understating the percentage increases net plant, and overstating the percentage decreases net plant. The accuracy of COR also impacts deprecation studies, where the FERC 300 account rates are established based on the actual versus theoretical reserve by FERC 300 accounts, including cost of removal and salvage. Those rates are used to accrue depreciation expense.

Blue Ridge agrees that the COR rate should be reviewed in 2020 and reviewed every three to five years, or sooner if a significant change in how the Company conducts business takes place.

Blue Ridge reviewed the 72 work orders / projects with charges to cost of removal and found that 18 of them had notably small cost of removal charges. Blue Ridge found that the Company's responses to the cost of removal charges were not unreasonable.[111]

Blue Ridge also identified 11 work orders / projects that had retirements charged but no cost of removal. Blue Ridge found the Company's various explanations that follow were not unreasonable for ten out of the eleven work orders / projects:[112]

- Project was 100% cost of removal.
- There was nothing to remove or retire—Retirements submitted were not relate to this project, rather they were installed as part of this project and retired in conjunction with other projects.
- Software project—There were no retirements or cost of removal at the time of implementation. Per Company policy, in-house software is systematically retired upon becoming fully amortized.

[107] DEO Response to Data Request BRDR-45 (CEP Revenue Requirements COR and Retirements).
[108] DEO Response to Data Request BRDR-62 (CEP Revenue Requirements COR and Retirements).
[109] DEO Response to Data Request BRDR-62 (CEP Revenue Requirements COR and Retirements).
[110] DEO Response to Data Request BRDR-63 (CEP Revenue Requirements COR and Retirements).
[111] Workpaper DEO Detailed Transactional Testing Matrix.
[112] Workpaper DEO Detailed Transactional Testing Matrix.

- Communication equipment replacement—No cost of removal was associated with this project. Communication equipment is booked to FERC 397; per Company policy, assets in this account automatically retire once fully amortized.
- Purchase of non-AMR metering equipment—No cost of removal associated with these purchases.
- Massed asset betterment project—No cost of removal is applied to massed asset betterment projects.
- Assets underlying this project were sold to Blue Racer, and retirements were recorded. The assets were subsequently repurchased. No cost of removal at the time of repurchase.
- No cost of removal associated with the Stryker Acquisition, including Lawrence Station. The retirements recorded were associated with Lawrence Station, which was decommissioned and retired in 2016.[113]

Blue Ridge found that the Company inadvertently charged cost of removal to additions for the following work order/ project.

- FCDEO.13.GAS.7B - CPY RENOVATIONS - After reviewing this project, it was determined that $65,000 of cost of removal associated with WBS element FCDEO.13.GAS.7B was inadvertently charged to additions. The Company is working to correct its plant records.[114]

Blue Ridge found that the Company charged COR as an addition. Therefore, CEP plant is overstated as of 12/31/18 by $65,000. Blue Ridge recommends that CEP plant in service be reduced by $65,000 and the CEP reserve should be adjusted by $(15,979) because of the over accrual of depreciation. This results in a reduction to CEP net plant in service of $49,021. This adjustment flows through the recast CEP revenue requirements. **[ADJUSTMENT #7]**

T12: Field Verification

T12A: Is the project a candidate for field verification?

Blue Ridge identified 22 work orders / projects within the sample as candidates for field visits. Further discussion on field inspections and desktop audits below in Section: Field Inspections and Desktop Reviews.

INSURANCE RECOVERY

The Company indicated that no significant events related to Utility Plant occurred from March 31, 2007, through December 31, 2018, that resulted in an insurance claim recovery greater than $50,000. In addition, there were no pending Utility Plant-in-Service insurance claim recoveries as of December 31, 2018, that are not recorded or accrued that would be charged to capital.[115]

UNITIZATION BACKLOG

Blue Ridge reviewed the unitization backlog for two reasons. First, it provides an indication of how well the Company controls the process, and second, if the backlog were both significant and old, it represents a potential retirement issue.

[113] DEO Response to Data Request BRDR-102.
[114] DEO Response to Data Request BRDR-135.
[115] DEO Response to Data Request BRDR-37 (Insurance Recovery).

As new construction costs are charged to work orders, they need to be assigned to the appropriate company, project, FERC account, location code, and retirement unit asset. The accurate setup of a work order ensures that the appropriate amount of accumulated reserve for depreciation is calculated from the time the asset is placed in-service. The unitization process is used to confirm that all appropriate charges related to the work order are assigned correctly. An over or under accrual of accumulated reserve for depreciation may arise in instances where the unitization process results in changes to the assignment of work order charges.

In the Gas utility industry, it is not uncommon for work orders to remain in FERC 106 for several months, waiting for the completion of the project. Frequently projects cannot be 100% completed because of weather conditions that may obstruct the Company's ability to complete paving and seeding and other functions. In accordance with FERC accounting, a project can be substantially complete, used and useful, and waiting for completion of work that does not hinder the functionality of the asset(s).

Table 20 CEP 2018 Work Order Backlog as of December 31, 2018[116]

	Amount	Work Orders Backlogged
0-3 Months	$ 93,194,055	635
4-6 months	$ 1,158,846	332
7-9 months	$ 1,684	1
10-12 months	$ -	0
Over 12 months	$ 10,557	1
	$ 94,365,143	**969**

As of December 31, 2018, $94 million was recorded in FERC 106 (Construction Completed but not Classified). Assets in FERC 106 are considered in service based on information provided by operations personnel. Of the $94 million, approximately $50 million is related to a PowerPlan performance issue that occurred at year end. Typically, massed assets are recorded to FERC 101 as costs are incurred monthly and are not initially recorded to FERC 106. Because of this performance issue, the $50 million of massed assets were recorded to FERC 106. In January 2019, the entire value was unitized. Sixteen million dollars of the $94 million was related to assets that were inadvertently placed in service. The Company's Fixed Asset department has not yet determined how this happened and whether it was a system performance issue.[117]

Blue Ridge reviewed the reasons the $50 million was in FERC 106 as of December 31, 2018, as well as another $16 million that was inadvertently closed and found the Company responses not unreasonable

FIELD INSPECTIONS AND DESKTOP REVIEWS

For the field inspections and detailed desktop reviews, Blue Ridge selected a total of 23 locations: detailed desktop audits were performed for 15 of those locations, field audits only were conducted for four locations, and a combination of desktop review and field audit were performed for four locations.

The following criteria were used for the field inspection and/or desktop review:

- The assets were operational (used and useful) and providing service to the customer.

[116] DEO Response to Data Request BRDR-35, Attachment 1 and WP BRDR-35, Attachment 1 (Work Order Backlog Analysis).
[117] DEO Response to Data Request BRDR-35 (Unitization).

- The purpose of the project was reasonable.
- The assets that were installed were in accordance with the original scope of work, and no assets were installed that were not in the original scope of work.
- The equipment that was installed matched the equipment that was capitalized.
- Company personnel understood the scope of work and were able to provide staff with detailed answers to questions about the work.
- Problems identified during the process of construction were identified and discussed.
- The project was not over built or "gold plated."

Work orders / projects were excluded from selection for the following reasons:

1. The work cannot be visually seen because it is underground or out of sight.
2. The workorder is an adjustment or transfer of dollars and therefore no physical assets have been installed
3. The workorder is a blanket and therefore multiple assets have been installed at various locations and therefore, it would not be practical to try and find them. In addition, those assets are generally minor in terms of dollar value. An example is meters installed at multiple locations.
4. The workorder is for installed software and it would be difficult to review an entire software program to see what was added. An example is PowerPlan.
5. The workorder is for a mass unitization where the total dollars are large but each workorder is small

The field observations were performed by Blue Ridge and Commission Staff with assistance from Company representatives. The field verifications were done on March 2, 2020, through March 4, 2020. Information for each work order / project was provided to the observation team and a standard questionnaire was completed for each location. Where possible, pictures were taken of the installed assets. For the detailed desktop reviews, pictures of the selected project documents, before and after gas pressure simulation models, detailed asset attribute tables, and before and after drawings were available. The completed questionnaires and applicable pictures are included as workpapers with this report.

Blue Ridge concludes the following items:

- The assets audited were operational (used and useful) and providing service to the customer.
- The purposes of the audited projects were reasonable.
- The assets that were installed were in accordance with the original scope of work.
- Company personnel understood the scope of work and were able to provide Staff and Blue Ridge with detailed answers and supporting documentation to questions about the work.
- The projects audited were determined not to be over built or "gold plated."
- The Company provided adequate documentation to support projects that were reviewed as Desk-top audits.

The following list provides information for the field-inspected, desktop-reviewed, and combination (desktop-reviewed and field-audited) projects:

1. WBS FCDEO.13.GAS.12A, FCDEO.13.GAS.12B, FCDEO.13.GAS.12C, FCDEO.13.GAS.12D, and FCDEO.13.GAS.12E
    a. Type of Inspection: Field Audit
    b. Final Project Cost:
        i. FCDEO.13.GAS.12A - $2,236,724

ii. FCDEO.13.GAS.12B - $12,756,227
iii. FCDEO.13.GAS.12C - $767,287
iv. FCDEO.13.GAS.12D - $2,798,885
v. FCDEO.13.GAS.12E - $430,891

c. Budget Category: Facilities
d. Project Description: New Dominion East Ohio Technical Training Center building, 418 East Hines Hill Road, Boston Heights, OH
e. Project in Service Date: May 28, 2016

Comments: Confirmed that use of the building is to train Dominion Ohio Employees only. No additional information is required. Building and Equipment inspected is confirmed to be installed, prudent and used and useful

2. WBS FCDEO.13.GAS.7B
   a. Type of Inspection: Field Audit
   b. Final Project Costs: $10,362,324
   c. Budget Category: Facilities
   d. Project Description: CANTON PERRY YARD RENOVATIONS - Canton Perry Yard; Remodel of existing office building within existing footprint and the construction of a new warehouse and storage building at the Canton Perry Yard
   e. Project in Service Date: February 19, 2014

   Comments: No additional information is required, the building inspected is confirmed to be renovated and warehouse built, thus considered prudent and used and useful

3. WBS FCDEO.14.GAS.7F
   a. Type of Inspection: Field Audit
   b. Final Project Costs: $9,476,379
   c. Budget Category: Facilities
   d. Project Description: Purchase of 320 Springside - (office where Engineering and other support staff are located) was a remodel of existing footprint plus additional space purchased from a former abutter.
   e. Project in Service Date: November 14, 2014

   Comments: No additional information is required. The building's three floors plus basement level were inspected and confirmed to be renovated, prudent and used and useful

4. WBS OC.I.PIG.000010 and OC.I.PIG.000015
   a. Type of Inspection: Desktop Review and Field Audit
   b. Final Project Costs:
      i. OC.I.PIG.000010: $1,231,218
      ii. OC.I.PIG.000015: $784,548
   c. Budget Category: IMP Piggability
   d. Project Description: TPL-2 Transmission line; These two projects are associated with Transmission line 2 (TP2) to allow the installation of various pipeline integrity access points called "pigging"
      i. OC.I.PIG.000010: TPL Four 4 different PIPE REPLACEMENT locations and 4 different STATION locations within Summit County in the municipalities of Barberton, Coventry, and New Franklin
      ii. OC.I.PIG.000015: Five Pipe Replacement, 3 Stations

e. Project in Service Date:
    i. OC.I.PIG.000010: September 11, 2014
    ii. OC.I.PIG.000015: September 4, 2015

Comments: No additional information is required. Based on review of Optimain Asset model, confirmed to be installed, prudent and used and useful.

5. WBS OC.TSG.000071 and P400008469
    a. Type of Inspection: Desktop Review and Field Audit
    b. Final Project Costs:
        i. OC.TSG.000071: $5,928,340
        ii. P400008469: $5,953,973
    c. Budget Category: TSG Normal Infrastructure
    d. Project Description: Chippewa Compressor #7; Note: OC.TSG.000071 rolls up to P400008469, confirmed during detailed desk top audit on March 4, 2020. Thus both of these projects are duplicates but listed for information purposes, since it was also listed twice in BRDR 156.
        i. OC.TSG.000071: 2370 HP Compressor Unit at Chippewa
        ii. P400008469: Chippewa project 7 to support added storage for Project 8 (WBSP400214043)
    e. Project in Service Date: April 7, 2014

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

6. WBS P400120518.001
    a. Type of Inspection: Desktop Review and Field Audit
    b. Final Project Costs: $1,114,446
    c. Budget Category: Gathering
    d. Project Description: Install Over pressure regulation protection @ Well, Costello, Flowers, S&S Condo, Turkey foot - Over pressure regulation for four locations; each location having similar protection equipment installed. While all four locations were desk top audited, field visited was the S&S Condo site
    e. Project in Service Date: November 10, 2016

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

7. WBS P400214043.001
    a. Type of Inspection: Desktop Review and Field Audit
    b. Final Project Costs: $10,557,354
    c. Budget Category: Storage
    d. Project Description: Install 3,750 HP compressor Chippewa Compressor Station (project 8)
    e. Project in Service Date: August 17, 2017

    Comments: No additional information is required. Building and Equipment inspected is confirmed to be installed, prudent and used and useful

8. WBS P400239583.001
    a. Type of Inspection: Field Audit
    b. Final Project Costs: $1,387,393

c. Budget Category: Storage
d. Project Description: L#2925 Lawrence Township – Pipe replacement - Transmission line #2925; This job involved the Gross Point and Robinson Compressor stations pipe installation within the stations area to allow transmission pipe integrity testing via pigging.
e. Project in Service Date: October 4, 2017

Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

9. WBS P400000457
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $7,568,975
    c. Budget Category: Revenue Generating
    d. Project Description: Northern Separation Project - Stadium Station heading east - To support the separation of the Blue Racer investment, and support service to Kent State Power plant
    e. Project in Service Date: November 27, 2013

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

10. WBS P400008320.006
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $2,766,031
    c. Budget Category: TSG Normal Infrastructure
    d. Project Description: Roadway Improvements - State of Ohio requested transmission line relocation
    e. Project in Service Date: November 13, 2013

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

11. WBS P400028409.006
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $57,507,043
    c. Budget Category: Revenue Generating
    d. Project Description: Install new compressor
    e. Project in Service Date: December 22, 2014

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

12. WBS P400039686.017
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $1,295,518
    c. Budget Category: Transmission
    d. Project Description: Replacement of L#285 (30in CHP) - due to defects found during inspection, replacement of sections of the 30” transmission pipe
    e. Project in Service Date: September 2, 2014

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

13. WBS P400114046.073
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $33,524,283
    c. Budget Category: Revenue Generating
    d. Project Description: Lordstown Energy Center Project (LEC) - transmission line to supply new customer
    e. Project in Service Date: June 13, 2017

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

14. WBS P400158837
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $2,594,428
    c. Budget Category: Revenue Generating
    d. Project Description: Cap 5,000' of 20" pipe and add new service line of 20" pipe and execute an asset purchase agreement - Service line extension; Cleveland Thermal
    e. Project in Service Date: November 23, 2016

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

15. WBS 37639.1.2.1
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $1,516,270
    c. Budget Category: SERGH
    d. Project Description: Install new Transmission line to Freemont Energy Center
    e. Project in Service Date: November 29, 2010

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

16. WBS 54379.1.1.1
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $855,756
    c. Budget Category: SERGH
    d. Project Description: Three Compressor Station - 43 miles of main line upgrades to three compressor stations; Davis Creek, Field, and Degussa
    e. Project in Service Date: January 23, 2012

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

17. WBS 6T07179411
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $22,697,460
    c. Budget Category: TSG
    d. Project Description: Installation of 20”/.500w/X65/FBE-Powercrete pipe - Installation of new 20” pipe; Storage area pipe replaced to limit migration outside the field
    e. Project in Service Date: December 10, 2009

Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

18. WBS O8100.3C.1.1.1 - (3C07420173, 3C07408845, and 3C07422574)
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $1,053,974
    c. Budget Category: NCA
    d. Project Description: A new Mainline Extension - Navarre Road in three phases
    e. Project in Service Date: June 26, 2012

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful.

19. WBS O8100.3W.1.1.1 (3W07437611)
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $1,846,095
    c. Budget Category: NCA
    d. Project Description: Smuckers MLX - Installation Project - new 8" steel pipe installation
    e. Project in Service Date: September 12, 2012

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

20. WBS P400384703
    a. Type of Inspection: Desktop Review
    b. Final Project Costs: $987,792
    c. Budget Category: Revenue Generating
    d. Project Description: Pratt Industries MLX and Meter Manifold Installation - pipe replacement and station work required to supply new customer
    e. Project in Service Date: August 28, 2018

    Comments: No additional information is required. Building and Equipment inspected is confirmed to be installed, prudent and used and useful

21. WBS P400015882
    f. Type of Inspection: Desktop Review
    g. Final Project Costs: $2,767
    h. Budget Category: Hybrid PIR and CEP
    i. Project Description: 4176 E 181ST-REPL M/L #14686-CLEVELAND, PIR ELIGIBLE - ONGOING ACCEL / C&M, and ONGOING ACCEL / C&M - Distribution Mainline Replacement - ineffective coded pipe installed in 1957 replacement. Split between CEP and PIR
    a. Project in Service Date: May 2013

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

22. WBS P400014183
    j. Type of Inspection: Desktop Review
    k. Final Project Costs: $695
    l. Budget Category: CEP

a. Project Description: 8123 Brunner Ave – Cut SL – Cleveland - PIR ELIGIBLE - ONGOING ACCEL / C&M, and ONGOING ACCEL / C&M - Abandon service on Brenner Road
b. Project in Service Date: May 15, 2013

Comments: No additional information is required. Equipment inspected is confirmed to be removed thus work was prudent and remaining lines used and useful

23. WBS P400031800
    m. Type of Inspection: Desktop Review
    n. Final Project Costs: $4,119
    o. Budget Category: CEP
    a. Project Description: 1935 FAYE RD-REPL M/L-AKRON - PIR ELIGIBLE - ONGOING ACCEL / C&M, and ONGOING ACCEL / C&M - Mainline Replacement
    b. Project in Service Date: October 21, 2013

    Comments: No additional information is required. Equipment inspected is confirmed to be installed, prudent and used and useful

VALIDATION AND VERIFICATION OF SCHEDULES

The following section discusses Blue Ridge's review, including our validation and verification of (1) the Schedules B-2 et al. and B-3 et al. from the last base rate case (March 31, 2007) through December 31, 2018, (2) the CEP Deferral Schedules included in the Company's 2019 Annual Informational Filing, and (3) the CEP Revenue Requirement Schedules that support the Company's request for an alternative rate plan to establish its Capital Expenditure Program (CEP) Rider.

PLANT SCHEDULE B-2 ET AL. AND B-3 ET AL.

The following section provides our review of the Plant Schedules B-2 et al. (Plant in Service) and B-3 et al. (Accumulated Depreciation) provided in the Company's May 1, 2019, Application, Exhibit H:

Plant in Service

The following schedules that report the plant-in-service balances were reviewed.

- Schedule B-2 Plant in Service by Major Property Groupings is a summary of the Company's plant in service by major property groupings as of December 31, 2018.
- Schedule B-2.1 Plant in Service by Accounts and Sub Accounts details, by plant FERC account, the book cost of the plant-in-service data as of December 31, 2018, summarized in Schedule B-2.
- Schedule B-2.2 Adjustments to Plant in Service is labeled as not applicable by the Company. The data within the plant-in-service schedules reflect the actual balances per DEO's books without adjustments.
- Schedule B-2.3 shows gross additions, retirements, and transfers by FERC account for each major property grouping from March 31, 2007, the date certain in DEO's most recent rate case, Case No. 07-829-GA-AIR, through December 31, 2018, the date certain in this case.
- Schedule B-2.3a provides a breakdown of the data contained in Schedule B-2.3 by year from March 31, 2007, through December 31, 2018.
- Schedule B-2.4 is a list of the leased property that is capitalized and included in rate base. The Company reports a lease of computer equipment with a dollar value of $610,242.

The Company reports the following plant-in-service balances by major property group as of December 31, 2018.[118]

Table 21: Plant in Service as of December 31, 2018

Intangible Plant	$	58,128,111
Production and Gathering		192,643,172
Storage		259,199,348
Transmission		485,170,692
Distribution		3,498,087,522
General		173,887,833
Total	$	4,667,116,677

Blue Ridge performed mathematical checks for accuracy of the roll-forward balances from the last base rate case (March 31, 2007) through December 31, 2018, as reported in the plant-in-service-related schedules (Schedules B-2 et al.). We found that the beginning balances as of March 31, 2007, on Schedule B-2.3 did not match the balances approved in the last base rate case[119] as shown in the following table.

Table 22: Comparison of 3/31/2007 Plant Balance to Balances Approved in Last Base Rate Case

	Approved Case No. 07-829-GA-AIR	Beginning Balance Per Schedules	Difference
Intangible Plant	$ 44,963,636	$ 44,992,154	$ (28,518)
Production and Gathering	90,787,404	91,446,248	(658,844)
Storage	114,485,195	114,672,039	(186,844)
Transmission	208,990,672	210,255,996	(1,265,324)
Distribution	1,330,545,150	1,345,843,831	(15,298,681)
General	126,361,923	126,243,431	118,492
Total	$ 1,916,133,980	$ 1,933,453,699	$ (17,319,719)

Further review found that the differences in the beginning balances from those approved in the last base rate case were the approved adjustments not reflected in the beginning balances. Thus, the beginning balance of the plant in service was overstated by $17,319,717.[120]

Table 23: Staff Adjustments to Plant from Last Base Rate Case Not Reflected in Beginning Balances

	Plant in-Service
Elimination of Plant No Longer in Service	$ (6,561,282)
Elimination of Plant Retirement Obligation	(10,707,160)
Leasehold Improvements No Longer in Service	(163,635)
Contribution in Aid of Construction	(28,517)
Unspecified Leased Plant	140,877
	$ (17,319,717)

While Blue Ridge believes these Commission-approved adjustments, totaling $(17,319,717), should have been reflected in the Company's beginning balance as reported on Schedule B-2, and has labeled the finding as an adjustment, we are not recommending the plant-in-service balance be

[118] Case No. 19-0468-GA-ALT, Application, May 1, 2019, Exhibit H, Schedule B-2.
[119] DEO Response to Data Request BRDR-4 (Case No. 07-0829-GA-AIR) and WP Staff DR 1 – Exhibit H – Schedule B-2, B-2.1, B-2.2, B-2.3.
[120] WP Beg Balance Staff RMAs BRDR-4 Attachment 1 Staff Report Last Rate Case.

adjusted at this time. Blue Ridge recommends that they be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time. [**ADJUSTMENT #10**]

Blue Ridge also found errors and inconsistencies in the roll-forward schedules in B-2.3a. These problems included hard-coded numbers where formulas should be and incomplete formulas. In addition, we found a hard-coded number that not only should have been a formula but also had the wrong hard-coded value. A list of Blue Ridge's observations is included in our workpapers.[121] With the exception of the following, Blue Ridge's findings had no impact on the ending balances as of December 31, 2018. The following error would affect the balance as of December 31, 2018.

- Schedule 2.3a 2007: The total 2007 Additions for General Plant was overstated by $64,210. The schedule's spreadsheet cell in which the total was located was hard-coded with an incorrect total. The total was overstated. Blue Ridge recommends that Total General Plant be reduced by the overstated amount.[122] The adjustment reduces Total General Plant by $64,210. This adjustment flows through the recast Schedule B-2. [**ADJUSTMENT #12**]

Blue Ridge found that, other than the beginning balances not reflecting the approved adjustments from the last base rate case and hard-coded values and incomplete formulas, the remaining schedule calculations rolled forward from year to year from March 31, 2007, through December 31, 2018.

Blue Ridge compared plant balances for each scope year (2007 through 2018) to the annual reports filed with the Commission to identify and reconcile any differences. Blue Ridge found the following differences.[123]

Table 24: Differences Between Plant Balances Reported in PUCO Annual Reports and Roll-Forward Schedule B-2.3a

Year Ending	Total Difference	% of Total
12/31/07	$ (1,915,179)	-0.10%
12/31/08	(2,166,442)	-0.08%
12/31/09	(1,627,320)	-0.05%
12/31/10	(3,317,942)	-0.12%
12/31/11	855,597	-0.06%
12/31/12	1,738,797	-0.03%
12/31/13	1,769,580	-0.02%
12/31/14	(1,330,346)	-0.01%
12/31/15	(358,231)	-0.01%
12/31/16	(264,509)	-0.01%
12/31/17	(419,260)	-0.01%
12/31/18	(94,696,477)	-2.07%

While many of the year's differences were immaterial (less than 0.10%), the difference in the amount reported in the PUCO Annual Report and the balances on Schedule B-2.3a was significant. The difference was $94.7 million or 2.07 percent of the total. The difference was further analyzed and summarized by Asset Group in the following table.

[121] WP Staff DR 1-Exhibit H – Schedule B-2.3a.
[122] WP Staff DR-1-Exhibit H – Schedule B-2.3a, Tab Sch2.3a 2007.
[123] WP Schedule B-2.3a Reconcile to Annual Report – Plant.

Table 25: 12/31/2018 Differences Between Plant Balances Reported in PUCO Annual Reports and Roll-Forward Schedule B-2.3a by Asset Group

Asset Group	Schedule 2.3a Balance	Annual Rpt Balance	Difference
INTANGIBLE PLANT	$ 58,128,111	$ 58,128,111	$ (0)
PRODUCTION & GATHERING PLANT	192,643,172	191,501,449	(389,625)
STORAGE PLANT	259,199,348	240,519,838	(18,546,022)
TRANSMISSION PLANT	485,170,692	482,607,861	(1,916,231)
DISTRIBUTION PLANT	3,498,087,521	3,436,341,668	(52,540,943)
GENERAL PLANT	173,887,833	163,321,273	(21,303,657)
TOTAL	**$ 4,667,116,677**	**$ 4,572,420,200**	**$ (94,696,478)**

The Company explained that the difference of $94,696,477 was comprised of two components:[124]

FERC 106 Completed Construction Not Classified	$94,365,143
FERC 101.1 Property Under Capital Leases, Net	331,335
	$94,696,478

The Company further explained that the $94,365,143 was included in FERC account 106 Construction Completed but not Classified at December 31, 2018, and represented plant that was in service as of December 31, 2018, but not included in the schedule of assets in FERC Account 101 in the 2018 PUCO Annual Report. The assets were subsequently reclassified to FERC account 101 and reflected in a revised 2018 year-end plant statement from Fixed Assets, which provided the basis for the Company's Schedule B-2.3a. In addition, the net value of property under capital leases of $331,336 is separately reported in the PUCO Annual Report and was included in FERC 391.20 on Schedule B-2.3a. The amounts can be seen in the "Utility Plant" section of the balance sheet in the 2018 PUCO Annual Report on page 9.[125] Blue Ridge confirmed that the balances were included on the balance sheet in the 2018 PUCO Annual Report and found that the Company's explanation for the differences between Schedule 2.3a and the PUCO annual report not unreasonable.

The Company explained that of the $94 million, approximately $50 million is related to a PowerPlan performance issue that occurred at year end. Typically, massed assets are recorded to FERC 101, as costs are incurred monthly, and are not initially recorded to FERC account 106. Because of the performance issue, $50 million of massed assets were recorded to FERC account 106. In January 2019, the entire value was unitized.[126] Blue Ridge recommends that the Company evaluate the performance issue that occurred and develop a plan to identify and rectify the issue should it occur again in the future.

As part of our verification of the reported additions, the Company prepared and Blue Ridge reviewed the work order population used to develop our work order transactional testing sample to the amounts reported in the Company's PUCO Annual Reports for 2007 through 2018.[127] We did not identify any unreconcilable inconsistencies between the continuing property records and the balances reported on the plant and related schedules.

[124] DEO Response to Data Request BRDR-163 (Schedule 2.3a Tie Out to Annual Report).
[125] DEO Response to Data Request BRDR-163 (Schedule 2.3a Tie Out to Annual Report).
[126] DEO Response to Data Request BRDR-35 (Unitization).
[127] DEO Response to Data Request BRDR-9 (Work Orders) and DEO Response to Staff DR-2.

Accumulated Depreciation and Amortization

The following schedules that report the plant-in-service balances were reviewed.

- Schedule B-3 shows the total Plant Investment and Reserve for Accumulated Depreciation and Amortization by major property grouping, and jurisdictional allocation percentages as of December 31, 2018.
- Schedule B-3.1 is labeled as not applicable by the Company. The data within the Reserve for Accumulated Depreciation and Amortization schedules reflect the actual balances per DEO's books, without adjustments.
- Schedule B-3.2 provides the Jurisdictional Plant and Reserve Balances at December 31, 2018, by major property grouping and FERC account. Schedule B-3.2 further shows the current depreciation and amortization accrual rates and calculated annualized depreciation and amortization expense at current rates.
- Schedule B-3.3 provides the Depreciation Reserve Accruals, Retirements, and Transfers by major property grouping and FERC account from March 31, 2007, the date certain in Case No. 08-0729-GA-AIR, through December 31, 2018, the date certain in this case.
- Schedule B-3.3a provides a summarized breakdown of the data contained in Schedule B-3.3 by year from March 31, 2007, through December 31, 2018.
- Schedule B-3.4 shows the plant investment, accumulated depreciation reserve, and annual expense for leased property as of the date certain. The schedule reflects the depreciation reserve for leased computer equipment with a dollar value of $610,242.[128]

The Company reports the following reserve balances by major property group as of December 31, 2018.[129]

Table 26: Reserve for Accumulated Depreciation Balances as of December 31, 2018

Intangible Plant	$	29,623,377
Production and Gathering		69,727,514
Storage		81,969,654
Transmission		119,309,184
Distribution		1,052,806,859
General		42,304,137
Other		(206,301,467)
Total	$	1,189,439,258

Blue Ridge performed mathematical checks on the accuracy of the roll-forward balances from the last base rate case (March 31, 2007) through December 31, 2018, as reported in the reserve-related schedules (Schedules B-3 et al.). We found that the beginning balances as of March 31, 2007, on Schedule B-3.3a did not match the balances approved in the last base rate case[130] as shown in the following table.

[128] Case No. 19-0468-GA-ALT, Direct Testimony of Vicki H. Friscic, page 6, line 16: page 10, line 3.
[129] Case No. 19-0468-GA-ALT, Application, May 1, 2019, Exhibit H, Schedule B-3.
[130] DEO Response to Data Request BRDR-4 (Case No. 07-0829-GA-AIR) and WP Staff DR 1 – Exhibit B-3-3a.

Table 27: Comparison of 3/31/2007 Reserve Balances to Balances Approved in Last Base Rate Case

	Approved Case No. 07-829-GA-AIR	Beginning Balance Per Schedules	Difference
Intangible Plant	$ 28,100,470	$ 28,101,776	$ (1,306)
Production and Gathering	36,285,888	36,294,584	(8,696)
Storage	56,112,511	56,172,397	(59,886)
Transmission	101,747,928	102,177,452	(429,524)
Distribution	480,433,071	486,380,573	(5,947,502)
General	70,055,483	70,077,868	(22,383)
Other Reserves	76,612,394	16,321,044	60,291,352
Total	$ 849,347,745	$ 795,525,693	$ 53,822,056

Further review found that the differences in the beginning balances from those approved in the last base rate case were Commission-approved adjustments not reflected in the beginning balances. Thus, the beginning balance of the Reserve for Accumulated Depreciation was understated by $53,822,056.[131]

Table 28: Staff Adjustments to Reserve from Last Base Rate Case Not Reflected in Beginning Balances

	Reserve
Elimination of Plant No Longer in Service	$ (6,129,909)
Elimination of Plant Retirement Obligation	59,985,396
Leasehold Improvements No Longer in Service	(163,635)
Contribution in Aid of Construction	(1,306)
Unspecified Leased Plant	131,507
	$ 53,822,053

While Blue Ridge believes these Commission-approved adjustments, totaling $53,822,053, should have been reflected in the Company's beginning balance as reported on Schedule B-3, and have labeled the finding as an adjustment, we are not recommending the reserve be adjusted at this time. Blue Ridge recommends that they be considered in the Company's next base rate case to ascertain their rolled-forward impact and relevance at that time. [**ADJUSTMENT #11**]

In addition to the beginning balances not reflecting the approved adjustments from the last base rate case, the schedule calculations in Schedule B-3.3a had several hard-coded numbers and inaccurate formulas as the totals were rolled forward from year to year from March 31, 2007, through December 31, 2018. A list of Blue Ridge's observations is included in our workpapers.[132] With the exception of the following, Blue Ridge's findings had no impact on the ending balances as of December 31, 2018. The following error would affect the balance as of December 31, 2018.

- Schedule 3.3a 2016: Hard-coded ending balance of zero when calculation should be $83,095, resulting in understated reserve for FERC account 375.03 Structures & Improvements-Leasehold Improvements. The adjustment increases the reserve by $83,095 (reducing net plant by the same amount). This adjustment flows through the recast Schedule B-3. [**ADJUSTMENT #13**]

In addition, Blue Ridge compared the reserve balances for each scope year (2007 through 2018) to the annual reports filed with the Commission to identify and reconcile any differences. Blue Ridge found the following differences.[133]

[131] WP BRDR-4 Attachment 1 Staff Report Last Rate Case.
[132] WP Staff DR 1-Exhibit H – Schedule B-3.3a.
[133] WP Schedule B-3.3a Reconcile to Annual Report – Reserve.

Table 29: Differences Between Reserve Balances Reported in PUCO Annual Reports and Roll-Forward Schedule B-3.3a

Year Ending	Schedule B-3.3a	Annual Report	Difference	% Difference
12/31/07	$ 828,361,910	$ 785,939,112	$ (42,422,798)	-5.40%
12/31/08	858,446,230	828,884,164	(29,562,066)	-3.57%
12/31/09	900,787,718	864,964,370	(35,823,348)	-4.14%
12/31/10	933,439,427	901,730,242	(31,709,185)	-3.52%
12/31/11	967,375,213	945,122,990	(22,252,223)	-2.35%
12/31/12	990,455,587	972,696,393	(17,759,194)	-1.83%
12/31/13	1,011,761,071	997,446,278	(14,314,793)	-1.44%
12/31/14	1,040,675,211	1,029,969,828	(10,705,383)	-1.04%
12/31/15	1,089,486,988	1,077,373,546	(12,113,442)	-1.12%
12/31/16	1,071,638,753	1,062,449,960	(9,188,793)	-0.86%
12/31/17	1,125,829,664	1,120,458,849	(5,370,815)	-0.48%
12/31/18	1,189,439,258	1,171,468,973	(17,970,285)	-1.53%

The Company explained that Schedule B-3.3a provides the amounts recorded to FERC account 108 Accumulated Provision for Depreciation. Amortization for items like computer software and land rights are recorded in FERC account 111 Accumulated Provision for Amortization and Depletion or in FERC account 101.1 Property Under Capital Leases. The Company provided a reconciliation for the differences in each year.[134] Blue Ridge reviewed the reconciliations and found them not unreasonable.

Conclusion on Validation and Verification of Plant Schedule B-2 et al. and B-3 et. al.

Blue Ridge performed various validations and verification checks of the accuracy of the roll-forward balances from the last base rate case (March 31, 2007) through December 31, 2018. We identified the following items that would impact the balances.

- Beginning balances for plant in service and the reserve did not match balances approved in the last base rate case. The differences were identified as Commission-approved ratemaking adjustments that were not reflected in the beginning balances for plant in service ($17,319,719) and the reserve ($53,822,053), resulting in net plant being overstated by $71,141,772. Blue Ridge recommends an adjustment be made to plant in service and the reserve to reflect the ratemaking adjustments in the last base rate case.
- Formulas used in the roll-forward schedules (B-2.3a and B-3.3a) included errors and inconsistencies. The following two errors, including hard-coded numbers where a formula should have been, affected the plant-in-service and reserve balances.
  - 2007 Additions for General Plant was overstated by $64,210. This overstated amount rolled forward through to the December 31, 2018, balance. Blue Ridge recommends an adjustment be made to the plant-in-service balance.
  - 2016 FERC account 375.03 Structures & Improvements-Leasehold Improvements Reserve reported a hard-coded ending balance of zero when the calculated amount was $83,095. The amount was rolled forward to the December 31, 2028, balance, resulting in understated reserve. Blue Ridge recommends an adjustment be made to the reserve balance.
- In 2018, a performance issue with PowerPlan resulted in approximately $50 million massed assets that are typically recorded to FERC 101 as costs are incurred monthly to be recorded

[134] DEO Response to Data Request BRDR-168 (Schedule B-3.3a Tie Out to Annual Report).

> to FERC account 106 Construction Completed but not Classified. Assets in both FERC account 101 and FERC account 106 are in service and impact only the reporting. However, due to the magnitude of the issue in 2018, Blue Ridge recommends that the Company evaluate the performance issue that occurred and develop a plan to identify and rectify the issue should it occur again in the future.

In addition, Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service, depreciation-reserve, and annualized depreciation expense schedules. Blue Ridge's recommended adjustments are summarized in Section 13 Adjustments and Other Recommendations. The recommended revised Schedules B-2 and B-3 are provided in the attached Appendix D.

2019 ANNUAL INFORMATIONAL FILING (CEP DEFERRAL)

This section summarizes the findings and recommendations from verifying and validating the CEP Deferral Schedules included in the 2019 Annual Informational filing docketed on April 30, 2019.

Background

The Commission's Order in Case No. 11-6024-GA-UNC required certain annual filings associated with the CEP deferral as follows

> DEO should docket an annual informational filing by April 30 of each year that details the monthly CEP investments and the calculations used to determine the associated deferrals, as recommended by Staff. Each annual informational filing should include schedules showing the inputs and all calculations used to determine the monthly deferred amounts, including a breakdown of investments (by budget class), PISCC, depreciation expense, property tax expense, and all incremental revenue, as well as a capital budget for the year following the year covered in the filing. The annual informational filings should also include a schedule showing the potential impact on GSS customer rates, if the deferrals were to be included in rates.[135]

On April 30, 2019, under Case No. 13-2410-GA-UNC, the Company filed its 2019 Annual Information filing, which included 14 schedules supporting the CEP Deferral.

Each major component reflected in the 2019 Annual Informational Filing of the CEP Deferral is discussed below, along with Blue Ridge's comments.

Schedule 1 Capital Investment and Deferral Summary

Schedule 1 summarizes the cumulative CEP annual Capital Investment and Deferral Summary through December 31, 2018. The summary amounts are supported by other schedules included in the Annual Informational Report that are discussed later.

Capital Investments

The Commission's Order provided implementation of a CEP for any of the following reasons:

a) Any infrastructure expansion, infrastructure improvement, or infrastructure replacement program

[135] Case No. 11-06024-GA-UNC, Finding and Order (December 12, 2012) at 14.

b) Any program to install, upgrade, or replace information technology systems

c) Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction[136]

Schedule 1 provides monthly balances for capital additions, cost of removal, retirements, accumulated provisions for depreciation to derive Total Capital Additions, Net. Each component is summarized in the following table and discussed later.

Table 30: CEP Capital Investments Summary[137]

Capital Additions		
Infrastructure Expansion, Improvement, or Replacement	$	460,774,367
Information Technology		61,552,806
Compliance / Operations		200,531,296
Total Capital Additions	$	722,858,469
Cost of Removal (COR)		(55,386,345)
Retirements		(52,678,594)
Total Capital Additions, Net COR and Retirements	$	614,793,531
Accumulated Provision for Depreciation		
Depreciation Expense	$	72,221,347
Cost of Removal		(55,386,345)
Retirements		(52,678,594)
Total Accumulated Provision for Depreciation, Net	$	(35,843,592)
Total Capital Additions, Net	$	650,637,123

Deferrals

The deferral section of Schedule 1 summarizes monthly PISCC, depreciation expense, and property tax expense to derive Deferred Costs, Net.

The Commission ordered that the Company "should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's sur-reply comments."[138] The formula for the Total Monthly Deferral is as follows:

Figure 2: Commission Approved Formula for Total Monthly Deferral[139]

Total Monthly Deferral	=	(PISCC) + (Depreciation Expense) + (Property Tax Expense) - (Incremental Revenues)

The cumulative Deferral through December 31, 2018, is shown in the following table. Each deferral item is discussed later.

[136] Case No. 11-6024-GA-UNC, Finding and Order (December 12, 2012) at 13.
[137] WP DEO V&V 2019 Annual Report CEP.
[138] Case No. 11-6024-GA-UNC (December 12, 2012), page 13.
[139] Case No. 11-6024-GA-UNC, Sur-Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio (September 20, 2012), page 11.

Table 31: CEP Deferral Summary[140]

Deferrals		
Post In-Service Carrying Costs (PISCC)	$	110,632,427
Depreciation Expense		72,221,347
Property Tax Expense		21,422,462
Total Deferrals	$	204,276,235
Reduction for Incremental Revenues		-
Deferred Costs, Net	$	204,276,235

Both the Capital Investment and Deferrals reported in the 2019 Annual Informational Report would be expected to flow through the Company's CEP Rider Revenue Requirements.

Schedule 2 Rate Projection for the GSS/ECTS Class

Schedule 2 provides the 2018 rate projections of the GSS/ECTS Class. Reviewing the Company's projections was not in Blue Ridge's scope, and we did not confirm the calculations included on this schedule.

Schedule 3 Gross Capital Investment and Schedule 4 Gross Capital Investment – Cumulative

Schedule 3 provides the monthly investment by FERC account for 2018. Schedule 4 provides the cumulative capital investment by FERC account. The following table summarizes the Company's CEP Capital Investment.

Table 32: CEP Capital Investment[141]

Capital Investments		
Infrastructure Expansion, Improvement, or Replacement	$	460,774,367
Information Technology		61,552,806
Compliance / Operations		200,531,296
Total Capital Investments	$	722,858,469

Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analyses and detailed transactional testing. Blue Ridge's investigation identified several adjustments that should be applied to the CEP Capital Investment balances. These adjustments are addressed within the report and are summarized in Section 13 Adjustments and Other Recommendations. These adjustments are reflected in the recast CEP Revenue Requirements Schedules included in Appendix E.

Schedule 5 Cost of Removal (COR) and Schedule 6 Cost of Removal (COR) – Cumulative

Schedule 5 provides the Cost of Removal (COR) by FERC account for each month in 2018. Schedule 6 provides the cumulative COR by FERC account. Cost of Removal (COR) reflects the cost of demolishing, dismantling, tearing down, or otherwise removing the assets(s), including the cost of related transportation.[142] The Company is reporting COR of $55,386,345 through December 31, 2018.

[140] WP DEO V&V 2019 Annual Report CEP.
[141] WP DEO V&V 2019 Annual Report CEP.
[142] DEO Response to Data Request BRDR 13 (Policies and Procedures) Confidential, Attachment 3 (Disposal of Assets) Confidential.

The Company stated that a fixed project can receive direct charges for cost of removal whereas the Company does not direct charge COR (e.g., labor, materials, etc.) on small dollar, high-volume (massed) pipeline replacement projects. Fixed Assets Accounting developed allocation rates based on historical direct-charge data in order to develop an average COR rate to be used in allocating project costs between the new pipeline asset and COR on the retired asset. An allocation percentage of 2.91% was established in 2003 and used until 2014 when DEO's Internal Audit team reviewed and updated the COR allocation percentage to 1.11%. The 1.11% is the current percentage being utilized. Additionally, when service lines to inactive premises are cut and capped or removed, the associated costs are considered costs of removal and are included in both the capital and cost of removal values.[143] The Company stated that is intends to review the allocation percentage in 2020.[144]

The Company stated, "To minimize costs, DEO generally abandons old pipe in place to the extent possible, with removal costs generally associated with tie-in points, where pipe must be removed and replaced to permit the installation and operation of the new pipe."[145]

Blue Ridge calculated the COR to CEP Capital Additions and found that COR is 7.66% of the CEP Capital Additions as shown in the following table. The 7.66% is significantly higher than the COR allocation percentage of 1.11% that the Company uses on small dollar, high-volume (massed) pipeline replacement projects.

Table 33: COR as a Percent of CEP Capital Additions[146]

Year	Additions	Cost of Removal	COR % of Adds
2011	$ 19,040,861	$ (582,793)	3.06%
2012	76,999,970	(1,814,977)	2.36%
2013	68,658,088	(6,818,227)	9.93%
2014	98,230,614	(11,927,523)	12.14%
2015	106,728,146	(7,349,477)	6.89%
2016	111,224,766	(9,709,049)	8.73%
2017	108,900,290	(8,745,982)	8.03%
2018	133,075,734	(8,438,317)	6.34%
Cumulative 12/31/18	**722,858,469**	**(55,386,345)**	**7.66%**

To better understand the type of projects that incurred the majority of COR, Blue Ridge isolated the FERC accounts that represented greater than 2.5% of the total COR and compared those FERC accounts' COR to the capital addition balances for those accounts. Of note, the Other FERC accounts COR was 1.1% of the capital additions, which is consistent with the COR allocation percentage of 1.11% that the Company uses on small dollar, high-volume (massed) pipeline replacement projects.

[143] DEO Response to Data Request BRDR-45 (CEP Revenue Requirements Cost of Removal and Retirements).
[144] DEO Response to Data Request BRDR-62 (CEP Revenue Requirements Cost of Removal and Retirements).
[145] DEO Response to Data Request BRDR-62 (CEP Revenue Requirements Cost of Removal and Retirements).
[146] WP CEP V&V Rev Req Staff DR 1-Exhibit 1-Additional Supporting Schedules.

Table 34: FERC Accounts with Majority of COR[147]

Description	FERC	COR	% of Total COR	Capital Additions	% COR of Capital Addition
Production/Gathering					
Field Lines	332.01	(3,259,434)	5.9%	14,478,209	22.5%
Storage					
Wells - Well Construction	352.01	(2,832,105)	5.1%	10,130,863	28.0%
Lines	353.01	(6,935,924)	12.5%	33,232,573	20.9%
M&R Equipment - Other	355.02	(1,416,755)	2.6%	15,747,373	9.0%
Transmission					
Mains	367.01	(1,639,620)	3.0%	16,489,275	9.9%
M&R Station Equipment - Other	369.03	(5,065,350)	9.1%	23,646,355	21.4%
Distribution					
Lines, Relocations and Betterments	376.01	(2,817,854)	5.1%	124,037,875	2.3%
M&R Station Equipment - Other	378.02	(1,295,997)	2.3%	10,771,813	12.0%
Services - LP & RP	380.00	(20,483,333)	37.0%	47,066,884	43.5%
Pipeline Integrity					
Transmission Mains	367.01	(5,111,614)	9.2%	28,293,144	18.1%
Subtotal		(50,857,986)	91.8%	323,894,364	15.7%
Other FERC Accounts		(4,528,359)	8.2%	398,964,106	1.1%
Total COR		(55,386,345)	100.0%	722,858,469	7.7%

Blue Ridge's work order transactional testing also reviewed the COR on retired assets. Blue Ridge found that, except for the adjustment regarding COR discussed in work order testing step T11B, the COR is not unreasonable. These adjustments are reflected in the recast CEP Revenue Requirements Schedules included in Appendix E.

Schedule 7 Retirements and Schedule 8 Retirements – Cumulative

Schedule 7 provides the retirements by FERC account for each month in 2018. Schedule 8 provides the cumulative retirements by FERC account. An asset is retired from the asset management system when it is taken out of service. The Company is reporting retirements of $52,678,594 through December 31, 2018

Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analyses and detailed transactional testing, which included a review on whether assets no longer in service were timely retired in the Fixed Asset System. Blue Ridge's investigation identified some adjustments, summarized in Section 13 Adjustments and Other Recommendations. These adjustments are reflected in the recast CEP Revenue Requirements Schedules included in Appendix E.

Schedule 9 Depreciation Expense

Schedule 9 calculates the annualized depreciation expense by plant FERC account. The Company is reporting $72,221,347 in deferred depreciation expense through December 31, 2018.

[147] WP CEP V&V Rev Req Staff DR 1-Exhibit 1-Additional Supporting Schedules.

The Commission-approved calculation for CEP depreciation expense is "accumulated gross plant less cumulative COR and retirements, times the associated depreciation rate."[148] The Commission ordered that the Company "should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's sur-reply comments."[149] The formula for annualized depreciation is shown in the following figure.

Figure 3: Approved Methodology for Deferred Depreciation Expense[150]

Depreciation Expense	=	[(Current Month's Cumulative Gross Plant Additions) - (Current Month's Cumulative Cost of Removal) - (Current Month's Cumulative Retirements)] x [(Depreciation Rate) / (12 Months)]

The depreciation accrual rates are based on the depreciation rates approved by the Commission in Case No. 13-1988-GA-AAM. The Commission's Finding and Order (October 23, 2013) stated that the Company should apply the approved depreciation accrual rates to investments made in 2013 and thereafter under its AMR, PIR, and CEP Programs. The Company was also ordered to submit a new deprecation study for all gas plant accounts no later than September 1, 2019, with a study date of December 31, 2018.[151] The Company stated that no new FERC 300 accounts and/or subaccounts were added since the most recent Commission-approved depreciation accrual rates.[152]

Blue Ridge confirmed the December 31, 2017, deferred depreciation expense balances rolled forward to the 2019 Annual Information Report.[153] We also validated the depreciation accrual rates. There were several anomalies discussed in the CEP Revenue Requirement's Schedule 8 section of this report that were reviewed and determined not unreasonable. We verified the calculations used and found the calculation for the deferred depreciation expense not unreasonable. However, any adjustments to the components reflected in capital additions, COR, or retirements could affect the deferred depreciation expense.

Schedule 10 Post In-Service Carrying Costs (PISCC)

Schedule 10 calculates the deferred post-in-service carrying costs by plant FERC account. The Company is reporting $110,632,427 in deferred PISCC through December 31, 2018.

The Commission ordered that the Company "should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's sur-reply comments."[154] The formula for PISCC is shown in the following figure.

[148] DEO Response to Data Request BRDR-14 (CEP Accounting) and Case No. 11-06024-GA-UNC (December 12, 2012), page 6.
[149] Case No. 11-6024-GA-UNC (December 12, 2012), page 13.
[150] Case No. 11-6024-GA-UNC, Sur-Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio (September 20, 2012), page 11.
[151] DEO Response to Data Request BRDR-31 (Depreciation), Case No. 13-1988-GA-AAM, Finding and Order (October 23, 2013), page 2.
[152] DEO Response to Data Request BRDR-31 (Depreciation).
[153] Blue Ridge's scope regarding the validation and verification of the schedules was limited to a review of the 2019 Annual Informational Report. We did not verify calculations nor validate rolled forward balances in prior Annual Informational Report.
[154] Case No. 11-6024-GA-UNC (December 12, 2012), page 13.

Figure 4: Approved Methodology for Deferred PISCC[155]

PISCC	=	[Previous Month's Cumulative Gross Plant Additions) - (Previous Month's Cumulative Cost of Removal) - (Previous Month's Cumulative Retirements) - (Previous Month's Accumulated Depreciation)] x [(Long Term Debt Rate) / (12 Months)]

Blue Ridge confirmed the December 31, 2017, deferred PISCC balances rolled forward to the 2019 Annual Information Report.[156] We also validated the PISCC was based on the long-term debt rate of 6.5%, approved in the last rate case using a one-month lag. We verified the calculations and validated that the PISCC was based on the cumulative capital additions less retirements and depreciation. Deferred PISCC are recorded on a monthly basis. PISCC is calculated on a one-month lag.[157] Blue Ridge found the calculation for the deferred PISCC not unreasonable. However, any adjustments to the components reflected in capital additions, COR, or retirements could affect the deferred PISCC.

Schedule 11 Property Tax Expense

Schedule 11 calculates the deferred property tax expense. The Company is reporting $21,290,687 in deferred property tax expense through December 31, 2018.

The Commission ordered that the Company "should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's sur-reply comments."[158] The formula for property tax expense is shown in the following figure.

Figure 5: Approved Methodology for Deferred Property Tax Expense[159]

Property Tax Expense	=	[(Prior Year-end Cumulative Gross Plant Additions) - (Prior Year's Cumulative Cost of Removal) - (Prior Year-End Cumulative Retirements)] x [(Effective Property Tax Rate) / (12 Months)]

The Company stated, and Blue Ridge confirmed, that the property tax deferral is calculated on accumulated gross plant as of December 31 of the preceding year (the lien date in Ohio), net of cumulative COR and retirements, times the associated property tax rate for the given year. The property tax rate is provided by the DEO Tax department.[160] The Company stated that the 2018 property tax deferral was based on the latest known annual property tax rate, which was the 2017 tax year rate of 1.3308%.[161] The Company stated, and Blue Ridge recommends, that the estimated property tax rates used should be trued up to actual rates. Going forward, because actual property

[155] Case No. 11-6024-GA-UNC, Sur-Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio (September 20, 2012), page 11.
[156] Blue Ridge's scope regarding the validation and verification of the schedules was limited to a review of the 2019 Annual Informational Report. We did not verify calculations nor validate rolled forward balances in prior Annual Informational Report.
[157] DEO Response to Data Request BRDR-14 (CEP Accounting).
[158] Case No. 11-6024-GA-UNC (December 12, 2012), page 13.
[159] Case No. 11-6024-GA-UNC, Sur-Reply Comments Submitted on Behalf of the Staff of the Public Utilities Commission of Ohio (September 20, 2012), page 11.
[160] DEO Response to Data Request BRDR-14 (CEP Accounting).
[161] DEO Response to Data Request BRDR-80 (Property Tax).

tax rates will likely not be known until after the Company makes its annual rider filing, the Company suggested, and Blue Ridge recommends, that it use an estimated rate in its filing and true up that year's expense to the actual rate in the subsequent annual filing.[162]

Blue Ridge also recommends another adjustment be made to deferred property taxes. The Company inadvertently included an adjustment for lease payment reclass in Tax Years 2015 through 2017. The lease payment reclass represents an amount the Company pays as part of its property tax payment to Wood County and, therefore, should be included in the property tax rate calculation. The tax payments for the tax rate calculations were captured from the property tax liability account. The reclassification entry is between liability accounts and does not reduce the amount of tax paid.

The Company provided a revised Deferred Property Tax calculation reflecting actual effective tax rates and the correction for the lease payment reclass for Tax Years 2015 through 2017.

Table 35: Modification to Deferred Property Taxes

BRDR-147 Attachment 1

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Capital Expenditure Program (CEP) Rider

Asset base	Tax Year	Asset value	Annual Rate Filed	Actual Effective Rate (1)	Annual Filing	CEP Application	Actual Effective Rate
12/31/11	2012	$ 18,327,375.54	1.0794%	1.1521%	$ 197,825.69	$ 197,825.69	$ 211,149.69
12/31/12	2013	$ 82,271,922.96	1.1521%	1.1971%	$ 947,854.82	$ 947,854.82	$ 984,877.19
12/31/13	2014	$ 139,654,152.95	1.1971%	1.2468%	$ 1,671,799.87	$ 1,671,799.87	$ 1,741,207.98
12/31/14	2015	$ 217,691,158.77	1.2468%	1.2714%	$ 2,714,173.37	$ 2,714,173.37	$ 2,767,758.92
12/31/15	2016	$ 308,844,312.15	1.2680%	1.3118%	$ 3,916,145.88	$ 3,916,145.88	$ 4,051,393.10
12/31/16	2017	$ 401,145,340.63	1.3088%	1.3334%	$ 5,250,190.20	$ 5,250,190.20	$ 5,349,058.50
12/31/17	2018	$ 495,393,546.96	1.3308%	1.3344%	$ 6,592,697.32	$ 6,724,472.01	$ 6,610,531.49
					$ 21,290,687.15	$ 21,422,461.84	$ 21,715,976.87
						(a)	(b)
Proposed Deferred Property Tax Adjustment to CEP Application						(b) - (a)	$ 293,515.03

Note:
(1) Tax Years 2015 through 2017 have been revised from the originally submitted schedule of cumulative deferred property tax in BRDR-81 Attachment 1, which this schedule supersedes.

Blue Ridge found the Company's property tax deferral, as reported in the 2019 Annual Informational Filing, not unreasonable. However, the deferred property taxes reflected in the CEP revenue requirements should be updated to reflect the actual tax rate and the correction for the tax rates for Tax Years 2015, 2016, and 2017, removing the lease payment reclass. The adjustment would increase the Deferred Property Taxes by $293,515, reflected in the CEP revenue requirements calculation as discussed later in the report.

Blue Ridge's investigation identified some adjustments, summarized in Section 13 Adjustments and Other Recommendations. These adjustments are reflected in the recast CEP Revenue Requirements Schedules included in Appendix E.

[162] DEO Response to Data Request BRDR-146 (Annualized Property Taxes)

Schedule 12 Amortization of Deferrals

Schedule 12 provides the amortization of the deferred balances for PISCC, Depreciation Expense, and Property Tax Expense using the composite asset life amortization rate of 3.31%.

Schedule 12A Calculation of Composite Asset Life

Schedule 12A provides the calculation that the Company used to derive the composite asset life amortization rate of 3.31% that was used to amortize the deferred balances for PISCC, Depreciation Expense, and Property Tax Expense.

Schedule 13 Incremental Revenue Calculation

The Commission ordered, "DEO should offset the monthly regulatory asset amount charged to the CEP by those revenues generated from assets included in the CEP for SFV customers, non-SFV customers, and any other revenue sources directly attributed to CEP investments."[163]

Schedule 13 reflects the Company's incremental revenue calculation. The schedule reports no incremental revenue related to CEP investments.

The Company was asked how it identified CEP plant that will generate additional revenue. The Company stated

> a) Revenue generating projects comprise new business additions or additions, such as a mainline extension requested by an existing customer, will generate additional revenue. An economic analysis of the project is performed that considers revenues to be generated and associated expenses to ensure that the project yields a return that is at least DEO's authorized return.
>
> b) Revenue generating plant is identified in the Company's SAP Business Warehouse (BW) system by "Rev Gen" in the Plan Category and "Base Rate" in the Recovery field.
>
> c) DEO generally does not include such projects in the CEP, as the support provided by the CEP mechanism is not considered necessary for such projects. DEO does not believe that there are any revenue-generating investments reflected in CEP plant through December 31, 2018.[164]

As part of Blue Ridge's transactional testing and field work, we considered whether the projects included within the CEP for recovery could generate incremental revenue. Blue Ridge questioned three projects. The Company was able to adequately explain why the projects would not generate incremental revenue. Based on the Company explanation, Blue Ridge did not find any projects that could generate incremental revenue.

Schedule 14 Summary of Projected 2019 Capital Expenditure Plan Investments

Schedule 14 provides a summary of projected 2019 capital expenditure plan investments. The Company is projecting total capital expenditures in 2019 of $131.3 million. Blue Ridge did not review the projected 2019 Capital Expenditure Plan Investments.

[163] Case No. 11-6024-GA-UNC, Finding and Oder (December 12, 2012), pages 13–14.
[164] DEO Response to Data Request BRDR-25 (Revenue-generating CEP Investments).

Conclusion on 2019 Annual Informational Filing (CEP Deferral)

Blue Ridge performed various validations and verification checks on the schedules included in the 2019 Annual Informational Filing. Blue Ridge found that the Company calculated the deferral balances consistent with the December 12, 2012, Order in Case No. 11-6024-GA-UNC. However, Blue Ridge recommends that the deferred property taxes reflected in the CEP revenue requirements should be updated to reflect the actual tax rate and the correction for the tax rates for Tax Years 2015, 2016, and 2017, removing the lease payment reclass.

Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service, depreciation reserve, and annualized depreciation expense reflected in the 2019 Annual Information Filings. Blue Ridge's recommended adjustments are summarized in Section 13 Adjustments and Other Recommendations. The resulting recommended revised CEP revenue requirement schedules are provided in the attached Appendix E.

CEP Revenue Requirement Schedules

This section of the report summarizes the findings and recommendations from verifying and validating the CEP Revenue Requirement and Rate Design schedules that support the Company's requested alternative rate plan to establish a CEP Rider provided in the Company's May 1, 2019, Application, Exhibit I.

The Company has proposed a CEP Rider to earn a return on and of the net plant investment attributable to the CEP, which was not included in the rate base from the Company's last distribution rate case. The Company provided revenue requirement schedules in support of its request. The revenue requirement reflects investment activity from October 1, 2011, through December 31, 2018.

The Company's request is supported by 14 schedules. Mathematical checks were performed on each schedule and on the schedules' roll-forward balances to the revenue requirement calculation. In addition, we traced the values used in the schedules to source documentation and reviewed the reasonableness of the approach proposed by the Company. Each major component of the proposed CEP revenue requirements and Rate Design is discussed below, along with Blue Ridge's comments.

Schedule 1: Rate Design

The proposed CEP Rider charges were determined by allocating the revenue requirement shown on Schedule 1 at line 1 to each of DEO's rate schedules.

Blue Ridge found that the Rate Design schedule carried forward and allocated the Revenue Requirement from Schedule 2 by rate class based on Total Plant in Service Allocators. The schedule references "Total Plant in Service Allocators from the Company's base last rate case (Case No. 07-0829-GA-AIR, Schedule E 3.2)." However, the Company explained that an updated cost of service study was subsequently submitted in Case No. 09-654-GA-UNC. The Company further stated that while the total revenue approved by the Commission in the last rate case did not change, the updated study was the basis for the base rates currently in effect.[165] Blue Ridge compared the Total Plant in Service Allocators (in dollars) reflected on Schedule 1, lines 2–8 and found that the balances reconciled to Case No. 07-0829-GA-AIR, Schedule E.3.2, page 12 of 16.

[165] DEO Response to Data Request BRDR-78 (CEP Rider Rate Design).

The mathematical calculations used to allocate the CEP revenue requirements were not unreasonable.

The schedule also provides the projected impact per Bill/MCF for each rate class. The projected impact per Bill/MCF was calculated based on the Number of Bills Issued/MCFs (supported by Schedule 11). Commission Staff will verify and validate the information included on Schedule 11.

Schedule 2: Revenue Requirements

The Company is seeking recovery of $82,918,394 through the CEP Rider. The CEP Rider revenue requirements summary schedule is provided on Schedule 2. The summary schedule that pulls together the various components of CEP deferrals for which the Company seeks recovery through the CEP Rider and calculates the resultant revenue requirements as summarized in the following table.

Table 36: CEP Revenue Requirements Calculated by Company

Rate Base	
Plant in Service	$ 614,793,531
Less: Accumulated Provision for Depreciation	(35,843,592)
Net Capital Additions	$ 650,637,123
Depreciation Offset	(310,120,037)
Net Capital Additions Less Depreciation Offset	$ 340,517,086
Regulatory Deferrals	204,276,235
Accumulated Deferred Income Tax (ADIT)	(85,505,756)
Rate Base	$ 459,287,565
Pre-Tax Rate of Return	9.91%
Annualized Return on Rate Base	$ 45,515,398
Operating Expenses	
Annualized Depreciation Expense	$ 22,129,022
Annualized Property Tax Expense	8,512,431
Amortization of Deferred PISCC	3,661,933
Amortization of Deferred Depreciation Expense	2,390,527
Amortization of Deferred Property Tax Expense	709,083
Total Operating Expenses	$ 37,402,996
Total Revenue Requirement	$ 82,918,394

Most of the components included in the revenue requirements calculation were developed and rolled forward from other schedules. Blue Ridge's review of these other schedules and their supporting source data is discussed later.

The ADIT on PISCC Deferral Balance and ADIT on Property Tax Deferral Balance was calculated on the summary schedule using the federal tax rate of 21%. The derivation of ADIT on the PISCC Deferral Balance Property Tax Deferral Balance is consistent with the stipulation approved by the Commission for the Columbia Gas of Ohio CEP Rider[166] and is not unreasonable.

Blue Ridge found that the mathematical calculations used to calculate the CEP revenue requirements were not unreasonable. However, any adjustments to the components reflected in the calculation could affect the CEP revenue requirements that would be recovered through the CEP

[166] Case No. 17-2202-GA-ALT Columbia Gas Stipulation and Recommendation (October 28, 2018), Stipulation Exhibit 1.

Rider. Recommended adjustments are summarized in Section 13 Adjustments and Other Recommendations.

Schedule 3: Annual Capital Investments and Deferral Summary

Schedule 3 shows the CEP Annual Capital Investment and Deferral Summary. The Annual Capital Investments and Deferrals are presented by year from 2011 through 2018. The schedule provides annual balances for capital additions, cost of removal, retirements, accumulated provisions for depreciation to derive Total Capital Additions, Net. The deferral section of the schedule provides annual PISCC, depreciation expense, and property tax expense to derive Deferred Costs, Net.

The Company stated in testimony supporting its application that "Each annual value reflects what was filed in the Annual Informational Filings filed as part of the CEP through 2017. The 2018 Annual Informational Filing is being filed concurrently with this Application."[167]

Blue Ridge found that the capital additions, cost of removal, and retirements reflected in the CEP revenue requirements reconciled to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report. In addition, the deferrals associated with PISCC and depreciation expense also tied to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report.

However, Blue Ridge found that the deferral associated with property tax expense included in the CEP revenue requirements was greater than the amount reflected in the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report as shown in the following table.

Table 37: 2019 Annual Information Report vs. CEP Revenue Requirement – Property Tax Deferral

Deferral-Property Tax Expense	2019 Annual Report	CEP Revenue Requirements	Difference
Infrastructure Expansion, Improvement, or Replacement	$ 13,286,267	$ 13,370,187	$ 83,921
Information Technology	$ 2,332,654	$ 2,343,769	$ 11,116
Compliance / Operations	$ 5,671,767	$ 5,708,505	$ 36,739
Total Property Tax Expense Deferrals	$ 21,290,687	$ 21,422,462	$ 131,775

Blue Ridge examined the difference and found that it is related to the deferral in 2018 as shown in the following table.

Table 38: Property Tax Deferral-Comparison of Balances in 2019 Annual Report and CEP Revenue Requirements

Period	2019 Annual Report	CEP Rev Req Deferral Summary	Difference
2011		-	-
2012	197,826	197,826	-
2013	947,855	947,855	-
2014	1,671,800	1,671,800	-
2015	2,714,173	2,714,173	-
2016	3,916,146	3,916,146	-
2017	5,250,190	5,250,190	-
2018	6,592,697	6,724,472	131,775
Cumulative 12/31/18	21,290,687	21,422,462	131,775

[167] Case No. 19-0468-GA-ALT Direct Testimony of Celia Hashlamoun, 4:12–14.

The Company explained, "Both deferral balances utilized plant as of 12/31/17, which is the lien date for 2018 property tax expense, when calculating the 2018 deferral value. The reason for the difference in balances is the property tax rate. The 2019 CEP Annual Information Filing applied the latest known annual property tax rate, which was the 2017 tax year rate of 1.3308%. The 2018 property tax deferral included in the CEP revenue requirement was calculated at an estimated rate of 1.3574%. DEO has since determined that the actual effective property tax rate in 2018 was 1.3344%."[168]

The Company modified the Deferred Property Tax reflected in its CEP Revenue Requirements from the information provided in the 2019 Annual Informational Filing. Blue Ridge recommends that, in the future, the Company provide an explanation and reconciliation of any differences between what is reported in the Annual Informational Filings to the amounts it requests through the CEP.

As discussed in Blue Ridge's review of the Deferred Property Taxes reflected in the 2019 Annual Informational Filing, two adjustments should be made to the Deferred Property Taxes reflected in the CEP revenue requirements.

First, Blue Ridge recommends that estimated property tax rates used should be trued up to actual rates. Going forward, because actual property tax rates will likely not be known until after the Company makes its annual rider filing, the Company suggested, and Blue Ridge recommends, that it use an estimated rate in its filing and true up that year's expense to the actual rate in the subsequent annual filing.[169]

Second, Blue Ridge recommends the deferred property taxes for Tax Years 2015 through 2017 be corrected to remove the lease payment reclass.

The Company provided a revised Deferred Property Tax calculation reflecting actual effective tax rates and the correction for the lease payment reclass for Tax Years 2015 through 2017.

[168] DEO Response to Data Request BRDR-81 (Property Tax).
[169] DEO Response to Data Request BRDR-146 (Annualized Property Taxes)

Table 39: Modification to Deferred Property Taxes

BRDR-147 Attachment 1

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Capital Expenditure Program (CEP) Rider

Asset base	Tax Year	Asset value	Annual Rate Filed	Actual Effective Rate (1)	Annual Filing	CEP Application	Actual Effective Rate
12/31/11	2012	$ 18,327,375.54	1.0794%	1.1521%	$ 197,825.69	$ 197,825.69	$ 211,149.69
12/31/12	2013	$ 82,271,922.96	1.1521%	1.1971%	$ 947,854.82	$ 947,854.82	$ 984,877.19
12/31/13	2014	$ 139,654,152.95	1.1971%	1.2468%	$ 1,671,799.87	$ 1,671,799.87	$ 1,741,207.98
12/31/14	2015	$ 217,691,158.77	1.2468%	1.2714%	$ 2,714,173.37	$ 2,714,173.37	$ 2,767,758.92
12/31/15	2016	$ 308,844,312.15	1.2680%	1.3118%	$ 3,916,145.88	$ 3,916,145.88	$ 4,051,393.10
12/31/16	2017	$ 401,145,340.63	1.3088%	1.3334%	$ 5,250,190.20	$ 5,250,190.20	$ 5,349,058.50
12/31/17	2018	$ 495,393,546.96	1.3308%	1.3344%	$ 6,592,697.32	$ 6,724,472.01	$ 6,610,531.49
					$ 21,290,687.15	$ 21,422,461.84	$ 21,715,976.87
						(a)	(b)
Proposed Deferred Property Tax Adjustment to CEP Application						(b) - (a)	$ 293,515.03

Note:
(1) Tax Years 2015 through 2017 have been revised from the originally submitted schedule of cumulative deferred property tax in BRDR-81 Attachment 1, which this schedule supersedes.

Blue Ridge recommends that Deferred Property Taxes reflected in the CEP revenue requirements should be changed from $21,422,462 to $21,715,977, for an increase of $293,515. [**ADJUSTMENT #9**]

Schedule 4: Rate of Return on Rate Base

Schedule 4 provides the Company's calculation of the rate of return that is applied to rate base. Blue Ridge found that the Company appropriately used the rate of return of 8.29% approved in its last rate case.[170] The rate of return was grossed up to reflect the federal income tax rate of 21%. The rate-of-return approach is consistent with the stipulation approved by the Commission for the Columbia Gas of Ohio CEP Rider.[171]

Schedule 5: Calculation of Depreciation Offset

The CEP Revenue Requirements Rate Base includes a deprecation offset. The Company explained the purpose of the depreciation offset: "For accounting purposes, as depreciation expense is recovered, the accumulated depreciation reserve increases, therefore reducing rate base. The depreciation offset was created to represent the portion of depreciation expense that has been collected from customers through base rates, but not yet recognized as an offset to rate base. The offset effectively provides a credit to customers by reducing CEP rate base."[172]

Schedule 5 provides the calculation of the deprecation offset. Commission Staff will verify and validate the information included on this schedule.

[170] Case No. 07-829-GA-AIR Order & Opinion (October 15, 2008), page 32.
[171] Case No. 17-2202-GA-ALT Columbia Gas Stipulation and Recommendation (October 28, 2018), Stipulation Exhibit 2.
[172] Case No. 19-0468-GA-ALT Direct Testimony of Celia Hashlamoun, 4:15–21.

Schedule 6: Total Company Retirements Net of PIR Retirements for Depreciation Offset Calculation

Schedule 6 shows the support of the data used on Schedule 5. Commission Staff will verify and validate the information included on this schedule.

Schedule 7: Accumulated Deferred Income Tax (ADIT) on Liberalized Depreciation

Schedule 7 calculates the ADIT offset in rate base attributable to book-tax differences involving CEP plant. Tax law provisions generally enable companies to accelerate the expensing of capital investments in deriving taxable income relative to when book depreciation is recognized on the financial statement under accrual accounting principles. The timing difference results in the recordation of deferred tax liabilities as lower cash taxes are paid in the earlier years of asset lives. For this reason, the accumulated deferred tax balance, or ADIT, is often referred to as an interest-free loan from the government. Most regulatory jurisdictions treat ADIT as a rate base reduction to the extent the revenue requirement permits the recovery of total income taxes, whether current or deferred.

The Company calculated the ADIT balance by applying the federal statutory tax rate of 21 percent to the variance between the net book value and net tax value of CEP plant. The net book value represents original costs, excluding cost of removal and retirements, less accumulated Book Depreciation (Line 2). On a book basis, depreciation expense is computed using the Commission-approved depreciation accrual rates. Accumulated book depreciation is discussed in another section of this report. The net tax value represents original cost, excluding cost of removal and retirements, less accumulated Tax Depreciation (Line 5), plus Capitalized Interest (Line 6).

Tax Depreciation. Blue Ridge requested and reviewed supporting schedules to verify and validate the accumulated tax depreciation balance. The reports generated from the Company's PowerTax system showed AFUDC basis differences, 50 percent deductions on internally developed software, bonus depreciation prior to 2018, and other tax depreciation computed using the Modified Accelerated Cost Recovery System (MACRS), Internal Revenue Code (IRC) §197, or straight line.[173] The accumulated tax depreciation balance was $354,774,779, as filed, but the Company updated the reported value to $350,685,236.[174] The Company explained that the filed ADIT calculation did not properly deduct AFUDC from original cost. Moreover, when the Company initially prepared its application in early 2019, the tax books for the prior year had not settled. The Company was still reconfiguring its tax depreciation software to comply with the tax normalization rules surrounding the return of excess deferred income taxes to ratepayers.[175] Blue Ridge found the cumulative tax depreciation as updated and the Company's explanation for the revision to be not unreasonable. Blue Ridge recommends that the ADIT reflect the updated values.

Capitalized Interest. Blue Ridge inquired about the Capitalized Interest reflected as an addition to original cost. The Company explained that under certain circumstances IRC §263A(f) results in more interest being capitalized for tax than for book purposes. The higher tax basis of $7,438,056 results in the reflection of a $1,561,991 Deferred Tax Asset (DTA), which increases rate base.[176] Blue Ridge found inclusion of the DTA to be not unreasonable because the tax provision related to construction

[173] DEO Response to Data Request BRDR-149 (CEP ADIT on Liberalized Depreciation), Attachment 1.
[174] DEO Response to Data Request BRDR-83 (CEP ADIT on Liberalized Depreciation), Attachment 1.
[175] DEO Response to Data Request BRDR-173 (CEP ADIT on Liberalized Depreciation); Phone Interview on April 8, 2020.
[176] DEO Response to Data Request BRDR-150 (CEP ADIT on Liberalized Depreciation).

period interest offsets the cash tax benefits the Company received from the accelerated tax depreciation discussed above.

Blue Ridge found the ADIT as updated and the underlying book-tax differences reflected in the calculation to be not unreasonable. The Company's ADIT on Liberalized Depreciation in rate base is $56,915,425, as updated, compared to $57,774,229, as filed.[177] Blue Ridge recommends that the ADIT updated. The revision decreases ADIT by $858,804. The recommended CEP plant adjustments discussed in other sections also affect the ADIT balance; Adjustments #1 through #7 further decrease the offset in rate base by $23,818. The adjustment decreases ADIT in the CEP revenue requirements calculation by $882,621. [**ADJUSTMENT #8**]

Blue Ridge's recommendations to plant or depreciation discussed in other sections may further impact the Company's updated ADIT balance as a flow through adjustment.

Schedule 8: Annualized Depreciation and Property Tax Expense

Schedule 8 provides the calculations of the annual depreciation and property tax expense.

Annualized Depreciation

The Commission-approved calculation for CEP depreciation expense is "accumulated gross plant less cumulative COR and retirements, times the associated depreciation rate." [178] Annualized Depreciation is calculated for each asset by plant FERC account based on the depreciation rates approved by the Commission in Case No. 13-1988-GA-AAM. The Commission's Finding and Order (October 23, 2013) stated that the Company should apply the approved depreciation accrual rates to investments made in 2013 and thereafter under its AMR, PIR, and CEP Programs. The Company was also ordered to submit a new deprecation study for all gas plant accounts no later than September 1, 2019, with a study date of December 31, 2018.[179]

The Company stated that no new FERC 300 accounts and/or subaccounts were added since the most recent Commission-approved depreciation accrual rates.[180]

Blue Ridge compared the deprecation accrual rates approved to those used in the CEP revenue requirements to calculate the annualized depreciation expense and found several inconsistencies:

- Storage Other Equipment 357.00-6.67%: The CEP Revenue Requirements model includes Storage Other Equipment 357.00. There are no FERC account 357.00 approved depreciation accrual rates. It appears that the Company used the rate for Underground Storage Plant Other Equipment-Other 357.03. The accrual rates are the same and would have no impact on the CEP revenue requirements. The Company is technically using a FERC account without an approved depreciation accrual rate.
- Distribution Services-LP & RP 380.00-3.43%: The CEP Revenue Requirements model includes Distribution Services-LP & RP 380.00. There are no FERC account 380.00 approved deprecation accrual rates. However, the description includes LP and RP, and it appears that the Company combined rates for Distribution Plant Services-Low Pressure 380.02-3.43% and Distribution Plant Services-Regulated Pressure 380.03-3.43%. The accrual rates are the

[177] DEO Response to Data Request BRDR-83 (CEP ADIT on Liberalized Depreciation), Attachment 1.
[178] DEO Response to Data Request BRDR-14 (CEP Accounting) and Case No. 11-06024-GA-UNC (December 12, 2012), page 6.
[179] DEO Response to Data Request BRDR-31 (Depreciation), Case No. 13-1988-GA-AAM, Finding and Order (October 23, 2013), page 2.
[180] DEO Response to Data Request BRDR-31 (Depreciation).

same and would have no impact on the CEP revenue requirements. The Company is technically using a FERC account without an approved depreciation accrual rate.

- Distribution-New Customer Facilities 380.00-3.43%: The CEP Revenue Requirements model includes Distribution-New Customer Facilities 380.00. There is no FERC account 380.00 approved deprecation accrual rate. The approved deprecation accrual rates for similar accounts are different: 380.01-2.40%; 380.02-3.43%; 380.03-3.43%; 380.04-3.14%. The Company was asked why they selected the 3.43% rate over the other accrual rates related to FERC Account 380. The Company explained that there have been no additions to FERC Accounts 380.01 (Services – All Pressures) or 380.04 (Special Services) since 2011. Additions have been made to FERC Accounts 380.02 (Services – Low Pressure) and 380.03 (Services-Regulated Pressure), which both had the depreciation accrual rate of 3.43 percent through December 31, 2018.[181] Blue Ridge found that it appears that the Company has blended the approved accounts of 380.02 (Services – Low Pressure) and 380.03 (Services - Regulated Pressure), which had approved depreciation accrual rates, into 380.00 (Services – LP&RP) for convenience. The Company's explanation was not unreasonable. However, the Company is technically using a FERC account without an approved depreciation accrual rate.

In conclusion, Blue Ridge found that the Company has used depreciation accrual rates for several FERC accounts (357.00-Storage Other Equipment, 380.00-Distribution Services-LP & RP, and 380.00-Distribution-New Customer Facilities) that have not technically been approved by the Commission. From a practical standpoint, there is no impact on the CEP revenue requirements. However, Blue Ridge recommends that the Company correct this issue, if not already addressed, prior to the Commission approving the new deprecation study for all gas plant accounts that was presumably filed on or before September 1, 2019.

Blue Ridge confirmed that the Company used the accumulated gross plant less cumulative COR and retirements balances to calculate depreciation expense. The balances are consistent with what is reported in the 2019 Annual Information Filing (April 30, 2019).[182]

Blue Ridge found that the mathematical calculations used to calculate the CEP annualized depreciation expense and the resultant annualized depreciation expense were not unreasonable. However, any revisions to plant, cost of removal, or retirements discussed in other sections could affect the annualized depreciation expense.

Annualized Property Taxes

The Company calculated annualized property tax based on Cumulative Plant less COR less Retirements through December 31, 2018. However, the property tax rate of 1.3846% (labeled as "2018 Effective Rate") used to calculate property tax did not agree with the supporting documentation. The documentation for the 2018 effective tax rate supported a tax rate of 1.3344%.[183] The Company stated that the rate of 1.3846% was an estimate. The Company suggested, and Blue Ridge recommends, that the property taxes based on estimated rates should be trued up using the actual rate in the subsequent annual filing.[184]

[181] DEO Response to Data Request BRDR-145 (Annualized Depreciation Expense).
[182] The 2019 Annual Information Filing
[183] DEO Response to Data Request BRDR-80 (Property Tax), Attachment 8 (Tax Year 2018).
[184] DEO Response to Data Request BRDR-146 (Annualized Property Taxes).

Blue Ridge verified the mathematical accuracy of the annualized property tax expense calculation and found it not unreasonable. However, any revisions to plant, cost of removal, or retirements discussed in other sections could affect the annualized property tax expense.

Schedule 9: Annualized Amortization of Deferrals

Schedule 9 reflects the Company's proposed recovery of the Deferred Balances for PISCC, Depreciation Expense, and Property Tax Expense. The Company has proposed to amortize the balances using a composite life amortization rate of 3.31% that was developed on Schedule 10 and discussed later. Blue Ridge found that the mathematical calculations used to amortize the Deferred balances not unreasonable.

Amortization of Deferred PISCC

The Company seeks to recover Deferred PISCC of $110,632,426. The amount is consistent with the balance reflected in the 2019 Annual Informational Report.

Amortization of Deferred Depreciation Expense

The Company seeks to recover Deferred Depreciation Expense of $72,221,347. The amount is consistent with the balance reflected in the 2019 Annual Informational Report.

Amortization of Deferred Property Tax Expense

The Company seeks to recover Deferred Property Taxes of $21,422,462. The balance should be updated to reflect the recommended changes related to the true up of the estimated tax rate to actual and the correction to remove the lease payment reclass.

Schedule 10: Calculation of Composite Asset Life Amortization Rate

Schedule 10 provides the calculation that the Company used to derive the composite asset life amortization rate of 3.31% that was used to amortize the deferred balances for PISCC, Depreciation Expense, and Property Tax Expense.

Schedule 11: Actual Bills Issued and DTS Volume

Schedule 11 provides the actual bills issued and DTS Volumes for the 12 months ended December 31, 2018, and the maximum storage capacity volumes for the 2018/2019 season that support the Rate Design on Schedule 1. Commission Staff will verify and validate the information included on this schedule. [185]

Conclusion on Validation and Verification of CEP Revenue Requirement Schedules

Blue Ridge performed various validations and verification checks on the schedules reflected in the calculation of the CEP revenue requirement. Blue Ridge found that the capital additions, cost of removal, and retirements reflected in the CEP revenue requirements rate base reconciled to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Report. In addition, the deferrals associated with PISCC and depreciation expense also tied to the December 31, 2018, cumulative totals provided in the 2019 Annual Informational Filing. However, it was found that the Deferred Property Taxes reported, for which the Company is seeking recovery through the CEP revenue requirements, was different from the amount reflected in the 2019 Annual Informational Filing. Further analysis resulted in two recommended adjustments to Deferred Property Taxes. The estimated tax rate should be trued up to actual, and the deferred property taxes for Tax Years 2015

[185] DEO Response to Data Request BRDR-79 (CEP Rider Rate Design).

through 2017 should be corrected to remove the lease payment reclass. These adjustments increase Deferred Property Taxes by $293,515.

During discovery, the Company updated its ADIT on Liberalized Depreciation balance. Blue Ridge recommends that the ADIT on Liberalized Depreciation be adjusted to reflect the revision that removed AFUDC from original cost and to reflect the settled balances, following the tax return filing. The Company's ADIT on Liberalized Depreciation in rate base is $56,915,425, as updated, compared to $57,774,229, as filed.

Blue Ridge found that the Company has used depreciation accrual rates for several FERC accounts (357.00-Storage Other Equipment, 380.00-Distribution Services-LP & RP, and 380.00-Distribution-New Customer Facilities) that have not technically been approved by the Commission. From a practical standpoint, there is no impact on the CEP revenue requirements. However, Blue Ridge recommends that the Company correct this issue, if not already addressed, prior to the Commission approving the new deprecation study for all gas plant accounts that was presumably filed on or before September 1, 2019.

The Company used an estimated property tax rate to calculate its annualized property taxes. Blue Ridge recommends that the property taxes based on estimated rates be trued up using the actual rate in the subsequent annual filing.

Blue Ridge's investigation included data requests, interview notes, field inspections, and analyses, including variance analysis and detailed transactional testing. Blue Ridge's investigation identified adjustments that should be applied to the plant-in-service, depreciation-reserve, and annualized depreciation expense. Blue Ridge's recommended adjustments are summarized in Section 13 Adjustments and Other Recommendations. The recommended revised CEP Revenue Requirements Schedules are provided in the attached Appendix E.

Additionally, Blue Ridge recommends that the revenue collected through the CEP Rider be reconciled to the CEP revenue requirements and a mechanism for true up should be established.

The following table summarizes the effect of Blue Ridge's recommended adjustments on the CEP Revenue Requirement. The recast CEP revenue requirement schedules are provided in Appendix E.

Table 40: Recommended Adjustments to CEP Revenue Requirements

	As Filed	Adjustments	Recommended
Rate Base			
Plant in Service	$ 614,793,531	$ (1,898,489)	$ 612,895,042
Less: Accumulated Provision for Depreciation	(35,843,592)	(376,064)	(36,219,656)
Net Capital Additions	$ 650,637,123	$ (1,522,425)	$ 649,114,698
Depreciation Offset	(310,120,037)	-	(310,120,037)
Net Capital Additions Less Depreciation Offset	$ 340,517,086	$ (1,522,425)	$ 338,994,661
Regulatory Deferrals	204,276,235	(181,507)	204,094,728
Accumulated Deferred Income Tax (ADIT)	(85,505,756)	841,765	(84,663,991)
Rate Base	$ 459,287,565	$ (862,167)	$ 458,425,398
Pre-Tax Rate of Return	9.91%	0.00%	9.91%
Annualized Return on Rate Base	$ 45,515,398	$ (85,441)	$ 45,429,957
Operating Expenses			
Annualized Depreciation Expense	$ 22,129,022	$ (111,455)	$ 22,017,567
Annualized Property Tax Expense	8,512,431	(36,443)	8,475,988
Amortization of Deferred PISCC	3,661,933	(3,275)	3,658,658
Amortization of Deferred Depreciation Expense	2,390,527	(12,448)	2,378,079
Amortization of Deferred Property Tax Expense	709,083	9,715	718,799
Total Operating Expenses	$ 37,402,996	$ (153,906)	$ 37,249,090
Total Revenue Requirement	$ 82,918,394	$ (239,347)	$ 82,679,047

APPENDICES

Appendix A: Background Information Reviewed

Appendix B: Data Requests and Information Provided

Appendix C: Work Papers

Appendix D: Recast Total Company Schedules B-2 and B-3

Appendix E: Recast CEP Revenue Requirement Schedules

APPENDIX A: BACKGROUND INFORMATION REVIEWED

Blue Ridge reviewed the applicable testimony, workpapers, and Commission orders in Case Nos.

The following excerpts from the Commission Opinion and Order and the Combined Stipulation specifically related to the last Rate Case, PIS, and CEP relevant to this audit are provided below.

Case No. 07-829-GA-AIR et al

On August 30, 2007, DEO filed an application for approval of an increase in gas distribution rates, for approval of an alternative rate plan for its gas distribution service, and for approval of an application to modify certain accounting methods. On August 22, 2008, the parties entered into a settlement with the only issue not resolved was the rate design.

On May 23, 3008, Staff filed its report. Staff recommended the following net plant in-service balances. The recommendation reflects several adjustments.

	Company	Staff Adjustments	Staff Adjusted Balance	Staff Schedule
Plant in Service	$1,933,453,697	$(17,319,717)	$1,916,133,980	B-2.1
Depreciation Reserve	(795,525,692)	53,822,053	(849,347,745)	B-3
Net Plant in Service	$1,087,131,795	$(20,345,560)	$ 1,066,786,235	

Staff's recommendation included several adjustments as summarized below.

	Plant in-Service	Reserve
Elimination of Plant No Longer in Service	$ (6,561,282)	$ (6,129,909)
Elimination of Plant Retirement Obligation	(10,707,160)	59,985,396
Leasehold Improvements No Longer in Service	(163,635)	(163,635)
Contribution in Aid of Construction	(28,517)	(1,306)
Unspecified Leased Plant	140,877	131,507
	$ (17,319,717)	$ 53,822,053

The Stipulation and Recommendation filed on August 22, 2008, stated that unless otherwise specifically provided in the Stipulation and Recommendation, all rates, terms, conditions, and other items shall be treated in accordance with the Staff Report.

On October 15, 2008, the Commission approved the joint stipulation with modifications. The Commission found that the value of all of the company's property used and useful for the rendition of service to its customers affected by this application, determined in accordance with Section 4909.15, Revised Code, is not less than $1,404,744,493. The Commission also approved a rate of return of 8.29%.[186]

Case No. 11-6024-GA-UNC

On December 23, 2011, DEO filed an application for authority to implement a capital expenditure program (CEP) for the period of October 1, 2011, through December 31, 2012. DEO sought accounting authority to capitalize post-in-service carrying costs (PISCC) on program investments for assets placed in service but not yet reflected in rates; defer depreciation expense and property tax expense

[186] Case No. 07-829-GA-AIR Opinion and Order, dated October 15, 2008, pages 30–31,

directly associated with the assets placed in service; and establish a regulatory asset to which PISCC, depreciation expense, and property tax expense will be deferred for recovery.

Staff Sur-Reply Comments dated September 20, 2012

F. The Commission should establish the specific formulas that should be used to calculate DEO's total monthly CAPEX deferrals.

As the preceding discussion above demonstrates, there is now a substantial amount of agreement between DEO and the Staff on DEO's proposal for creation of a CAPEX Program and calculation of associated deferrals. Similarly, the formulas for calculating DEO's CAPEX deferrals that the Staff and DEO are recommending are consistent with similar formulas that the Commission adopted for Columbia in the Columbia CEP Order. As a result, the Staff recommends that the Commission adopt the following specific formulas for calculating DEO's monthly CAPEX deferrals:

Total Monthly Deferral	=	(PISCC) + (Depreciation Expense) + (Property Tax Expense) - (Incremental Revenues)

Where:

PISCC	=	[Previous Month's Cumulative Gross Plant Additions) - (Previous Month's Cumulative Cost of Removal) - (Previous Month's Cumulative Retirements) - (Previous Month's Accumulated Depreciation)] x [(Long Term Debt Rate) / (12 Months)]

Depreciation Expense	=	[(Current Month's Cumulative Gross Plant Additions) - (Current Month's Cumulative Cost of Removal) - (Current Month's Cumulative Retirements)] x [(Depreciation Rate) / (12 Months)]

Property Tax Expense	=	[(Prior Year-end Cumulative Gross Plant Additions) - (Prior Year's Cumulative Cost of Removal) - (Prior Year-End Cumulative Retirements)] x [(Effective Property Tax Rate) / (12 Months)]

Incremental Revenue	=	[(Current Month's Customers - Baseline Customers) x (Cost Portion of Rate)] + [(Consumption by non-SFV customers directly attributable to program investment) x (Cost Portion of Rate)] + (Other revenues directly attributable to program investment)

Finding and Order dated December 12, 2012

(34) Upon review of DEO's application and the comments filed by the parties, the Commission finds that the application should be approved, with the following modifications and clarifications:

(a) DEO should calculate the total monthly deferral, PISCC, depreciation expense, property tax expense, and incremental revenue by using the specific formulas set forth in Staff's surreply comments.

(b) DEO should offset the monthly regulatory asset amount charged to the CEP by those revenues generated from the assets included in the CEP for SFV customers, non-SFV customers, and any other revenue sources directly attributable to CEP investments.

(c) DEO should maintain sufficient records to enable Staff to verify that all revenue generated from CEP investments is accurately excluded from the total monthly deferral.

(d) DEO should calculate the PISCC, as well as the depreciation and property tax deferrals, for the CEP in a manner consistent with Staff's recommendations.

(e) DEO should docket an annual informational filing by April 30 of each year that details the monthly CEP investments and the calculations used to determine the associated deferrals, as recommended by Staff. Each annual informational filing should include schedules showing the inputs and all calculations used to determine the monthly deferred amounts, including a breakdown of investments (by budget class), PISCC, depreciation expense, property tax expense, and all incremental revenue, as well as a capital budget for the year following the year covered in the filing. The annual informational filings should also include a schedule showing the potential impact on GSS customer rates, if the deferrals were to be included in rates.

(f) DEO may accrue CEP deferrals up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the GSS class of customers to increase by more than $1.50 per month. Accrual of all future CEP-related deferrals should cease once the $1.50 per month threshold is surpassed, until such time as DEO files to recover the existing accrued deferrals and establish a recovery mechanism under Section 4909.18, 4929.05, or 4929.11, Revised Code.

Case No. 12-3279-GA-UNC

On December 20, 2012, DEO filed an application for authority to implement a CEP for the period of January 1, 2013, through December 31, 2013. On October 9, 2013, the Commission approved DEO's application as modified.

On April 30, 2013, DEO docketed its annual informational filing in 11-6024 (2013 filing).

Finding and Order dated October 9, 2013

(11) Upon review of DEO's application and the comments, the Commission finds that the application should be approved, subject to Staff's recommendations, which are not opposed by the Company.

(12) With respect to DEO's annual informational filings due on April 30 of each year (CEP Order at 14), the Company should include revenue data from all potential sources of revenue delineated in the incremental revenue formula adopted by the Commission in 11-6024. DEO should work with Staff to confirm that the necessary data is included in the Company's annual informational filing due on April 30, 2014.

(13) Additionally, the Commission emphasizes that, consistent with DEO's application, we approve the Company's request for deferral authority, but do not authorize recovery of the deferred amounts at this time. The question of recovery of the deferred amounts, including, but not limited to, issues such as prudence, proper computation, proper recording, and reasonableness, will be considered when DEO files an application to recover the deferred amounts. As we stated in the CEP

Order, the Commission has not granted cost recovery for any CEP-related items, and the prudence and reasonableness of the magnitude of DEO's CEP-related regulatory assets and associated capital spending will be considered by the Commission in any future proceedings seeking cost recovery, at which time the Company will be expected to provide detailed information regarding the expenditures for our review (CEP Order at 15).

Case No. 13-2410-GA-UNC et al

On December 19, 2013, in the above-captioned cases, DEO filed an application for authority to implement a CEP for the period of January 1, 2014, through December 31, 2014.

Finding and Order dated July 2, 2014

(7) In its comments. Staff explains that it reviewed DEO's application to determine whether the proposed CEP and associated deferrals are just and reasonable under R.C, 4929.111, as well as consistent with sound ratemaking principles and the Commission's prior orders in the 2012 CEP Case and the 2013 CEP Case. Staff notes that it will investigate and recommend any necessary adjustments to the CEP deferrals when DEO applies to recover the deferred assets in a future proceeding. Subject to the acknowledgements and agreements in DEO's application, as well as continued ongoing cooperation between Staff and the Company, Staff concludes that the Commission should approve the application, as filed.

---

(10) Upon review of DEO's application. Staffs comments, and the Company's reply comments, the Commission finds that the Company has demonstrated that the CEP is consistent with its obligation under R.C. 4905.22 to furnish necessary and adequate services and facilities, which the Commission finds to be just and reasonable. Further, the Commission finds that DEO's application will not result in an increase in any rate or charge. Accordingly, the application should be considered as an application not for an increase in rates under R.C. 4909.18.

(11) With the requirements set forth below, the Commission finds DEO's proposed CEP to be both reasonable and consistent with R.C. 4929.111. Accordingly, DEO is authorized, pursuant to R.C. 4909.18 and 4929.111, to implement the CEP and modify its accounting procedures as necessary to carry out the implementation of the CEP, consistent with this Finding and Order and the Commission's orders in the 2012 CEP Case and the 2013 CEP Case, in 2014 and succeeding years, up until the point where the accrued deferrals, if included in rates, would cause the rates charged to the GSS class of customers to increase by more than $1.50 per month.

(12) While the Commission approves DEO's application for 2014 and succeeding years, we find that a process should be adopted, as proposed by the Company and clarified herein, to allow interested persons and Staff to comment on the information provided by the Company in its annual informational filings due on April 30 of each year….

(13) Additionally, the Commission emphasizes that, consistent with DEO's application, we approve the Company's request for deferral authority, but do not authorize recovery of the deferred amounts at this time. The question of recovery of the deferred amounts, including, but not limited to, issues such as prudence, proper computation, proper recording, and reasonableness, will be considered when DEO files an application to recover the deferred amounts. As we stated in the 2012 CEP Case and the 2013 CEP Case, the Commission has not granted cost recovery for any CEP-related items, and the prudence and reasonableness of the magnitude of DEO's CEP related regulatory assets and associated capital spending will be considered by the Commission in any future proceedings

seeking cost recovery, at which time the Company will be expected to provide detailed information regarding the expenditures for our review.

ORDERED, That DEO's application be approved, subject to the Commission's review of the Company's annual informational filings and any comments or reply comments received in response.

APPENDIX B: DATA REQUESTS AND INFORMATION PROVIDED

BRDR 1-17 SUBMITTED 9/25/19

1) **Organization**: Please provide a current organization chart of the Company.

2) **Organization**: Please provide contiguous information for the period from March 31, 2007 through December 31, 2018, for the following items:
   a) Name of the person with responsibility for plant accounting
   b) Duration the person held the position
   c) Summary of the qualifications of the person
   d) Whether the person is still with the Company, and if so, the person's current position
   e) Changes in the number of personnel in the Plant Accounting department.

3) **Accounting:** Please provide a chart (code) of accounts as of December 31, 2018.

4) **Case No. 07-0829-GA-AIR B Schedules**: Please provide, in Excel format, the final approved B Schedules in Case No. 07-0829-GA-AIR. If the final approved B Schedules are not available, please provide the B Schedules, in Excel format, included in the Company's revised schedules that reflect the removal of cost of plant sold after date certain.

5) WITHDRAWN

6) **Case No. 11-6024-GA-UNC and 12-3279-GA-UNC Annual Informational Filings**: Please provide copies of the Company's schedules included in the Company's Annual Informational Filings in Excel format for 2007–2018. Also provide any supporting schedules that support the balances included within the annual information filings (e.g., depreciation and property tax calculations).

7) **Case No. 12-3279-GA-UNC Annual Informational Filing:** Please provide updated schedules in Excel format in the 2018 filing replacing fourth quarter estimates with fourth quarter actuals.

8) **Work Orders**: Please provide in Microsoft Excel format a list of all work orders put in service by calendar year, from 2007 through 2018. Please identify the work orders as either CEP or NON-PIR. For each work order, please include the following information for each year:
   a) Plant accounts charged (FERC 300 accounts)
   b) Project identification numbers (work order and project roll up, if applicable)
   c) Project description. Single line description will be acceptable along with location numbers
   d) Project Description (e.g., Replacement & Betterment, Relocations and, programs required to comply with Commission Rules and Regulations. , Information Technology, etc.)
   e) Work Order Construction Complete Date (when project became used and useful)
   f) Work Order Accounting In-Service Date
   g) Unitization Date
   h) Dollar amount by FERC 300 account number
   i) Whether the work was an addition or replacement
   j) Whether the work order was a blanket project work order and, if so, associated project identification numbers, if applicable.

9) **Work Orders**: For each year that the lists of work orders are provided in the previous request, please provide a reconciliation of the work order total to the totals in the annual report of utility plant in service filed with the PUCO. For any differences, provide an explanation.

10) **Work Order Number**: Please provide any explanations available that define what the project numbers mean.

11) **Major Additions or Replacements**: Please provide a list with a description and total dollar amount of any major CEP additions and/or replacements placed in service from October 1, 2011 through December 31, 2018.

12) **Timeline**:
    a) Please provide a timeline of major events that occurred since March 31, 2007, that had an impact on the plant-in-service balances. Examples of major events include, among other such events, major sales of assets, acquisitions, mergers and system conversions, and upgrades… We have the list of the system conversions and upgrades from our May 20th teleconference. For those we will need parts b and c answered.
    b) Please provide an explanation of each event and how the event affected plant balances.
    c) Please provide an explanation of what steps were taken to ensure that plant balances were accurate following the impact of the event.

13) **Policies and Procedures**: Please provide the current policies and procedures and flowcharts for the following activities that provide input to distribution plant:
    a) Plant Accounting:
        i) Capitalization vs. Expense
        ii) Preparation and approval of work orders
        iii) Recording of CWIP, including the systems that feed the CWIP trial balance;
        iv) Application of AFUDC
        v) Recording and closing of additions, retirements, cost of removal and salvage to plant
        vi) Unitization process based on the retirement unit catalog
        vii) Application of depreciation
        viii) Contributions in Aid of Construction (CIAC)
        ix) Damage Claims
    b) Purchasing/Procurement
    c) Accounts Payable/Disbursements
    d) Accounting/Journal Entries
    e) Payroll (direct charged and allocated)
    f) Insurance recovery
    g) Allocations
    h) Work Management System
    i) Information Technology
    j) Capital Project selection and prioritization
    k) System planning and load growth

14) **Work Order Accounting:** Please provide a narrative of the CEP accounting with examples of how the following items take place:
    a) A completed project is designated as CEP
    b) The accounting entry or entries to record the deferral of a CEP project.

c) The accounting entry or entries to record the retirements of a CEP project.
d) The accounting entry or entries to record the retirement of a non-PIR project, where the replacement is a CEP project.
e) The accounting entry or entries to record PISCC, depreciation on the closed assets, and incremental property taxes.
f) The accounting entries to retire a CEP project.
g) How CEP ~~deferred~~ projects are unitized

15) **Policies and Procedures**: Please specifically explain any major changes that have been made to the Company's capitalization policy from March 31, 2007, through December 31, 2018.

16) **Commission Annual Reports:** Please provide the Annual Report for the year ending December 31, 2018 filed with the Commission when it is available.

17) WITHDRAWN

BRDR 18-47 DATA REQUEST SUBMITTED 10/15/19

18) **Policies and Procedures Changes:** Follow-up to BRDR-13. Please identify major changes to policies and procedures that occurred from April 1, 2007, through December 31, 2018. Please provide an explanation for the change and when they occurred.

19) **WITHDRAWN**

20) **Interviews**: Please provide the person(s) responsible for and/or capable of discussing in detail the following areas:
a) Major events that affect plant accounting
b) Plant Accounting
c) Capital budgeting
d) Project Engineering
e) Work Order Management

21) **PIR Investment**: The audit focuses on CEP, non-PIR, non-AMR plant. The following requests will help isolate the plant that will be audited. For PIR investments, please provide the following information:
a) List of the type of work included in the PIR
b) List of FERC plant accounts in which PIR project activity is charged
c) List of project/work order numbers used for PIR
d) Explanation for how PIR plant investment is identifiable in the plant accounting system(s)
e) Annual reports filed with the Commission on PIR plant from 2007 through 2018

22) **AMR Investment**: The audit focuses on CEP, non-PIR, non-AMR plant. The following requests will help isolate the plant that will be audited. For AMR investments, please provide the following information:
a) List of the type of work included in the AMR
b) List of FERC plant accounts in which AMR project activity is charged
c) List of project/work order numbers used for AMR
d) Explanation for how AMR plant investment is identifiable in the plant accounting system(s)

e) Annual reports filed with the Commission on AMR plant from 2007 through 2018

23) **Reconciliation of Plant Balances**: Reference Exhibit H, Schedule B-2 and B-2.1. Total plant in service on Schedule B.2 as of December 31, 2018, is $4,667,116,677. Please break out the total by the CEP, PIR, AMR, and other (non-CEP, non-PIR, and non-AMR) plant by FERC account similar to the format provided in Schedule B-2.1. (See attached template)

24) **PIR, AMR, and Other Non-CEP Plant**: Reference Exhibit H, Schedule B-2.3a. Please provide beginning balance, additions, retirements, transfers, and adjustments for each year from 2007 through 2018 for the following breakdowns:
   a) Plant in service for PIR investments
   b) Plant in service for AMR investments
   c) Plant in service for Other Plant (non-CEP, non-PIR, and non-AMR)

25) **Revenue-generating CEP investments**:
   a) How does the Company identify CEP plant that will generate additional revenue?
   b) How is that plant identified?
   c) Is that plant included within the CEP? If so, how is the revenue reflected in the CEP?

26) **Unit of Property Catalog**:
   a) Does the Company maintain a unit of property catalog?
   b) If yes, how frequently is the catalog updated?
   c) If not, why not?
   d) What is the approval process necessary to establish a new retirement unit of property?

27) **Systems** (from April 2007 through December 2018):
   a) What system has the Company used to record entries to the General Ledger?
   b) What system has the Company used to record assets to and from Utility Plant?
   c) What system has the Company used to maintain the detail for the FERC 300 accounts?

28) **Project / Capital Work Order Identification**: Please explain how the project / capital work order numbering system works regarding the following items:
   a) What do the project / work order numbers mean?
   b) How does the Company identify programs and projects that may be considered blanket work orders?
   c) Is there a hierarchy of program, project, and work order numbers? If so, please explain how it works.
   d) How are specific work orders identified?
   e) How are retirement work orders identified?

29) **Cost Codes**: Please provide a list of the cost codes (charge types) that identify the type of charges included in the work order detail that supports FERC accounts 101 and 106. For example, identify cost codes related to charge types for Payroll, overheads, Materials and Supplies, contractor charges, AFUDC, Transportation, and employee expenses.

30) **Approval Signatures**: Please provide the Level of Signature Authority (LOSA) document(s) that supports the approval of capital projects from March 31, 2007, through December 31, 2018.

31) **Depreciation:** Reference Schedule B-3.2.
   a) Please provide a copy of the approved depreciation study.
   b) Were any depreciation accrual rates added or changed from date certain March 31, 2007, through December 31, 2018? For any change, please explain the reason for each change, when the change was made, what the change was, and whether it was approved by the Commission.
   c) Has the Company added any additional FERC 300 accounts and/or subaccounts that were not included in the most recent Commission-approved depreciation accrual rates? If so, please provide a list and the reason each subaccount was added.

32) **FERC Audits**: Please provide a copy of all FERC audit reports, if any, that were issued during the period March 31, 2007, through December 31, 2018. Also provide the Company's response to any findings and the ultimate resolution of those findings.

33) **Internal Audits**: Please provide a list of internal audits completed or in progress from March 31, 2007, through December 31, 2018. List the name of the audit, scope, objective, and when the work was performed.

34) **SOX Compliance Audits**: For any feeder system that feeds CWIP, please provide any SOX Compliance audits performed from March 31, 2007, through December 31, 2018. Include whether the controls passed or failed and, if failed, the severity and impact of the failure and how the failure was corrected or otherwise mitigated. NOTE: Utility Plant in Service is fed from CWIP. Therefore, any system that feeds CWIP, including, but not limited to WMS, Payroll, M&S, Overheads, AFUDC, Transportation, and direct contractor charges through purchasing, could have an impact on plant balances.

35) **Unitization Backlog**: Please provide information regarding any backlog in the unitization of distribution work orders as of December 31, 2018. Please provide the number of backlogged work orders, the dollar values of each, and the length of time for each in months (e.g., under three months, four to 12 months, and over 12 months). If possible, provide the list for both CEP work orders and non-CEP work orders.

36) **AFUDC**: Please provide the AFUDC interest rate for each year from 2007 through 2018.

37) **Insurance Recovery**: (Response Received 10/10/19)
   a) Have there been any significant events from March 31, 2007, through December 31, 2018, that resulted in an insurance claim recovery greater than $50,000 related to Utility Plant In Service? If so, please provide a list of such events, how each recovery was recorded to the Company's books, and how it was reflected in plant balances.
   b) Are there any pending Utility Plant-in-Service insurance claim recoveries as of December 31, 2018, that are not recorded or accrued that would be charged to capital? Please provide the type of recovery, estimated amount, and when receipt is expected.

38) **Tax Cuts and Jobs Act (TCJA)**: How has the TCJA effect been reflected in the Company's non-PIR/CEP recovery related to ADIT and Excess Accumulated Deferred Income Taxes (EDIT)?

39) **Overhead and Indirect Costs:** Please provide a list of all overheads (labor loadings, etc.) and any other indirect items charged to DEO work orders/projects, including descriptions of the type

of charge and how that charged item is applied (e.g., calculation with descriptions of factors used in the calculations).

40) **Commission Annual Reports:** Please provide copies of the Annual Reports filed with the Commission for the years ending December 31, 2007, through 2018.

41) **Budget**: Please provide the budgets supporting the CEP capital expenditures and related assets for 2011 through 2018. Also, include the assumptions supporting the budget/projected data.

42) **Labor Costs**:
   a) Please provide the approximate percentage of contractor vs. in-house labor used for capital activities for years 2011 through 2018.
   b) Please provide a copy of any analysis performed that evaluates the least cost alternative regarding the use of internal labor vs. the use of contractors.

43) **Labor Costs**:
   a) Please provide a list of contractors, description of work performed, and amount paid each contractor that provided services for CEP in 2011 through 2018.
   b) Please provide a copy of the contracts for contractors performing CEP and related asset work from 2011 through 2018.
   c) How has the demand for gas contractors in Ohio and surrounding states impacted the overall cost to complete capital work?
   d) What steps has the Company taken to address the demand constraints for gas contractors?
   e) Please describe what process and initiatives are in place now and anticipated to manage contractor costs going forward.

44) **Labor Costs**: What steps has the Company taken to contain non-contractor construction costs?

45) **CEP Revenue Requirements Cost of Removal and Retirements.** Reference Exhibit I, Schedules 2 and 3. Please explain why Cost of Removal ($55,386,344) is significantly higher than Retirements ($52,678,594).

46) **Plant Additions Total General Plant 2007**: Reference Exhibit H, Schedule 2.3a 2007. Please confirm that total general plant additions in 2007 should be $1,906,011 instead of the hard coded $1,970,222 shown on the schedule.

47) **Composite Life Amortization Rate**: Reference Exhibit I, Schedule 9. Please provide the source and calculation for the Composite Life Amortization Rate used for annual amortization of deferrals.

BRDR 48-51 DATA REQUEST SUBMITTED OCTOBER 22, 2019

48) **SOX Compliance Audits:** Follow-up to Data Request response BRDR #34- SOX Compliance Audits. The Company response did not fully answer the request. The original request asked for the SOX compliance audits performed from March 31, 2007, through December 31, 2018. The response indicated that no control deficiencies were identified related to DEO CWIP feeder systems during that time period. Please provide a list of the SOX compliance audits performed from March 31, 2007, through December 31, 2018. Please include whether the controls passed

or failed and, if failed, the severity and impact of the failure and how the failure was corrected or otherwise mitigated.

49) **CEP Capital Budget:** Follow-up to Data Request response BRDR #41-attachment 1—CEP Capital Budget.
   a) Plan Category: Please explain what the following plan categories references mean: C&M, MLR, F&BS, Majors, and TSG.
   b) Plan Category: Please explain how a new customer fits into the allowed CEP Infrastructure Expansion, Improvement, or Replacement; Installation, Upgrade, or Replacement of Information Technology; or Programs Reasonably Necessary to Comply with Commission Rules, Regulations, and Orders.
   c) 2018: Please explain why F&BS was included in 2018 and not 2011–2017.
   d) Plan Category: Please explain why the capital budget for TSG went from $27.484m in 2017 to $70.379m in 2018. An increase of $156%.
   e) Plan Category: Please explain why New Customer did not have a 2018 budget.
   f) Grand Total: Please explain the reasons the CEP capital budget increased from $60.6m in 2012 to $153.6m in 2019. An increase of 153%.
   g) Please provide the actual dollars spent by Plan category in the same format as the Company response to BRDR #41, attachment 1.

50) **Internal Audits:** Follow-up to Data Request response BRDR #33—Internal Audits, attachment 1 (CONFIDENTIAL). Please provide the summary findings and recommendations for the following Internal audits. If available and appropriate, please provide any information that supports implementation of the audit recommendations: The list of audits was labeled confidential and has been removed.

51) **Policies and Procedures:** Follow-up to BRDR-13. The Company's response indicated that items (h) and (j) were "not governed by a unitary, discrete set of policies and procedures."
   a) For item (h), Work Management System, please provide the current policies and procedures identifying what types of projects go through the WMS system, including the engineering, design, and determination that a project is ready for service.
   b) For item (j), Capital Project selection and prioritization, please provide the policies and procedures that explain how the Company selects the projects to be included in the capital budget (for example, regarding setting priorities and tools used, such as risk analysis).

BRDR 52-54 DATA REQUEST SUBMITTED 11/1/19 – DUE 11/15/19

52) **Budget vs Actual**: Follow up to teleconference interview conducted October 24th, 2019.
   a) Please provide the year to date CEP variance reports by budget category for years 2011-2018.
   b) Please provide the year to date variance reports for non-CEP, non-AMR and non-PIR activity, by budget category, for years 2007-2018.

53) **Variance Analysis**: Reference "Staff DR 1 Exhibit H-Sch B-2.3a.xlsx". Please verify that Account 392.03—Transportation Equipment-Trailers (WV, OH & VA) includes amounts for only Ohio.

54) **Variance Analysis:** See attachment BRCS WP—Var Analysis—Staff DR 1-Exhibit H-Sch B-2.3a.xlsx". For each of the highlighted items in the attachment, please provide a detailed explanation for the associated condition

a) Significant Additions over Retirements
b) Significant Retirements over Additions
c) Negative Additions
d) Negative Retirements

Description Helps for Attached Spreadsheet:

1. Columns in which highlights occur are only column h (Scope Additions) and column l (Scope Retirements)
2. The Scope Additions and Scope Retirements take the additions and retirements from Staff DR 1-Exhibit H-Sch B 2.3a and subtract out the PIR additions and retirements from BRDRs 21 and 22.

BRDR 55-59 DATA REQUEST SUBMITTED 11/7/19

55) **Rate Base Reconciliation:** Reference Staff DR 2 – 2007-2018 Plant Additions. Please confirm that removing Total Regulatory Investment from the Total Adjusted Additions results in Rate Base.
a) Please explain why Rate Base in negative in 2018.
b) Please explain why there are no adjustments in 2018.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)=(e)+(f)+(g)	(i)=(d)-(h)
Years	Amount Posted in Staff DR 2 - 2007-2018 Plant Additions	Adjustments from Staff DR 2	Total Additions, per Annual Report	PIR	AMR	CEP	Total Regulatory Investment	Rate Base
2007	**$ 81,513,195.08**	$ (602,157.21)	$ 80,911,037.87	-	7,900,411	-	$ 7,900,411	$ 73,010,627
2008	**$ 141,755,888.99**	$ (176,399.99)	$ 141,579,489.00	35,171,082	24,991,177	-	$ 60,162,259	$ 81,417,230
2009	**$ 171,848,156.95**	$ (6,359,320.95)	$ 165,488,836.00	86,350,144	20,717,212	-	$ 107,067,356	$ 58,421,480
2010	**$ 225,722,613.35**	$ 7,694,459.81	$ 233,417,073.16	111,927,836	20,193,621	-	$ 132,121,457	$ 101,295,616
2011	**$ 218,589,140.39**	$ 4,200,518.61	$ 222,789,659.00	128,944,758	16,154,200	19,040,861	$ 164,139,819	$ 58,649,840
2012	**$ 260,387,536.24**	$ (264,204.94)	$ 260,123,331.30	148,306,791	674,330	76,999,970	$ 225,981,091	$ 34,142,240
2013	**$ 258,470,369.67**	$ (313,136.41)	$ 258,157,233.26	163,617,989	-	68,658,088	$ 232,276,077	$ 25,881,156
2014	**$ 358,317,720.62**	$ (45,293.14)	$ 358,272,427.48	154,774,311	-	98,230,614	$ 253,004,925	$ 105,267,502
2015	**$ 321,057,620.47**	$ (3,902,775.94)	$ 317,154,844.53	171,294,049	-	106,728,146	$ 278,022,195	$ 39,132,650
2016	**$ 455,276,918.85**	$ (75,626.04)	$ 455,201,292.81	187,514,469	-	111,224,766	$ 298,739,235	$ 156,462,058
2017	**$ 346,105,582.77**	$ 162,228.43	$ 346,267,811.20	203,713,240	-	108,900,290	$ 312,613,530	$ 33,654,281
2018	**$ 243,815,430.47**	$ -	$ 243,815,430.47	202,399,771	-	133,075,734	$ 335,475,505	$ (91,660,075)
Total	**$ 3,082,860,173.85**	**$ 318,292.23**	**$ 3,083,178,466.08**	**$ 1,594,014,440.00**	**$ 90,630,951.00**	**$ 722,858,469.00**	**$ 2,407,503,860.00**	**$ 675,674,606.08**

56) **CEP Reconciliation:** Reference Staff DR 2 – 2007-2018 Plant Additions and BRDR#8 Attachment 1. The following table compares the balances in CEP by year between the two sources of information. Please explain why there is a $4,012,238 between the two sources of information in 2014.

Years	CEP Total from BRDR#8 Attachment 1	CEP Total from Staff DR 2 Program Summary	Difference
2011-2012	$ 96,040,831.83	96,040,832	-
2013	$ 68,658,088.11	68,658,088	-
2014	$ 102,242,851.90	98,230,614	(4,012,238.03)
2015	$ 106,728,146.18	106,728,146	-
2016	$ 111,224,765.55	111,224,766	-
2017	$ 108,900,290.04	108,900,290	-
2018	$ 133,075,733.81	133,075,734	-
Grand Total	**$ 726,870,707.42**	**722,858,469**	**(4,012,238.03)**

57) **PIR Reconciliation:** Reference Staff DR 2 – 2007-2018 Plant Additions and BRDR#8 Attachment 1. The following table compares the PIR balances by Case Number/Year between the PIR balances provided in Staff DR 2 and the information provided in BRDR#8, Attachment 3. Please explain why there is a difference in the period of 2008-2011.

Case No.	Year	Total per BRDR #8 Attachment 3	PIR from Staff DR 2 Program Summary	Difference
09-458	2008-09	85,500,973.43	35,171,082	50,329,891.91
10-733	2009-10	89,078,267.91	86,350,144	2,728,123.55
11-3238	2010-11	115,190,628.83	111,927,836	3,262,792.42
12-0812	2011	72,633,382.95	128,944,758	(56,311,374.81)
12-3125	2012	148,306,791.23	148,306,791	-
13-2320	2013	163,617,989.09	163,617,989	-
14-2134	2014	154,774,310.77	154,774,311	-
15-1987	2015	171,294,049.33	171,294,049	-
16-2205	2016	187,514,468.99	187,514,469	-
17-2177	2017	203,713,240.13	203,713,240	-
18-1587	2018	202,399,770.87	202,399,771	-
Grand Total		**1,594,023,873.53**	**$ 1,594,014,440.46**	**9,433.07**

58) **WBS Population:** Reference Staff DR 2 – 2007-2018 Plant Additions and BRDR#8 Attachment 1. The files show WBS elements but not all WBS elements have a Project IDs. Please explain why not all the WBS elements have Project IDs.

59) **FERC/Population:** Reference BRDR#8 Attachment 1 Tab 2014-HB95-Original. The file does not include FERC account. Please provide.

BRDR 60 DATA REQUEST SUBMITTED 11/8/19

60) **Major Additions:** Reference BRDR#11, BRDR #8 Attachment 1, and Staff DR 2 Attachment 2007-2018 Plant Additions. For each of the major additions provided in BRDR#11
   a) Identify the line items supporting the spend in BRDR #8, Attachment 1.
   b) Also, identify the line items supporting the spend in Staff DR 2 2007-2018 Plant Additions.
      - Project ID
        - P400031294
        - P400031293
        - P400008469
        - P400214043
        - P400142569
      - WBS Elements
        - FCDEO.13.GAS.12A
        - FCDEO.13.GAS.12E
        - FCDEO.15.GAS.2D
        - FCDEO.15.GAS.2G

BRDR 61 DATA REQUEST SUBMITTED 11/13/19

61) **CEP Work Order Sample:** Reference Company response to BRDR#8 – Attachment 1. Please refer to the attached "WP BRDR 8 – CEP Sample Final" for a list of work orders selected from the population provided in response to the referenced data request. Please note that the selection is work order/project/programs (hereafter referred to as "work orders"). For each work order on the list, please provide the following information in sortable Microsoft Excel spreadsheets:

a) Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).
b) Identify the work order as either addition, replacement, non project allocation or other.
c) Work order justification and approval at the highest approval level available based on the nature of the work order in accordance with the LOSA document in affect at the time the work order was prepared.
d) Estimated in-service date and actual in-service date.
e) For non-blanket work orders, and blanket work orders where the specific blanket work orders can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%. For purposes of this examination blanket work orders are mass assets or any other project budgeted to close every 30 days.
f) Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses.
g) Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

Notes:
- To avoid unnecessary work, please send a sample of the detail that will be provided to make sure it is what we need.
- If you have any questions, please contact XXXX.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

BRDR 62-63 DATA REQUESTS SUBMITTED ON 11/19/19

62) **CEP Revenue Requirements Cost of Removal and Retirements:** Follow-up to data request response BRDR #45:
   a) Please explain why the cost of removal allocation percentage in 2003 of 2.91% was not changed until 2014.
   b) Is the allocation percentage reviewed on a periodic basis? If not, why not, and if so, how frequently?
   c) What caused the allocation percent to drop over 50% from 2003 to 2014?
   d) Has the allocation percentage of 1.11% been reviewed since 2014? If not, why not?

63) **CEP Revenue Requirements Cost of Removal and Retirements:** Follow-up to data request response BRDR #45: The Company stated, "Additionally, when service lines to inactive premises are cut and capped or removed, the associated costs are considered costs of removal and are included in both the capital and cost of removal values. Although the net is zero, resulting in no impact to rate base or deferral values, inclusion of these service line cuts does increase the cumulative value of cost of removal." Please clarify this statement further:
   a) Please explain why cost of removal would be charged against capital.
   b) Please explain why cost of removal does not change rate base.
   c) Please cite where the Code of Federal Regulations (18CFR) allows the Company to charge cost of removal against a capital asset.

Case No. 19-468-GA-ALT
Dominion Energy Ohio
Plant-in-Service & Capital-Spending-Prudence Audit

BRDR 64 DATA REQUESTS SUBMITTED ON 11/20/19

64) **Base Rates Work Order Sample:** Reference Company response to BRDR#8 – Attachment 4-8. Please refer to the attached "WP Rate Base Sample Final" for a list of work orders selected from the population provided in response to the referenced data request. Please note that the selection is work order/project/programs (hereafter referred to as "work orders"). For each work order on the list, please provide the following information in sortable Microsoft Excel spreadsheets:
   a) Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).
   b) Identify the work order as either addition, replacement, non project allocation or other.
   c) Work order justification and approval at the highest approval level available based on the nature of the work order in accordance with the LOSA document in affect at the time the work order was prepared.
   d) Estimated in-service date and actual in-service date.
   e) For non-blanket work orders, and blanket work orders where the specific blanket work orders can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%. For purposes of this examination blanket work orders are mass assets or any other project budgeted to close every 30 days.
   f) Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses.
   g) Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

Notes:
- To avoid unnecessary work, please send a sample of the detail that will be provided to make sure it is what we need.
- If you have any questions, please contact XXXX
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

BRDR 65 DATA REQUESTS SUBMITTED ON 12/10/19 – UPDATED REQUEST SUBMITTED 12/22/19

65) **Base Rates Work Order Sample:** Reference Company response to BRDR#8 – Attachment 4-8. Please refer to the attached "BRDR#65 – WP DEO – Base Rates Sample 2007-2012" for a list of work orders selected from the population provided in response to the referenced data request. Please note that the selection is work order/project/programs (hereafter referred to as "work orders"). For each work order on the list, please provide the following information in sortable Microsoft Excel spreadsheets:
   a) Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).
   b) Identify the work order as either addition, replacement, non project allocation or other.
   c) Work order justification and approval at the highest approval level available based on the nature of the work order in accordance with the LOSA document in affect at the time the work order was prepared.
   d) Estimated in-service date and actual in-service date.

e) For non-blanket work orders, and blanket work orders where the specific blanket work orders can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%. For purposes of this examination blanket work orders are mass assets or any other project budgeted to close every 30 days.
f) Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses.
g) Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

Notes:

- To avoid unnecessary work, please send a sample of the detail that will be provided to make sure it is what we need.
- If you have any questions, please contact XXXX.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

BRDR 66-71 DATA REQUESTS SUBMITTED ON 12/26/19

66) **Base Rates Work Order Sample:** Reference Company response to BRDR#8 – Attachment 4-8. Please refer to the attached "BRDR#65 – WP DEO – Base Rates Sample 2007-2012" for a list of work orders selected from the population provided in response to the referenced data request. Please note that the selection is work order/project/programs (hereafter referred to as "work orders"). For each work order on the list, please provide the following information in sortable Microsoft Excel spreadsheets:
a) Detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).
b) Identify the work order as either addition, replacement, non project allocation or other.
c) Work order justification and approval at the highest approval level available based on the nature of the work order in accordance with the LOSA document in affect at the time the work order was prepared.
d) Estimated in-service date and actual in-service date.
e) For non-blanket work orders, and blanket work orders where the specific blanket work orders can be specifically identified as part of the larger project or program, provide budget and total cost with any explanation of variances in excess of 20%. For purposes of this examination blanket work orders are mass assets or any other project budgeted to close every 30 days.
f) Supporting cost detail for each addition to plant (run of charges by FERC account and units). The detail should be by charge code (or charge code description) with amounts by year and month. Examples of charge code descriptions would include such information as payroll, contractor charges, overheads, other allocations, M&S, Transportation, and employee expenses.
g) Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

Notes:

- To avoid unnecessary work, please send a sample of the detail that will be provided to make sure it is what we need.
- If you have any questions, please contact XXXX.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

67) **Plant Accounting Interview:** Follow up to the Plant Accounting interview conducted on December 3, 2019. Please provide a report that shows the un-unitized dollars by project, amount, and in-service date as of December 31, 2018.

68) **Plant Accounting Interview:** Follow up to the Plant Accounting interview conducted on December 3, 2019. Did the Power Plan Fixed Asset implementation project accrue AFUDC? If so, was the AFUDC suspended for the period of time the project was suspended, which was from mid- 2016 until early 2018? If not, why not?

69) **Plant Accounting Interview:** Follow up to the Plant Accounting interview conducted on December 3, 2019. What was the total cost of the Power Plan Fixed Asset Implementation project?

70) **Plant Accounting Interview:** Follow up to the Plant Accounting interview conducted on December 3, 2019. Did the approximate 20-month suspension of the Power Plan Fixed Asset implementation project create any additional startup costs as a result of such things as old data, change in personnel working on the project, or updates necessary to bring the project current? If so, please quantify those additional costs and if not, why not?

71) **Approval Signatures**: The Company response to BRDR-30 (Approval Signatures) did not fully answer the Data Request. The request asked for the Company Expenditure Control Policy in effect from March 31, 2007 through December 31, 2018. The response provided the policy effective August 2014 and April 2016. Please provide the approval signature policy and/or updates that covers the entire period from March 31 2007 through December 31, 2018.

BRDR 72-76 DATA REQUESTS SUBMITTED ON 1/8/20

72) **Account Entries**: Follow up to Significant Events interview conducted on December 4, 2019. Please provide the accounting entries, by FERC account and amount, for the following:
   a) The sale of assets to Blue Racer Mid- stream 50-50 joint Venture starting 2012 and ending in 2014.
   b) The repurchase of assets from Blue Racer Mid-stream 50-50 joint venture in 2016.

73) **Variance Analysis**: Reference response to BRDR-54, Attachment 1. Please respond to the following questions:
   a) Tab Sch2.3a 2007, account 367.00 Mains. The response provided three work orders totaling about $800,000 of the approximate $1.8 million scope additions over retirements for that account, leaving approximately $1.0 million unaccounted for. Please provide additional information relative to the unaccounted for additions amount that is significantly greater than retirements.

b) Tab Sch 2.3a 2007, account 381.01 Meters – Hexagram. The response gives the reason retirements were done, but it does not explain why retirements exceeded additions significantly. Please provide the reason for the significant retirements over additions.
c) Tab Sch 2.3a 2008, account 367.00 Mains. The response provided three work orders totaling about $1.75 million of the approximate $2.6 million scope additions over retirements for that account, leaving approximately $850,000 unaccounted for. Please provide additional information relative to the unaccounted for additions amount that is significantly greater than retirements.
d) Tab Sch 2.3a 2016, account 381.01 Meters – Meters. The response explaining the negative addition stated this was a "reclass entry for distribution meters." It is our understanding that a reclass would be a transfer. If so, (1) why is there a negative addition rather than a transfer, and (2) Where is the other half of the entry?
e) Tab Sch 2.3a 2016, account 390.01 Structures & Improvements – Other. The response indicates that approximately $18.2 million of building renovations was completed without retirements. Please provide additional detailed information explaining what kind of renovations were performed to what buildings.
f) Tab Sch 2.3a 2017, account 353.00 Lines. The response for significant additions over retirements states that these additions were "planned storage assessment projects." Please provide additional information to explain what "planned storage assessment projects" are and why they resulted with a significant amount of additions without retirements.
g) Tab Sch 2.3a 2017, account 355.02 M & R Equipment-Other. The response for significant additions over retirements states that these additions were "planned storage assessment projects." Please provide additional information to explain what "planned storage assessment projects" are and why they resulted with a significant amount of additions without retirements.
h) Tab Sch 2.3a 2018, account 352.01 Wells-Well Construction. The response for significant additions over retirements states that these additions were for "scheduled storage system construction." Please provide additional information to explain what "scheduled storage system construction" is and why it resulted with a significant amount of additions without retirements.
i) Tab Sch 2.3a 2018, account 355.02 M & R Equipment-Other. The response for significant additions over retirements states that these additions were for "scheduled storage system construction." Please provide additional information to explain what "scheduled storage system construction" is and why it resulted with a significant amount of additions without retirements.

74) **Unitization Backlog**: Follow-up to Data Request response BRDR-35, Attachment 1: Please provide the same backlog schedule for non-PIR, non-AMR, and non-CEP base rate spending.

75) **Budget**: Follow-up to Data Request response BRDR -41, Attachment 1: Please provide the same schedule for the non-PIR, non-AMR, and non-CEP base rate spending.

76) **Budget**: Follow-up to Data Request response BRDR -41:
    a. Please explain in detail how the following statement impacts Plant in Service and the unitization backlog: "[A]pproximately $50 million is related to a PowerPlan performance issue that occurred at year end."
    b. Please explain in detail how the following statement impacts Plant in Service, Depreciation, and the unitization backlog, and how the issue was resolved: "Sixteen

million dollars of the $94 million was related to assets that were inadvertently placed in service. The Company's Fixed Asset department has not yet determined how this happened and whether it was a system performance issue"

BRDR 77-79 DATA REQUESTS SUBMITTED ON 1/9/20

77) **Variance Analysis**: Reference response to BRDR-54, Attachment 1. Please respond to the following question: Tab Sch2.3a 2012, account 367.00 Mains. The response identified about $1.9 million of the approximate $7.2 million scope additions over retirements for that account, leaving approximately $5.3 million unaccounted for. Please provide additional information relative to the unaccounted for additions amount that is significantly greater than retirements.

78) **CEP Rider Rate Design**:

- Reference Application, Exhibit I, Schedule 1. Lines 2–7 (footnoted to the Company's last base rate case and 2019 Annual Report, work paper Rate Case Allocation)
- Reference Case No. 07-0829-GA-AIR: DEO Application, Volume 2, Section 3 of 3, Schedule E 3.2, page 1-3 of 16, Staff Report dated May 23, 2008, page 29.
- The Staff Report found that the Company's cost of service study was a reasonable starting point.
- The CEP Deferral Gross Plant allocators used in the CEP Deferral and the last base rate case were compared and are summarized on the first page of the attached file.
- The remaining pages in the attached file are from the last rate case and Staff's report for ease of reference.

a. Please explain the difference between the Cost of Service Gross Plant allocators filed in the last rate case (and presumably approved by Staff) and the Gross Plant allocators used in the CEP Deferral.
b. If the Cost of Service was modified during the rate case, please provide the final approved Cost of Service Gross Plant Allocators in Case No. 07-0829-GA-AIR.
c. Explain any difference between the final approved Plant-in-Service Allocators in Case No. 07-0829-GA-AIR and those used in the CEP rate design.
d. Please provide the support that allocates GSS/ECTS between Residential and Non-Residential.

79) **CEP Rider Rate Design**, Number of Bills/Mcf, Reference Application, Exhibit I, Schedule 11. Please provide the source of the information provided on Schedule 11.

BRDR 80-81 DATA REQUESTS SUBMITTED ON 1/13/20

80) **CEP Property Tax Deferral and Annualized Depreciation Expense:** Reference: Prior Year's Annual Reports-Property Tax Expense and CEP Revenue Requirements. Provide the property tax returns that support the following effective property tax rates. If the rate is not apparent on the property tax return, please provide how the rate was determined:

a) 2011 1.0794%
b) 2012 1.1521%
c) 2013 1.1971%
d) 2014 1.2468%
e) 2015 1.2680%
f) 2016 1.3088%

g) 2017 1.3308%
h) 2018 1.3846%

81) **Property Tax**: There is a difference between the property tax deferral reflected in the 2019 Annual Report and the balance reflected in the CEP Revenue Requirements. The 2019 Annual Report shows $21,290,687 and the CEP Revenue Requirements shows $21,422,462. It appears that the 2019 Annual Report property tax deferral for 2018 uses the prior year's plant balance and the prior year's property tax rate. Whereas, the CEP Revenue Requirements property tax deferral uses the current year plant balance and the current year property tax rate.
   a) Please confirm that this is the reason for the difference
   b) Does the Company agree that an adjustment should be made to the CEP Revenue Requirements Property Tax Deferral balance? If not, why not?

BRDR 82 DATA REQUESTS SUBMITTED ON 1/23/20

82) **Unitization Backlog**: Follow-up to Data Request response BRDR-35 (Unitization Backlog).
   a) The Company explained that of the $94 million backlog, approximately $50 million relates to a PowerPlan performance issue that occurred at year end and was unitized in 2019. Please confirm that the unitization backlog was reduced by approximately $50 million dollars in January 2019.
   b) Please confirm that massed assets are recorded directly to Gas Plant in Service and do not go through FERC 106 (Completed Construction not Classified).
   c) Please explain what the performance issue was and how it was corrected?
   d) The Company explained that approximately $16 million of the $94 million backlog was inadvertently placed in service.
      i) Please provide a narrative of how the approximately $16 million was inadvertently place in service.
      ii) What has been done to correct the problem and to ensure it does not happen again?
      iii) Please explain the impact of the $16 million inadvertently placed in service on plant in service and the depreciation reserve balance for the CEP and/or non-CEP rate base balance as of 12/31/18.

BRDR 83 DATA REQUEST SUBMITTED ON 2/13/20

83) **CEP ADIT on Liberalized Depreciation (Schedule 7):** Please provide the detailed workpapers that support Line 5 Tax Depreciation and Line 6 Capitalized Interest amounts provided by the Company's Tax Records.

BRDR 84-114 DATA REQUEST SUBMITTED ON 2/14/20

84) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) 25633.1.1.1 – Mains – Regulated Pressure
   a. Please explain what the Project Clearing Entry of $1,598.000.00 represents.
   b. This entry was posted 9/26/2005. Please explain why this base rate amount is included in the scope of the audit.

85) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) 27511.1.3 – Guernsey Control. Please explain for what the $293,289.90 spent on postage/shipping freight was used.

86) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) FCDEO.14.GAS.7F – Building at 320 Springside. Please provide additional supporting detail for the Consulting Services of $9,449,551.43.

87) Follow-up to BRDR#64 (Base Rates) – The following WBS numbers represent Massed Asset Reallocation entries, but the amounts do not match the detail provided by the Company (submitted 1/31/2020) in support of those entries. Please explain the reason for the mismatch.
- WBS 08000.1.1.- Sample ($1,100,087.91) Submitted ($1,102,411.92)
- WBS 08000.1.11 – Sample ($2,506,804.45), Submitted ($2,506,804.45)
- WBS 080001.2 – Sample ($2,530,830.56), Submitted ($2,590,969.66)
- WBS 08500.1.11 – Sample ($4,365,258.53), Submitted ($4,362,612.21)
- WBS 08500.1.2 – Sample ($12,744,612.53), Submitted ($12,976,496.60)
- WBS 09000_FA.1.1 – Sample ($1,381,506.68), Submitted ($1,568,425.34)

88) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) P400001220 – Pipe. Please explain why only approximately $2,200 of Cost of Removal was charged on approximately $4,173,165 of additions to plant.

89) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) P400008320.006 – Pipe 20" Transmission for 175 Lima for roadway improvements
   a. Please explain the negative additions of $(660,988.06).
   b. Please explain why the total project cost detail does not match the project sample. The cost detail was $250.84, and the project included in the work order sample was $(1,800,069.56).

90) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) P400018004.042 – 24" Generic Pipe (associated references) P400118004.034, P400128004.43 and P400018004.107. Please explain why Cost of Removal was only $87,699 on $23,546,836.12 of additions.

91) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) P400028409.006 – Switzerland Compressor (associated sub projects .019, .023, .027, .100, .108, .127, .268, .294). Please explain why the total additions were $57,238,299.27 and Cost of Removal was only $268,743.

92) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) P400040604.007 – Augusta Station interconnect Intangible (associated sub projects .032, .034, .042, .044, .047, .052, .054, .056, .058, .093, .124, and .190). Please explain why the Sample Project indicates charges to FERC account 303 (Intangibles) and the additions to plant detail does not indicate any charges were recorded to FERC 303.

93) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) IT DEO.PIPP.2 – Software/Hardware purchase
   a. Why is this Software/Hardware purchase charged to only FERC 399, Other Tangible Property in General Plant and not FERC 303 as well?
   b. Why is AFUDC being accrued on a purchase?

94) Follow-up to BRDR#64 (Base Rates) – Project (WBS element) IT SW DEO.ARM_C.2 – IT software Consulting Services
   a. Please provide more detail on the charges to ClrngCAP 7000.
   b. Why are charges in 2006–2009 while the posting dates are from 1/1/2005 to 12/31/08?

c. Why does the supporting detail from SAP indicate $1,132,296.00 charged in 2009 and yet cost element detail indicates the same charges covering 2006–2009?

95) Follow-up to BRDR#65 (Base Rates) – Project (WBS element) 54386.1.9 -Equipment Acquisition. Please explain for what the $40,000 project clearing entry was.

96) Follow-up to BRDR#65 (Base Rates) – Project (WBS element) SW DEO.ARM_B LEAK.2
   a. Please explain for what the $736,508.29 Project Clearing Entry was.
   b. Please explain the reason(s) $65,351.09 of AFUDC was charged to this project.
   c. Was this project a software purchase or developed internally?

97) Follow-up to BRDR#65 (Base Rates) – Project (WBS element) SW DEO.ARM_B LEAK.3. This project accrued $126,640.99 of AFUDC. Was any of that accrual related to the stwr/hrdwr purchase of $175,361.13.? If so, what was the amount of AFUDC related to the stwr/hrdwr purchase.

98) Follow-up to BRDR#65 (Base Rates) – Project (WBS element) OH14439 – Right of Way. Please explain for what the expense reimbursement credit of ($206,514) was.

99) Follow-up to BRDR#65 (Base Rates) – Project (WBS elements) OH14616 – 35270.1 – Pike Compress. Please explain why only $975 was charged to Cost of Removal on $6,266,537 of additions.

100) Follow-up to BRDR#65 (Base Rates) – Project (WBS elements) OH11281, WBS 07600.08.1W.1.9.2 – Computer software Mobile work Management
   a. The project description indicates computer software, but the cost detail indicates the charges were to FERC 387 (Other Equipment). Please explain why.
   b. If this was a computer software project, why was $696,917.13 charged to Material Exp-Non Stock?

101) Follow-up to BRDR#65 (Base Rates) – Project (WBS element) 37639.1.2.1 – Freemont Energy Center. Please explain the project clearing entry of $1,017,187.90.

102) WBS Testing: Please explain why the following projects had retirements but no cost of removal charged.
   a. Follow-up to BRDR-61 – CEP
      i. 51565.1.2.8
      ii. 52070.8.7
      iii. DEOG.PPM.2
      iv. O7300.12.GAS.5B
      v. O9700.1.ERT
      vi. OC.P.MLR.000400
      vii. P400096569.001
      viii. P400098817.001
   b. Follow-up to BRDR-64 thru 66 – Base Rates
      i. 27511.1.3
      ii. OH14852

103) WBS Testing: Please explain why the following replacement projects did not have retirements or cost of removal charged
   a. Follow-up to BRDR-61 – CEP
      i. 6T07367543
      ii. 6T07367548
      iii. 6T07377794
      iv. FCDEO.15.GAS.2D
      v. FCDEO.15.GAS.2G
      vi. FCDEO.16.GAS.8D
      vii. OC.TSG.000584
      viii. P400301174.001
   b. Follow-up to BRDR-64 thru 66 – Base Rates
      i. OH14759
      ii. P400384703

104) WBS Testing: The summary for the following list of WBSs indicated that there are Capital Request Form are available however, no PDFs were submitted on 1/22/20. Please provide all the available PDF documentation for the following list of WBSs.6C07267745
   a. OC.P.REL.000214
   b. P400208223.001

105) WBS Testing: Please provide an explanation for why the Change Order Agreements do not account for the majority of cost overruns found within the list of projects
   a. Follow-up to BRDR-61 (CEP)
      i. 6T07371814
      ii. FCDEO.15.GAS.3J
      iii. OC.P.DI.M.000305
      iv. OC.P.REL.000034
      v. OC.P.REL.000383
      vi. OC.TSG.000584
      vii. P400090072.001
      viii. P400120518.001
      ix. P400161431.001
      x. P400239583.001
   b. Follow-up to BRDR-64-66 (base Rates)
      i. 6N07360615
      ii. P400046319.035
      iii. P400194684.007

106) WBS Testing: Please explain how WBS element P400090072.001 has more CEP Actual dollars than Overall Project dollars. CEP Actuals = $2,041,729 vs. Overall Project dollars = $1,992,960.

107) WBS Testing: Service Type – what does Service Type 4B indicate?

108) WBS Testing: BRDR-65 - WBS Element OH10259 / 34275.11 – The current approval documentation provided a screen shot of signatures but did not reference this the project. Please provide the approval documentation specific to this project.

109) WBS Testing: For the following WBSs P400096569.001 and P400136758.001 both have Service Type: 1 = Extension / New Install and the CRF indicates that the project is 100%HB95. Does this project generate revenue?

110) WBS Testing: WBS Element OH13929 – please provide screen shots to document the retirement data provided in BRDR-65 on 1/27/20.

111) WBS Testing: BRDR-61 – WBS Element DEO CREDIT.3 – The current approval documentation does not provide a link to the project. Please provide additional approval documentation that links to the project.

112) WBS Testing: BRDR-61 – WBS Element DEO.CCSENHAN.2 and FCDEO.17.GAS.6A – Please provide approval documentation for these projects.

113) WBS Testing: BRDR-61 – WBS Element O9700.1.OMD – please provide retirement documentation for this project.

114) WBS Testing: Please verify that there is no PDF documentation for the following list of CEP WBSs.
a. O1125.1E
b. O5557.1.8.2
c. O9200_FA.2A.1.8
d. O9700.1.ERT
e. O9700.1.MTR
f. O9700.1.OMD

BRDR 115-126 SUBMITTED 2/18/20

115) WBS Testing: The summary for WBS 6T07377794 indicated that the Capital Request Form is available however, no PDFs were submitted on 1/22/20. Please provide all the available PDF documentation.

116) WBS Testing: Please explain why P400114046.058 – Detailed Scope shows that the project is 100% Base Rate Recoverable while the summary document BRDR-64 (Parts A-E) January 20, 2020 Submission (Part 2) indicates that $20,081,817 are CEP Actuals.)

117) Withdrawn

118) WBS Testing: The following list of projects had Cost of Removal dates significantly later than the in-service dates. Please explain the delay.
a) Follow-up to BRDR-61 - CEP

WBS Element	Actual In-Service Date	Date of COR	COR Months past In-Service Date
i) OC.I.OOS.000001	10/28/14	1/1/18	39
ii) OC.P.DI.M.000305	3/17/15	6/2/16	15
iii) OC.P.DI.M.000334	3/18/16	5/1/17	14

WBS Element	Actual In-Service Date	Date of COR	COR Months past In-Service Date
iv) OC.P.REL.000383	1/13/16	1/1/17	12
v) OC.TSG.000028	11/3/13	9/3/14	10
vi) OC.TSG.000071	4/4/14	2/1/17	34
vii) OC.TSG.000208	9/10/14	5/2/16	20
viii) OC.TSG.000599	9/3/15	5/2/16	8
ix) P400071878.001	9/16/15	6/2/18	33
x) P400090072.001	10/5/16	12/5/18	26
xi) P400120518.001	12/30/16	4/3/18	15
xii) P400142373.001	3/30/16	4/3/17	12
xiii) P400214043.001	9/7/17	6/2/18	9

b) Follow-up to BRDR-64 thru 66 - Base Rates

WBS Element	Actual In-Service Date	Date of COR	COR Months past In-Service Date
i) P400046319.035	9/14/15	5/1/17	20
ii) P400098163.047	8/30/16	1/4/19	29

119) WBS Testing: Please provide a variance explanation for the list of projects that are significantly under budget
   a) Follow-up to BRDR-61 (CEP)
      i) 51565.1.2.8
      ii) 6T07423760
      iii) IT DEO.RATE CASE.2
   b) Follow-up to BRDR-64-66 (base Rates)
      i) OH13335
      ii) OH15352
      iii) P400384703

120) WBS Testing: For the below list of IT Projects, were the project costs split between East Ohio and any other subsidiary? If so, please explain the rationale.
   a) Follow-up to BRDR-61 (CEP)
      i) DEO CREDIT.3
      ii) DEO PLNT MAINT.2
      iii) DEO.CCSENHAN.2
      iv) DEO.LEAK.2
      v) DEO.PPMII.3
      vi) DEOG.PPM.2
      vii) EOG-2295.2
      viii) EOG-2489.2
      ix) IT DEO.RATE CASE.2
      x) O7000.15.GAS.6B
      xi) O7300.12.GAS.5B

xii) O7300.15.GAS.4A

b) Follow-up to BRDR-64 – 66 (Base Rates)
   i) DEO.DATACOMM.1.9
   ii) IT DEO.PIPP.2
   iii) IT SW DEO.ARM_C.2
   iv) OH11281
   v) OH14759
   vi) SW DEO.ARM_B LEAK.2
   vii) SW DEO.ARM_B LEAK.3

121) WBS Testing: Please explain how the CEP Actuals are greater than Overall Project Actuals for the following list of projects.
   a) FCDEO.13.GAS.7B (CEP Actuals = $10,362,324.15 vs Overall Project Actuals = $6,714,017 – 35% difference)
   b) P400090072.001 (CEP Actuals = $2,041,729 vs. Overall Project Actuals = $1,992,960 – 2% difference)
   c) P400098817.001 (CEP Actuals = $1,198,575 vs. Overall Project Actuals = $1,153,650 – 4% difference)

122) WBS Testing: For the following list of 100% HB95/CEP projects, please explain why CEP Actuals are significantly less than Overall Project Actuals:

WBS Element	CEP Actuals	Overall Project Actuals	CEP to Actuals
a) 6T07367543	$ 108,220.00	$ 225,421.57	-108%
b) 6T07367548	$ 117,202.00	$ 225,422.00	-92%
c) OC.P.DI.M.000334	$ 311,261.00	$ 376,741.00	-21%
d) OC.P.MLR.000645	$ 190,318.00	$ 241,619.48	-27%
e) OC.TSG.000028	$ 226,328.00	$ 251,037.17	-11%
f) P400071878.001	$ 177,443.00	$ 236,839.80	-33%
g) P400120518.001	$ 1,114,446	$ 1,346,964.11	-21%
h) P400127645.001	$ 1,443,913.34	$ 1,673,115.46	-16%
i) P400239583.001	$ 1,387,392.64	$ 1,593,663.81	-15%

123) WBS Testing: The following list of WBS elements show within their documentation that they are 100%HB95, please explain how there were Acct 107 charges as of 12/31/18.

WBS Element	Additions	Acct 107 as of 12/31/18	Total
a) OC.TSG.000028	$219,669	**$528**	$251,037.17
b) OC.TSG.000071	$5,994,671	**$42**	$6,020,743
c) P400120518.001	$1,080,870	**$226,428**	$1,346,964
d) P400127645.001	$1,253,545	**$268**	$1,673,115.46
e) P400161431.001	$223,199	**$50**	$236,175

124) WBS Testing: Please provide documentation showing the project type (100% HB95, PIR, Hybrid etc) for the following WBS elements. Follow-up to BRDR-61 (CEP)

a) O7400.13.GAS.12A
b) O9200_FA.2A.1.8
c) O1125.1E
d) O5557.1.8.2
e) O9700.1.ERT
f) O9700.1.MTR
g) O9700.1.OMD
h) OC.I.OOS.000001
i) DEO.CCSENHAN.2

125) WBS Testing: For the below list of Hybrid Projects, how were the costs split between the PIR and CEP determined?
   a) Follow-up to BRDR-61 (CEP)
      i) 1N07366468
      ii) OC.P.CM (P400000699, P400000700, P400000705, P400000712)
      iii) OC.P.MLR.000171
      iv) OC.P.REL.000214
      v) P400123606.001
      vi) P400268867.001
   b) Follow-up to BRDR-64-66 (Base Rates)
      i) P400008331.093
      ii) P400014128.027
      iii) P400018004
      iv) O9750.1.2.3.1

126) Salvage:
   a) Please explain how salvage is applied to massed assets.
   b) How is salvage applied to fixed projects?
   c) How does salvage get to the reserve (not the accounting but the is it done via a separate
   d) WBS and is it different for massed and fixed projects?

BRDR 127-151 SUBMITTED 2/19/20

127) **WBS Testing:** WBS element 6C07267745. Please explain what cost element Management (8201010) means within the cost detail.

128) **WBS Testing:** WBS element OC.TSG.000071. Please explain what the project clearing entry of $2,226,855.94 represents within the cost detail.

129) **WBS Testing:** WBS element DEO CREDIT.3
   a) Please explain what the $89,000 represents for Security and Investigation Services within the cost detail.
   b) Please explain the reasoning for including it in the CEP.

130) **WBS Testing:** WBS element DEO.PLNT MAINT.2 – WMIS TO SAP.
   a) Please explain why SAP plant maintenance is charged to the CEP.
   b) Why is plant maintenance considered capital?
   c) What does the $1,682,443.24 of Clearing Capital ICO Expense represent within the cost detail?

131) **WBS Testing:** WBS element DEO PLNT MAINT.2.BA.
   a) Please explain why plant maintenance is considered capital.
   b) What does the $277,360.73 of Finance/Accounting represent within the cost detail?

132) **WBS Testing:** WBS element DEO.CCSENHAN.2 - Unauthorized Use.
   a) Please explain the project description.
   b) Why are the costs charged to FERC 399 (other tangible property) when the SAP supporting data indicates in-house software?

133) **WBS Testing:** WBS element FCDEO.11.GAS.4C
   a) Please explain why this project is charged to FERC 390.05 (General Plant, Structures and Improvements).
   b) Please provide the detail for the Contractor Services charges of $1,454,882.87.

134) **WBS Testing:** WBS element FCDEO.12.GAS.6B. Renovation Corporate HQ. Why is the Corporate HQ renovation charged to FERC 375.03 (Distribution Plant Structures and Improvements) and not FERC 390 (General plant Structures and Improvements)?

135) **WBS Testing:** WBS element FCDEO.13.GAS.7B Please explain why no Cost of Removal was charged for the renovation work.

136) **WBS Testing:** WBS element FCDEO.16.GAS.8D – Asphalt removal and replacement. Please explain why no Cost of Removal was charged to this project

137) **WBS Testing:** WBS element IT.DEO.RATE CASE.2 – Update receiving recommendations from PUCO
   a) Please explain why this project is charged to FERC 399.01(General Plant other tangible property) and not FERC 303 (Misc. tangible plant).
   b) Please explain why this project should be charged to the CEP.

138) **WBS Testing:** For the following projects, the scope explanations were vague and/or we could not determine whether the project should be included in the CEP and not the PIR or should be in both. Please explain the scope in more detail and support why the project is in the CEP and not the PIR. If the project is a Hybrid, explain how the costs were split between the PIR and CEP.

   a) WBS element – 1N07366468
   b) WBS element – 6T07367543
   c) WBS element – 6T07406185
   d) WBS element – OC.I.PIG.000010-P, OC.I.PIG.000011, OC.I.PIG.000012, OC.I.PIG.000015, OC.I.PIG.000016, OC.I.PIG.000017, OC.I.PIG.000018, OC.I.PIG.00000, OC.I. PIG. 000021, OC.I.PIG.000022. TPL-2
   e) WBS element – OC.P.MLR.000171
   f) WBS element – OC.P.MLR.000645
   g) WBS element – PC.P.REL.000383
   h) WBS element – PC.TSG.000071

i) WBS element – OC.TSG.000596
j) WBS element – P400071878.001
k) WBS element – P400127645.001
l) WBS element – P400098817.001
m) WBS element – 52070.8.7
n) WBS element – 51565.1.2.8
o) WBS element – 6T07371814
p) WBS element – P400145825.001
q) WBS element – P400239583.001
r) WBS element – P400422422.001
s) WBS element – 6C07267745
t) WBS element – 6T07416176
u) WBS element – 6T07423760

139) **WBS Testing:** WBS OC.P.DI.M.000305 Summary Notes on Variance indicates that "the original project estimate was too low. Estimate included the cost of a heater, and the installations costs"; however, the Change Order Agreements add only an additional $41,000 to the project for materials. Please provide the Change Order(s) that covers the additional installation costs mentioned in the variance notes?

140) **WBS Testing:** The following projects had actual in-service dates that were significantly later than the in-service date Estimate. Please explain the reason(s) for the delays and over accrual of AFUDC that resulted from the delays.
a) Follow-up to BRDR#61 (CEP)

	WBS Element	Construction Complete Date	Estimate	Months past estimate	F/M	AFUDC CHARGED	MULTI-YEAR
i.	6C07267745	1/4/13	2011	12	F	$31,853.73	14-18
ii.	6T07377794	2/22/13	2011	14	F	$7,099.04	11-13
iii.	OC.I.OOS.000001	10/28/14	2011	34	M	$1,121.71	13-15
iv.	OC.P.DI.M.000334	3/18/16	2014	15	F	$1,141,19	14-17
v.	OC.TSG.000596	7/14/16	2015	7	F	$1,737.26	14-16
vi.	P400090072.001	10/5/16	2015	9	F	$4,499.49	15-18
vii.	P400120518.001	12/30/16	2015	12	F	$3,302.43	15-18
viii.	P400142569.001	12/4/18	2016	23	F	$82,926.01	15-18
ix.	P400422422.001	12/3/18	2016	23	F	$405.22	18
x.	DEO CREDIT.3	12/11/12	2011	12	F	$7,172.49	11-12
xi.	DEO.CCSENHAN.2	11/30/17	2014	36	F	$42,137.23	13-17
xii.	DEO.LEAK.2	12/10/14	2013	11	F	$9,664.86	13-15
xiii.	DEO.PPMII.3	12/10/14	2013	11	F	$12,378.71	12-14
xiv.	EOG-2295.2	3/31/18	2015	27	F	$31,853.73	14-18
xv.	EOG-2489.2	6/30/16	2015	6	F	$4,323.01	14-16
xvi.	FCDEO.13.GAS.12A-E	5/31/16	2013	29	F	$165,538.94	14-17
xvii.	FCDEO.15.GAS.2D /G	10/26/18	2015	34	F	$204,484.81	15-18
xviii.	FCDEO.15.GAS.8A	11/30/16	2015	11	F	$1,294.77	15-16
xix.	FCDEO.15.GAS.8B	10/31/17	2015	22	F	$44,156.24	15-17
xx.	FCDEO.17.GAS.6A	1/1/19	2017	12	F	$25,357.26	17-18
xxi.	IT DEO.RATE CASE.2	11/14/11	2009	23	F	$36,511.33	09-11

b) Follow-up to BRDR#64–66 (Base Rates)

WBS Element	Construction Complete Date from documentation	Estimated In-Service Date	Months past Estimate	F/M	AFUDC Charged	MULTI-YEAR
i. P400000905.004	8/5/14	2013	7	?	$5,846.57	13-14
ii. P400008331.093	7/31/14	2013	7	M	($110,358.98)	13-17
iii. P400040604	1/12/16	2014	13	F	$5,7074.18	14-18
iv. P400046319.035	9/14/15	2014	9	?	$2,782.85	14-17
v. P400114046	11/14/17	2016	11	M	$370,724.61	15-18
vi. 37639.1.2.1	11/28/10	2008	23	?	$14,545.33	10-12
vii. DEO.DATACOMM.1.9	3/11/08	2004	39	?	$30,971.28	05-07
viii. IT DEO.PIPP.2	3/18/11	2007	39	?	$33,377.69	08-11
ix. IT SW DEO.ARM_C.2	10/29/09	2004	59	?	$91,560.91	07-09
x. OH10259	7/1/10	2007	30	?	$14,763.11	07-10
xi. OH11281 WBS O7600.08.1W.1.9.2 WBS IT DEO.MOBILE MGMT.2 WBS IT SW DEO.CCS.10.2 WBS IT SW DEO.MINSRV.2	12/29/08	2007	12	?	$906,049.94	04-12
xii. OH13335	10/12/10	2009	10	?	$105,786.35	09-10
xiii. OH14616	10/15/17	2005	144	?	$372,285.11	07-10
xiv. OH14619	10/15/17	2005	144	?	$15,740.80	05-10
xv. OH14934	4/1/10	2008	15	?	$70,053.12	08-10
xvi. OH15317 WBS 41590.1.3 WBS 6F07165965	6/22/10	2009	6	?	$202,409.92	09-11
xvii. SW DEO.ARM_B LEAK.2	12/12/08	2004	48	?	$65,351.09	08
xviii. SW DEO.ARM_B LEAK.3	12/12/08	2004	48	?	$126,640.99	08

141) **WBS Testing:** Follow-up to BRDR#35 and BRDR#64 (Base Rates) - WBS P400002271
   a) Please explain why this project had $(119,805) of Cost of Removal.
   b) Please explain why this project had a COR date significantly later than its in-service / capitalization date (COR date: 9/5/18—in-service date 11/3/13).
   c) Please explain why this project is listed in BRDR#35 with an in-service date of 9/5/18 for $(119,805) – CIAC Johnston Station PXXXXX if the project was in-service as of 11/3/13 and COR was posted as of 9/5/18.
   d) When was the project completed?

142) WBS Testing: Follow-up to BRDR#61 (CEP)—Please provide an explanation for why the Additional Funds requested on the Purchase Requisition Form do not account for the majority of cost overruns found within P400208223.001.

WBS Element	Project Baseline	Change Orders	Overall Project Actuals
P400208223.001	$1,362,807.00	$99,000.00	$2,026,791.77

143) WBS Testing: Follow-up to BRDR#8 and BRDR#61 (CEP Cost Detail)—Please provide explanations for why the CEP Actuals (provided in BRDR-8 Attachment 1) do not agree to the Cost Detail (provided in BRDR-61 Cost Detail) for the following projects.

WBS Element	CEP Actuals (BRDR-8)	Total Project Costs (BRDR-61 Cost Detail)	Variance
a) DEO PLNT MAINT.2	$3,062,521.43	$3,062,521.43	$(488,397.57)
b) DEO PLNT MAINT.2.BA	$477,316.00	$488,397.88	$(11,082.00)

c) DEO.LEAK.2	$1,032,060.90	$1,033,102.53	$(254,159.10)
d) DEO.PPMII.3	$1,024,501.74	$1,024,501.74	$217,695.74
e) O7400.13.GAS.12A	$1,589,019.64	$1,556,901.24	$32,118.40

144) WBS Testing: Follow-up to BRDR#8 and BRDR#61 (CEP Summary)—Please provide explanations for why the CEP Actuals (provided in BRDR-8 Attachment 1) do not agree to the CEP Actuals (provided in BRDR-61 Summary) for the following projects.

WBS Element	CEP Actuals (BRDR-8)	CEP Actuals (BRDR-61- Summary)	Variance
a) FCDEO.15.GAS.8B.11	$72,862.50	$2,451,432.77	$(2,378,570.27)
b) O9200_FA.2A.1.8	$235,787.63	$1,959,000.54	$(1,723,212.91)
c) O9700.1.ERT	$7,469,727.52	$7,504,954.72	$(35,227.20)

145) **Annualized Depreciation Expense**: Reference CEP Revenue Requirements Schedule 8 and BRDR-31, Attachment 1. Distribution-New Customer Facilities 380.00-3.43%: The CEP Revenue Requirements model includes Distribution-New Customer Facilities 380.00. There is no FERC account 380.00 approved deprecation accrual rates. The approved deprecation accrual rates for similar accounts are different: 380.01-2.40%; 380.02-3.43%; 380.03-3.43%; 380.04-3.14%. Why did the Company selected the 3.43% rate over the other accrual rates related to FERC Account 380.

146) **Annualized Property Taxes**: Reference CEP Revenue Requirements Schedule 8 and BRDR-80, Attachment 8 (2018 Property Tax Effective Rate). Annualized property taxes is calculated using 1.3846% and is labeled "2018 Effective Tax Rate" (Schedule 8). The supporting documentation provided in response to BRDR-80 supports an 2018 Property Tax Effective Rate of 1.3344%.

a) Please explain the reason for the difference.
b) If the difference is due to the use of an estimate, how does the Company intend to true-up to actual?

147) **Annualized Property Taxes**: Reference CEP Revenue Requirements Schedule 8 and BRDR-80. The property tax paid for Tax Years 2015, 2016, and 2017 removed Lease Payment-Reclass. The 2018 Tax Year support (Attachment 8) does not reflect an adjustment for Lease Payments. Please explain why no adjustment was made.

	2016	2017	2018	2019
Property Tax Paid	43,257,997	48,625,343	55,553,208	59,839,594
Leases-Payment Reclass	(114,996)	(112,473)	(109,949)	0
Geauga County		(2,099)		
Total Tax Property Tax Expense	43,143,001	48,510,771	55,443,259	59,839,594

148) **CEP ADIT on Liberalized Depreciation (Schedule 7):** Provide a breakdown of the cumulative ADIT calculation by plant vintage.

149) **CEP ADIT on Liberalized Depreciation (Schedule 7):** For each plant vintage, provide a schedule outlining the cost basis, bonus election, and annual tax depreciation through to completion. Indicate the MACRS table and life underlying the annual tax depreciation.

150) **CEP ADIT on Liberalized Depreciation (Schedule 7):** Clarify the Company's definition of Capitalized Interest on Line 6 (i.e., AFUDC-Debt and -Equity, AFUDC-Debt, AFUDC-Equity).

151) **CEP ADIT on Liberalized Depreciation (Schedule 7):** Where or how was it established that the Company could/would incorporate capitalized interest into the tax basis calculation?

BRDR #152-161 SUBMITTED 2/20/20

152) **FIELD VISITS**: As a continuation of the audit process, we have selected certain work orders/projects, for field verification from the work order sample. The purpose of the field verification is to determine that the assets have been installed per the work order scope and description.

Blue Ridge will conduct the verifications from 8 AM on Monday March 2, 2020 through Wednesday March 4, 2020.

The lists of the projects to be reviewed are included below. To assist Blue Ridge in that endeavor, please provide, or have available, the following items:

a. An individual(s) who can coordinate all the field verification with Blue Ridge
b. Representatives from the Company who can field assist Blue Ridge at each location
c. The Project Manager or a person who was responsible for the work on each project available to answer Blue Ridge's questions
d. Schematics/drawings or any other visual diagrams that indicate what was built or installed
e. A list of material and or equipment installed along with any applicable serial numbers

If the Company has questions about the selection or any other requirement, please contact XXXX.

Field Observation Type	WBS Elements	Description	CEP Actuals (BRDR-8)
Physical on site walk thru	FCDEO.13.GAS.12A	New Dominion East Ohio Technical Training Center building, 418 East Hines Hill Road, Boston Heights, OH	$ 2,236,724.06
	FCDEO.13.GAS.12B		$ 12,756,226.95
	FCDEO.13.GAS.12C		$ 767,286.98
	FCDEO.13.GAS.12D		$ 2,798,884.88
	FCDEO.13.GAS.12E		$ 430,891.39
Physical on site walk thru	FCDEO.13.GAS.7B	CANTON PERRY YARD RENOVATIONS	$ 10,362,324.15
Physical on site walk thru	FCDEO.14.GAS.7E	Drainage System in Akron	$ 14,694.00
Physical on site walk thru	FCDEO.14.GAS.7F	Purchase of 320 Springside	$ 9,476,379.00
Desktop Audit	OC.I.PIG.000010	TPL Four 4 different PIPE REPLACEMENT locations and 4 different STATION locations within Summit County in the municipalities of Barberton, Coventry, and New Franklin	$ 1,231,218.45
Desktop Audit	OC.I.PIG.000015	Five Pipe Replacement, 3 Stations	$ 784,548.13
Physical onsite walk thru	OC.TSG.000071	2370 HP Compressor Unit at Chippewa	$ 5,928,340.12

Field Observation Type	WBS Elements	Description	CEP Actuals (BRDR-8)
Physical onsite walk thru	P400120518.001	Install Over pressure regulation protection @ Well, Costello, Flowers, S&S Condo, Turkeyfoot	$ 1,114,445.91
Physical onsite walk thru	P400214043.001	Install 3,750 HP compressor Chippewa Compressor Station (project 8)	$ 10,557,353.73
Physical on site walk thru	P400239583.001	L#2925 Lawrence Township – Pipe replacement	$ 1,387,392.64
Physical on site walk thru	P400008469	Chippewa project 7 to support added storage for Project 8 (WBSP400214043)	$ 5,953,972.92

Follow-up to BRDR-64-66 (Base Rates)

Field Observation Type	WBS Elements	Description	Overall Project Actuals
Desktop Audit	P400000457	Northern Separation Project - Stadium Station heading east	$7,568,975.00
Desktop Audit	P400008320.006	Roadway Improvements	$2,766,030.55
Desktop Audit	P400028409.006	Install new compressor	$57,507,043.00
Desktop Audit	P400039686.017	Replacement of L#285 (30in CHP).	$1,295,518.33
Desktop Audit	P400114046.073	Lordstown Energy Center Project (LEC).	$33,524,283
Desktop Audit	P400158837	Cap 5,000' of 20" pipe and add new service line of 20" pipe and execute an asset purchase agreement	$2,594,428.47
Desktop Audit	37639.1.2.1	Install new Transmission line to Freemont Energy Center	$1,516,269.68
Desktop Audit	54379.1.1.1	Three Compressor Station	$855,756
Desktop Audit	6T07179411	Installation of 20"/.500w/X65/FBE-Powercrete pipe	$22,697,460
Desktop Audit	O8100.3C.1.1.1 3C07420173 3C07408845 3C07422574	A new Mainline Extension	$1,053,974.02
Desktop Audit	O8100.3W.1.1.1 3W07437611	Smuckers MLX - Installation Project	$1,846,095
Desktop Audit	P400384703	Pratt Industries MLX and Meter Manifold Installation	$987,792.46

Blue Ridge reserves the right to select additional projects while in the field and to perform field verification on any Desktop audit performed.

153) WITHDRAWN

154) WBS Testing: Follow-up BRDR#61 - WBS P400142569, FCDEO.15.GAS.2D and FCDEO.15.GAS.2G.

a. What does the following note included in the project support mean "Project closed in 2018 due to Power Plan system issue. Charges were not moved to 101 in 2018."
b. How does that impact the CEP?

155) WBS Testing: Follow-up BRDR#61 - WBS FCDEO.16.GAS.1A – Building addition and Renovation. Why did this project not have Cost of Removal charged to it?

156) WBS Testing: Follow-up BRDR#61 - WBS O7300.12.GAS.5B – IT Infrastructure Projects. Please explain why telecommunication equipment is charged to an M&S non-stock expense.

157) WBS Testing: Follow-up BRDR#61 - WBS O9700.1.OMD – Meter Purchases – OMD. Why is measuring devices charged to material expense non-stock?

158) WBS Testing: Follow-up BRDR#61 - WBS OC.I.OOS.000001 – 2010 OOS work RH16 Marietta. Please explain the charges to cost element 5399997 Project Clearing.

159) WBS Testing: Follow-up BRDR#61 - WBS P400145825.001. Why was only $2,707 charged to Cost of Removal on a project that had $2,538,291 of additions?

160) WBS Testing: Follow-up BRDR#61 - WBS P400422422.001.
   a. Was this project in CWIP as of 12/31/18?
   b. If yes, why is it included in the CEP?

161) WBS Testing: For the following list of projects please align the approval level provided in the Summary documents to the LOSA documentation provided in BRDR-30 Attachment 1.

Follow-up to BRDR-61 (CEP)

WBS Element	Appropriate Approval Level LOSA - BRDR-30 Attachment 1 (2016)	Construction Complete Date	Year Approved	Project Baseline	Overall Project Actuals	Approval Level from Summary
a. FCDEO.14.GAS.11E	R4 - Officer (Vice President, General Auditor, Controller)	2/29/16	2015	$754,000	$900,979	Director
b. FCDEO.16.GAS.1A	R4 - Officer (Vice President, General Auditor, Controller)	3/31/17	2016	$2,200,000	$2,319,518	Director
c. FCDEO.16.GAS.8D	R4 - Officer (Vice President, General Auditor, Controller)	11/30/16	2016	$880,000	$813,959	Director
d. FCDEO.17.GAS.6A	R4 - Officer (Vice President, General Auditor, Controller)	1/1/19	unknown	$2,000,000	$2,368,924	Director
e. OC.P.DI.M.000334	R3 - Director Level, Deputy General Counsel, Assistant Controller, Assistant Treasurer, General Manager, Senior Policy Advisor	3/18/16	2014	$282,088	$376,741	Manager
f. OC.TSG.000584	R3 - Director Level, Deputy General Counsel, Assistant Controller, Assistant Treasurer, General Manager, Senior Policy Advisor	1/25/17	2014	$175,000	$353,561	Manager
g. OC.TSG.000596	R3 - Director Level, Deputy General Counsel, Assistant Controller, Assistant Treasurer, General Manager, Senior Policy Advisor	7/14/16	2014	$351,130	$361,895	Manager
h. P400090072.001	R4 - Officer (Vice President, General Auditor, Controller)	10/5/16	2014	$1,472,264	$1,992,960	Manager
i. P400120518.001	R4 - Officer (Vice President, General Auditor, Controller)	12/30/16	2015	$1,031,252	$1,346,964	Director
j. P400142373.001	R4 - Officer (Vice President, General Auditor, Controller)	3/30/16	2015	$374,331	$511,721	Director
k. P400214043.001	R5 - Senior Officer (Senior Vice President)	9/7/17	2016	$11,133,384	$10,678,663	VP
l. P400239583.001	R4 - Officer (Vice President, General Auditor, Controller)	10/4/17	2016	$1,095,297	$1,593,664	GM
m. P400301174.001	R3 - Director Level, Deputy General Counsel, Assistant Controller, Assistant Treasurer, General Manager, Senior Policy Advisor	10/30/17	2017	$56,734	$66,249	Manager

WBS Element	Appropriate Approval Level LOSA - BRDR-30 Attachment 1 (2016)	Construction Complete Date	Year Approved	Project Baseline	Overall Project Actuals	Approval Level from Summary
n. P400422422.001	R4 - Officer (Vice President, General Auditor, Controller)	12/3/18	2018	$1,065,010	$876,801	Director

Follow-up to BRDR#64-66 (Base Rates)

WBS Element	LOSA - BRDR-30 Attachment 1 (2016)	Actual In-Service from documentation	Year Approved	Project Baseline	Overall Project Actuals	Approval Level from Summary
a. P400098163.047	R4 - Officer (Vice President, General Auditor, Controller)	8/30/16	2014	$1,282,775	$1,405,533	Manager
b. OH14619	R4 - Officer (Vice President, General Auditor, Controller)	10/15/17	No date	$3,066,729	to be provided	Unknown
c. P400384703	R4 - Officer (Vice President, General Auditor, Controller)	8/28/18	2018	$1,212,893	$987,792	Director

BRDR-162-167 SUBMITTED 2/26/20

162) **Approvals**: Follow-up to "2018 Board Capital Budget Approval.pdf" document provided on January 31, 2020. For years 2007–2017, please provide the same approval documentation as provided in the 2018 Board Capital Budget.

163) **Schedule 2.3a Tie Out to Annual Report**: Blue Ridge compared the balances reported on Schedules 2.3a for 2007–2018 provided in Exhibit H. After taking into consideration the differences in reporting of ARO between Schedule 2.3a and the Annual Reports, there remained unidentified differences as shown in the following summary.

Year Ending	Differences in ARO Spread	Unidentified Difference	Total Difference	% Difference
12/31/07	$ (1)	$ (1,915,178)	$ (1,915,179)	-0.10%
12/31/08	(423,247)	(1,743,195)	(2,166,442)	-0.08%
12/31/09	(527,381)	(1,099,939)	(1,627,320)	-0.05%
12/31/10	(261,397)	(3,056,545)	(3,317,942)	-0.12%
12/31/11	2,350,461	(1,494,864)	855,597	-0.06%
12/31/12	2,712,841	(974,044)	1,738,797	-0.03%
12/31/13	2,357,341	(587,761)	1,769,580	-0.02%
12/31/14	(1,008,737)	(321,609)	(1,330,346)	-0.01%
12/31/15	0	(358,231)	(358,231)	-0.01%
12/31/16	(0)	(264,509)	(264,509)	-0.01%
12/31/17	0	(419,260)	(419,260)	-0.01%
12/31/18	1	(94,696,478)	(94,696,477)	-2.07%

Due to the significant differences between the 12/31/2018 Schedule 2.3 balances and the Annual Report (with the Schedule under audit reporting a higher balance than the Annual Report), Blue Ridge attempted to match amounts by FERC Account. The attached spreadsheets reflect our by FERC account analysis. The differences are also summarized below.

Asset Group	Schedule 2.3a Balance	Annual Rpt Balance	Difference
INTANGIBLE PLANT	$ 58,128,111	$ 58,128,111	$ (0)
PRODUCTION & GATHERING PLANT	192,643,172	191,501,449	(1,141,723)
STORAGE PLANT	259,199,348	240,519,838	(18,679,510)
TRANSMISSION PLANT	485,170,692	482,607,861	(2,562,831)
DISTRIBUTION PLANT	3,498,087,521	3,436,341,668	(61,745,853)
GENERAL PLANT	173,887,833	163,321,273	(10,566,560)
TOTAL	**$ 4,667,116,677**	**$ 4,572,420,200**	**$ (94,696,477)**

a) Please explain the reason for the 12/31/2018 differences?
b) Does the Company agree that a $94,696,477 adjustment to plant in service balances should be made to reflect the amounts reported in the Annual Report?

Attachments:
WP Schedule B-2.3a Reconcile to Annual Report-Plant
WP Staff DR 1-Exhibit H-Schedule B-2.3a-Tie to Annual Report

164) WBS Testing: Follow-up to BRDR-61 (CEP). For the following list of WBS Elements/projects, please explain why these projects should be included in the CEP and not in the PIR or Base Rates.
a) OC.I.OOS.000001
b) OC.P.MLR.000400
c) OC.P.MLR.000645
d) OC.P.REL.000034
e) OC.P.REL.000383
f) P400145825.001

165) WBS Testing: Fixed vs. Massed Projects. Follow-up to BRDR-64–66. Please indicate whether the following WBS elements are massed or fixed.

a. FCDEO.14.GAS.7F
b. P400000457
c. P400001220.009
d. P400001220.027
e. P400001220.054
f. P400018502.026
g. P400028409.006
h. P400028409.019
i. P400028409.021
j. P400028409.023
k. P400028409.027
l. P400028409.100
m. P400028409.108
n. P400028409.127
o. P400028409.268
p. P400028409.294
q. P400158837
r. 37639.1.2.1
s. 54379.1.1.1
t. 54386.1.9
u. DEO.DATACOMM.1.9
v. DEOAMR.1.ERT
w. IT DEO.PIPP.2
x. O8100.3C.1.1.1
y. O8100.3W.1.1.1
z. O9000_FA.2A.1.8
aa. O9500_FA.2A.1.8
bb. O9500_FA.3C.1.8
cc. O9500_FA.3L.1.8
dd. O9505.2A.1.8
ee. O9505.2Y.1.8
ff. O9700.1.MTR
gg. O9700.TIN.DR
hh. O9750.1.2.3.1

ii. OH00000
jj. OH10259
kk. OH11281
ll. OH13929
mm. OH13959
nn. OH13961
oo. OH13971
pp. OH14439
qq. OH14759
rr. OH15317
ss. OH15352
tt. P400384703

166) WBS Testing: Follow-up to BRDR-61 (CEP). For the following list of WBS Elements, please indicate which project category / recovery mechanism the projects fit under (HB95-1, HB95-2, or HB95-3).
a) OC.I.OOS.000001
b) OC.P.REL.000034
c) OC.P.REL.000383
d) P400123606.001

167) WBS Testing: Follow-up to BRDR-64–66 (Base Rate). For the following list of WBS elements, please explain why the asset retirement dates are significantly later than the project actual in-service dates and the impact on depreciation expense as a result of the delay.

WBS Element	Actual In-Service from documentation	Retirement Date	Number of Months Retirements took place after Actual in-Service Date
a) 25633.1.1.1	12/29/05	12/30/13	97
b) 6T07179411	12/10/09	1/26/15	62
c) IT SW DEO.ARM_C.2	10/29/09	9/30/16	84
d) OH13335	10/12/10	10/7/14	49
e) OH14616	12/18/09	12/30/13	49
f) OH14852	12/13/11	11/30/16	60
g) SW DEO.ARM_B LEAK.2	12/12/08	12/18/13	61
h) SW DEO.ARM_B LEAK.3	12/12/08	12/18/13	61

BRDR-168 SUBMITTED 2/27/20

168) **Schedule B-3.3a Tie Out to Annual Report**: Blue Ridge compared the balances reported on Schedules B-3.3a for 2007–2018 provided in Exhibit H. Attached is a file showing the comparison by major asset class. The following table summarizes our results.

Year Ending	Schedule B-3.3a	Annual Report	Difference	% Difference
12/31/07	$ 828,361,910	$ 785,939,112	$ (42,422,798)	-5.40%
12/31/08	858,446,230	828,884,164	(29,562,066)	-3.57%
12/31/09	900,787,718	864,964,370	(35,823,348)	-4.14%
12/31/10	933,439,427	901,730,242	(31,709,185)	-3.52%
12/31/11	967,375,213	945,122,990	(22,252,223)	-2.35%
12/31/12	990,455,587	972,696,393	(17,759,194)	-1.83%
12/31/13	1,011,761,071	997,446,278	(14,314,793)	-1.44%
12/31/14	1,040,675,211	1,029,969,828	(10,705,383)	-1.04%
12/31/15	1,089,486,988	1,077,373,546	(12,113,442)	-1.12%
12/31/16	1,071,638,753	1,062,449,960	(9,188,793)	-0.86%
12/31/17	1,125,829,664	1,120,458,849	(5,370,815)	-0.48%
12/31/18	1,189,439,258	1,171,468,973	(17,970,285)	-1.53%

Please explain the differences between the amounts reported on Schedule 3.3a and the amounts reported in the PUCO Annual Report.
Attachments:
WP Schedule B-3.3a Reconcile to Annual Report-Reserve

BRDR #169-171 SUBMITTED 3/4/20

169) **WBS Testing**: Follow up to Data Request response BRDR #61 (CEP) - Project FCDEO.15.GAS.8B – Main BLDG RENO-NCN 15000003
   a) Please explain why no retirements or Cost of Removal was recorded on this Building Renovation.
   b) Please explain what the ($400,000) Credit to Cost Element 5309020 represents.

170) **WBS Testing**: Follow up to Data Request response BRDR #61 (CEP) - Project O7000.15.GAS.6B – TOUGHBOOKS. Please provide the detail that supports cost element 5304340 – Stwr/Hrdw Purchase. Include the number of TOUCHBOOKS purchased, unit cost, no deployed, and no kept as spares.

171) **WBS Testing**: Follow up to Data Request response BRDR #61 (CEP) - Project O9700.1.MTR – Meter Purchases.
   a) Please explain why meter purchases are charged to cost element 5304200 – Material Exp-Non Stock
   b) Are meters capitalized upon purchase? If not, how are the purchase of meters accounted for?

172) **WBS Testing**: Follow up to Data Request response BRDR-127. The Company explained what cost element 8201010 is used for.
   a) Does the Managers activity pricing in SAP end up as an actual cost charged to a WBS and therefore, a work order/project or is it purely an internal budget pricing issue?
   b) If an internal budget pricing, please confirm that WBS (projects) charges are based on actual payroll dollars?

c) If the activity pricing represents actual charges to a project, please explain why individual payroll is not used.

BRDR#173 SUBMITTED MARCH 31, 2020

173) **CEP ADIT on Liberalized Depreciation (Schedule 7):** Reference the Company's response to BRDR #83 which states, "Subsequent to the pre-filing notice, the value of the CEP ADIT as of December 31, 2018 was updated." Does the update reflect a true-up to the actual 2018 tax return? If not, please explain the reason.

BRDR #174 SUBMITTED 4/20/20

174) **WBS Testing:** Does 09200_FA.2A.1.8 generate incremental revenue? If not, please explain why.

APPENDIX C: WORK PAPERS

Blue Ridge's workpapers are available on a thumb drive and were delivered to the PUCO Staff per the RFP requirements.

Adjustments

- ADJ 1 - WP Assets Not Retired BRDR-73 Attachment 2.xlsx
- ADJ 2 - BRDR-137 (WBS Testing -IT.DEO.RATE CASE.2).pdf
- ADJ 4 - BRDR-106 (WBS Testing P400090072).pdf
- ADJ 5 - BRDR-143 (WBS Testing).pdf
- ADJ 6 - BRDR-103 (WBS Testing).pdf
- ADJ 7 - BRDR-135 (WBS Testing - FCDEO.13.GAS.7B).pdf
- ADJ 8 - BRDR-83 (CEP ADIT).pdf
- ADJ 8 - BRDR-83 Attachment 1.xlsx
- ADJ 9 - WP Deferred Property Tax BRDR-147 Attachment 1.xlsx
- ADJ 10 11 - WP Beg Balance Staff RMAs BRDR-4 Attachment 1 Staff Report Last Rate Case.xlsx
- ADJ 10 11 - WP Staff DR 1- Exhibit H - Schedule B-2, B-2.1, B-2.2, B-2.3.xlsx
- ADJ 12 - WP Staff DR 1- Exhibit H - Schedule B-2.3a.xlsx
- ADJ 13 - WP Staff DR 1- Exhibit H - Schedule B-3.3a R1.xlsx
- ADJ 14 - BRDR-141 (WBS Testing - P400002271).pdf
- WP CEP Rev Req Recast with Adj Staff DR 1- Exhibit I - Additional Supporting Schedules R4.xlsx
- WP DEO 2018 Adjustments to Plant and Reserve R5.xlsx
- WP RECAST Staff DR 1- Exhibit H - Schedule B-2, B-2.1, B-2.2, B-2.3.xlsx
- WP RECAST Staff DR 1- Exhibit H - Schedule B-3, B-3.1, B-3.2, B-3.3.xlsx

Detailed Transactional Testing FOLDER

- Workpaper DEO Detailed Transactional Testing FINAL.docx
- WP – DEO Scope against Variance Explanations (BRDR-61, 64-66)..xlsx
- WP BRDR-170 Attachment 1 (TOUGHPADS).xlsx
- WP DEO - Field Test Sample Selected Based on BRDR-8.xlsx
- WP DEO Base Rates Matrix CONFIDENTIAL FINAL.xlsx
- WP DEO CEP Matrix CONFIDENTIAL FINAL.xlsx
- Documents to Reconcile and Pull Sample
- WP - Population Analysis.docx
- WP BRDR 8 Stats.xlsx
- WP BRDR-8 Attachment 4 (2013 Addition Summary).xlsb
- WP BRDR-8 Attachment 5 (2014 Addition Summary).xlsb
- WP BRDR-8 Attachment 6 (2015 Addition Summary).xlsb
- WP BRDR-8 Attachment 7 (2016 Addition Summary).xlsb
- WP BRDR-8 Attachment 8 (2017 Addition Summary).xlsb
- WP BRDR-8 Attachment 9 (2007 Addition Summary) Revised.xlsb
- WP BRDR-8 Attachment 9 (2007 Addition Summary).xlsb
- WP BRDR-8 Attachment 10 (2008 Addition Summary).xltx
- WP BRDR-8 Attachment 11 (2009 Addition Summary).xlsb
- WP BRDR-8 Attachment 12 (2010 Addition Summary).xlsb
- WP BRDR-8 Attachment 13 (2011 Addition Summary).xlsb
- WP BRDR-8 Attachment 14 (2012 Addition Summary).xlsb

- WP BRDR-8 Attachment 15 (2018 Addition Summary).xlsb
- WP DEO - Base Rates Initial Sample 2007-2012 to JNF for Judgement.xlsx
- WP DEO - Base Rates Sample Based on Judgement R2.xlsx
- WP Describing Base Rates Calcuation and Population Justification.docx
- WP Staff 2 Comparison to BRDR 8 attachment 4-8 and 9-14 and 15.xlsx
- WP Staff DR 2 - 2007 - 2018 Plant Additions.xlsx

Exhibit H B-Schedules

- WP BRDR-4 Attachment 1 Staff Report Last Rate Case.xlsx
- WP Schedule B-2.3a Reconcile to Annual Report - Plant.xlsx
- WP Schedule B-3.3a Reconcile to Annual Report - Reserve.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-2, B-2.1, B-2.2, B-2.3.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-2.3a - Tie to Annual Report.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-2.3a.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-2.4.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-3, B-3.1, B-3.2, B-3.3 R1.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-3, B-3.1, B-3.2, B-3.3.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-3.3a - Tie to Annual Report.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-3.3a R1.xlsx
- WP Staff DR 1- Exhibit H - Schedule B-3.3a.xlsx

Field Observations

- DEO_ System map they gave me during field audit
- Inspection Results vr March 17, 2020 DEO Field Audit FINAL.docx
- Re_ Dominion CEP Field Visit Wednesday - Charlie Update on Projects Discussed

Interviews

- Dominion Interview Forms - Capital Budgeting .docx
- Dominion Interview Forms - Cost.docx
- Dominion Interview Forms- EngineeringWMISsystem planning and load growth.docx
- Dominion Interview Forms- Significant events Apr 2007 through Dec 2018.docx
- Dominion Interview Forms- Plant Accounting.docx
- Notes on Various Calls for Fact Check.docx

Variance Analysis

- WP BRDR-54 Attachment 1 Variance Analysis.xlsx
- WP Schedule B-2.3a Reconcile to Annual Report Plant.xlsx
- WP Staff DR 1-Exhibit H-Schedule B-2.3a .xlsx

WP - Comparison - Staff DR 2 (GL) to BRDR-8 (BW) Attachment 1 and 3.xlsx
WP 19-0468-GA-ALT Sensitivity and Sample Size FINAL.xlsx
WP Approved Deferral Formulas.xlsx
WP BRDR- 54 Attachment 1 FROM COMPANY.xlsx
WP BRDR-6 Attachment 7 (2018 Costs).xlsx
WP BRDR-35 Attachment 1 (Work order Backlog Analysis).xlsx
WP BRDR-73 Attachment 2.xlsx
WP CEP V&V Rev Req Staff DR 1- Exhibit I - Additional Supporting Schedules.xlsx
WP DEO Property Tax .xlsx
WP Dominion V&V 2019 Annual Report CEP.xlsx

APPENDIX D: RECAST TOTAL COMPANY SCHEDULES B-2 AND B-3

This section includes the recast Schedules B-2, B-2.1, and B-3 with Blue Ridge recommended adjustments to plant and the reserve.

The following table reflects Commission-approved ratemaking adjustments by FERC account from the Company's last base rate case that were not reflected in the Company's beginning balances. Blue Ridge is not recommending the adjustments to the December 31, 2018 balance, but rather recommends that they be considered in the Company's next base rate case to ascertain their rolled forward impact and relevance at that time.

Dominion Energy Ohio
Adjustments to Plant and Reserve Not Reflected in Recast Schedule B-2 and B-3

							Adjustment		
Adjustment #	Issue	Source	Schedule	Work Order	Description	FERC	Gross Plant	Reserve	Net Plant
10a	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	303	$ (28,517.00)		$ (28,517)
10b	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	332	$ (1,003)		$ (1,003)
10c	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	339	$ (657,841)		$ (657,841)
10d	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	358	$ (186,844)		$ (186,844)
10e	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	365.1	$ (2,198)		$ (2,198)
10f	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	367	$ (424,735)		$ (424,735)
10g	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	369	$ (4,788)		$ (4,788)
10h	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	372	$ (833,604)		$ (833,604)
10i	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	374	$ (429,175)		$ (429,175)
10j	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	374	$ (17,436)		$ (17,436)
10k	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	375	$ (42,943)		$ (42,943)
10l	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	375	$ (133,227)		$ (133,227)
10m	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	375	$ (143,613)		$ (143,613)
10n	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	376	$ (5,321,765)		$ (5,321,765)
10o	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	378	$ (49,145)		$ (49,145)
10p	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	380	$ (37)		$ (37)
10q	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	381	$ (132,466)		$ (132,466)
10r	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	388	$ (9,028,871)		$ (9,028,871)
10s	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	390	$ (20,022)		$ (20,022)
10t	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	391	$ (873)		$ (873)
10u	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	391.2	$ 140,877		$ 140,877
10v	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	394	$ (89)		$ (89)
10w	PIS Beginning Balance Overstated	BRDR-4	Base Rate B-2.1	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	398	$ (1,402)		$ (1,402)
							$ (17,319,717)		$ (17,319,717)
11a	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	303		$ (1,306)	$ 1,306
11b	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	332		$ (1,003)	$ 1,003
11c	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	339		$ (7,693)	$ 7,693
11d	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	358		$ (59,887)	$ 59,887
11e	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	367		$ (424,735)	$ 424,735
11f	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	369		$ (4,788)	$ 4,788
11g	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	374		$ (17,436)	$ 17,436
11h	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	375		$ (42,943)	$ 42,943
11i	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	375		$ (276,840)	$ 276,840
11j	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	376		$ (5,321,765)	$ 5,321,765
11k	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	378		$ (49,145)	$ 49,145
11l	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	380		$ (37)	$ 37
11m	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	381		$ (132,466)	$ 132,466
11n	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	388		$ (106,867)	$ 106,867
11o	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	390		$ (20,022)	$ 20,022
11p	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	391		$ (873)	$ 873
11q	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	394		$ (89)	$ 89
11r	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	398		$ (1,402)	$ 1,402
11s	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	108		$ (21,797,890)	$ 21,797,890
11t	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	108		$160,657,161	$ (160,657,161)
11u	Reserve Beinning Balance Overstated	BRDR-4	Base Rate B-3	n/a	Last Rate Case RMAs not reflected in Beg. Bal.	108		$ (78,567,921)	$ 78,567,921
								$ 53,822,053	$ (53,822,053)
							$ (17,319,717)	$ 53,822,053	$ (71,141,770)

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Adjustments to Plant in Service

			Adjustment			
#	**FERC**	**Sort**	**Gross Plant**	**Reserve**	**Net Plant**	**Comments**
14	333	333	$ 1,974.00	$ 317.12	$ 1,656.88	
		333 Total	$ 1,974.00	$ 317.12	$ 1,656.88	
4	353	353	$ 7,330.24	$ 412.33	$ 6,917.91	
4	353	353	$ 4,995.78	$ 281.01	$ 4,714.77	
4	353	353	$ (61,094.40)	$ (3,436.56)	$ (57,657.84)	
		353 Total	$ (48,768.38)	$ (2,743.22)	$ (46,025.16)	
6	375	375	**$ (81,636.25)**	**$ (2,823.25)**	**$ (78,813.00)**	
		375 Total	**$ (81,636.25)**	**$ (2,823.25)**	**$ (78,813.00)**	
13	375.03	375.03		$ 83,095.00	$ (83,095.00)	
		375.03 Total	$ -	$ 83,095.00	$ (83,095.00)	
1a	390/394	390	$ (110,681.72)	$ (11,529.35)	$ (99,152.37)	Allocation between 390 and 394 not known. Recorded to 390
1b	390	390	$ (109,612.58)	$ (10,961.26)	$ (98,651.32)	
1c	390	390	$ (49,484.59)	$ (4,948.46)	$ (44,536.13)	
1d	390	390	$ (374,585.70)	$ (92,085.65)	$ (282,500.05)	
1e	390	390	$ (262,684.12)	$ (27,362.93)	$ (235,321.19)	
1i	390/398	390	$ (200,130.56)	$ (25,850.20)	$ (174,280.36)	Allocation between 390 and 398 not known. Recorded to 390
1p	390	390	$ (113,584.63)	$ (11,831.73)	$ (101,752.90)	
1q	390	390	$ (17,501.00)	$ (2,114.70)	$ (15,386.30)	
1r	390	390	$ (29,450.05)	$ (3,190.42)	$ (26,259.63)	
1s	390	390	$ (76,913.76)	$ (11,216.59)	$ (65,697.17)	
1t	390	390	$ (52,690.22)	$ (5,488.56)	$ (47,201.66)	
7	390	390	**$ (65,000.00)**	**$ (15,979.17)**	**$ (49,020.83)**	
		390 Total	**$ (1,462,318.93)**	**$ (222,559.02)**	**$ (1,239,759.91)**	
12	**Formula**	**Formula**	$ (64,210.00)		$ (64,210.00)	
		Formula Total	$ (64,210.00)	$ -	$ (64,210.00)	General Plant Overstated. New row
		Grand Total	$ (1,654,959.56)	$ (144,713.37)	$ (1,510,246.19)	

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Major Property Groupings
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2
Page 1 of 1
Witness Responsible: V. H. Friscic

Line No.	Major Property Groupings	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
1	Intangible Plant	$ 58,128,111	100%	$ 58,128,111	$ -	$ 58,128,111
2	Production and Gathering	192,643,172	100%	192,643,172	1,974	192,645,146
3	Storage	259,199,348	100%	259,199,348	(48,768)	259,150,579
4	Transmission	485,170,692	100%	485,170,692	0	485,170,692
5	Distribution	3,498,087,522	100%	3,498,087,522	(81,636)	3,498,005,886
6	General	173,887,833	100%	173,887,833	(1,526,529)	172,361,304
7	Total	$ 4,667,116,677		$ 4,667,116,677	$ (1,654,960)	$ 4,665,461,717

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1

Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		INTANGIBLE PLANT					
1	303.01	Misc Intangible Plant-Contribution In Aid of Construction	$ 13,403,304	100%	$ 13,403,304		$ 13,403,304
2	303.03	Misc Intangible Plant-Computer Software	44,724,807	100%	44,724,807		44,724,807
3		Total Intangible Plant	$ 58,128,111		$ 58,128,111	$ -	$ 58,128,111

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1
Page 2 of 6
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		PRODUCTION & GATHERING PLANT					
1	325.40	Rights Of Way	$ 2,967,361	100%	$ 2,967,361	$ -	$ 2,967,361
2	325.50	Other Land & Land Rights-Land	718,487	100%	718,487		718,487
3	327.00	Field Compressor Station Structures	4,030,437	100%	4,030,437		4,030,437
4	328.00	Field M&R Station Structures	1,075,198	100%	1,075,198		1,075,198
5	329.00	Other Structures	265,888	100%	265,888		265,888
6	330.00	Well Construction	209,686	100%	209,686		209,686
7	331.00	Well Equipment	845,232	100%	845,232		845,232
8	332.00	Field Lines	107,480,809	100%	107,480,809		107,480,809
9	333.00	Field Compressor Station Equipment	48,221,369	100%	48,221,369	1,974	48,223,343
10	334.11	Field M&R Station Equip-Purchase Gas-Meters & Gauges	1,736,271	100%	1,736,271		1,736,271
11	334.12	Field M&R Station Equip-Purchase Gas-Other	23,861,418	100%	23,861,418		23,861,418
12	335.00	Drilling & Cleaning Equipment-NY, PA & OH	478,919	100%	478,919		478,919
13	339.00	Production Equipment Held Under ARO	752,098	100%	752,098		752,098
14		Total Production & Gathering Plant	$ 192,643,172		$ 192,643,172	$ 1,974	$ 192,645,146

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1
Page 3 of 6
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		STORAGE PLANT					
1	350.10	Land	$ 316,563	100%	$ 316,563	$ -	$ 316,563
2	350.02	Rights Of Way	170,397	100%	170,397		170,397
3	351.03	Structures & Improvements-Compressor Station Structures	9,630,705	100%	9,630,705		9,630,705
4	351.04	Structures & Improvements-M & R Station Structures	1,294,761	100%	1,294,761		1,294,761
5	352.01	Structures & Improvements-Other Structures	3,186,169	100%	3,186,169		3,186,169
6	352.02	Wells-Well Construction	66,780,203	100%	66,780,203		66,780,203
7	352.02	Wells-Well Equipment	17,111,646	100%	17,111,646		17,111,646
8	352.11	Land & Land Rights-Leaseholds	6,465,690	100%	6,465,690		6,465,690
9	352.12	Land & Land Rights-Storage Rights	338,911	100%	338,911		338,911
10	352.30	Non-Recoverable Natural Gas	5,251,191	100%	5,251,191		5,251,191
11	353.00	Lines	61,595,194	100%	61,595,194	(48,768)	61,546,426
12	354.00	Compressor Station Equipment - Compressor Station Equipment	57,801,843	100%	57,801,843		57,801,843
13	355.01	M & R Equipment-Meters & Gauges	13,207	100%	13,207		13,207
14	355.02	M & R Equipment-Other	28,232,207	100%	28,232,207		28,232,207
15	357.00	Other Equipment-Other	877,174	100%	877,174		877,174
16	358.00	Underground Storage Equipment Held Under ARO	133,488	100%	133,488		133,488
17		Total Storage Plant	$ 259,199,348		$ 259,199,348	$ (48,768)	$ 259,150,579

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1
Page 4 of 6
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		TRANSMISSION PLANT					
1	365.11	Land & Land Rights-Land	$ 1,545,295	100%	$ 1,545,295		$ 1,545,295
2	365.11	Land & Land Rights-Land Rights	-	100%	-		-
3	365.21	Rights Of Way	4,025,534	100%	4,025,534		4,025,534
4	366.01	Structures & Improvements-Compressor Station Structures	5,728,060	100%	5,728,060		5,728,060
5	366.02	Structures & Improvements-M&R Station Structures	5,967,142	100%	5,967,142		5,967,142
6	366.03	Structures & Improvements-Other Structures	1,177,423	100%	1,177,423		1,177,423
8	366.20	M&R Structures	-	100%	-		-
9	367.00	Mains	333,900,476	100%	333,900,476		333,900,476
10	368.00	Compressor Station Equipment-Compressor Station Equipment	42,245,847	100%	42,245,847		42,245,847
11	369.02	M&R Station Equipment-Meters & Gauges	3,322,912	100%	3,322,912		3,322,912
12	369.03	M&R Station Equipment-Other	85,837,988	100%	85,837,988		85,837,988
13	370.01	Communication Equipment-Communication	-	100%	-		-
14	370.03	Communication Equipment-Radio	-	100%	-		-
15	371.00	Other Equipment-Odorization	8,940	100%	8,940		8,940
16	371.01	Other Equipment-Other Equipment	764,475	100%	764,475		764,475
17	372.00	Transmission Equipment Held Under ARO	646,600	100%	646,600		646,600
18		Total Transmission Plant	$ 485,170,692		$ 485,170,692	$ -	$ 485,170,692

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1
Page 5 of 6
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		DISTRIBUTION PLANT					
1	374.00	Land & Land Rights	$ 6,155,106	100%	$ 6,155,106	$ -	$ 6,155,106
2	374.00	Land & Land Rights - Land Rights	-	100%	-		-
3	374.00	Land & Land Rights - Leased Sites	-	100%	-		-
4	374.00	Land & Land Rights - Rights-of-Way	-	100%	-		-
5	375.01	Structures & Improvements-M & R Station Structures (General)	7,143,927	100%	7,143,927	(81,636)	7,062,291
6	375.02	Structures & Improvements-M & R Station Structures (Industrial)	273,332	100%	273,332		273,332
7	375.03	Structures & Improvements-Leasehold Improvements	3,826,205	100%	3,826,205		3,826,205
8	375.04	Structures & Improvements-Other Structures	61,964,515	100%	61,964,515		61,964,515
9	376.01	Low Pressure Mains	1,034,718,790	100%	1,034,718,790		1,034,718,790
10	376.02	Regulated Pressure Mains	1,154,631,089	100%	1,154,631,089		1,154,631,089
11	378.01	M & R Station Equipment (General)-Meters & Gauges	103,603	100%	103,603		103,603
12	378.02	M & R Station Equipment (General)-Other Equipment	83,564,709	100%	83,564,709		83,564,709
13	380.01	Services - All Pressures	2,393,629	100%	2,393,629		2,393,629
14	380.02	Services - Low Pressure	407,480,197	100%	407,480,197		407,480,197
15	380.03	Services - Regulated Pressure	400,871,702	100%	400,871,702		400,871,702
16	380.04	Special Services	11,690	100%	11,690		11,690
17	381.01	Meters - Meters	172,565,591	100%	172,565,591		172,565,591
18	381.01	Meters - Recording Gauges	13,245,897	100%	13,245,897		13,245,897
19	381.01	Meters - Hexagram	4,559,181	100%	4,559,181		4,559,181
20	382.00	Meter Installations - Residential	80,942,212	100%	80,942,212		80,942,212
21	382.00	Meter installations - Commercial	26,360,356	100%	26,360,356		26,360,356
22	383.01	House Regulators - Small	8,238,824	100%	8,238,824		8,238,824
23	383.02	House Regulators - Large	6,470,491	100%	6,470,491		6,470,491
24	384.00	House Regulator Installation	1,207,863	100%	1,207,863		1,207,863
25	385.03	Industrial M & R Station Equipment - Other	8,266,964	100%	8,266,964		8,266,964
26	387.00	Other Equipment - Other Equipment	3,886,738	100%	3,886,738		3,886,738
27	388.00	Distribution Equipment Held Under ARO	9,204,911	100%	9,204,911		9,204,911
29		Total Distribution Plant	$ 3,498,087,522		$ 3,498,087,522	$ (81,636)	$ 3,498,005,886

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Plant in Service by Accounts and Subaccounts
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-2.1
Page 6 of 6
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		GENERAL PLANT					
1	389.00	Land & Land Rights - Land	$ 4,429,414	100%	$ 4,429,414		$ 4,429,414
2	390.00	Structures & Improvements - Leasehold Improvements	-	100%	-		-
3	390.01	Structures & Improvements - Other	86,990,101	100%	86,990,101	(1,462,319)	85,527,782
4	391.00	Office Furniture & Equipment - Equipment	1,114,987	100%	1,114,987		1,114,987
5	391.01	Office Furniture & Equipment - Furniture	4,420,520	100%	4,420,520		4,420,520
6	391.20	Office Furniture & Equipment - Computer Hardware	5,955,943	100%	5,955,943		5,955,943
7	392.00	Transportation Equipment - Non Luxury Automobiles	1,398	100%	1,398		1,398
8	392.01	Transportation Equipment - Light Trucks	1,238,647	100%	1,238,647		1,238,647
9	392.03	Transportation Equipment -Trailers (WV, OH & VA)	1,457,047	100%	1,457,047		1,457,047
10	392.05	Transportation Equipment - NGV Kits NonLux Autos	31,193	100%	31,193		31,193
11	392.05	Transportation Equipment - NGV Kits Light Trucks<10k	-	100%	-		-
12	392.05	Transportation Equipment - NGV Kits Med Trucks<26k	-	100%	-		-
13	393.00	Stores Equipment	38,090	100%	38,090		38,090
14	394.00	Tools, Shop & Garage Equipment - Shop Equipment	-	100%	-		-
15	394.01	Tools, Shop & Garage Equipment - Garage Equipment	14,274,131	100%	14,274,131		14,274,131
16	394.03	Tools, Shop & Garage Equip - NGV Compression/Station	5,066,856	100%	5,066,856		5,066,856
17	394.02	Tools, Shop & Garage Equip - Tools & Equipment	-	100%	-		-
18	395.00	Laboratory Equipment	4,277	100%	4,277		4,277
19	396.00	Power Operated Equipment - Distribution/Compression/Welding	8,140,317	100%	8,140,317		8,140,317
20	397.01	Communications Equipment - Communication Equipment	6,912,252	100%	6,912,252		6,912,252
21	397.02	Communications Equipment - Telephone System	2,047,782	100%	2,047,782		2,047,782
22	397.00	Communications Equipment - Microwave System	-	100%	-		-
23	397.00	Communications Equipment - Radio	-	100%	-		-
24	398.00	Miscellaneous Equipment - Misc Equipment	5,071,627	100%	5,071,627		5,071,627
25	399.00	Other Computer Software	26,700,214	100%	26,700,214		26,700,214
26	399.10	General Plant Equipment Held Under ARO	(6,962)	100%	(6,962)		(6,962)
						(64,210)	(64,210)
27		Total General Plant	$ 173,887,833		$ 173,887,833	$ (1,526,529)	$ 172,361,304

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Adjustments to Reserve
As of December 31, 2018

			Adjustment			
#	**FERC**	**Sort**	**Gross Plant**	**Reserve**	**Net Plant**	**Comments**
14	333	333	$ 1,974.00	$ 317.12	$ 1,656.88	
		333 Total	$ 1,974.00	$ 317.12	$ 1,656.88	
4	353	353	$ 7,330.24	$ 412.33	$ 6,917.91	
4	353	353	$ 4,995.78	$ 281.01	$ 4,714.77	
4	353	353	$ (61,094.40)	$ (3,436.56)	$ (57,657.84)	
		353 Total	$ (48,768.38)	$ (2,743.22)	$ (46,025.16)	
6	375	375	**$ (81,636.25)**	**$ (2,823.25)**	**$ (78,813.00)**	
		375 Total	**$ (81,636.25)**	**$ (2,823.25)**	**$ (78,813.00)**	
13	375.03	375.03		$ 83,095.00	$ (83,095.00)	
		375.03 Total	$ -	$ 83,095.00	$ (83,095.00)	
1a	390/394	390	$ (110,681.72)	$ (11,529.35)	$ (99,152.37)	Allocation between 390 and 394 not known. Recorded to 390
1b	390	390	$ (109,612.58)	$ (10,961.26)	$ (98,651.32)	
1c	390	390	$ (49,484.59)	$ (4,948.46)	$ (44,536.13)	
1d	390	390	$ (374,585.70)	$ (92,085.65)	$ (282,500.05)	
1e	390	390	$ (262,684.12)	$ (27,362.93)	$ (235,321.19)	
1i	390/398	390	$ (200,130.56)	$ (25,850.20)	$ (174,280.36)	Allocation between 390 and 398 not known. Recorded to 390
1p	390	390	$ (113,584.63)	$ (11,831.73)	$ (101,752.90)	
1q	390	390	$ (17,501.00)	$ (2,114.70)	$ (15,386.30)	
1r	390	390	$ (29,450.05)	$ (3,190.42)	$ (26,259.63)	
1s	390	390	$ (76,913.76)	$ (11,216.59)	$ (65,697.17)	
1t	390	390	$ (52,690.22)	$ (5,488.56)	$ (47,201.66)	
7	390	390	**$ (65,000.00)**	**$ (15,979.17)**	**$ (49,020.83)**	
		390 Total	**$ (1,462,318.93)**	**$ (222,559.02)**	**$ (1,239,759.91)**	
12	**Formula**	**Formula**	$ (64,210.00)		$ (64,210.00)	
		Formula Total	$ (64,210.00)	$ -	$ (64,210.00)	General Plant Overstated. New row
		Grand Total	$ (1,654,959.56)	$ (144,713.37)	$ (1,510,246.19)	

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3

Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		INTANGIBLE PLANT						
1	303.01	Misc Intangible Plant - Contribution In Aid of Construction	$ 13,403,304	$ 9,506	100%	$ 9,506	$ -	$ 9,506
2	303.03	Misc Intangible Plant-Computer Software	44,724,807	29,613,871	100%	29,613,871	-	29,613,871
3		Total Intangible Plant	$ 58,128,111	$ 29,623,377		$ 29,623,377	$ -	$ 29,623,377

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3

Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		PRODUCTION & GATHERING PLANT						
1	325.40	Rights Of Way	$ 2,967,361	$ 1,489,114	100%	$ 1,489,114	$ -	$ 1,489,114
2	325.50	Other Land & Land Rights-Land	718,487	-	100%	-	-	-
3	327.00	Field Compressor Station Structures	4,030,437	2,112,803	100%	2,112,803	-	2,112,803
4	328.00	Field M&R Station Structures	1,075,198	405,962	100%	405,962	-	405,962
5	329.00	Other Structures	265,888	252,534	100%	252,534	-	252,534
6	330.00	Well Construction	209,686	60,722	100%	60,722	-	60,722
7	331.00	Well Equipment	845,232	127,627	100%	127,627	-	127,627
8	332.00	Field Lines	107,480,809	33,641,671	100%	33,641,671	-	33,641,671
9	333.00	Field Compressor Station Equipment	48,221,369	18,622,354	100%	18,622,354	317	18,622,671
10	334.11	Field M&R Station Equip-Purchase Gas-Meters & Gauges	1,736,271	474,349	100%	474,349	-	474,349
11	334.12	Field M&R Station Equip-Purchase Gas-Other	23,861,418	12,061,458	100%	12,061,458	-	12,061,458
12	335.00	Drilling & Cleaning Equipment-NY, PA & OH	478,919	478,919	100%	478,919	-	478,919
14	339.00	Production Equipment Held Under ARO	752,098		100%	-	-	-
15		Total Production & Gathering Plant	$ 192,643,172	$ 69,727,514		$ 69,727,514	$ 317	$ 69,727,831

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3
Page 3 of 7
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		STORAGE PLANT			100%			
1	350.10	Land	$ 316,563	$ -	100%	$ -	$ -	$ -
2	350.02	Rights Of Way	170,397	114,912	100%	114,912	-	114,912
3	351.03	Structures & Improvements-Compressor Station Structures	9,630,705	1,394,928	100%	1,394,928	-	1,394,928
4	351.04	Structures & Improvements-M & R Station Structures	1,294,761	250,783	100%	250,783	-	250,783
5	352.01	Structures & Improvements-Other Structures	3,186,169	1,941,304	100%	1,941,304	-	1,941,304
6	352.02	Wells-Well Construction	66,780,203	19,783,354	100%	19,783,354	-	19,783,354
7	352.02	Wells-Well Equipment	17,111,646	10,390,644	100%	10,390,644	-	10,390,644
8	352.11	Land & Land Rights-Leaseholds	6,465,690	3,954,106	100%	3,954,106	-	3,954,106
9	352.12	Land & Land Rights-Storage Rights	338,911	1,049,431	100%	1,049,431	-	1,049,431
10	352.30	Non-Recoverable Natural Gas	5,251,191	5,251,191	100%	5,251,191	-	5,251,191
11	353.00	Lines	61,595,194	13,496,015	100%	13,496,015	(2,743)	13,493,272
12	354.00	Compressor Station Equipment - Compressor Station Equipment	57,801,843	18,110,365	100%	18,110,365	-	18,110,365
13	355.01	M & R Equipment-Meters & Gauges	13,207	-	100%	-	-	-
14	355.02	M & R Equipment-Other	28,232,207	5,821,609	100%	5,821,609	-	5,821,609
15	357.00	Other Equipment-Other	877,174	411,012	100%	411,012	-	411,012
16	358.00	Underground Storage Equipment Held Under ARO	133,488		100%	-	-	-
17		Total Storage Plant	$ 259,199,348	$ 81,969,654		$ 81,969,654	$ (2,743)	$ 81,966,911

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3
Page 4 of 7
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		TRANSMISSION PLANT						
1	365.11	Land & Land Rights-Land	$ 1,545,295	$ -	100%	$ -	$ -	$ -
2	365.11	Land & Land Rights-Land Rights	-	-	100%	-	-	-
3	365.21	Rights Of Way	4,025,534	975,059	100%	975,059	-	975,059
4	366.01	Structures & Improvements-Compressor Station Structures	5,728,060	577,248	100%	577,248	-	577,248
5	366.02	Structures & Improvements-M&R Station Structures	5,967,142	1,890,881	100%	1,890,881	-	1,890,881
6	366.03	Structures & Improvements-Other Structures	1,177,423	580,746	100%	580,746	-	580,746
7	366.20	M&R Structures	-	-	100%	-	-	-
8	367.00	Mains	333,900,476	87,908,178	100%	87,908,178	-	87,908,178
9	368.00	Compressor Station Equipment-Compressor Station Equipment	42,245,847	5,738,567	100%	5,738,567	-	5,738,567
10	369.02	M&R Station Equipment-Meters & Gauges	3,322,912	413,234	100%	413,234	-	413,234
11	369.03	M&R Station Equipment-Other	85,837,988	20,858,066	100%	20,858,066	-	20,858,066
12	370.01	Communication Equipment-Communication	-	696	100%	696	-	696
13	370.03	Communication Equipment-Radio	-	-	100%	-	-	-
14	371.00	Other Equipment-Odorization	8,940	8,043.14	100%	8,043	-	8,043
15	371.01	Other Equipment-Other Equipment	764,475	358,465	100%	358,465	-	358,465
16	372.00	Transmission Equipment Held Under ARO	646,600		100%	-	-	-
17		Total Transmission Plant	$ 485,170,692	$ 119,309,184		$ 119,309,184	$ -	$ 119,309,184

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3
Page 5 of 7
Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
		DISTRIBUTION PLANT						
1	374.00	Land & Land Rights	$ 6,155,106	$ 1,415,874	100%	$ 1,415,874	$ -	$ 1,415,874
2	374.00	Land & Land Rights - Land Rights	-	-	100%	-	-	-
3	374.00	Land & Land Rights - Leased Sites	-	-	100%	-	-	-
4	374.00	Land & Land Rights - Rights-of-Way	-	-	100%	-	-	-
5	375.01	Structures & Improvements-M & R Station Structures (General)	7,143,927	3,371,758	100%	3,371,758	(2,823)	3,368,935
6	375.02	Structures & Improvements-M & R Station Structures (Industrial)	273,332	68,460	100%	68,460	-	68,460
7	375.03	Structures & Improvements-Leasehold Improvements	3,826,205	-	100%	-	83,095	83,095
9	375.04	Structures & Improvements-Other Structures	61,964,515	38,047,783	100%	38,047,783	-	38,047,783
10	376.01	Low Pressure Mains	1,034,718,790	235,520,853	100%	235,520,853	-	235,520,853
11	376.02	Regulated Pressure Mains	1,154,631,089	255,336,086	100%	255,336,086	-	255,336,086
12	378.01	M & R Station Equipment (General)-Meters & Gauges	103,603	37,193	100%	37,193	-	37,193
13	378.02	M & R Station Equipment (General)-Other Equipment	83,564,709	17,480,283	100%	17,480,283	-	17,480,283
14	380.01	Services - All Pressures	2,393,629	1,435,219	100%	1,435,219	-	1,435,219
15	380.02	Services - Low Pressure	407,480,197	187,257,605	100%	187,257,605	-	187,257,605
16	380.03	Services - Regulated Pressure	400,871,702	173,947,698	100%	173,947,698	-	173,947,698
17	380.04	Special Services	11,690	8,478	100%	8,478	-	8,478
18	381.01	Meters - Meters	172,565,591	77,894,925	100%	77,894,925	-	77,894,925
19	381.01	Meters - Recording Gauges	13,245,897	8,675,761	100%	8,675,761	-	8,675,761
20	381.01	Meters - Hexagram	4,559,181	4,559,181	100%	4,559,181	-	4,559,181
21	382.00	Meter Installations - Residential	80,942,212	26,362,862	100%	26,362,862	-	26,362,862
22	382.00	Meter installations - Commercial	26,360,356	2,918,584	100%	2,918,584	-	2,918,584
23	383.01	House Regulators - Small	8,238,824	7,793,893	100%	7,793,893	-	7,793,893
24	383.02	House Regulators - Large	6,470,491	4,607,953	100%	4,607,953	-	4,607,953
25	384.00	House Regulator Installation	1,207,863	613,115	100%	613,115	-	613,115
26	385.03	Industrial M & R Station Equipment - Other	8,266,964	3,573,516	100%	3,573,516	-	3,573,516
27	387.00	Other Equipment - Other Equipment	3,886,738	1,879,781	100%	1,879,781	-	1,879,781
28	388.00	Distribution Equipment Held Under ARO	9,204,911		100%	-	-	-
29		Total Distribution Plant	$ 3,498,087,522	$ 1,052,806,859		$ 1,052,806,859	$ 80,272	$ 1,052,887,131

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3

Witness Responsible: V. H. Friscic

Line No.	Account No.	Account Title	Total Company Plant Investment	Reserve Balances: Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
1		GENERAL PLANT						
2	389.00	Land & Land Rights - Land	$ 4,429,414	$ -	100%	$ -	$ -	$ -
3	390.00	Structures & Improvements - Leasehold Improvements	-	-	100%	-	-	-
4	390.01	Structures & Improvements - Other	86,990,101	10,971,159	100%	10,971,159	(222,559)	10,748,600
5	391.00	Office Furniture & Equipment - Equipment	1,114,987	444,520	100%	444,520	-	444,520
6	391.01	Office Furniture & Equipment - Furniture	4,420,521	3,144,708	100%	3,144,708	-	3,144,708
7	391.20	Office Furniture & Equipment - Computer Hardware	5,955,942	2,158,459	100%	2,158,459	-	2,158,459
8	392.00	Transportation Equipment - Non Luxury Automobiles	1,398	-	100%	-	-	-
9	392.01	Transportation Equipment - Light Trucks	1,238,647	1,107,241	100%	1,107,241	-	1,107,241
10	392.03	Transportation Equipment -Trailers (WV, OH & VA)	1,457,047	26,075	100%	26,075	-	26,075
11	392.05	Transportation Equipment - NGV Kits NonLux Autos	31,193	31,193	100%	31,193	-	31,193
12	392.05	Transportation Equipment - NGV Kits Light Trucks<10k	-	-	100%	-	-	-
13	392.05	Transportation Equipment - NGV Kits Med Trucks<26k	-	-	100%	-	-	-
14	393.00	Stores Equipment	38,090	18,714	100%	18,714	-	18,714
15	394.00	Tools, Shop & Garage Equipment - Shop Equipment	-	-	100%	-	-	-
16	394.01	Tools, Shop & Garage Equipment - Garage Equipment	14,274,131	2,687,417	100%	2,687,417	-	2,687,417
17	394.03	Tools, Shop & Garage Equip - NGV Compression/Station	5,066,856	5,066,856	100%	5,066,856	-	5,066,856
18	394.02	Tools, Shop & Garage Equip - Tools & Equipment	-	2,067,856	100%	2,067,856	-	2,067,856
19	395.00	Laboratory Equipment	4,277	3,807	100%	3,807	-	3,807
20	396.00	Power Operated Equipment - Distribution/Compression/Welding	8,140,317	1,306,329	100%	1,306,329	-	1,306,329
21	397.01	Communications Equipment - Communication Equipment	6,912,252	2,792,954	100%	2,792,954	-	2,792,954
22	397.02	Communications Equipment - Telephone System	2,047,782	1,536,644	100%	1,536,644	-	1,536,644
23	397.00	Communications Equipment - Microwave System	-	-	100%	-	-	-
24	397.00	Communications Equipment - Radio	-	-	100%	-	-	-
25	398.00	Miscellaneous Equipment - Misc Equipment	5,071,627	788,602	100%	788,602	-	788,602
26	399.00	Other Computer Software	26,700,214	8,151,602	100%	8,151,602	-	8,151,602
27	399.10	General Plant Equipment Held Under ARO	(6,962)	-	100%	-	-	-
28		Total General Plant	$ 173,887,833	$ 42,304,137		$ 42,304,137	$ (222,559)	$ 42,081,578

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Case No. 19-0468-GA-ALT
Reserve for Accumulated Depreciation
As of December 31, 2018

Exhibit H

Data: Actual
Type of Filing: Original
Work Paper Reference Nos.:

Schedule: B-3
Page 7 of 7
Witness Responsible: V. H. Friscic

Line No.	GL Account No.	Account No.	Major Property Groupings & Account Titles	Total Company Plant Investment	Reserve Balances Total Company	Allocation %	Allocated Total	Adjustments	Adjusted Jurisdictional
1			OTHER						
2	1331810	108	Cost of Removal	$ -	$ -	100%	$ -	$ -	$ -
3	1331811	108	Cost of Removal - Pipelines	-	-	100%	-	-	-
4	1331800	108	Salvage	-	8,504,566	100%	8,504,566	-	8,504,566
5	1331900	108	Accumulated Depreciation - Plant History - Conversion	-	(363,362,198)	100%	(363,362,198)	-	(363,362,198)
6	1331900	108	Asset Retirement Obligations		2,942,201	100%	2,942,201	-	2,942,201
7	2220260	108	Regulatory Liability - Cost of Removal for FERC Reporting	-	157,144,332	100%	157,144,332	-	157,144,332
8	2220261	108	ARO Accretion & Depreciation	-	(20,135,118)	100%	(20,135,118)	-	(20,135,118)
9	2171200	108	Regulatory Liability - COR Current Pd	-	8,604,750	100%	8,604,750	-	8,604,750
10			Total Other Reserves	$ -	$ (206,301,467)		$ (206,301,467)	$ -	$ (206,301,467)
11			Total Utility Plant in Service	$ 4,667,116,677	$1,189,439,258		$1,189,439,258	$ (144,713)	$ 1,189,294,545

APPENDIX E: RECAST CEP REVENUE REQUIREMENTS SCHEDULES

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Rate Design

Exhibit I
Schedule 1

Line No.	Description	Value	Reference	As Filed	Difference
1	Revenue Requirement from Case No. 19-0468-GA-ALT	$ 82,679,046.81	Schedule 2, Line 29	$ 82,918,394.00	$ 239,347.19
	Total Plant in Service Allocators (in dollars[1])				
2	GSS/ECTS - Residential	$ 1,213,738,249.05		$ 1,213,738,249.05	$ -
3	GSS/ECTS - Non Residential	246,424,884.03		246,424,884.03	-
4	LVGSS/LVECTS	56,579,515.66		56,579,515.66	-
5	GTS/TSS	226,572,082.50		226,572,082.50	-
6	DTS	134,457,811.04		134,457,811.04	-
7	FSS	38,361,438.42		38,361,438.42	-
8	Total	$ 1,916,133,980.70		$ 1,916,133,980.70	$ -
	Total Plant in Service Allocators (in percentages)				
9	GSS/ECTS - Residential	63.34%	Line 2 / Line 8	63.34%	0.00%
10	GSS/ECTS - Non Residential	12.86%	Line 3 / Line 8	12.86%	0.00%
11	LVGSS/LVECTS	2.95%	Line 4 / Line 8	2.95%	0.00%
12	GTS/TSS	11.82%	Line 5 / Line 8	11.82%	0.00%
13	DTS	7.02%	Line 6 / Line 8	7.02%	0.00%
14	FSS	2.00%	Line 7 / Line 8	2.00%	0.00%
15	Total	100.00%	∑ Line 9 thru 14	100.00%	0.00%
	Revenue Requirement by Rate Schedule				
16	GSS/ECTS - Residential	$ 52,371,453.42	Line 1 * Line 9	$ 52,523,063.29	$ 151,609.87
17	GSS/ECTS - Non Residential	10,632,959.24	Line 1 * Line 10	10,663,740.55	30,781.31
18	LVGSS/LVECTS	2,441,343.07	Line 1 * Line 11	2,448,410.51	7,067.44
19	GTS/TSS	9,776,332.97	Line 1 * Line 12	9,804,634.43	28,301.46
20	DTS	5,801,704.77	Line 1 * Line 13	5,818,500.10	16,795.33
21	FSS	1,655,253.34	Line 1 * Line 14	1,660,045.12	4,791.78
22	Total	$ 82,679,046.81	∑ Line 16 thru 21	$ 82,918,394.00	$ 239,347.19
	Number of Bills Issued/Mcfs				
23	GSS/ECTS - Residential (bills)	13,514,617	Schedule 11, Line 1	13,514,617	0
24	GSS/ECTS - Non Residential (bills)	963,937	Schedule 11, Line 2	963,937	0
25	LVGSS/LVECTS (bills)	47,414	Schedule 11, Line 3	47,414	0
26	GTS/TSS bills)	21,900	Schedule 11, Line 4	21,900	0
27	DTS (Mcf)	122,607,509	Schedule 11, Line 6	122,607,509	0
28	FSS (Mcf)	13,079,737	Schedule 11, Line 7	13,079,737	0
	Projected Impact per Bill/Mcf				
29	GSS/ECTS - Residential (per bill)	$ 3.88	Line 16 / Line 23	$ 3.89	$ 0.01
30	GSS/ECTS - Non Residential (per bill)	$ 11.03	Line 17 / Line 24	$ 11.06	$ 0.03
31	LVGSS/LVECTS (per bill)	$ 51.49	Line 18 / Line 25	$ 51.64	$ 0.15
32	GTS/TSS (per bill)	$ 446.41	Line 19 / Line 26	$ 447.70	$ 1.29
33	DTS (per Mcf)	$ 0.0473	Line 20 / Line 27	$ 0.0475	$ 0.0002
34	FSS (per Mcf)	$ 0.1266	Line 21 / Line 28	$ 0.1269	$ 0.0003

Notes:

[1] Total Plant in Service Allocators from the Company's base last rate case (Case No. 07-0829-GA-AIR, Schedule E 3.

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Revenue Requirement

Exhibit I
Schedule 2

Line No.	Description	Cumulative through 12/31/2018	Reference	As Filed	Change
	Return on Investment				
	Plant in Service				
1	Capital Additions	$ 720,959,980.46	Schedule 3, Line 4	$ 722,858,469.39	$ 1,898,488.93
2	Cost of Removal	(55,386,344.68)	Schedule 3, Line 5	(55,386,344.68)	-
3	Retirements	(52,678,594.21)	Schedule 3, Line 6	(52,678,594.21)	-
4	Total Plant in Service, Net	612,895,041.57	∑ Line 1 thru Line 3	614,793,530.50	1,898,488.93
	Less: Accumulated Provision for Depreciation				
5	Depreciation Expense	71,845,282.51	Schedule 3, Line 8	72,221,346.87	376,064.36
6	Cost of Removal	(55,386,344.68)	Schedule 3, Line 9	(55,386,344.68)	-
7	Retirements	(52,678,594.21)	Schedule 3, Line 10	(52,678,594.21)	-
8	Total Accumulated Provision for Depreciation, Net	(36,219,656.38)	∑ Line 5 thru Line 7	(35,843,592.02)	376,064.36
9	Subtotal: Net Capital Additions	649,114,697.95	Line 4 - Line 8	650,637,122.52	1,522,424.57
10	Depreciation Offset	(310,120,036.91)	Schedule 5, Line 16	(310,120,036.91)	-
11	Subtotal: Net Capital Additions Less Depreciation Offset	338,994,661.04	∑ Line 9, Line 10	340,517,085.61	1,522,424.57
	Regulatory Deferrals				
12	Post-In-Service Carrying Costs (PISCC)	110,533,469.05	Schedule 3, Line 16	110,632,426.65	98,957.60
13	Depreciation Expense	71,845,282.51	Schedule 3, Line 20	72,221,346.87	376,064.36
14	Property Tax Expense	21,715,976.84	Schedule 3, Line 24	21,422,461.84	(293,515.00)
15	Total Deferrals	204,094,728.40	∑ Line 12 thru Line 14	204,276,235.36	181,506.96
	Accumulated Deferred Income Tax (ADIT)				
16	ADIT on PISCC Deferral Balance	(23,212,028.50)	Line 12 * Tax Rate of 21%	(23,232,809.60)	(20,781.10)
17	ADIT on Liberalized Depreciation	(56,891,607.46)	Schedule 7, Line 10	(57,774,229.11)	(882,621.65)
18	ADIT on Property Tax Deferral Balance	(4,560,355.14)	Line 14 * Tax Rate of 21%	(4,498,716.99)	61,638.15
19	Total Deferred Income Tax	(84,663,991.10)	∑ Line 16 thru Line 18	(85,505,755.70)	(841,764.60)
20	Rate Base	458,425,398.34	∑ Line 11, 15 , 19	459,287,565.27	862,166.93
21	Pre-Tax Rate of Return	9.91%	Schedule 4, Line 8	9.91%	0.00%
22	Annualized Return on Rate Base	45,429,956.98	Line 20 * Line 21	45,515,397.72	85,440.74
	Operating Expenses				
23	Annualized Depreciation Expense	22,017,566.57	Schedule 8, Line 84	22,129,021.67	111,455.10
24	Annualized Property Tax Expense	8,475,987.75	Schedule 8, Line 84	8,512,431.22	36,443.47
25	Amortization of Deferred PISCC	3,658,657.83	Schedule 9, Line 6	3,661,933.32	3,275.50
26	Amortization of Deferred Depreciation Expense	2,378,078.85	Schedule 9, Line 7	2,390,526.58	12,447.73
27	Amortization of Deferred Property Tax Expense	718,798.83	Schedule 9, Line 8	709,083.49	(9,715.35)
28	Total Operating Expenses	37,249,089.83	∑ Line 23 thru 27	37,402,996.28	153,906.45
29	**Total Revenue Requirement**	**$ 82,679,046.81**	∑ Line 22, 28	**$ 82,918,394.00**	**$ 239,347.19**

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Annual Capital Investment and Deferral Summary

Exhibit I
Schedule 3

Line No.	Description	2011	2012	2013	2014	2015	2016	2017	2018	ADJUSTMENTS	Cumulative 12/31/18	As Filed Cumulative 12/31/18	Difference
	Capital Additions												
	Infrastructure Expansion,												
1	Improvement, or Replacement	$ 5,670,020.45	$ 41,867,555.54	$ 48,509,704.29	$ 57,509,921.93	$ 69,085,368.44	$ 78,783,108.28	$ 67,524,519.45	$ 91,824,169.09	$ (1,898,488.93)	$ 458,875,878.54	$ 460,774,367.47	1,898,488.93
2	Information Technology	4,288,880.99	17,755,743.62	5,751,975.37	8,913,187.77	5,061,519.54	5,016,167.35	5,540,168.51	9,225,162.51		61,552,805.66	61,552,805.66	-
3	Compliance / Operations	9,081,959.98	17,376,671.25	14,396,408.45	31,807,504.17	32,581,258.20	27,425,489.92	35,835,602.08	32,026,402.21		200,531,296.26	200,531,296.26	-
4	Total Capital Additions	19,040,861.42	76,999,970.41	68,658,088.11	98,230,613.87	106,728,146.18	111,224,765.55	108,900,290.04	133,075,733.81	(1,898,488.93)	720,959,980.46	722,858,469.39	1,898,488.93
5	Cost of Removal (COR)	(582,793.47)	(1,814,976.50)	(6,818,227.31)	(11,927,522.76)	(7,349,476.99)	(9,709,048.55)	(8,745,981.70)	(8,438,317.40)	-	(55,386,344.68)	(55,386,344.68)	-
6	Retirements	(130,692.41)	(11,240,446.49)	(4,457,630.81)	(8,266,085.29)	(8,225,515.81)	(9,214,688.52)	(5,906,102.01)	(5,237,432.87)	-	(52,678,594.21)	(52,678,594.21)	-
7	Total Capital Additions, Net COR ar	**18,327,375.54**	**63,944,547.42**	**57,382,229.99**	**78,037,005.82**	**91,153,153.38**	**92,301,028.48**	**94,248,206.33**	**119,399,983.54**	**(1,898,488.93)**	**612,895,041.57**	**614,793,530.50**	1,898,488.93
	Accumulated Provision for Depreciation												
8	Depreciation Expense	101,533.42	2,134,090.44	4,567,423.65	6,785,910.07	9,646,913.54	12,821,474.40	16,352,651.06	19,811,350.29	(376,064.36)	71,845,282.51	72,221,346.87	376,064.36
9	Cost of Removal	(582,793.47)	(1,814,976.50)	(6,818,227.31)	(11,927,522.76)	(7,349,476.99)	(9,709,048.55)	(8,745,981.70)	(8,438,317.40)	-	(55,386,344.68)	(55,386,344.68)	-
10	Retirements	(130,692.41)	(11,240,446.49)	(4,457,630.81)	(8,266,085.29)	(8,225,515.81)	(9,214,688.52)	(5,906,102.01)	(5,237,432.87)		(52,678,594.21)	(52,678,594.21)	-
11	Total Accumulated Provision for De	(611,952.46)	(10,921,332.55)	(6,708,434.47)	(13,407,697.98)	(5,928,079.26)	(6,102,262.67)	1,700,567.35	6,135,600.02	(376,064.36)	(36,219,656.38)	(35,843,592.02)	376,064.36
12	**Total Capital Additions, Net**	**$ 18,939,328.00**	**$ 74,865,879.97**	**$ 64,090,664.46**	**$ 91,444,703.80**	**$ 97,081,232.64**	**$ 98,403,291.15**	**$ 92,547,638.98**	**$ 113,264,383.52**	**$ (1,522,424.57)**	**$ 649,114,697.95**	**$ 650,637,122.52**	1,522,424.57
	Deferrals by Category												
	Post In-Service Carrying Costs (PISCC)												
	Infrastructure Expansion,												
13	Improvement, or Replacement	$ 21,655.86	$ 1,396,526.42	$ 3,654,440.45	$ 6,237,229.48	$ 9,461,697.60	$ 13,300,405.15	$ 17,090,876.71	$ 20,734,710.70	$ (98,957.60)	$ 71,798,584.77	$ 71,897,542.37	98,957.60
14	Information Technology	-	450,433.61	1,097,380.39	1,257,775.42	1,492,311.11	1,645,232.50	1,606,905.15	1,950,616.56		9,500,654.74	9,500,654.74	-
15	Compliance / Operations	24,646.89	809,521.46	1,545,400.37	2,329,552.25	3,744,821.85	5,354,017.93	7,216,471.15	8,209,797.64		29,234,229.54	29,234,229.54	-
16	Total PISCC Deferrals	46,302.75	2,656,481.49	6,297,221.21	9,824,557.15	14,698,830.56	20,299,655.58	25,914,253.01	30,895,124.90	(98,957.60)	110,533,469.05	110,632,426.65	98,957.60
	Depreciation Expense												
	Infrastructure Expansion,												
17	Improvement, or Replacement	27,614.75	767,771.39	1,595,438.53	2,614,513.92	3,934,381.80	5,427,894.55	6,944,107.48	8,558,572.45	(376,064.36)	29,494,230.51	29,870,294.87	376,064.36
18	Information Technology	39,290.41	893,725.86	1,847,166.11	2,298,887.85	2,898,942.58	3,422,104.41	3,693,500.94	4,604,372.63		19,697,990.79	19,697,990.79	-
19	Compliance / Operations	34,628.26	472,593.19	1,124,819.01	1,872,508.30	2,813,589.16	3,971,475.44	5,715,042.64	6,648,405.21		22,653,061.21	22,653,061.21	-
20	Total Depreciation Expense Deferra	101,533.42	2,134,090.44	4,567,423.65	6,785,910.07	9,646,913.54	12,821,474.40	16,352,651.06	19,811,350.29	(376,064.36)	71,845,282.51	72,221,346.87	376,064.36
	Property Tax Expense												
	Infrastructure Expansion,												
21	Improvement, or Replacement	-	55,496.20	514,792.46	1,026,146.76	1,655,006.07	2,450,674.20	3,385,595.16	4,282,476.48	293,515.00	13,663,702.33	13,370,187.33	(293,515.00)
22	Information Technology	-	46,294.18	194,226.96	269,478.48	361,239.98	424,221.24	481,087.80	567,220.44		2,343,769.08	2,343,769.08	-
23	Compliance / Operations	-	96,035.31	238,835.40	376,174.63	697,927.32	1,041,250.44	1,383,507.24	1,874,775.09		5,708,505.43	5,708,505.43	-
24	Total Property Tax Expense Deferra	-	197,825.69	947,854.82	1,671,799.87	2,714,173.37	3,916,145.88	5,250,190.20	6,724,472.01	293,515.00	21,715,976.84	21,422,461.84	(293,515.00)
	Total Deferrals												
	Infrastructure Expansion,												
25	Improvement, or Replacement	49,270.61	2,219,794.01	5,764,671.44	9,877,890.16	15,051,085.47	21,178,973.90	27,420,579.35	33,575,759.63	(181,506.96)	114,956,517.61	115,138,024.57	181,506.96
26	Information Technology	39,290.41	1,390,453.65	3,138,773.46	3,826,141.75	4,752,493.67	5,491,558.15	5,781,493.89	7,122,209.63	-	31,542,414.61	31,542,414.61	-
27	Compliance / Operations	59,275.15	1,378,149.96	2,909,054.78	4,578,235.18	7,256,338.33	10,366,743.81	14,315,021.03	16,732,977.94	-	57,595,796.18	57,595,796.18	-
28	**Total Deferrals**	**$ 147,836.17**	**$ 4,988,397.62**	**$ 11,812,499.68**	**$ 18,282,267.09**	**$ 27,059,917.47**	**$ 37,037,275.86**	**$ 47,517,094.27**	**$ 57,430,947.20**	**$ (181,506.96)**	**$ 204,094,728.40**	**$ 204,276,235.36**	181,506.96
29	Reduction for Incremental Rever	-	-	-	-	-	-	-	-		-	-	-
30	**Deferred Costs, Net**	**$ 147,836.17**	**$ 4,988,397.62**	**$ 11,812,499.68**	**$ 18,282,267.09**	**$ 27,059,917.47**	**$ 37,037,275.86**	**$ 47,517,094.27**	**$ 57,430,947.20**	**$ (181,506.96)**	**$ 204,094,728.40**	**$ 204,276,235.36**	181,506.96

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Rate of Return on Rate Base

Exhibit I
Schedule 4

Line No.		
1	Capital Structure	
2	Debt	48.66%
3	Equity	51.34%
4	Cost of Capital	
5	Debt	6.50%
6	Equity	10.38%
7	Return on Rate Base	8.49%
8	Return on Rate Base using Pre-Tax Equity[1]	9.91%

Notes:

[1] The pre-tax rate of return reflects the federal income tax rate of 21% in accordance with the Tax Cuts and Jobs Act of 2017.

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Calculation of Depreciation Offset

Exhibit I
Schedule 5

Line No.	Description	Base Rate Case 3/31/07	Reference
1	Plant in Service	$ 1,916,133,980.70	Case No. 07-0829-GA-AIR, Schedule B 2
2	Annualized Depreciation	48,908,074.10	Case No. 07-0829-GA-AIR, Schedule C 3.26
3	Composite Depreciation Rate	2.55%	Line 2 / Line 1

	Year	Plant in Service	Total Retirements, Net PIR Retirements	Plant in Service, Net Retirements	Annual Depreciation	Accumulated Depreciation Offset[1]
	[A]	[B]	[C]	[D]	[E]	[F]
	Reference :		Schedule 6, Column E	Column B - C	Column D * Line 3	Column E
4	2007	$ 1,916,133,980.70	$ 10,902,162.75	$ 1,905,231,817.95	$ -	$ -
5	2008	1,905,231,817.95	23,690,712.81	1,881,541,105.14	48,025,113.44	-
6	2009	1,881,541,105.14	6,507,828.47	1,875,033,276.67	47,859,005.35	-
7	2010	1,875,033,276.67	11,340,654.06	1,863,692,622.61	47,569,542.53	-
8	2011	1,863,692,622.61	16,217,167.37	1,847,475,455.24	47,155,609.88	11,788,902.47
9	2012	1,847,475,455.24	55,897,126.64	1,791,578,328.60	45,728,872.06	45,728,872.06
10	2013	1,791,578,328.60	59,598,659.41	1,731,979,669.19	44,207,655.02	44,207,655.02
11	2014	1,731,979,669.19	32,571,729.67	1,699,407,939.52	43,376,282.80	43,376,282.80
12	2015	1,699,407,939.52	11,030,717.13	1,688,377,222.39	43,094,730.92	43,094,730.92
13	2016	1,688,377,222.39	84,407,232.89	1,603,969,989.50	40,940,291.18	40,940,291.18
14	2017	1,603,969,989.50	12,054,435.90	1,591,915,553.60	40,632,609.54	40,632,609.54
15	2018	1,591,915,553.60	11,045,006.51	1,580,870,547.09	40,350,692.93	40,350,692.93
16	Cumulative Depreciation Offset (October 2011 - December 2018)					$ 310,120,036.91

Notes:

[1] Depreciation offset to begin at CEP program inception (October 2011). Year 2011 accumulated depreciation offset is equal to 25% of 2011 annual depreciation.

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Total Company Retirements Net of PIR Retirements for Depreciation Offset Calculation

Exhibit I
Schedule 6

Line No.	Year	Total Retirements, Net of ARO	PIR Retirements	Retirements, Net of PIR Retirements
	[A]	[B]	[C]	[D] = [B+C]
1	2007	$ 10,902,162.75	$ -	$ 10,902,162.75
2	2008	24,657,498.43	(966,785.62)	$ 23,690,712.81
3	2009	9,950,975.73	(3,443,147.26)	$ 6,507,828.47
4	2010	18,489,899.82	(7,149,245.76)	$ 11,340,654.06
5	2011	22,751,674.78	(6,534,507.41)	$ 16,217,167.37
6	2012	63,665,445.55	(7,768,318.91)	$ 55,897,126.64
7	2013	64,010,764.80	(4,412,105.39)	$ 59,598,659.41
8	2014	38,474,160.49	(5,902,430.82)	$ 32,571,729.67
9	2015	19,500,302.65	(8,469,585.52)	$ 11,030,717.13
10	2016	92,435,391.40	(8,028,158.51)	$ 84,407,232.89
11	2017	20,632,467.00	(8,578,031.10)	$ 12,054,435.90
12	2018	25,451,092.57	(14,406,086.06)	$ 11,045,006.51
13	Total	$ 410,921,835.97	$ (75,658,402.36)	$ 335,263,433.61

Notes:

Column A: March 31, 2007 is the date certain of the last base rate case. Year 2007 retirements are estimated at 75% of full year, representing post rate case retirements (April - December).

Column B: Total DEO Utility Plant in Service Retirements Net of Asset Retirement Obligations (ARO), which are not included in rate base. These values are based on the Company's Annual Reports filed with the Commission.

Column C: Retirements per annual PIR application filed with the Commission.

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Accumulated Deferred Income Tax (ADIT) on Liberalized Depreciation

Line No.	Description	Cumulative through 12/31/2018	Exhibit I Schedule 7 Reference	As Filed Cumulative through 12/31/2018	Adjustment #8 Impact	Adjustment #8 Updated Values	Adjustment #1-7 Impact	Cumulative through 12/31/2018
	Book Value							
1	Original Cost (Plant less COR less Retirements)	$ 612,895,041.57	Schedule 3, Line 7	$ 614,793,530.50	$ -	$ 614,793,530.50	$ (1,898,488.93)	$ 612,895,041.57
2	Book Depreciation	(71,845,282.51)	Schedule 3, Line 8	(72,221,346.87)	-	(72,221,346.87)	376,064.36	(71,845,282.51)
3	Net Book Value	541,049,759.06	∑ Lines 1, 2	542,572,183.63	-	542,572,183.63	(1,522,424.57)	541,049,759.06
	Tax Value							
4	Original Cost (Plant less COR less Retirements)	612,895,041.57	Line 1	614,793,530.50	-	614,793,530.50	(1,898,488.93)	612,895,041.57
	AFUDC Debt	(1,539,103.00)			(1,539,103.00)	(1,539,103.00)	-	(1,539,103.00)
	AFUDC Equity	(942,434.00)			(942,434.00)	(942,434.00)	-	(942,434.00)
	Bonus Depreciation	(247,027,452.00)			(247,027,452.00)	(247,027,452.00)	-	(247,027,452.00)
5	Tax Depreciation	489,483.00	Company's Tax Records	(354,774,779.24)	354,774,779.24	-	489,483.00	489,483.00
6	Capitalized Interest	7,438,054.00	Company's Tax Records	7,438,055.64	(1.64)	7,438,054.00	-	7,438,054.00
	In-house Software Depreciation	(19,316,850.00)			(19,316,850.00)	(19,316,850.00)	-	(19,316,850.00)
	Other Tax Depreciation	(81,859,397.00)			(81,859,397.00)	(81,859,397.00)	-	(81,859,397.00)
7	Total Tax Reduction	(342,757,699.00)	∑ Lines 5, 6	(347,336,723.60)	4,089,541.60	(343,247,182.00)	489,483.00	(342,757,699.00)
8	Net Tax Value	270,137,342.57	∑ Lines 4, 7	267,456,806.90	4,089,541.60	271,546,348.50	(1,409,005.93)	270,137,342.57
					-			
9	Net Tax Value minus Net Book Value	(270,912,416.49)	Line 8 - Line 3	(275,115,376.73)	4,089,541.60	(271,025,835.13)	113,418.64	(270,912,416.49)
					$ -			
10	ADIT @ 21%	$ (56,891,607.46)	Line 9 * 21%	$ (57,774,229.11)	$ 858,803.74	$ (56,915,425.38)	$ 23,817.91	$ (56,891,607.46)

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Annualized Depreciation and Property Tax Expense

Exhibit I
Schedule 8
Page 1 of 2

Line No.	Description	FERC	Depr Rate	Cumulative Plant Less COR Less Retirements through 12/31/2018	Annualized Depreciation Expense	Annualized Property Tax Expense	As Filed: Cumulative Plant Less COR Less Retirements through 12/31/2018	As Filed: Annualized Depreciation Expense	As Filed: Annualized Property Tax Expense
	Infrastructure Expansion, Improvement, or Replacement					@ 2018 Effective Rate			@ 2018 Effective Ra
	Production/Gathering					1.3846%			1.3846%
1	Rights of Way	325.41	1.25%	$ 16,607.24	$ 207.59	$ 229.94	$ 16,607.24	$ 207.59	$ 229.94
2	Field Compressor Station Structures	327.01	4.08%	4,565.19	186.26	63.21	4,565.19	186.26	63.21
3	Field M&R Station Structures	328.01	3.50%	58,231.15	2,038.09	806.27	58,231.15	2,038.09	806.27
4	Other Structures	329.01	1.67%	5,735.83	95.79	79.42	5,735.83	95.79	79.42
5	Producing Gas Wells Well Equipment	331.01	2.20%	110,367.24	2,428.08	1,528.14	110,367.24	2,428.08	1,528.14
6	Field Lines	332.01	1.60%	10,802,144.21	172,834.31	149,566.49	10,802,144.21	172,834.31	149,566.49
7	Field Compressor Station Equipment	333.01	3.06%	5,429,130.57	166,131.40	75,171.74	5,429,130.57	166,131.40	75,171.74
8	Field M&R Station Equipment - Meters and Gaug	334.11	4.20%	254,455.57	10,687.13	3,523.19	254,455.57	10,687.13	3,523.19
9	Field M&R Station Equipment - Other	334.12	3.91%	3,942,857.98	154,165.75	54,592.81	3,942,857.98	154,165.75	54,592.81
10	Total Production/Gathering			20,624,094.98	508,774.39	285,561.22	20,624,094.98	508,774.39	285,561.22
	Storage								
11	Structures & Improvements - Compressor Statior	351.02	1.92%	1,783,804.07	34,249.04	24,698.55	1,783,804.07	34,249.04	24,698.55
12	Structures & Improvements - M&R Station Struct	351.03	1.72%	610,869.05	10,506.95	8,458.09	610,869.05	10,506.95	8,458.09
13	Structures & Improvements - Other Structures	351.04	2.67%	507,135.34	13,540.51	7,021.80	507,135.34	13,540.51	7,021.80
14	Wells - Well Construction	352.01	1.43%	6,874,365.49	98,303.43	95,182.46	6,874,365.49	98,303.43	95,182.46
15	Wells - Well Equipment	352.02	1.54%	44,593.12	686.73	617.44	44,593.12	686.73	617.44
16	Lines	353.01	2.50%	23,899,786.72	597,494.67	330,916.45	23,948,554.72	598,713.87	331,591.69
17	Compressor Station Equipment	354.01	3.33%	17,619,041.36	586,714.08	243,953.25	17,619,041.36	586,714.08	243,953.25
18	M&R Equipment - Other	355.02	2.60%	13,070,346.01	339,829.00	180,972.01	13,070,346.01	339,829.00	180,972.01
19	Other Equipment	357.00	6.67%	298,115.50	19,884.30	4,127.71	298,115.50	19,884.30	4,127.71
20	Total Storage			64,708,056.66	1,701,208.71	895,947.75	64,756,824.66	1,702,427.91	896,622.99
	Transmission								
21	Structures & Improvements - M&R Station Struct	366.02	1.33%	567,376.95	7,546.11	7,855.90	567,376.95	7,546.11	7,855.90
22	Structures & Improvements - Other Structures	366.03	2.13%	15,858.73	337.79	219.58	15,858.73	337.79	219.58
23	Mains	367.01	1.85%	14,735,514.94	272,607.03	204,027.94	14,735,514.94	272,607.03	204,027.94
24	Compressor Station Equipment	368.01	3.23%	2,260,257.71	73,006.32	31,295.53	2,260,257.71	73,006.32	31,295.53
25	M&R Station Equipment - Meters & Gauges	369.02	4.04%	258,315.66	10,435.95	3,576.64	258,315.66	10,435.95	3,576.64
26	M&R Station Equipment - Other	369.03	2.10%	17,065,151.63	358,368.18	236,284.09	17,798,721.63	373,773.15	246,441.10
27	Other Equipment	371.03	1.67%	124,374.63	2,077.06	1,722.09	124,374.63	2,077.06	1,722.09
28	Total Transmission			35,026,850.25	724,378.45	484,981.77	35,760,420.25	739,783.42	495,138.78
	Distribution								
29	M&R Station Structures - General	375.01	1.66%	218,937.42	3,634.36	3,031.41	300,573.42	4,989.52	4,161.74
30	M&R Station Structures - Industrial	375.02	1.67%	38.35	0.64	0.53	38.35	0.64	0.53
31	Lines, Relocations and Betterments	376.01	1.71%	113,256,863.90	1,936,692.37	1,568,154.54	113,256,863.90	1,936,692.37	1,568,154.54
32	M&R Station Equipment - Other	378.02	2.35%	8,454,435.98	198,679.25	117,060.12	8,454,435.98	198,679.25	117,060.12
33	Services - LP & RP	380.00	3.43%	26,583,550.39	911,815.78	368,075.84	26,583,550.39	911,815.78	368,075.84
34	Industrial M&R Station Equipment - Meters	385.01	2.27%	29,352.59	666.30	406.42	29,352.59	666.30	406.42
35	Industrial M&R Station Equipment - Other	385.03	2.62%	617,144.99	16,169.20	8,544.99	617,144.99	16,169.20	8,544.99
36	Total Distribution			149,160,323.62	3,067,657.90	2,065,273.84	149,241,959.62	3,069,013.06	2,066,404.17
	Distribution - New Customer Facilities								
37	NCF New Mainlines	376.01	1.71%	35,929,194.56	614,389.23	497,475.63	35,929,194.56	614,389.23	497,475.63
38	NCF Services	380.00	3.43%	83,722,230.89	2,871,672.52	1,159,218.01	83,722,230.89	2,871,672.52	1,159,218.01
39	NCF New Meter Installations	382.00	2.63%	7,494,124.68	197,095.48	103,763.65	7,494,124.68	197,095.48	103,763.65
40	Total NCF			127,145,550.13	3,683,157.23	1,760,457.29	127,145,550.13	3,683,157.23	1,760,457.29
41	Total Category [1]			396,664,875.64	9,685,176.67	5,492,221.87	397,528,849.64	9,703,156.00	5,504,184.45
	Information Technology								
42	IT Software	303.03	10.00%	39,196,592.70	3,919,659.27	542,716.02	39,195,550.70	3,919,555.07	542,701.59
43	Communications Equipment	397.01	10.00%	6,018,849.07	601,884.91	83,336.98	6,018,849.07	601,884.91	83,336.98
44	IT Software - CCS	399.01	6.67%	5,491,223.51	366,264.61	76,031.48	5,798,030.51	386,728.64	80,279.53
45	Total Category [2]			50,706,665.28	4,887,808.79	702,084.49	51,012,430.28	4,908,168.61	706,318.11

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Annualized Depreciation and Property Tax Expense

Line No.	Description	FERC	Depr Rate	Cumulative Plant Less COR Less Retirements through	Annualized Depreciation Expense	Annualized Property Tax Expense	Exhibit I Schedule 8 Page 2 of 2 As Filed Cumulative Plant Less COR Less Retirements through	Annualized Depreciation Expense	Exhibit I Schedule 8 Page 2 of 2 Annualized Property Tax Expense
	Compliance / Operations					@ 2018 Effective Rate			@ 2018 Effective Ra
	Distribution					1.3846%			1.3846%
46	Land & Land Rights - Rights of Way	374.04	1.33%	16,256.48	216.21	225.09	16,256.48	216.21	225.09
47	M&R Station Structures - General	375.01	1.66%	775,506.91	12,873.41	10,737.67	775,506.91	12,873.41	10,737.67
48	M&R Station Structures - Industrial	375.02	1.67%	7,137.26	119.19	98.82	7,137.26	119.19	98.82
49	Other Structures	375.03	2.18%	4,257,181.15	92,806.55	58,944.93	4,257,181.15	92,806.55	58,944.93
50	Lines, Relocations and Betterments	376.01	1.71%	1,549,239.41	26,491.99	21,450.77	1,549,239.41	26,491.99	21,450.77
51	M&R Station Equipment - Other	378.02	2.35%	2,014,316.16	47,336.43	27,890.22	2,014,316.16	47,336.43	27,890.22
52	Services - LP & RP	380	3.43%	137,683.82	4,722.56	1,906.37	137,683.82	4,722.56	1,906.37
53	Meters	381.01	3.33%	12,793,961.07	426,038.90	177,145.18	12,793,961.07	426,038.90	177,145.18
54	Meters - Recording Gauges	381.02	10.00%	4,397,694.43	439,769.44	60,890.48	4,397,694.43	439,769.44	60,890.48
55	Meters - ERT Modules	381.04	6.67%	5,591,773.28	372,971.28	77,423.69	5,591,773.28	372,971.28	77,423.69
56	Meter Installations	382.00	2.63%	8,391,927.89	220,707.70	116,194.63	8,391,927.89	220,707.70	116,194.63
57	Meter Installations ERT Modules	382.04	6.67%	128,699.52	8,584.26	1,781.97	128,699.52	8,584.26	1,781.97
58	House Regulators - Small	383.01	4.00%	288,762.04	11,550.48	3,998.20	288,762.04	11,550.48	3,998.20
59	House Regulators - Large	383.02	4.00%	678,779.68	27,151.19	9,398.38	678,779.68	27,151.19	9,398.38
60	House Regulator Installation	384.01	2.86%	112,634.32	3,221.34	1,559.53	112,634.32	3,221.34	1,559.53
61	Industrial M&R Station Equipment - Other	385.03	2.62%	407,503.12	10,676.58	5,642.29	407,503.12	10,676.58	5,642.29
62	Other Equipment	387.01	4.55%	679,477.24	30,916.21	9,408.04	679,477.24	30,916.21	9,408.04
63	Total Distribution			42,228,533.78	1,736,153.74	584,696.28	42,228,533.78	1,736,153.74	584,696.28
	Pipeline Integrity								
64	Production & Gathering - Field Lines	332.01	1.60%	259,940.87	4,159.05	3,599.14	259,940.87	4,159.05	3,599.14
65	Storage Lines	353.01	2.50%	2,704,540.48	67,613.51	37,447.07	2,704,540.48	67,613.51	37,447.07
66	Storage M&R Equipment - Other	355.02	2.60%	39,515.97	1,027.42	547.14	39,515.97	1,027.42	547.14
67	Transmission - M&R Station Structures	366.02	1.33%	55,759.49	741.60	772.05	55,759.49	741.60	772.05
68	Transmission Mains	367.01	1.85%	21,566,801.99	398,985.84	298,613.94	21,566,801.99	398,985.84	298,613.94
69	Transmission M&R Station Equipment - Other	369.03	2.10%	1,959,786.55	41,155.52	27,135.20	1,959,786.55	41,155.52	27,135.20
70	Total Pipeline Integrity			26,586,345.35	513,682.94	368,114.54	26,586,345.35	513,682.94	368,114.54
	General Plant/Facilities								
71	Land & Land Rights	389.01	0.00%	2,785,508.55	-	38,568.15	2,785,508.55	-	38,568.15
72	Structures & Improvements - Main Office	390.02	5.00%	48,474.48	2,423.72	671.18	48,474.48	2,423.72	671.18
73	Structures & Improvements - Other	390.05	5.00%	74,669,026.07	3,733,451.30	1,033,867.33	76,131,345.07	3,806,567.25	1,054,114.60
74	Office Furniture & Equipment - Furniture	391.01	5.00%	2,315,282.69	115,764.13	32,057.40	2,315,282.69	115,764.13	32,057.40
75	Office Furniture & Equipment - Computer Hardw	391.02	20.00%	2,349,566.67	469,913.33	32,532.10	2,349,566.67	469,913.33	32,532.10
76	Office Furniture & Equipment - Equipment	391.03	10.00%	1,103,977.72	110,397.77	15,285.68	1,103,977.72	110,397.77	15,285.68
77	Transportation Equipment - Trailers	392.03	5.17%	766,975.29	39,652.62	10,619.54	766,975.29	39,652.62	10,619.54
78	Stores Equipment	393.01	5.00%	79,855.00	3,992.75	1,105.67	79,855.00	3,992.75	1,105.67
79	Tools, Shop & Garage Equipment	394.01	5.00%	4,821,728.20	241,086.41	66,761.65	4,821,728.20	241,086.41	66,761.65
80	Power Operated Equipment	396.01	7.00%	2,682,033.63	187,742.35	37,135.44	2,682,033.63	187,742.35	37,135.44
81	Miscellaneous Equipment	398.01	6.67%	4,352,624.15	290,320.03	60,266.43	4,352,624.15	290,320.03	60,266.43
82	Total General Plant / Facilities			95,975,052.45	5,194,744.44	1,328,870.58	97,437,371.45	5,267,860.39	1,349,117.85
83	Total Category [3]			164,789,931.58	7,444,581.11	2,281,681.39	166,252,250.58	7,517,697.06	2,301,928.66
84	Total Capital (Categories 1-3)			$ 612,161,472.50	$ 22,017,566.57	$ 8,475,987.75	$ 614,793,530.50	$ 22,129,021.67	$ 8,512,431.22
				612,895,041.57 Sch 2			**614,793,530.50** Sch 2		

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Annual Amortization of Deferrals

Exhibit I
Schedule 9

Line No.	Description	Cumulative Balance through 12/31/2018	Reference	As Filed	Difference
	Deferral Balance				
1	PISCC	$ 110,533,469.05	Schedule 3, Line 16	$ 110,632,426.65	$ 98,957.60
2	Depreciation Expense	71,845,282.51	Schedule 3, Line 20	72,221,346.87	376,064.36
3	Property Tax Expense	21,715,976.84	Schedule 3, Line 24	21,422,461.84	(293,515.00)
4	Total	$ 204,094,728.40	∑ Line 1 thru Line 3	$ 204,276,235.36	$ 181,506.96
5	Composite Life Amortization Rate	3.31%	Schedule 10, Line 87	3.31%	0.00%
	Annual Amortization				
6	PISCC	$ 3,658,657.83	Line 1 * Line 5	$ 3,661,933.32	$ 3,275.50
7	Depreciation Expense	2,378,078.85	Line 2 * Line 5	2,390,526.58	12,447.73
8	Property Tax Expense	718,798.83	Line 3 * Line 5	709,083.49	(9,715.35)
9	Total	$ 6,755,535.51	∑ Line 6 thru Line 8	$ 6,761,543.39	$ 6,007.88

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Calculation of Composite Asset Life Amortization Rate

Line No.	Description	SAP FERC	Asset Life	Cumulative Plant Less COR Less Retirements through 12/31/2018	Asset Weighting	Weighted Average [1]
	Infrastructure Expansion, Improvement, or Replacement					
	Production/Gathering					
1	Rights of Way	325.41	1.25%	$ 16,607.24	0.00%	0.00%
2	Field Compressor Station Structures	327.01	4.00%	4,565.19	0.00%	0.00%
3	Field M&R Station Structures	328.01	3.33%	58,231.15	0.01%	0.00%
4	Other Structures	329.01	1.67%	5,735.83	0.00%	0.00%
5	Producing Gas Wells Well Equipment	331.01	2.00%	110,367.24	0.02%	0.00%
6	Field Lines	332.01	1.33%	10,802,144.21	1.77%	0.02%
7	Field Compressor Station Equipment	333.01	3.03%	5,429,130.57	0.89%	0.03%
8	Field M&R Station Equipment - Meters and Gauges	334.11	4.00%	254,455.57	0.04%	0.00%
9	Field M&R Station Equipment - Other	334.12	2.94%	3,942,857.98	0.64%	0.02%
10	Total Production/Gathering			20,624,094.98		
	Storage					
11	Structures & Improvements - Compressor Station Structures	351.02	1.92%	1,783,804.07	0.29%	0.01%
12	Structures & Improvements - M&R Station Structures	351.03	1.64%	610,869.05	0.10%	0.00%
13	Structures & Improvements - Other Structures	351.04	2.22%	507,135.34	0.08%	0.00%
14	Wells - Well Construction	352.01	1.43%	6,874,365.49	1.12%	0.02%
15	Wells - Well Equipment	352.02	1.43%	44,593.12	0.01%	0.00%
16	Lines	353.01	1.67%	23,948,554.72	3.91%	0.07%
17	Compressor Station Equipment	354.01	2.17%	17,619,041.36	2.88%	0.06%
18	M&R Equipment - Other	355.02	1.82%	13,070,346.01	2.14%	0.04%
19	Other Equipment	357.00	6.67%	298,115.50	0.05%	0.00%
20	Total Storage			64,756,824.66		
	Transmission					
21	Structures & Improvements - M&R Station Structures	366.02	1.33%	567,376.95	0.09%	0.00%
22	Structures & Improvements - Other Structures	366.03	2.13%	15,858.73	0.00%	0.00%
23	Mains	367.01	1.54%	14,735,514.94	2.41%	0.04%
24	Compressor Station Equipment	368.01	3.23%	2,260,257.71	0.37%	0.01%
25	M&R Station Equipment - Meters & Gauges	369.02	4.00%	258,315.66	0.04%	0.00%
26	M&R Station Equipment - Other	369.03	1.67%	17,798,721.63	2.91%	0.05%
27	Other Equipment	371.03	1.67%	124,374.63	0.02%	0.00%
28	Total Transmission			35,760,420.25		
	Distribution					
29	M&R Station Structures - General	375.01	1.43%	300,573.42	0.05%	0.00%
30	M&R Station Structures - Industrial	375.02	1.67%	38.35	0.00%	0.00%
31	Lines, Relocations and Betterments	376.01	1.43%	113,256,863.90	18.51%	0.26%
32	M&R Station Equipment - Other	378.02	1.54%	8,454,435.98	1.38%	0.02%
33	Services - LP & RP	380.00	2.86%	26,583,550.39	4.34%	0.12%
34	Industrial M&R Station Equipment - Meters	385.01	2.22%	29,352.59	0.00%	0.00%
35	Industrial M&R Station Equipment - Other	385.03	2.22%	617,144.99	0.10%	0.00%
36	Total Distribution			149,241,959.62		
	Distribution - New Customer Facilities					
37	NCF New Mainlines	376.01	1.43%	35,929,194.56	5.87%	0.08%
38	NCF Services	380.00	2.86%	83,722,230.89	13.68%	0.39%
39	NCF New Meter Installations	382.00	2.63%	7,494,124.68	1.22%	0.03%
40	Total NCF			127,145,550.13		
41	Total Category [1]			397,528,849.64		
	Information Technology					
42	IT Software	303.03	10.00%	39,195,550.70	6.40%	0.64%
43	Communications Equipment	397.01	10.00%	6,018,849.07	0.98%	0.10%
44	IT Software - CCS	399.01	6.67%	5,798,030.51	0.95%	0.06%
45	Total Category [2]			51,012,430.28		

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Calculation of Composite Asset Life Amortization Rate

No.	Description	SAP FERC	Asset Life	Cumulative Plant Less COR Less Retirements through 12/31/2018	Asset Weighting	Weighted Average [1]
	Compliance / Operations					
	Distribution					
46	Land & Land Rights - Rights of Way	374.04	1.33%	16,256.48	0.00%	0.00%
47	M&R Station Structures - General	375.01	1.43%	775,506.91	0.13%	0.00%
48	M&R Station Structures - Industrial	375.02	1.67%	7,137.26	0.00%	0.00%
49	Other Structures	375.03	1.43%	4,257,181.15	0.70%	0.01%
50	Lines, Relocations and Betterments	376.01	1.43%	1,549,239.41	0.25%	0.00%
51	M&R Station Equipment - Other	378.02	1.54%	2,014,316.16	0.33%	0.01%
52	Services - LP & RP	380.00	2.86%	137,683.82	0.02%	0.00%
53	Meters	381.01	3.33%	12,793,961.07	2.09%	0.07%
54	Meters - Recording Gauges	381.02	10.00%	4,397,694.43	0.72%	0.07%
55	Meters - ERT Modules	381.04	6.67%	5,591,773.28	0.91%	0.06%
56	Meter Installations	382.00	2.63%	8,391,927.89	1.37%	0.04%
57	Meter Installations ERT Modules	382.04	6.67%	128,699.52	0.02%	0.00%
58	House Regulators - Small	383.01	4.00%	288,762.04	0.05%	0.00%
59	House Regulators - Large	383.02	4.00%	678,779.68	0.11%	0.00%
60	House Regulator Installation	384.01	2.86%	112,634.32	0.02%	0.00%
61	Industrial M&R Station Equipment - Other	385.03	2.22%	407,503.12	0.07%	0.00%
62	Other Equipment	387.01	4.55%	679,477.24	0.11%	0.01%
63	Total Distribution			42,228,533.78		
	Pipeline Integrity					
64	Production & Gathering - Field Lines	332.01	1.33%	259,940.87	0.04%	0.00%
65	Storage Lines	353.01	1.67%	2,704,540.48	0.44%	0.01%
66	Storage M&R Equipment - Other	355.02	1.82%	39,515.97	0.01%	0.00%
67	Transmission - M&R Station Structures	366.02	1.33%	55,759.49	0.01%	0.00%
68	Transmission Mains	367.01	1.54%	21,566,801.99	3.52%	0.05%
69	Transmission M&R Station Equipment - Other	369.03	1.67%	1,959,786.55	0.32%	0.01%
70	Total Pipeline Integrity			26,586,345.35		
	General Plant/Facilities					
71	Land & Land Rights	389.01	0.00%	2,785,508.55		
72	Structures & Improvements - Main Office	390.02	5.00%	48,474.48	0.01%	0.00%
73	Structures & Improvements - Other	390.05	5.00%	76,131,345.07	12.44%	0.62%
74	Office Furniture & Equipment - Furniture	391.01	5.00%	2,315,282.69	0.38%	0.02%
75	Office Furniture & Equipment - Computer Hardware	391.02	20.00%	2,349,566.67	0.38%	0.08%
76	Office Furniture & Equipment - Equipment	391.03	10.00%	1,103,977.72	0.18%	0.02%
77	Transportation Equipment - Trailers	392.03	8.33%	766,975.29	0.13%	0.01%
78	Stores Equipment	393.01	5.00%	79,855.00	0.01%	0.00%
79	Tools, Shop & Garage Equipment	394.01	5.00%	4,821,728.20	0.79%	0.04%
80	Power Operated Equipment	396.01	10.00%	2,682,033.63	0.44%	0.04%
81	Miscellaneous Equipment	398.01	6.67%	4,352,624.15	0.71%	0.05%
82	Total General Plant / Facilities			97,437,371.45		
83	Total Category [3]			166,252,250.58		
84	Total Capital (Categories 1-3)			614,793,530.50		
85	Non-Depreciable Assets					
86	Land & Land Rights			(2,785,508.55)		
87	Total Depreciable Assets			$ 612,008,021.95	100.00%	3.31%

Notes: [1] Excluded land from calculation since it does not have a depreciable life.

THE EAST OHIO GAS COMPANY d/b/a DOMINION ENERGY OHIO
Capital Expenditure Program (CEP) Rider
Case No. 19-0468-GA-ALT
Actual Bills Issued and DTS Volumes for the Twelve Months Ended December 31, 2018
and Maximum Storage Capacity Volumes for the 2018/2019 Season

Exhibit I
Schedule 11

Line No.	Customer Class	Billing System CCS	Billing System SBS	Total
1	GSS / ECTS - Residential	13,514,617	-	13,514,617
2	GSS / ECTS - Non-Residential	962,441	1,496	963,937
3	LVGSS / LVECTS	45,520	1,894	47,414
4	GTS / TSS	14,076	7,824	21,900
5	Total Bills	14,536,654	11,214	14,547,868
6	DTS Volumes			122,607,509
7	FSS Volumes [1]			13,079,737

Notes:

[1] Total Maximum Storage Capacity volumes contracted from April 1, 2018 - March 31, 2019.

Summary: Report Plant in Service and Capital Spending Audit Of The East Ohio Gas Company d/b/a Dominion Energy Ohio electronically filed by Mrs. Tracy M Klaes on behalf of Blue Ridge Consulting Services, Inc