# PLANT IN SERVICE AND CAPITAL SPENDING PRUDENCE AUDIT OF DUKE ENERGY OHIO, INC. (NATURAL GAS) COVERING THE PERIOD APRIL 1, 2012 THROUGH DECEMBER 31, 2018

Case No.19-0791-GA-ALT

May 11, 2020

***Prepared for:***
***PUBLIC UTILITIES COMMISSION OF OHIO***
***180 EAST BROAD STREET***
***COLUMBUS, OH 43215-3793***

***Prepared by:***


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|---|---|
| ***LARKIN & ASSOCIATES PLLC***<br>***15728 FARMINGTON ROAD***<br>***LIVONIA, MI 48154***<br>***(734) 522–3420*** | |

# TABLE OF CONTENTS

**1 TRANSMITTAL LETTER/DISCLAIMER ........ 1-1**

**2 EXECUTIVE SUMMARY/SUMMARY OF FINDINGS AND RECOMMENDATIONS ........ 2-1**

Background to the Capital Expenditure Program ........ 2-1
Project Requirements and Related Summary Conclusions ........ 2-2
Part 1 - Plant In-Service Balances ........ 2-2
Part 2 - Capital Expenditures Prudence Audit ........ 2-3
Interviews ........ 2-17
Audit Report Outline ........ 2-18

**3 DUKE ENERGY OHIO BACKGROUND ........ 3-1**

Overview ........ 3-1

**4 CAPITAL EXPENDITURE PROGRAM ........ 4-1**

**5 FINANCIAL REVIEW- OVERVIEW ........ 5-1**

Capital Expenditure Program – Duke Calculated Revenue Requirement ........ 5-1

**6 DETAILED ANALYSIS, FINDINGS AND RECOMMENDATIONS ........ 6-1**

Review Period ........ 6-1
Capitalization and Budgeting Policies ........ 6-1
Internal Audits ........ 6-4
Historical Plant Balances ........ 6-4
Detailed Transactional Testing ........ 6-9
Insurance Recoveries ........ 6-13
Unitization Backlog ........ 6-13
Field Inspections and Table Top Reviews ........ 6-14
Capital Spending and Cost Containment ........ 6-41
Incremental Revenue Offset ........ 6-51

**7 ENABLE PROJECT ........ 7-1**
Enable Project Costs ........ 7-1
Enable Project Budget Overruns and Change Orders ........ 7-6

**8 METERS AND COMMUNICATION EQUIPMENT ........ 8-1**
AMI Meter Module Replacements ........ 8-1
Rider AU Costs Excluded from CEP ........ 8-3
The "Top End" $23,065,474 "Unretirement" ........ 8-4
Gas Meters Installed and Retired ........ 8-5
Replacement of Gas Meter Communication Equipment ........ 8-8

**9 ADJUSTMENTS TO DUKE ENERGY OHIO'S CEP COSTS ........ 9-1**
Incentive and Stock-Based Compensation ........ 9-1
Property Taxes ........ 9-10
Eastern Gas Operations Center Employee Fitness Room ........ 9-13
Correction of Errors in CEP Filing ........ 9-14
Composite Depreciation Rate Excluding Negative Net Salvage for Amortization of CEP Regulatory Assets ........ 9-16
Enable Project - Allocation of Costs to DEO Gas Utility ........ 9-16
AMI Meter Modules ........ 9-17

**ATTACHMENTS**
Attachment LA-1–Revenue Requirement and Adjustment Schedules
Attachment LA-2 – Adjusted Total Company Plant In-Service and Accumulated Depreciation and Amortization
Attachment LA-3 – Data Request Listing

# LIST OF EXHIBITS


Exhibit 2-1. Summary of Commission Approved Depreciation Rates....................................2-8
Exhibit 2-2. DEO Calculation of Composite Depreciation Rate ..............................................2-9
Exhibit 2-3. Summary of Impacts of Error Corrections..........................................................2-16
Exhibit 2-4. Interviews Conducted ........................................................................................2-17
Exhibit 5-1. Duke Energy Ohio CEP Revenue Requirement Calculation ...............................5-2
Exhibit 6-1. 2018 Retirement Entries .......................................................................................6-6
Exhibit 6-2. Reconciliations to FERC by Rider and Other Exclusions.....................................6-7
Exhibit 6-3. Reconciliation of 2018 On-Top Entry ...................................................................6-8
Exhibit 6-4. Summary of Project ID Work Orders ...................................................................6-9
Exhibit 6-5. Percentage of Work Orders Selected For Sampling - 2013 through 2018...........6-12
Exhibit 6-6. Feeder Line Risk Management Dashboard for Line A000b................................6-38
Exhibit 6-7. Summary of the Breakdown of Risk Related to Line A000b ...............................6-39
Exhibit 6-8. Risk of Breakdown By Component Related to Line A000b.................................6-39
Exhibit 6-9. Summary of CEP capital spending and Percentage Change .............................6-42
Exhibit 6-10. Summary of 2013 Budget to Actual Variances .................................................6-42
Exhibit 6-11. Summary of 2014 Budget to Actual Variances .................................................6-43
Exhibit 6-12. Summary of 2015 Budget to Actual Variances .................................................6-43
Exhibit 6-13. Summary of 2016 Budget to Actual Variances .................................................6-44
Exhibit 6-14. Summary of 2017 Budget to Actual Variances .................................................6-44
Exhibit 6-15. Summary of 2018 Budget to Actual Variances .................................................6-45
Exhibit 6-16. Summary of 2013 - 2018 Budget to Actual Variances ......................................6-45
Exhibit 6-17. Summary of Non-Rider Related Capital Projects For 2013-2018 ......................6-47
Exhibit 6-18. Summary of Large Non-Rider Related Capital Projects For 2017 .....................6-48
Exhibit 6-19. Summary of DEO's Incremental Offset to Revenue..........................................6-51
Exhibit 6-20. Summary of New Customers and Revenue Producing CEP Projects For 2013-2018 .........................................................................................6-52
Exhibit 7-1. Summary of Enable Project Costs Charged to all Duke Energy Business Units ..........................................................................................7-2
Exhibit 7-2. Summary of Duke Energy Business Units ...........................................................7-3
Exhibit 7-3. Enable Project Costs Allocated to DEO's Gas Utility ............................................7-4
Exhibit 7-4. Enable Project Costs Allocated to DEO's Gas Utility - Per Company....................7-5

Exhibit 7-5. Enable Project Costs Allocated to DEO's Gas Utility - As Recommended ........... 7-5
Exhibit 7-6. [redacted] ............................... 7-7
Exhibit 8-1. AMI Module Projects Included in CEP ................................................................ 8-2
Exhibit 8-2. AMI Module Projects That Should Have Been Included in Rider AU.................... 8-3
Exhibit 8-3. Rider AU Costs Excluded from CEP .................................................................... 8-3
Exhibit 8-4. Costs Included in Rider AU ................................................................................... 8-6
Exhibit 8-5. Summary of Meters in Service, Net Installs, Retirements and Replacements and Meter Costs ................................................................................................. 8-7
Exhibit 8-6. Summary of Meter Retirements and Associated Costs ........................................ 8-8
Exhibit 8-7. Summary of Meter Communication Node Costs................................................ 8-11
Exhibit 8-8. Summary of Meter Communication Equipment Projects .................................... 8-12
Exhibit 8-9. Summary of Meter Communication Equipment Removed by Project.................. 8-13
Exhibit 9-1. Summary of Resource Types for Incentive and Stock-Based Compensation ....... 9-1
Exhibit 9-2. Earnings Based Incentive Compensation andStock-Based Compensation Included in CEP Plant In-Service ..................................................................... 9-2
Exhibit 9-3. RWIP Earning Based Incentive Compensation .................................................. 9-3
Exhibit 9-4. Payroll Tax and Fringe Benefit Impacts of Earnings Based Incentive Compensation and Stock-Based Compensation............................................... 9-7
Exhibit 9-5. Quarterly Breakdown of Earnings Based Incentive Compensation and Stock-Based Compensation and Impacts to Depreciation, Accumulated Depreciation and ADIT ....................................................................... 9-8
Exhibit 9-6. Summary of Corrected Property Tax Rates....................................................... 9-12
Exhibit 9-7. Deferred Property Tax Expense Adjustment ..................................................... 9-12
Exhibit 9-8. Annualized Property Tax Expense Adjustment.................................................. 9-13
Exhibit 9-9. Comparison of Gross CEP Assets to CEP-Related Projects from Work Orders ................................................................................................... 9-14
Exhibit 9-10. Summary of 2017 Projects That Should Have Been Included in CEP Plant In-Service ........................................................................................... 9-15
Exhibit 9-11. Impacts of Adjusting CEP Plant Balances on Deferred Depreciation, Deferred Taxes and PISCC............................................................... 9-15
Exhibit 9-12. Impact of Using Annual Updated CAM Allocation Rates For Enable Project Costs Allocated to DEO Gas Distribution Utility ............................................. 9-17

# 1 TRANSMITTAL LETTER/DISCLAIMER

May 11, 2020

Ms. Nicci Crocker
Public Utilities Commission of Ohio
180 East Broad Street, 6th Floor
Columbus, OH 43215

Dear Ms. Crocker:

Attached is Larkin & Associates, PLLC's ("Larkin") report on the Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Natural Gas) for the period April 1, 2012 through December 31, 2018.

The words audit and examination, as used in this report are intended, as commonly understood in the utility regulatory environment, to mean a regulatory review, a field investigation, or a means of determining the appropriateness of a utility's 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. The term audit in this case does not refer to an analysis of financial statement presentation in accordance with the auditing standards established by the American Institute of Certified Public Accountants. The reader should distinguish the regulatory review performed for this engagement from financial audits performed for the purposes of expressing an opinion on the fair presentation of a company's financial statements in accordance with accounting principles generally accepted in the United States of America. This document and the analyses, evaluations, and recommendations are for the sole use and benefit of the contracting parties. There are no intended third-party beneficiaries, and Larkin 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, Larkin. While it is believed that the information is reliable, Larkin does not guarantee the accuracy of the information relied upon.

Sincerely,

Larkin & Associates PLLC

Larkin & Associates, PLLC

# 2 EXECUTIVE SUMMARY/SUMMARY OF FINDINGS AND RECOMMENDATIONS

## Background to the Capital Expenditure Program

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 ("PUCO" or "Commission") for approval of a Capital Expenditure Program ("CEP") for investment related to:

- Infrastructure expansion, improvement, or replacement;
- Any programs to install, upgrade, or replace information technology systems; or
- Any programs reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.

With approval of CEP, natural gas companies can establish a regulatory asset to defer for future recovery, the post in-service carrying costs ("PISCC"), depreciation, and property tax expenses associated with the CEP assets.

In Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM, Duke Energy Ohio, Inc. ("DEO" or "Company") sought and was granted authority to create a CEP and to begin deferring the related post in-service carrying costs ("PISCC"), depreciation and property tax expenses ("CEP deferral") for capital investments that were not part of its accelerated main replacement program ("AMRP"). Specifically, the Commission authorized DEO's CEP deferral starting January 1, 2013, and determined that the Company could only accrue the deferral up to the point where the deferred amount would exceed $1.50 per month for the General Sales - Small (GS-S) class of customers if it were included in customers rates. The Commission also restated its determination that it would consider the prudence, reasonableness, and magnitude of the CEP deferral and capital expenditures when DEO applied for recovery.

On May 3, 2019, DEO filed an application seeking authority from the Commission to establish a new alternative rate plan to establish a new capital expenditure program rider ("Rider CEP"). The Rider CEP would collect (1) the amounts accrued in the Company's capital expenditure program deferral ("CEP Deferral") through December 31, 2018, and (2) a return on and of the underlying CEP capital assets. In its Application, the Company stated that the purpose of Rider CEP is to recover the PISCC, incremental depreciation expense and property tax expense currently deferred pursuant to the CEP Deferral as well as a return on and of the underlying assets to which these expenses are directly attributable in the CEP.

## Project Requirements and Related Summary Conclusions

The PUCO issued a request for proposal ("RFP") seeking proposals to conduct a two-part audit of Duke Energy's CEP capital expenditures. Specifically, the first part of the audit is to review and attest to the accounting accuracy and used and useful nature of the Company's non AMRP and non-Rider advanced utility ("AU") capital expenditures and related assets and corresponding depreciation reserve since the date certain of its most recent base rate case (i.e., March 31, 2012 as set forth in Case No. 12-1865-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-AMRP and non-Rider AU capital expenditures and related assets, with an emphasis on the CEP expenditures and related assets for the period January 1, 2013 through December 31, 2018.

Larkin submitted a proposal and was selected by the PUCO Staff to perform the review. Larkin's investigation included reviewing the Company's filing, issuing discovery, interviews with Company personnel, field inspections (via video) and analyses, which included variance analysis and detailed transactional testing.

The objective for this project is to determine whether DEO has accurately determined and accounted for its non-AMRP and non-Rider AU plant in-service balance and depreciation reserve balance from the date certain balance (i.e., March 31, 2012) in the Company's last base rate case through December 31, 2018. In addition, we shall assess, form and support an opinion on the necessity, reasonableness and prudence of the Company's capital expenditures and associated assets from the date certain balance in DEO's last base rate case through December 31, 2018, with an emphasis on the CEP expenditures and assets.

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 Balances

Objectives for the review of Plant In-Service balances for DEO's CEP program include:

1. Plant In-Service Schedules

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

    - Audit DEO's plant in-service to determine the proper value for non-AMRP and non-Rider AU investments by account and subaccount.

2. Depreciation Reserve

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

- Audit DEO's plant in-service to determine the proper value for non-AMRP and non-Rider AU investments by account and subaccount.

3. Historical Records

    - Provide a determination as to the accuracy and completeness of DEO's historical plant records and continuing property records.

4. Classification - Capital vs. Expense

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

5. Subaccounts - Allocation 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.

## Part 2 - Capital Expenditures Prudence Audit

Objectives for the capital expenditures prudence audit include the following:

7. Necessity, Reasonableness and Prudence

    - Identify and assess the necessity, reasonableness, and prudence of DEO's non-AMRP and non-Rider AU capital expenditures and assets for the period January 1, 2013 through December 31, 2018, with an emphasis on CEP expenditures and assets.

8. Policies and Practices

    - Identify and assess the necessity, reasonableness, and prudence of DEO's policies and practices for plant additions, new construction, plant replacement, and plant retirements.
    - Utilize Larkin's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of any other DEO capital spending policies and practices or lack of such practices not specifically identified herein.

9. Causes for Increased non-AMRP and Rider AU

    - Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in the Company's non-AMRP and non-Rider AU capital expenditures coinciding with the CEP program.

10. Cost Containment

- Identify and assess the reasonableness and prudence of DEO's cost containment strategies and practices in the use of outside contractors for non-AMRP and non-Rider AU capital expenditures and assets for the period January 1, 2013 through December 31, 2018, with an emphasis on CEP expenditures and assets.
- Identify and assess the reasonableness and prudence of DEO's cost containment strategies and practices in the use of internal Company labor for non-AMRP and non-Rider AU capital expenditures and assets for the period January 1, 2013 through December 31, 2018, with an emphasis on CEP expenditures and assets.

11. Recommended Adjustments

- Recommend and support specific adjustments to the non-AMRP and non-Rider AU plant in-service balances based on any findings of lack of necessity, unreasonableness, or imprudence.

The following subsections address the RFP requirements delineated above and Larkin's summary conclusions based on our analysis. Additional information related to the analysis is provided in chapters 3 through 9 of this report.

### 1) Plant In-Service Schedules

*Requirement: Determine total Company plant in-service for each account and subaccount, from the date certain balance (i.e., March 31, 2012) approved in DEO's previous application to increase rates forward through December 31, 2018.*

*Requirement: Audit DEO's plant in-service to determine the proper value for non-AMRP and non-Rider AU investments by account and subaccount.*

The Company's last base rate case (Case No. 12-1685-GA-AIR) included plant in-service schedules (B Schedules) as of December 31, 2012. DEO's historical total Company plant in-service balances from the date certain period of April 1, 2012 through December 31, 2018 are reflected on Company Exhibit I - CEP Section A, B, C and D Schedules of Standard Filing Requirements in the B schedules. While the Company has not filed an application to increase its base rates, it supplied Larkin with plant in-service schedules as of December 31, 2018. The information provided also included roll forward balances from April 1, 2012 through December 31, 2018.

Larkin reviewed the information provided on the plant in-service schedules to confirm the reasonableness of the balances. Specifically, these schedules included the Company's plant in-service by major plant groupings on Schedule B-2, plant in service by account and subaccount on Schedule B-2.1, and gross additions, retirements and transfers on Schedule B-2.3. In addition, the Company-provided breakout by year of the gross additions, retirements, and transfers on Workpaper WPB-2.3. The information on WPB-2.3 ties into the aforementioned B schedules and is the schedule we used as the starting point to confirm the total Company plant in-service balances.

We reviewed the gross additions, retirements, and transfers on WPB-2.3 and compared them to DEO's historical plant records generated from the Peoplesoft system, which the Company provided in response to LARKIN-DR-01-001. We were able to tie out the majority of the amounts reflected on WPB-2.3 to the historical plant records. However, for 2018, we noted a number of significant differences between the retirements listed in the historical plant records to what DEO included on WPB-2.3.

As explained in the Company's response to LARKIN-DR-01-40, as of December 31, 2018, there was an "On-Top" retirement entry recorded only within the general ledger and not within DEO's fixed asset system. The entry applied to the various Company plant accounts in which we noted the discrepancies described above. Since this entry was not in the fixed asset system, it was not in the historical plant records provided, but it was recorded to the general ledger.

Larkin's review of the Company's historical plant balances are discussed in more detail in Chapter 6 of this report. In addition, Larkin is recommending adjustments to CEP-related plant in-service, which are discussed in Chapter 9 of this report.

Conclusion

Based upon our review of the Company's historical plant records for the period March 31, 2012 through December 31, 2018, coupled with the Company's explanation and documentation provided with respect to the 2018 On-Top retirement (discussed in Chapter 6), we are satisfied as to the accuracy of the Company's historical plant records. We do have some adjustments to CEP plant which are discussed in Chapter 9.

### 2) Depreciation Reserve

*Requirement: Determine total Company depreciation reserve for each account, from the date certain balance (i.e., March 31, 2012) approved in DEO's previous application to increase rates forward through December 31, 2018.*

*Requirement: Audit DEO's depreciation reserve to determine the proper value for non-AMRP and non-Rider AU investments by account and subaccount.*

DEO's historical total Company depreciation reserve balances from the date certain period of April 1, 2012 through December 31, 2018 are reflected on Company Exhibit I - CEP Section A, B, C and D Schedules of Standard Filing Requirements in the B schedules.

Larkin reviewed the information provided on the plant in-service schedules to confirm the reasonableness of the balances. Specifically, these schedules included the Company's depreciation reserve by major plant groupings on Schedule B-3, jurisdictional reserve groupings by account Schedule B-3.2-Proposed, and depreciation reserve accruals, salvage, retirements and cost of removal on Schedule B-3.3. In addition, the Company provided a breakout by year of the depreciation reserve accruals, salvage, retirements, and cost of removal on Workpaper WPB-3.3. The information on WPB-3.3 ties into the aforementioned B schedules and is the schedule we used to confirm the total Company depreciation reserve balances.

We reviewed the depreciation reserve accruals, salvage, retirements and cost of removal on WPB-3.3 and compared them to DEO's historical depreciation reserve records, which the Company provided in response to LARKIN-DR-01-002. We were able to tie out the majority of the amounts reflected on WPB-3.3 to the historical depreciation reserve records. However, for 2018, we noted a number of significant differences between the retirements listed in the historical depreciation reserve records and the amounts that DEO included on WPB-3.3. The amounts and accounts of the discrepancies in the depreciation reserve records were similar to those noted with the 2018 retirements discussed above with regard to the plant records. In the telephone interview conducted on January 21, 2020, in response to our inquiry, the Company confirmed that the 2018 retirements discrepancies in the depreciation reserve relates to the same On-Top retirement discussed above with respect to the historical plant balances.

Based upon our review of the Company's historical depreciation reserve records for the period March 31, 2012 through December 31, 2018, coupled with the Company's explanation and documentation provided with respect to the 2018 On-Top retirement discussed above (and in Chapter 6), we are satisfied as to the accuracy of the Company's historical depreciation reserve records.

Larkin found that the depreciation rates listed on Company Exhibit I, Schedule B-3.2-Proposed for the distribution and general plant accounts are the same depreciation rates reflected in the Company's CEP filing. These depreciation rates were approved by the Commission in its Opinion and Order dated November 13, 2013 in DEO's last rate case (Case No. 12-1685-GA-AIR et al.) and were in effect for the period March 31, 2012 through December 31, 2018.[1]

Conclusion

We found that the Commission approved depreciation rates from Case No. 12-1685-GA-AIR et al., were used in DEO's calculations. Therefore, we are not recommending any adjustments to the methodology used by DEO to calculate its depreciation reserve, deferred depreciation or annualized depreciation expense. We do have some adjustments, which affect these items, which are discussed in Chapter 9.

### 3) Historical Records

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

Pursuant to our analysis, Larkin found that the Company was able to provide detailed historical plant records (and continuing property records)[2] to support its plant in-service balances.

For the projects work order detail that the Company provided, Larkin performed detailed transaction testing. The results of this analysis are discussed in Chapter 6 of this report. The Company should continue to address the unitization backlog, as described in Chapter 6.

[1] See the response to LARKIN-DR-01-003.
[2] According to the response to LARKIN-DR-01-006, the Company's continuing property records are what the historical plant records and depreciation reserve records that were provided in LARKIN-DR-01-001 and LARKIN-DR-01-002, respectively.

### 4) Classification - Capital vs. Expense

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

Through reviewing Company records and our transactional detail testing of sampled work orders and plant records, Larkin found that the costs included in the sampled projects are capital in nature, and that the scope of work and cost detail tied to the applicable FERC 300 accounts to which the work applied in accordance with the FERC Uniform System of Accounts. The projects were classified to the proper distribution and general equipment FERC accounts. The Company should continue to address the unitization backlog, as described in Chapter 6.

### 5) Subaccounts - Allocations and Depreciation

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

**Depreciation Accrual Rates**

Schedule B-3.2 - Proposed from Exhibit I of the Company's standard filing requirements ("SFR") filing reflects the production, distribution, General and Common plant at the summary FERC 300 account level of the total Company jurisdictional net plant in-service. This depreciation schedule ties to Schedule B-2.1 and reflects the summary FERC 300 accounts with total Company amounts and the allocators (see additional discussion below) used to calculate the adjusted jurisdictional plant balances. Larkin confirmed that the calculations of depreciation expense for these accounts reflect the most recent Commission approved depreciation rates as discussed in its Opinion and Order dated November 13, 2013 in Case No. 12-1685-GA-AIR et al. .[3]

Included in the total Company plant in-service balances are the distribution and general plant accounts that the Company reflected in its CEP filing. As such, the Commission approved depreciation rates from Case No. 12-1685-GA-AIR et al. that DEO used for calculating its CEP related deferred depreciation expense and annualized depreciation expense in its CEP filing are summarized in the exhibit below:

[3] See the response to LARKIN-DR-01-003.

**Exhibit 2-1. Summary of Commission Approved Depreciation Rates**

| FERC Account | Company Account | Account Title | Depreciation Rate |
|---|---|---|---|
| | | **Distribution** | |
| 374 | 2740 | Land and Land Rights | 0.00% |
| 374 | 2741 | Rights of Way | 1.54% |
| 374 | 2742 | City Gate Check Station | 0.00% |
| 375 | 2750 | Structures & Improvements | 2.09% |
| 376 | 2761, 2764 | Mains - Cast Iron & Copper | 2.72% |
| 376 | 2762, 65, 67, 69 | Mains - Steel | 1.87% |
| 376 | 2763, 2766, 2768 | Mains - Plastic | 2.08% |
| 378 | 2780 | System Meas. & Reg. Station Equipment | 2.35% |
| 378 | 2781 | System Meas. & Reg. Station Equipment-Elec | 7.00% |
| 378 | 2782 | District Regulating Equipment | 2.40% |
| 379 | 2790 | Meas. & Reg. - City Gate | 6.67% |
| 380 | 2801 | Services- Cast Iron & Copper | 3.11% |
| 380 | 2802,2804, 2808 | Services-Steel | 2.88% |
| 380 | 2803,05, 06, 07 | Services-Plastic | 3.59% |
| 381 | 2810,2811 | Meters | 2.22% |
| 381 | 2812 | Utility of the Future Meters | 5.00% |
| 382 | 2820,2821 | Meter Installations | 2.00% |
| 383 | 2830 | House Regulators | 2.00% |
| 384 | 2840 | House Regulator Installations | 2.00% |
| 385 | 2850 | Large Industrial Meas. & Reg. Equipment | 2.63% |
| 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | 4.20% |
| 387 | 2870 | Other Equipment - Other | 6.67% |
| 387 | 2871 | Street Lighting Equipment | 2.67% |
| 390 | 2900 | Structures & Improvements | 3.33% |
| 394 | 2940 | Tools, Shop & Garage Equipment | 4.00% |
| 395 | 2950 | Laboratory Equipment | 6.67% |
| 396 | 2960 | Power Operated Equipment | 6.36% |
| 397 | 2970 | Communication Equipment | 6.67% |
| | | | |
| | | **General** | |
| 391 | 2911 | Electronic Data Processing | 20.00% |
| | 2030 | Miscellaneous Intangible Plant | 20.00% |
| | 20310 | Miscellaneous Intangible Plant - Enable | 10.00% |
| | | | |
| Depreciation rates approved in Case No. 12-1685-GA-AIR. | | | |

As shown in the exhibit above, for purposes of calculating CEP related (1) deferred depreciation expense, and (2) annualized depreciation expense, the Company reflected the Commission approved depreciation rates for the distribution and general plant accounts listed. Larkin confirmed that the depreciation rates listed above were in effect for the entire period March 31, 2012 through December 31, 2018.[4]

The Company's calculations of its deferred depreciation expense and annualized depreciation expense are shown on Exhibit J, Schedule 5a - Def Dep - Dist Impr and Schedule 5b - Def Dep - Info Tech. Specifically, for each distribution and general plant account included in CEP, the Company multiplied the net of the CEP plant assets and CEP retirements[5] by the depreciation rates shown in the exhibit above, on a monthly basis, for each year 2013 through 2018.

Conclusion

We reviewed the Company's calculations for deferred depreciation expense and annualized depreciation expense and conclude that (1) the Company's methodology for calculating depreciation, and (2) the Commission approved depreciation rates from Case No. 12-1685-GA-AIR et al., that were used in DEO's calculations, are reasonable. Therefore, we are not recommending any adjustments to the methodology by which DEO calculated its deferred depreciation or annualized depreciation expense.

However, as discussed in Chapter 9 of this report, we are recommending certain adjustments that impact the deferred and annualized depreciation in the context of those specific adjustments. These adjustments impacted the overall amounts of deferred and annualized depreciation expense flowing through the Company's CEP revenue requirement.

## Composite Depreciation Rate For Amortization of Deferred Costs/Regulatory Assets

To calculate the Amortization of Regulatory Assets on Exhibit J, Schedule No. 1 from its CEP filing, the Company multiplied its proposed regulatory asset amount totaling $44,981,818 by 2.54% to derive an amortization of regulatory asset amount of $1,142,538. Note B on Company Schedule No. 1 states that: "For purposes of this calculation Duke Energy Ohio used a composite deprecation rate calculated using data from the 2015 FERC Form 2." Specifically, the 2.54% was calculated as follows:

### Exhibit 2-2. DEO Calculation of Composite Depreciation Rate

| Description | Amount |
|---|---|
| Depreciation & Amortization | $ 49,194,937 |
| Total Gas Plant in Service | $ 1,935,849,008 |
| Composite Depreciation Rate | 2.54% |
| | |
| Source: 2015 FERC Form 2 | |

We asked the Company to explain why it used its 2015 FERC Form 2 data to calculate its proposed composite depreciation rate of 2.54% for all years rather than use more recent FERC Form 2 data. In its response to LARKIN-DR-01-044, DEO explained that in order to remain

4 These depreciation rates were in effect from March 31, 2012 through December 31, 2018 on a total Company basis, including for the non-CEP FERC 300 plant accounts. Also see DEO's response to LARKIN-DR-01-003.
5 These amounts are reflected on Company Exhibit J, WP4.1 - Assets by FERC and WP4.2 - Retirements by FERC.

consistent when calculating the $1.50 cap, it used the 2.54% composite rate as a simplifying assumption in its application. As discussed in the direct testimony of Company witness Jay Brown, in Orders in Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM dated October 1, 2014, the Commission authorized the Company to accrue CEP accruals until the accrued deferrals would cause the rates charged to residential customers to exceed $1.50 per month.

As discussed below, we are recommending the use of a 2.25% composite depreciation rate, which excludes negative net salvage/cost of removal to calculate the amortization of the deferred regulatory assets. It should be noted that using the 2.25% composite rate does not exceed the $1.50 per residential customer cap.

Conclusion

We disagree with the Company's use of the 2.54% composite depreciation rate, which includes negative net salvage/cost of removal, for purposes of calculating the amortization of regulatory assets.[6] In our view, using a composite rate calculated that includes negative net salvage/cost of removal is not a reasonable methodology for determining an estimate of the remaining life of the CEP assets, or by which to calculate the amortization of CEP regulatory assets. Larkin, in consultation with Staff, recommends using a 2.25% rate that excludes negative net salvage and is therefore a better estimate of the useful life of the CEP assets. The calculation of the 2.25% rate is shown on Attachment LA-1, Schedule 7. As shown on Attachment LA-1 Schedule 1, we applied the 2.25% rate to the adjusted regulatory asset balance (after reflecting certain recommended adjustments). This results in an adjusted annual amortization of regulatory assets of $ $1,007,416, which is $135,122 lower than DEO's proposed amount of $1,142,538.

**Depreciation Offset**

The Company's CEP related revenue requirement on Exhibit J, Schedule No. 1 includes a line item titled "2012 Rate Case Depreciation Offset" ("depreciation offset") in the amount of $225,989,904, and is reflected as an offset to CEP plant in-service. The Company's calculation of the depreciation offset is shown on Exhibit J, Schedule 11 from the Company's filing. The starting point on Schedule 11 is total Company depreciation expense from the Company's FERC Form 2 filings for each year 2013 through 2018. From these amounts, DEO then subtracted (1) Rider AMRP depreciation expense, (2) Rider AU depreciation expense, and (3) production depreciation expense.[7] The net CEP depreciation offset for 2013 through 2018 is the $225,989,904 reflected on Company Schedule No. 1 as an offset to CEP plant in-service.

In its response to LARKIN-DR-01-125, the Company stated that the rationale for the depreciation offset is that it is an estimate of the accumulated depreciation that would have accrued between January 1, 2013 and December 31, 2018. In addition, DEO explained that if the estimated accumulated depreciation had not been reflected as an offset to plant in-service, rate base would have been overstated, as Schedule No. 1 from Exhibit J would only reflect additions and not the corresponding accumulated depreciation that has accrued since the 2012 rate case.

[6] According to the response to LARKIN-DR-01-126, the Company used the 2.54% composite depreciation rate to calculate the estimated rate impacts to customers.

[7] Note A on Schedule 11 states that the depreciation offset does not include investments recovered through Rider AMRP or Rider AU.

Conclusion

We conclude that the methodology used by DEO for the depreciation offset adjustment is reasonable. We are not recommending any adjustments to the Company's methodology.

**Allocation Factors**

Exhibit I, CEP Sections A and B Schedules from the Company's SFR indicate that 100% of DEO's investment is jurisdictional. In its response to LARKIN-DR-01-63, the Company confirmed that the balances presented in Exhibit I CEP Section A and B Schedules (which include CEP) are not allocated to other DEO divisions (e.g., to DEO's electric operations).

The Enable Project, which is discussed in detail in Chapter 7 of this report, was a very substantial Duke Energy initiative to review and upgrade information technology over several of its business units, with a total cost of approximately $236.02 million. Enable Project cost was allocated to the DEO gas distribution utility using an allocation factor of 5.43%, which was from the Company's 2014 cost allocation manual. Larkin recommends applying the annual allocation factors, and has calculated an adjustment relating to this, which is described in Chapters 7 and 9 and which reduces the Enable Project cost allocated to the DEO gas utility by $133,123.

### 6) Physical Inspections

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

As discussed in more detail in the Field Inspections and Table Top Review subsection of Chapter 6, actual physical inspections of the Company's facilities were not conducted due to travel restrictions resulting from the coronavirus pandemic ("COVID-19"). In lieu of actual physical inspections being conducted, Larkin was able to conduct a substitution/replacement to field inspections via a combination of table top reviews with the Company and by Company personnel performing video walkthroughs of certain Company facilities. Table top reviews involved reviewing as-built diagrams and work orders and web-based conferences with Company representatives (and PUCO Staff). Such reviews were conducted for four major projects: Dicks Creek Station ("Dicks Creek"), Kellogg Eastern Gas Operations Center ("Eastern Gas Ops Center"), Line A000b and Line D. The accounting detail, work order and as-built documentation for each project was reviewed and Company personnel were asked questions in a series of on-line meetings/conference calls. Video walkthroughs were conducted for two of these projects which had significant costs, above ground utility assets that were included in the CEP: Dicks Creek Station and the Kellogg Eastern Gas Operations Center.

Larkin concludes that table top reviews and video walkthroughs in conjunction with the review of supporting accounting, work orders and as-built documentation provides an adequate basis for concluding that the reviewed assets are used and useful and provide benefit to the Company's ratepayers. The assets did not appear to be over built. Company personnel were knowledgeable about the projects.

As explained in more detail in the Field Inspections and Table Top Review subsection of Chapter 6, with one exception as it relates to the Eastern Kellogg Gas Operations Center (removal of fitness room costs), Larkin did not find anything in either the video walkthroughs or the table top reviews that was determined to be imprudent or unreasonable.

### 7) Necessity, Reasonableness, and Prudence

*Requirement: Identify and assess the necessity, reasonableness and prudence of DEO's non-AMRP and non-Rider AU capital expenditures and assets for the period January 1, 2013 through December 31, 2018, with an emphasis on CEP expenditures and assets.*

The necessity, reasonableness and prudence of DEO's CEP expenditures was considered throughout the entire audit, including the variance analysis, transactional testing, and table top reviews and onsite video walkthroughs. Our work in those areas is discussed in various sections of our report, including Chapters 6, 7, 8 and 9.

Other than our recommended adjustments, Larkin did not find anything to indicate that the remaining CEP related capital expenditures and assets for the period January 1, 2013 through December 31, 2018, were unnecessary, unreasonable, or imprudent. As described in Chapter 9 of this report, we are recommending adjustments to CEP costs for (1) incentive and stock-based compensation, (2) property taxes, (3) costs related to the employee fitness room at the Eastern Gas Ops Center, (4) the correction of errors in CEP plant in-service, revising the rate used the amortize the regulatory asset balances,(5)the allocation factor used for including Enable Project costs in CEP, and (6) removing AMI meter module equipment that DEO conceded should have been included in Rider AU. Larkin has identified certain concerns with significant replacements of meters and related communication equipment prior to the end of their expected useful life (in Chapter 8) and with significant change orders related to the Enable Project (in Chapter 7) which may deserve additional regulatory review in DEO's next gas utility rate case.

### 8) Policies and Practices

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

*Requirement: Utilize Larkin's familiarity and experience with natural gas distribution utility operations and capital spending practices to identify and assess the reasonableness and prudence of any other DEO capital spending policies and practices or lack of such practices not specifically identified herein.*

Larkin did not perform a management audit, but we reviewed the Company's processes and controls in order to determine whether they were sufficient and did not adversely affect the plant balances in DEO's gas utility plant in-service. Based on the documents reviewed, Larkin obtained an understanding of the Company's processes and controls that affect the plant balances. In addition, Larkin reviewed internal audit reports that were conducted that could impact the Company's plant in-service balances.[8] Larkin also reviewed the opinions on internal controls over financial reporting in the Company's annual financial statement audits. There have been no FERC audits conducted from 2012 through 2018.[9]During a telephone interview with the Company on January 21, 2020 (which was based on our review of several internal audit reports),

[8] The internal audit reports were provided in response to LARKIN-DR-01-41.

[9] The response to LARKIN-DR-01-28 referred to DEO's annual financial statement audits as it relates to the Company's SOX compliance audits of internal controls. This response also indicated there have been no FERC audits conducted during the period 2012-2019.

the Company described a formal system it has in place to track the internal audit reports, and hold the Company accountable when issues are encountered. The Internal Audit Department goes back and validates that management implements corrections and/or mitigates any issues disclosed by the Internal Audit Department.

There were no major events during the period January 1, 2013 through December 31, 2018 that impacted the Company's plant in-service balances.[10]

Additional details of the policies and procedures reviews are included in Chapter 6 of this report

Larkin reviewed the Company's capitalization policies that were in effect during the audit period. The Company provided five different versions of its capitalization guidelines, with the initial version effective as of January 1, 2010 and the subsequent updated versions that were applicable during the review period becoming effective on January 1 of 2014, 2016, 2017, and 2018. The Company explained that significant changes in capitalization policy during the period 2012 through 2018 was for 2016 and forward and relates to customer accounting for fees paid in a Cloud Computing Arrangement pursuant to FASB guidance in Accounting Standards Update2015-05 ("ASU 2015-05"), which clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software under ASC 350-40. As it relates to DEO's gas utility and/or CEP investments in 2016 and forward, the change discussed above would only affect DEO's accounting to the extent that cloud based applications were capitalized. The Company confirmed in its response to LARKIN-DR-01-137 that no amounts related to cloud computing were capitalized for DEO Gas in either 2016, 2017, or 2018 nor were amounts that were capitalized for cloud computing for DEO affiliates in 2016, 2017, and 2018 charged or allocated to DEO Gas.

Larkin's review of work orders for CEP includable projects also did not reveal any capitalized cloud computing projects being included in CEP plant in-service. A Duke Energy system project - the Enable Project - of which a portion of the cost was allocated to the DEO gas utility and included in DEO gas utility plant, is discussed in Chapters 7 and 9 of this report.

### 9) Causes for Increased Non-AMRP and Non-Rider AU Spending

*Requirement: Identify and assess the necessity, reasonableness, and prudence of the principal causes for increases in DEO's non-AMRP and non-Rider AU capital expenditures coinciding with the CEP program.*

The Company provided a listing of its project work orders for the period April 1, 2012 through December 31, 2018 in its response to LARKIN-DR-01-35. The project work orders included in this listing were designated as either CEP, AMRP, AU, or non-rider related (i.e., not CEP, AMRP nor AU). The non-rider related projects are broken out by (1) intangible plant; (2) production plant; (3) distribution plant; and (4) general plant. For each category of plant, the amount of non-rider related capital expenditures fluctuated significantly during the period 2013 through 2018.

[10] See the response to LARKIN-R-01-46.

For each category of plant, the amount of non-rider related capital expenditures fluctuated significantly during the period 2013 through 2018. On an overall basis, the only years in which there was net increase in non-rider related capital expenditures were 2016 and 2018 with decreases in the other years. In addition, the years in which there were significant increases in capital costs, they related to large projects, such as the ones addressed in the table top reviews, rather than an influx of several projects. We conclude that the non-rider related capital expenditures during the period 2013 through 2018 were reasonable and prudent.

Additional details of our review of the Company's capital spending in non-rider related projects are included in Chapter 6 of this report.

### 10) Cost Containment

*Requirement: Identify and assess the reasonableness and prudence of DEO's cost containment strategies and practices in the use of outside contractors and internal labor for non-AMRP and non-Rider AU capital expenditures and assets for the period January 1, 2013 through December 31, 2018, with an emphasis on CEP expenditures and assets.*

Labor costs are a major contributor to the CEP project costs. Materials and contractor costs are also significant contributors to the cost of CEP projects. As discussed in Chapter 6 of our report, we sampled dozens of project work orders for detailed testing and we observed that outside contractor labor costs comprise a significant portion of the costs included in the CEP projects.

The Company has no written guidelines and/or policies and procedures regarding the use of outside contractors vs. Company personnel as it relates to non-Rider AMRP and non-Rider AU capital expenditures. Generally, internal crews (DEO employees) work on projects when pipe is 100 feet in length or less. If the work requires specialized knowledge or the pipe length being replaced or installed is greater than 100 feet, the Company employs outside contractors for such work, which is supervised by DEO employees.

With regard to cost containment strategies related to using outside contractors, the Company competitively bids out work that consists of street improvements, main replacements, pressure improvements, and main extensions (8,000 feet or less and eight inches in diameter or less) for distribution main. DEO has four contractors that perform this work. In addition, the Company has set pricing for this type of work established in blanket contracts. If a project involves installing or replacing pipe that is longer than 8,000 feet, or greater than eight inches in diameter, the job is bid out to a pool of approved contractors. The Company typically uses external crews on blanket projects.[11]

An analysis of historical project data is the basis for the Company's practice of competitively bidding out work to the outside contractors to work on main extension projects.Approximately85% of DEO's distribution projects are 8,000 feet or less. The contractors used by the Company are large enough to efficiently perform work of this size at competitive pricing.

[11] Per the telephone interview conducted on January 24, 2020.

In the event a project falls outside the scope of blanket projects (i.e. greater than 8,000 feet for distribution mains), the Company has an approved bidder list that is managed by its sourcing group who works in conjunction with the operations group in an open-bid process. In addition, the Company has a robust RFP process for both blanket work orders and major individual projects.

In terms of internal labor cost containment strategies that DEO has in place, internal labor is managed on a project-by-project basis depending on deliverables and is monitored through the approval of timesheets. Specifically, supervisors and managers direct the work of internal labor with respect to which projects are worked on and how resources are allocated based on the annual budget and specific work scope of each Company crew. DEO internal labor is used to perform operations and management type work more so than work on capital projects.[12]

Conclusion

We conclude that DEO has implemented effective cost containment strategies regarding the use of outside contractors and internal labor for non-Rider AMRP and non-Rider AU capital expenditures and for CEP includable projects and assets during the period 2013 through 2018.

### 11) Recommended Adjustments

*Requirement: Recommend and support specific adjustments to the non -AMRP and non-Rider AU plant in-service balance based on any findings of lack of necessity, unreasonableness, or imprudence.*

Our recommended adjustments are discussed in detail in Chapter 9 of this report and are shown on Attachment LA-1 and are summarized below. Larkin recommends the following adjustments:

- Remove the earnings-based portion of incentive compensation and stock-based compensation. As discussed in further detail in Chapter 9 of this report, we recommend that the cumulative amounts of incentive and stock-based compensation totaling $775,173 (after factoring in the related depreciation, accumulated depreciation, and accumulated deferred income tax (ADIT)) for the period 2013 through 2018 be removed from the CEP rider. In addition, we recommend that the Company's calculation reflecting the impact of removing the earnings-based incentive and stock-based compensation on the PISCC deferral in the amount of $142,980 also be adopted. This adjustment is shown on Attachment LA-1, Schedule 3.

- Increase the regulatory asset for property taxes and increase annualized property tax expense. As discussed in further detail in Chapter 9 of this report, after reflecting the correction of errors in the Company's calculations for the property tax deferral, our recalculated deferred property tax regulatory asset totals $13,182,085. When compared to the amount from the Company's filing of $13,046,753, our recommended adjustment increases the deferred property tax regulatory asset by $135,332. In addition, after reflecting the correction of the errors related to annualized property tax expense, our

[12] Per the telephone interview conducted on January 24, 2020.

recalculated annualized property tax expense totals $5,738,579. When compared to the Company's as-filed amount of $5,705,526, our recommended adjustment increases the annualized property tax expense by $33,053. This adjustment is shown on Attachment LA-1, Schedule 4.

- Remove the construction costs and equipment costs associated with the employee fitness center at the Eastern Gas Ops Center. As discussed in further detail in Chapter 9 of this report, [redacted] This adjustment is shown on Attachment LA-1, Schedule 5.

- Remove and/or add projects during the period 2013 through 2015 that were erroneously included and/or excluded from the CEP plant in-service balances. Specifically, as discussed in further detail in Chapter 9 of this report, the Company conceded that due to incorrect data filtering methods in its system, for each year 2013 through 2015, the following adjustments should be made to the CEP plant in-service balances:

  a. For 2013, the CEP plant in-service balances should be decreased by $40,622.

  b. For 2014, the CEP plant in-service balances should be increased by $14,661.

  c. For 2015, the CEP plant in-service balances should be decreased by $531,609.

  In addition to adjusting the 2013 through 2015 CEP balances by the amounts shown above, the related deferred depreciation expense, ADIT and PISCC should also be adjusted by the amounts shown in the exhibit below (which includes the referenced adjustments to the CEP plant in-service balances):

### Exhibit 2-3. Summary of Impacts of Error Corrections

| Description | 2013 | 2014 | 2015 | Total |
|---|---|---|---|---|
| Net Plant in Service | $ (40,622) | $ 14,661 | $ (531,609) | $ (557,570) |
| Deferred Depreciation Expense | $ (4,266) | $ 1,218 | $ (43,284) | $ (46,350) |
| Deferred Tax - Liberalized Depreciation | $ (5,750) | $ 1,994 | $ (69,120) | $ (72,876) |
| Post In-Service Carrying Cost | $ (10,805) | $ 3,237 | $ (110,724) | $ (118,293) |

The cumulative amounts shown under the "Total" column represent the adjustments that are reflected on Attachment LA-1, Schedule 6.

- We disagree with the Company's use of the 2.54% composite depreciation rate (based on 2015 FERC Form 2 data) for calculating the amortization of regulatory assets. The 2.54% rate includes the impact of negative net salvage. As such, it is not a reasonable methodology for determining an estimate of the useful life of the CEP assets, or by which to calculate the amortization of regulatory assets. Larkin, in consultation with Staff, recommends using a 2.25% rate because this rate excludes the impact of negative net salvage and is therefore a better estimate of the average useful life of the CEP assets. The 2.25% rate is shown on Attachment LA-1, Schedule 7. We applied the 2.25% rate to the adjusted regulatory asset balance. This results in an adjusted amortization of regulatory assets amount of $1,007,416, which is $135,122 lower than the $1,142,538 that DEO proposed.

- Adjust Duke Energy Enable Project Costs allocated to the DEO gas utility by applying DEO gas utility annual allocation factors, rather than using a 2014 factor for all years. In the Company's CEP filing, the Duke Energy Enable Project costs for all applicable years were allocated to the DEO gas utility based on a 5.43% allocation factor which was from the Company's 2014 Cost Allocation Manual. We recommend that the recoverable Enable project costs that are included in the CEP be based on the CAM percentage allocation applicable to the DEO gas utility in each year 2013 through 2018. As shown on Attachment LA-1, Schedule 8, the result of our recommendation decreases CEP plant in-service by $133,123, deferred depreciation expense by $18,467, annualized depreciation expense by $13,852, and PISCC by $9,443.
- Remove the costs associated with AMI meter module replacements from 2013, 2014 and 2015 which the Company stated were projects that should have been included in Rider AU, but were not labeled properly so these projects were captured in CEP. The costs that were removed totaled $1,802. For this adjustment, because of the small plant adjustment amount, we did not attempt to reflect the impacts to deferred or annualized depreciation expense, or the PISCC, which would be even smaller. This adjustment is shown on Attachment LA-1, Schedule 9.

## Interviews

As noted above, Larkin conducted a series of telephone interviews with Duke Energy Ohio personnel on January21, 24, and 31, 2020 and February 3-4, 2020. The Company personnel interviewed are summarized in the exhibit below by interview date, job title, and department:

### Exhibit 2-4. Interviews Conducted

| Interview Date | Title | Department |
|---|---|---|
| Various | Rates & Regulatory Strategy Manager | OH/KY Rate Recovery & Analysis |
| 1/21/2020 | Manager Accounting II | US Asset Accounting |
| 1/21/2020 | Manager Accounting II | US Asset Accounting |
| 1/21/2020 | Director Regulated Business Audit | Internal Audit |
| 1/21/2020 | Director Customer & Corporate Audit | Internal Audit |
| 1/24/2020 | Director Gas Distribution Finance | Regulatory Utility Gas Ops Finance |
| 1/31/2020 | Director Rates & Regulatory Planning | OH/KY Rates & Regulatory Strategy |
| 1/31/2020 | Director Regional FIN Forecasting & Analysis | Finance Forecasting & Analysis |
| 1/31/2020 | Financial Manager | Midwest & Gas FIN Forecasting |
| 2/3/2020 | Senior Tax Analyst | EY Indirect Tax Group |
| 2/3/2020 | Manager, Natural Gas Damage Prevention | Gas Asset Risk Management |
| 2/3/2020 | Developmental Assignment Leader | Asset Risk Management |
| 2/4/2020 | Director, Allocations & Reporting | Corporate Accounting |

Follow-up interviews to clarify responses to audit discovery were conducted via telephone and/or through Microsoft Team Meetings, as needed, during the audit.

## Audit Report Outline

The outline of the remainder of this audit report is organized as follows:

- Chapter 3 Duke Energy Ohio Background
- Chapter 4 Capital Expenditure Program
- Chapter 5 Financial Review - Overview
- Chapter 6 Detailed Analysis, Findings and Recommendations
- Chapter 7 Enable Project
- Chapter 8 Meters and Communication Equipment
- Chapter 9 Adjustments to Duke Energy Ohio's CEP Costs

# 3 DUKE ENERGY OHIO BACKGROUND

## Overview

Duke Energy ("Duke") is headquartered in Charlotte, North Carolina and is a Fortune 150 company. Duke is one of the largest electric power holding companies in the United States, supplying and delivering energy to approximately 7.7 million U.S. customers. It has approximately 51,000 MW of electric generating capacity in North Carolina, South Carolina, Florida, Indiana, Kentucky, and Ohio from a diverse mix of coal, nuclear, natural gas, oil, and renewable resources. Duke's service area covers approximately 95,000 square miles in the Southeast and Midwest. It also has natural gas distribution services in the Carolinas, Ohio, Tennessee, and Kentucky. Duke's commercial and international businesses own and operate diverse power generation assets in North America and Latin America, including a portion of renewable energy assets.

In 1997, Duke Power merged with PanEnergy Corporation, a central player in the natural gas industry, and formed Duke Energy. Three years prior that, Cincinnati Gas & Electric Company and PSI Energy Inc. merged, forming Cinergy Corporation. In 2006, Duke merged with Cinergy Corporation, using the Duke Energy name, and expanded its service area into Ohio, Kentucky, and Indiana. On January 3, 2007, Duke spun off its gas business to Spectra Energy.

In 2012, Duke and Progress Energy combined, further expanding Duke's services to Florida and forming one of the largest electric utilities in the United States. In early 2015, Duke purchased a majority interest in REC Solar in San Luis Obispo, California. Duke also acquired a majority share of Phoenix Energy Technologies, which is based in Irvine, California.

On October 26, 2015, Duke announced the acquisition of Piedmont Natural Gas ("Piedmont"), which expanded Duke's territory into Tennessee. Duke completed the acquisition in October 2016, with Piedmont retaining its name as a subsidiary of Duke. Duke and Piedmont are also key partners in the $5 billion Atlantic Coast Pipeline that will be the first major natural gas pipeline to serve Eastern North Carolina.

DEO provides transmission and distribution services for natural gas to approximately 533,000 customers.

Pursuant to the Commission's Opinion and Order in Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM, DEO submits Annual Information Filings ("AIFs") related to the CEP and are filed by April 30 of each year. The AIFs should disclose the CEP regulatory asset balance at December 31 of each year; the calculations used to determine the monthly deferred amounts, including a breakdown of investments in PISCC, depreciation expense and property tax expense for each budget type; a breakdown of the rate impacts by customer class; capital budget for the calendar year in which the informational filing is made and the succeeding year; estimates of the effect that the deferred amounts would have on residential customer bills, if they were included in rates; schedules showing the calculations and inputs for the CEP deferrals; and explanations for any substantial deviations between the planned, estimated CEP expenditures and actual expenditures, where such substantial deviation would reasonably impede Staff's ability to monitor or review the filing.

As part of the approval of the CEP, the Commission ordered that DEO should be granted the accounting authority to defer PISCC on program investments for assets placed in service but not yet reflected in rates using the Company's cost of long-term debt as approved in its most recent gas distribution case; defer depreciation expense and property tax expense directly associated with the assets placed into service; and establish a regulatory asset to which PISCC, depreciation expense, and property tax expense will be deferred for future recovery. DEO also agreed to compute the PISCC deferral on a net plant basis. The Commission also ordered that the CEP should be subject to a cap for the period during which deferrals are being accrued. DEO should be allowed to accrue deferrals under the CEP until the accrued deferrals, if included in DEO's residential service rates, would cause the rates charged to residential customers to increase by more than $1.50 per month. If deferrals exceed the $1.50 per month threshold, DEO will stop accruing future CEP deferrals until it files for authority to recover existing deferred accruals.

# 4 CAPITAL EXPENDITURE PROGRAM

On December 20, 2013, in Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM, DEO filed an application for authority to implement an information CEP pursuant to R.C. 4909.18 and 4929.111 whereby DEO sought to implement the CEP to install, upgrade, or replace information technology systems. In addition to seeking approval of its proposed CEP, the Company also sought authority to change its accounting methods. Specifically, the Company requested authority to (1) capitalize PISCC on CEP assets placed into service, but not yet recovered in rates; (2) defer depreciation expense and property tax expense directly attributable to the CEP; and (3) establish a regulatory asset to which PISCC, depreciation expense and property tax expense would be deferred for recovery in a subsequent and separate proceeding. The Company asserted that any accrual for deferral of PISCC, depreciation expense and property tax expense related to CEP would be recorded in accordance with the system of accounts established by the Commission under R.C. 4905.13. Furthermore, DEO informed the Commission that the PISCC would be based on the Company's cost of long-term debt as approved in DEO's most recent natural gas distribution rate case (i.e., Case No. 12-1685-GA-AIR).[13]

In response to DEO's application to implement a CEP, Staff made nine comments and recommendations, which are discussed on pages 3-7 of the Commission's Finding and Order dated October 1, 2014 in Case Nos.13-2417-GA-UNC and 13-2418-GA-AAM. On September 12, 2014, the Company and Staff filed joint surreply comments, which, in consideration of certain modifications to DEO's application and Staff's comments and recommendations, resulted in DEO and Staff reaching a comprehensive agreement with regard to the Company's proposed CEP. The following summary lists the provisions of the agreement between DEO and Staff:[14]

- The CEP should be enlarged to include those programs delineated in R.C. 4929.111(A)(1) through (A)(3), initiated in and for 2013 and succeeding years.
- The proposed CEP meets DEO's obligation under R.C. 4905.22 to furnish necessary and adequate services and facilities that are just and reasonable.
- DEO should be granted authority to defer PISCC on program investments for assets placed in service but not yet reflected in rates, using the Company's cost of long-term debt as approved in its most recent gas distribution case; defer depreciation expense and property tax expense directly associated with the assets placed in service; and establish a regulatory asset to which PISCC, depreciation expense, and property tax expense will be

[13] On page 13, Section C, subsection 2 of the Commission's Opinion and Order dated November 13, 2013 in Case No. 12-1685-GA-AIR, et al., its states that DEO shall use 5.32% as its cost of debt for determining carrying charges for future gas deferral requests until the cost of debt is reset as part of the resolution of DEO's next gas distribution rate case.

[14] The provisions of the joint agreement between DEO and Staff are discussed on pages 8-11 of the Commission's Finding and Order dated October 1, 2014 in Case Nos.13-2417-GA-UNC and 13-2418-GA-AAM.

deferred for future recovery. DEO agrees to compute the PISCC deferral on a net plant basis.

- The CEP will not result in incremental revenue and, consequently, there is no need to adjust the deferred amounts to account for incremental revenue. For any future CEP that generates incremental revenue, the regulatory asset created to defer the total monthly PISCC, depreciation expense, and property tax expense associated with DEO's CEP should be reduced by any incremental revenue directly attributable to the capital investments made under the programs pursuant to the formula adopted in Vectren
- The CEP should be subject to a cap for the period during which deferrals are being accrued. Specifically, DEO should be allowed to accrue deferrals under the CEP until the accrued deferrals, if included in DEO's residential service rates, would cause the rates charged to residential customers to increase by more than $1.50 per month. If deferrals exceed the $1.50 per month threshold, DEO will stop accruing future CEP deferrals until it files for authority to recover existing accrued deferrals. DEO is not precluded from submitting an application to the Commission for a subsequent adjustment to the cap in response to changes in applicable laws, regulations, or compliance activities related to pipeline safety.
- DEO will file annual informational filings regarding its CEP on April 30, beginning in 2015. Within 30 days after each annual filing, Staff and any interested parties may file comments. If no comments are filed, DEO's CEP and related ongoing deferral authority shall be deemed approved. If comments are filed within 30 days, DEO shall be permitted 10 days to file reply comments. The Commission shall determine whether that year's filing shall be approved.
- DEO's annual filings shall consist of the following information: the CEP regulatory asset balance at December 31 of each year; calculations used to determine monthly deferred amounts, including a breakdown of investments in PISCC, depreciation expense, and property tax expense for each budget type; a breakdown of rate impact by customer class; capital budget for the calendar year in which the informational filing is made and the succeeding year; estimate of the effect that the deferred amounts would have on residential customer bills, if they were included in rates; schedules showing the calculations and inputs for deferrals; and explanation of any substantial deviation between the planned, estimated CEP expenditures and actual expenditures, where such substantial deviation would reasonably impede Staff's ability to monitor or review the filing. The first annual filing will include all of the above information, except for schedules showing the calculations and inputs for deferrals and explanation of any substantial deviation in estimated and actual CEP expenditures, for the 2013 and 2014 calendar years. All subsequent annual filings shall pertain to the immediately preceding calendar year.
- For purposes of these proceedings, DEO will not seek recovery of costs under the CEP more than one time in each calendar year.
- The parties recommend that the Commission find that the approvals requested in these proceedings under R.C. 4909.18 and 4929.111 to establish a CEP and for related

accounting authority are not for an increase in rates. Accordingly, the parties contend that the application, as modified by the joint surreply comments, should be considered an application not for an increase in rates and may be approved without a hearing.

- DEO and Staff agree that the joint surreply comments address the establishment of a CEP and accounting authority for related deferrals and that recovery of deferred amounts shall be considered in a separate proceeding.

As discussed on page 11, Section 19 of the Commission's Finding and Order dated October 1, 2014 in Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM, the Commission stated:

> R.C. 4929.111(A) provides that a natural gas company may file an application with the Commission under R.C. 4909.18, 4929.05, or 4929.11 to implement a CEP for any of the following:
>
> a. Any infrastructure expansion, infrastructure improvement, or infrastructure replacement programs;
>
> b. Any program to install, upgrade, or replace information technology systems; and
>
> c. Any program reasonably necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction.

The Commission ultimately approved DEO's application for a CEP in its Finding and Order dated October 1, 2014, as modified by the joint surreply comments noted above, subject to the Commission's review of the Company's annual informational filings and any comments or reply comments received in response.

# 5 FINANCIAL REVIEW- OVERVIEW

## Capital Expenditure Program – Duke Calculated Revenue Requirement

On May 3, 2019, in Case No. 19-1791-GA-ALT, DEO filed an application with the Commission pursuant to R.C. 4909.18, 4929.05, 4929.11 and 4929.111 in which it requested authority to implement an alternative regulation plan to establish Rider CEP., The purpose of which is to recover its PISCC, incremental depreciation expense, and property tax expense currently being deferred pursuant to the Company's CEP Deferral, as well as a return on and of the underlying assets for which the aforementioned expenses are directly attributable to DEO's CEP. DEO's application proposed that the Rider CEP rate design will be based on the billing determinants and revenue requirement authorized by the Commission in DEO's most recent gas rate case (i.e., Case No. 12-1685-GA-AIR, et al.).

DEO proposes to recover its CEP Deferral, and the corresponding assets to which the related expenses are directly attributable, by its calculated revenue requirement, which is based on cumulative plant investment for the period January 1, 2013 through December 31, 2018. As discussed on page 3 of the direct testimony of Company witness Jay Brown, pursuant to the Commission's Finding and Order in Case Nos. 13-2417-GA-UNC and 13-2418-GA-AAM, the Company was authorized to accrue CEP deferrals until the accrued deferrals, if included in rates, would cause residential customers rates to increase by more than $1.50 per month. Mr. Brown asserted in his testimony at page 3 that DEO had not reached the $1.50 per month cap with the deferrals of incremental depreciation expense, property tax expense, and PISCC as of December 31, 2018.

The Company filed several exhibits with its Application including Exhibit J - Additional Schedules Supporting the Application ("Exhibit J"). Included with Exhibit J is Schedule No. 1, which reflects the Company's calculated revenue requirement for the CEP deferral.

The Company's proposed revenue requirement and our recommended revenue requirement is shown on Attachment LA-1, Schedule No. 1, which is replicated in Exhibit 5-1 below.

## Exhibit 5-1. Duke Energy Ohio CEP Revenue Requirement Calculation

| Line | Description | Company Reference | Company Total (A) | Adjustments (B) | Adjusted (C) = (A) + (B) |
|---|---|---|---|---|---|
| | **Plant In-Service** | | | | |
| 1 | Additions | Schedule No. 4 Ln 9 (Sum of 2013 - 2018) | $ 341,830,234 | $ (898,452) | $ 340,931,782 |
| 2 | Original Cost Retired | Schedule No. 4 Ln 15 (Sum of 2013 - 2018) | $ 44,354,944 | $ - | $ 44,354,944 |
| 3 | Total Plant In-Service | | $ 297,475,290 | $ (898,452) | $ 296,576,838 |
| | **Less: Accumulation Provision for Depreciation** | | | | |
| 4 | Depreciation Expense | Schedule Nos. 5a & 5b | $ 21,273,627 | $ (71,992) | $ 21,201,635 |
| 5 | 2012 Rate Case Depreciation Offset | Schedule No. 11 Ln 5 | $ 225,989,904 | $ - | $ 225,989,904 |
| 6 | Original Cost Retired | Schedule No. 4 Ln 15 (Sum of 2013 - 2018) | $ 44,354,944 | $ - | $ 44,354,944 |
| 7 | Total Accumulated Provision for Depreciation | | $ (202,908,587) | $ 71,992 | $ (202,836,595) |
| 8 | **Net Plant In-Service** | Ln 3 + Ln 7 | $ 94,566,703 | $ (826,461) | $ 93,740,242 |
| | **Regulatory Assets** | | | | |
| 9 | Deferred Depreciation Expense | Schedule No. 3 Ln 1 | $ 21,273,627 | $ (71,992) | $ 21,201,635 |
| 10 | Post in Service Carrying Costs | Schedule No. 3 Ln 2 | $ 29,592,179 | $ (288,978) | $ 29,303,201 |
| 11 | Property Tax | Schedule No. 3 Ln 3 | $ 13,046,753 | $ 135,332 | $ 13,182,085 |
| 12 | Cumulative Offset for Incremental Revenue | Schedule No. 3 Ln 4 | $ (18,930,741) | $ - | $ (18,930,741) |
| 13 | Total Regulatory Assets | | $ 44,981,818 | $ (225,637) | $ 44,756,181 |
| | **Accumulated Deferred Income Taxes** | | | | |
| 14 | Accumulated Deferred Income Tax on Post in Service Carrying Costs | Line 10 x 21% | $ (6,214,358) | $ 60,685 | $ (6,153,672) |
| 15 | Accumulated Deferred Income Tax on Property Tax | Line 11 x 21% | $ (2,739,818) | $ (28,420) | $ (2,768,238) |
| 16 | Accumulated Deferred Income Tax on Cumulative Offset for Incremental Revenue | Line 12 x 21% | $ 3,975,456 | $ - | $ 3,975,456 |
| 17 | Accumulated Deferred Income Tax on Liberalized Depreciation | Schedule 12 Ln 6 | $ (36,809,812) | $ 72,876 | $ (36,736,936) |
| 18 | Total Accumulated Deferred Income Taxes | | $ (41,788,532) | $ 105,141 | $ (41,683,390) |
| 19 | Less: Earnings Based Capitalized Incentives Impact on Rate Base | | | $ (775,173) | $ (775,173) |
| 20 | **Net Rate Base** | | $ 97,759,989 | $ (1,722,130) | $ 96,037,860 |
| 21 | Approved Pre-tax Rate of Return | | 9.16% | 9.16% | 9.16% |
| 22 | **Annualized Return on Rate Base** | Line 20 x Line 21 | $ 8,954,815 | $ (157,747) | $ 8,797,068 |
| | **Operating Expenses** | | | | |
| 23 | Total Regulatory Assets | Line 13 Above | $ 44,981,818 | | $ 44,756,181 |
| 24 | Composite Depreciation Rate | | 2.54% | | 2.25% |
| 25 | Amortization of Regulatory Assets | Line 23 x Line 24 | $ 1,142,538 | $ (135,122) | $ 1,007,416 |
| 26 | Annualized Depreciation | Schedule 5a & Schedule 5b | $ 9,093,544 | $ (29,779) | $ 9,063,765 |
| 27 | Annualized Property Tax Expense | Schedule 7 | $ 5,705,526 | $ 33,053 | $ 5,738,579 |
| 28 | Total Annualized Operating Expenses | | $ 15,941,608 | $ (131,848) | $ 15,809,760 |
| 29 | **Total Revenue Requirement** | Sum Ln 22 - 28 | $ 24,896,423 | $ (289,595) | $ 24,606,828 |
| | **Allocation %** | | | | |
| 30 | Rate RS / RFT / RSLI | Case No. 12-1685-GA-AIR, Schedule E-3.2f, page 7 of 14 | 72.35% | | 72.35% |
| 31 | Rate GS / FT Small | | 7.46% | | 7.46% |
| 32 | Rate GS / FT Large | | 15.62% | | 15.62% |
| 33 | Rate IT | | 4.57% | | 4.57% |
| 34 | **Total Allocation** | | 100.00% | | 100.00% |
| | **Annual Revenue Requirement** | | | | |
| 35 | Rate RS / RFT / RSLI / RFTLI | Ln 29 x Ln 30 | $ 18,011,940 | $ (209,514.73) | $ 17,802,425 |
| 36 | Rate GS / FT Small | Ln 26 x Ln 31 | $ 1,858,070 | $ (21,613.05) | $ 1,836,457 |
| 37 | Rate GS / FT Large | Ln 26 x Ln 32 | $ 3,888,199 | $ (45,227.50) | $ 3,842,971 |
| 38 | Rate IT / GGIT | Ln 26 x Ln 33 | $ 1,138,215 | $ (13,239.70) | $ 1,124,975 |
| 39 | **Total Annual Revenue Requirement** | Sum Ln 32 - 35 | $ 24,896,423 | $ (289,595) | $ 24,606,828 |
| | **Annual Bills Issued** | | | | |
| 40 | Rate RS / RFT / RSLI / RFTLI | Schedule 3 Ln 25 | 4,836,307 | | 4,836,307 |
| 41 | Rate GS / FT Small | Schedule 3 Ln 26 | 255,797 | | 255,797 |
| 42 | Rate GS / FT Large | Schedule 3 Ln 27 | 85,973 | | 85,973 |
| 43 | Rate IT / GGIT | Schedule 3 Ln 28 | 881 | | 881 |
| | **Estimated Monthly Rate Impact** | | | | |
| 44 | Rate RS / RFT / RSLI / RFTLI | Ln 35 ÷ Ln 40 | $ 3.72 | $ (0.04) | $ 3.68 |
| 45 | Rate GS / FT Small | Ln 36 ÷ Ln 41 | $ 7.26 | $ (0.08) | $ 7.18 |
| 46 | Rate GS / FT Large | Ln 37 ÷ Ln 42 | $ 45.23 | $ (0.53) | $ 44.70 |
| 47 | Rate IT / GGIT | Ln 38 ÷ Ln 43 | $ 1,291.96 | $ (15.03) | $ 1,276.93 |

As shown in column A of the exhibit above at lines 1-3, the Company's revenue requirement calculation starts with total plant in-service, adjusted for retirements for adjusted plant in-service totaling $297,475,290. This amount is then offset by the accumulated provision for depreciation (lines 4-7), which is comprised of depreciation expense of $21,273,627, the 2012 rate case depreciation offset of $225,989,904 (see additional discussion below) and the original cost retired of $44,354,954 for a total accumulated provision for depreciation of $202,908,587, which results in net plant in-service of $94,566,703 as shown on line 8. As shown in column C, after reflecting our recommended adjustments to plant in-service and accumulated depreciation, our adjusted net plant in service is $93,740,242, or $826,461 lower than what DEO proposed.

The Company's revenue requirement calculation in column A then includes the CEP Deferral regulatory assets (lines 9-13) for depreciation expense of $21,273,627, PISCC of $29,592,179 and property tax expense of $13,046,753.  In addition, the Company included an offset for incremental revenue in the credit amount of $18,930,741, which results in the regulatory assets netting to $44,981,818.  According to Mr. Brown's direct testimony, the offset for incremental revenue relates to revenue earned that is attributed to the CEP investments being requested for recovery in Rider CEP.[15]  As shown in column C, after giving effect to our recommended adjustments, our adjusted regulatory assets total $44,756,181, or $225,637 lower than DEO's proposed amount.

Lines 14-18 of the Company's revenue requirement calculation include an offset for ADIT that have been calculated for the PISCC, deferred property tax expense and the offset for incremental revenue using the federal corporate income tax rate of 21%.  In addition, DEO included an offset for liberalized depreciation for a total ADIT offset of $41,788,532.  As shown in column C, after giving effect to our recommended adjustments, our adjusted ADIT totals $41,683,390 or $105,141 lower than DEO's proposed amount.

The sum of all the items discussed above as proposed by DEO results in a net rate base amount of $97,759,989.  The Company then multiplied this amount by 9.16%, which is the approved pre-tax rate of return that was set in accordance with the Stipulation in Case No. 12-1685-GA-AIR.  Note A at the bottom of Exhibit J, Schedule No. 1 states that upon the Tax Cut and Jobs Act of 2017 ("TCJA") being enacted, the pre-tax rate of return was adjusted to reflect the reduction of the federal corporate income tax rate from 35% to 21%.[16]Applying the pre-tax rate of return to the net rate base results in an annualized return on rate base of $8,954,815, as shown on line 21 of Exhibit 4-1.  As shown in column B, we have reduced rate base by an additional $775,173, which relates to our recommendation to remove earnings-based incentive compensation and stock-based compensation from CEP plant in-service.  As shown in column C, after reflecting that adjustment and our adjusted ADIT, we recommend a net rate base amount of $96,037,860.  Upon applying the 9.16% rate of return, our recommended annualized return on rate base is $8,797,068.

Lines 22-25 of column A Exhibit 5-1 above reflect the Company's proposed operating expenses for (1) the amortization of the regulatory assets of $1,142,538 (see additional discussion below), (2) annualized deprecation of $9,093,544, and (3) annualized property tax expense of $5,705,526 for total annualized operating expenses of $15,941,608.  The sum of this amount and the annualized return on rate base of $8,954,815 results in a total revenue requirement of $24,896,423 as shown on line 26 of Exhibit 4-1.  As shown in column C, after giving effect to our recommended adjustments to operating expenses, we are recommending a total revenue requirement of $24,606,828, which is $289,595 lower than DEO's proposed revenue requirement.

Lines 30-47 show how the Company's proposed and Larkin's proposed revenue requirements would be allocated among the Company's rate classes, including the estimated monthly rate impacts.

[15] See the direct testimony of DEO witness Jay Brown at page 5, lines 20-22.
[16] See the response to LARKIN-DR-01-42 for the calculation of the 9.16% pre-tax rate of return.

2012 Depreciation Offset

As noted above, the Company's CEP revenue requirement calculation includes the 2012 depreciation offset in the amount of $225,989,904. According to the DEO's response to LARKIN-DR-01-125, the 2012 depreciation offset is an estimate of the accumulated depreciation accrued from January 1, 2013 through December 31, 2018 related to plant balances. The Company stated that if the estimated accumulated depreciation had not been reflected as an offset, rate base would have been overstated because the Company's revenue requirement calculation would only reflect additions and not the corresponding accumulated depreciation that has accrued since the Company's most recent rate case (i.e., Case No. 12-1685-GA-AIR). The 2012 depreciation offset is discussed in more detail in a later section of our report.

Amortization of Regulatory Assets

As noted above, the operating expenses in the Company's CEP revenue requirement calculation includes the amortization of the regulatory assets (which total $44,981,818) in the amount of $1,142,538. Note B at the bottom of Exhibit J, Schedule No. 1 states: "For purposes of this calculation, Duke Energy Ohio used a composite depreciation rate calculated using data from the 2015 FERC Form 2." Specifically, the 2015 composite depreciation rate used by DEO is 2.54%, which was calculated by dividing the 2015 depreciation and amortization of $49,194,937 (page 337 of the 2015 FERC Form 2) and dividing it by the 2015 total gas plant in-service of $1,935,849,008 (page 209 of the 2015 FERC Form 2). The Company's use of the 2015 composite depreciation rate and our recommendation to use a composite depreciation rate of 2.25% is discussed in more detail in Chapter 9 of our report.

As discussed in Chapters 6, 7, 8, and 9 of our report, based on our review of the Company's CEP filing and workpapers, we are recommending adjustments which will impact the Company's revenue requirement calculation for the CEP Deferral.

# 6 DETAILED ANALYSIS, FINDINGS AND RECOMMENDATIONS

## Review Period

Larkin's review was focused on whether DEO has accurately accounted for its plant in-service and depreciation reserve as of December 31,2018, and whether those investments were used and useful, necessary, reasonable, and prudent. Our review included all capital assets from the Company's most recent rate case (i.e., a date certain of March 31,2012 as set forth in Case No. 12-1685-GA-AIR) through December 31, 2018, with a focus on CEP expenditures from January 1, 2013 through December 31,2018.

The following sections discuss Larkin's review of the Company's processes and controls, variance analysis and detailed transaction testing. We have also included a summary of our findings and recommendations, including recommended adjustments.

Larkin did not perform a management audit, but did review DEO's processes and controls to ensure that they were sufficient and did not adversely affect the plant balances in distribution and general net plant in-service. Based on the documents we reviewed, Larkin obtained an understanding of the Company's processes and controls. In addition, Larkin reviewed internal audit reports that were conducted on various areas of DEO's operations such that they could affect the utility plant in-service balances. In addition to reviewing the Company's formal policies and procedures, Larkin conducted telephone interviews, which focused on understanding the processes and any changes that have been made during the period March 31, 2012 through December 31, 2018.

## Capitalization and Budgeting Policies

We requested that DEO provide its capital budgeting and planning activities, including (1) forecasting methods; (2) risk assessment practices; and (3) prioritization methods for addressing risk. In its response to LARKIN-DR-01-009, the Company stated:

> Duke Energy's Financial Planning and Analysis ("FP&A") department manages an annual budgeting process that includes input from multiple groups across the Company. The process uses a "bottoms-up" approach that consists of several phases. To start, each functional organization that performs work for Duke Energy Ohio receives capital budget guidelines provided by Duke Energy's FP&A Department. In coordination with their budgeting partners, the functions then develop capital budgets, which are informed and prioritized by business objectives. The results of these budgets are reviewed by the respective leaders in each function.

During the budget process, functional teams work to develop capital budgets and prioritize investments based on many factors, including: regulatory and compliance requirements, customer requirements, system reliability, the integrated resource plan for each jurisdiction, capital constraints, and business objectives. As part of this work, the Company then engages in a capital optimization process, which compares and prioritizes capital projects across functions.

The Company's written guidelines and/or policies and procedures related to capital spending (i.e., plant additions, new construction, plant replacement, and plant retirements) during the period March 31, 2012 through December 31, 2018 are contained in the Duke Energy Capitalization Guidelines (Consolidated Guidelines), which were provided in the confidential response to LARKIN-DR-01-010. DEO provided five different versions of the capitalization guidelines, which were dated as follows: January 1, 2010 ("2010 version"); January 1, 2014 ("2014 version"), January 1, 2016 ("2016 version"), January 1, 2017 ("2017 version") and January 1, 2018 ("2018 version"). Each version of the capitalization guidelines were voluminous at upwards of 200 pages. In addition, the Executive Brief section of each version stated that [redacted]

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[17] The attachments provided in response to LARKIN-DR-01-60 (for 2013-2018) indicate that DEO calculates AFUDC in accordance with FERC Order No. 561, which was issued on October 22, 1993.

[redacted]

[redacted]

[redacted]

With all of these different versions of its capitalization guidelines, we asked the Company to clarify (i.e., identify and explain any significant changes in capitalization policy during the period 2012 through 2018), and specifically, how such changes during that period affected the accounting for DEO gas utility and/or CEP investments in any year. In its response to LARKIN-DR-01-87, the Company stated that one significant change resulting from new FASB or FERC guidance was follows:

> 2016 forward: Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. The FASB guidance in ASU 2015-05 which clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software under ASC 350-40.

As it relates to DEO's gas utility and/or CEP investments in 2016 and forward, DEO stated that the change noted in the passage above would only affect DEO's accounting to the extent that cloud based applications were capitalized.[18]The Company confirmed in its response to LARKIN-DR-01-137 that no amounts related to cloud computing were capitalized for DEO Gas in either 2016, 2017, or 2018. In addition, while there amounts capitalized for cloud computing for DEO affiliates in 2016, 2017 and 2018, none of these amounts were charged or allocated to DEO Gas.

There were no major events during the period January 1, 2013 through December 31, 2018 that impacted the Company's plant in-service balances.[19]

<u>Conclusion</u>

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[18] See the response to LARKIN-DR-01-87(b).
[19] See the response to LARKIN-DR-01-46.

Larkin concluded that the Company's capitalization guidelines, policies, and procedures are not unreasonable.

## Internal Audits

We requested that DEO identify and provide all internal audits that were conducted for the period March 31, 2012 through December 31, 2018 in the following areas: (1) CEP; (2) capital expenditures; (3) continuing property records; (4) capitalization of costs; (5) accounting for overhead costs; and (6) property taxes. In its response to LARKIN-DR-01-21, the Company stated that no internal audits had been conducted in the foregoing areas during the period March 31, 2012 through December 31, 2018.

Based on the foregoing, we expanded our request by asking DEO to provide a listing of (1) all internal audits that were conducted by or of the Company in 2012-2019; (2) all internal audits that were conducted by or of any affiliates that charged costs to DEO in 2012-2019; (3) all of the Company's SOX compliance audits on internal controls that were conducted on the Company in 2012-2019; and (4) all FERC audits that were conducted on the Company in 2012-2018. In its response to LARKIN-DR-01-28, the Company provided a confidential list of all internal audits conducted for the first and second categories listed above. With regard to DEO's SOX compliance audits on internal controls, the Company referred to the opinion on internal controls over financial reporting that is provided as part of its annual financial statement audit each year. In addition, DEO stated that there were no FERC audits conducted in years 2012 through 2019.

We reviewed the confidential listings and selected several internal audits for each year 2013 through 2018, which the Company provided in its confidential response to LARKIN-DR-01-41. Of all the internal audit reports we selected and reviewed, the vast majority had no reportable conditions. However, there were a few internal audit reports, that we discussed with the Company during the telephone interview conducted on January 21, 2020. During the interview, the Company stated that it has a formal system in place to track the internal audit reports and holds the Company accountable when issues are encountered and that the Internal Audit Department goes back and validates that management implements corrections and/or mitigates any issues disclosed by the Internal Audit Department.

Larkin also reviewed the opinions on internal controls over financial reporting in the Company's annual financial statement audits and found no issues reported. With regard to CEP, the Company stated during the telephone interview that CEP "exists on a spreadsheet" and is limited to certain individuals, and that there is no formal program for CEP for which an internal audit can be conducted.

Internal controls over the CEP spreadsheet and updating it periodically should be established.

## Historical Plant Balances

Larkin reviewed the information provided on the plant in-service schedules to confirm the reasonableness of the balances. Specifically, these schedules included the Company's plant in-service by major plant groupings on Schedule B-2, plant in service by account and subaccount on

Schedule B-2.1, and gross additions, retirements and transfers on Schedule B-2.3. In addition, the Company provided a breakout by year of the gross additions, retirements, and transfers on Workpaper WPB-2.3. The information on WPB-2.3 ties into the aforementioned B schedules and is the schedule we used to confirm the total Company plant in-service balances.

We reviewed the gross additions, retirements, and transfers on WPB-2.3 and compared them to DEO's historical plant records, which the Company provided in response to LARKIN-DR-01-001. We were able to tie out the majority of the amounts reflected on WPB-2.3 to the historical plant records. However, for 2018, we noted a number of significant differences between the retirements listed in the historical plant records to what DEO included on WPB-2.3. We asked DEO to reconcile each of the discrepancies noted. In its response to LARKIN-DR-01-40, the Company provided the following explanation:

> As of December 31, 2018, there was a retirement entry that was recorded only within the general ledger and not within the fixed asset system. The entry applies to the various Company plant accounts as shown below. The second column shows the grouping within WPB-2.3a where the on-top was reflected. This entry was not in the fixed asset system so is not in the historical plant records within DR01-001, but had to be added to WPB-2.3 so that it can tie to the G/L.

The schedule referenced in the passage above is replicated in the following exhibit:

### Exhibit 6-1. 2018 Retirement Entries

| Category | Company Account | Per WPB 2.3 | ARC Failure Adjustment |
|---|---|---|---|
| Common | 19000 | 1900 | $ (4,193,293) |
| | 19100 | 1910 | $ (312,525) |
| | 19700 | 1970 | $ (720,579) |
| | 19800 | 1980 | $ (8,586) |
| | | Common | $ (5,234,984) |
| | | | |
| Distribution | 27401 | 2741 | $ (111,953) |
| | 27500 | 2750 | $ (61,317) |
| | 27602 | combined below | $ (1,571,655) |
| | 27605 | combined below | $ (3,930,096) |
| | 27607 | combined below | $ (963,009) |
| | | 2762, 2765, 2767, 2769 | $ (6,464,760) |
| | | | |
| | 27603 | combined below | $ (2,106,594) |
| | 27608 | combined below | $ (1,205,778) |
| | | 2763, 2768 | $ (3,312,372) |
| | | | |
| | 27800 | 2780 | $ (2,462,673) |
| | 27801 | 2781 | $ (460,749) |
| | 27802 | 2782 | $ (405,506) |
| | 27900 | 2790 | $ (108,563) |
| | 28003 | combined below | $ (8,473) |
| | 28006 | combined below | $ (1,271) |
| | | 2803, 2805, 2806, 2807 | $ (9,744) |
| | | | |
| | 28500 | 2850 | $ (3,204) |
| | | | |
| General | 19000 | 2900 | $ (2,140) |
| | 29100 | 2910 | $ (150,291) |
| | 29500 | 2950 | $ (1,396) |
| | 29700 | 2970 | $ (3,652) |
| | | | |
| Intangibles | 20300 | 2030 | $ (6,560) |
| | | | |
| Manufactured | 20500 | 2050 | $ (39,372) |
| | 21100 | 2110 | $ (267,186) |
| | | Gas | $ (13,871,438) |

Source: LARKIN-01-40

As shown in the exhibit above, the adjustment related to the discrepancies totals $13,871,438 (see additional discussion below).

The response to LARKIN-DR-01-001 included Attachment H, which the Company stated is a reconciliation to FERC by rider and other exclusions. This reconciliation is replicated in the exhibit below:

## Exhibit 6-2.  Reconciliations to FERC by Rider and Other Exclusions

| Line No. | Description | Beginning Balance | 4/1/2012/ 12/31/2012 | Year 2013 | Year 2014 | Year 2015 | Year 2016 | Year 2017 | Year 2018 | Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Production Plant | $ 11,408,390 | $ 4,440,233 | $ 1,135,320 | $ (168,071) | $ 905,949 | $ 17,729,779 | $ (17,104,469) | $ 787,658 | $ 19,134,791 |
| 2 | Distribution Plant | $ 1,528,869,449 | $ 61,097,124 | $ 92,161,053 | $ 85,160,983 | $ 57,419,101 | $ 99,882,033 | $ 61,848,646 | $ 78,778,689 | $ 2,065,217,077 |
| 3 | General Plant | $ 28,540,790 | $ 29,009,755 | $ 7,472,398 | $ 4,454,435 | $ 948,756 | $ 7,885,075 | $ 16,327,880 | $ 17,604,224 | $ 112,243,311 |
| 4 | Common Plant | $ 316,993,656 | $ 9,594,656 | $ 54,319,406 | $ 20,778,068 | $ (54,111,529) | $ (3,036,587) | $ 17,426,176 | $ 4,334,919 | $ 366,298,764 |
| 5 | Total Additions, Retirements & Transfers B schedules | $ 1,885,812,285 | $ 104,141,768 | $ 155,088,177 | $ 110,225,415 | $ 5,162,278 | $ 122,460,299 | $ 78,498,232 | $ 101,505,490 | $ 2,562,893,944 |
| 6 | CEP B SCH Year End Balances | $ 1,885,812,285 | $ 1,989,954,053 | $ 2,145,042,229 | $ 2,255,267,644 | $ 2,260,429,922 | $ 2,382,890,222 | $ 2,461,388,454 | $ 2,562,893,944 | |
| 7 | CEP B SCH Year End Balances w/o Common | $ 1,568,818,629 | $ 1,663,365,741 | $ 1,764,134,511 | $ 1,853,581,858 | $ 1,912,855,665 | $ 2,038,352,552 | $ 2,099,424,608 | $ 2,196,595,179 | |
| 8 | Reconciling Item 375 / 2750 / Structures & Improvements | | | | | $ (72,132) | $ (16,844,341) | | | |
| 9 | Reconciling Item 381 / 2810, 2811 / Meters | | | | | $ 23,065,474 | | | | |
| 10 | FERC Form 2 Gas Plant in Service | | $ 1 663 365 740 | $ 1 764 134 512 | $ 1 853 581 859 | $ 1 935 849 008 | $ 2 021 508 212 | $ 2 099 424 610 | $ 2 196 595 180 | |
| 11 | Incremental Gas Plant In-service | | $ 94,547,112 | $ 100,768,771 | $ 89,447,347 | $ 82,267,149 | $ 85,659,204 | $ 77,916,397 | $ 97,170,571 | |
| | **Reconciling Items** | | | | | | | | | |
| 12 | CEP | | | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 |
| 13 | AMRP | | $ 67,056,748 | $ 65,237,342 | $ 59,952,369 | $ 38,324,708 | | | | |
| 14 | Rider AU | | $ 12,416,689 | $ 23,333,565 | $ 5,033,648 | $ (151,995) | | | | |
| 15 | Less Rider AU Common | | $ (5,531,194) | $ (8,291,903) | $ (2,796,044) | $ 2,580 | | | | |
| 16 | Less Rider AU Acct 17001 | | $ (866,164) | $ (7,988,510) | $ (675,242) | $ 2,518 | | | | |
| 17 | Production plant is not included in Rider CEP | | $ 4,440,233 | $ 1,135,320 | $ (168,071) | $ 905,949 | $ 17,729,779 | $ (17,104,469) | $ 787,658 | |
| 18 | Plant placed in service 4/1/12 - 12/31/12 is not included in Rider CEP | | $ 17,302,659 | | | | | | | |
| 19 | Accelerated Service Line Replacement Program is not included in Rider CEP | | | | | $ 1,685,700 | $ 10,511,649 | $ 8,317,312 | $ 11,798,827 | |
| 20 | Asset Retirement Obligation Costs are not included in Rider CEP | | $ (416,600) | $ (1,052,563) | $ - | $ 2,499,347 | $ 1,942,551 | $ 4,836,617 | $ 550,864 | |
| 21 | Business Unit 75027 in Account 20300 - Misc Intangible Plant is not included in CEP | | $ 144,740 | $ 0 | $ 418,084 | $ 309,628 | $ 3,408,085 | $ 90,045 | $ 7,600,586 | |
| 22 | 2018 Retirement On-Top entry not included in Rider CEP | | | | | | | | $ (13,558,319) | |
| 23 | Projects started prior to 2013 placed in Service after 2013 not included in Rider CEP | | | $ 9,662,268 | $ 3,137,406 | $ 648,700 | $ 265,939 | $ 304,318 | | |
| 24 | Other | | $ - | $ 1,055,540 | $ 1,752,285 | $ 569,031 | $ 1,887,343 | $ 1,904,422 | $ (60,722) | |
| 25 | Total | | $ 94,547,112 | $ 100,768,771 | $ 89,447,347 | $ 82,267,149 | $ 85,659,204 | $ 77,916,397 | $ 97,170,571 | |
| 26 | Source LARKIN-DR-01-001, Attachment H | | | | | | | | | |

By way of explanation, the amounts shown on lines 1-5 in the exhibit above are the historical total Company plant in-service amounts for the period April 1, 2012 through December 31, 2018.  These amounts tie back to Company Exhibit I, Schedule B-2.1 - Plant In-Service By Accounts and Subaccounts.  Lines 6 and 7 show the cumulative year-end balances with and without common plant included.  The Company stated that the reconciling items on lines 8 and 9 reflect CEP filing data that is off by one year.  The 2015 reconciling item of $23,065,474 relates to what the Company referred to an "un-retirement".[20]  The 2016 reconciling item of $16,844,341 relates to the construction costs associated with the Kellogg Eastern Gas Operations Center, which was placed into service in 2017.[21]  After reflecting the reconciling items, the totals tie to the Company's filed FERC Form 2's as shown on line 10.  Line 11 reflects the incremental gas plant in-service (i.e., lines 1-3 and the reconciling items on lines 8-9).

As shown on line12, the Company has broken out the amounts included in CEP, which total $297,475,290, which tie out to Exhibit J, Schedule No. 1 from DEO's CEP filing.  In addition, Rider AMRP and Rider AU amounts as well as various other items that have been excluded from CEP expenditures are shown on lines 13-24 with the totals on line 25 equaling the total Company incremental gas plant in-service amounts on line 11.

With regard to Rider AMRP and Rider AU (and common allocations to Rider AU), those riders ceased as of 2014 and 2015, respectively.  Therefore, as explained in the response to LARKIN-DR-01-47, once those riders ended, projects that would have been included in them shifted over to CEP.

With regard to the other reconciling items shown on lines 17-24 in the exhibit above, DEO provided the following explanations:

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[20] This "un-retirement" is discussed in further detail in Chapter 8 of this report.

[21] As discussed in Chapter 6 under the Field Inspections and Table Top Reviews section, this facility was the subject of a table top review and video walkthrough.

- Line 17: During the telephone interview on January 21, 2020, the Company stated that it took the conservative approach that production plant should not be included in CEP.
- Line 18: Plant into service prior to 2013 is not included in CEP.
- Line 19: Per the response to LARKIN-DR-01-50, the Service Line Replacement Program costs were excluded from CEP because the Company had previously proposed that these costs be recovered through a separate rider (Rider ASRP), but that this rider was never implemented.
- Line 20: Per the response to LARKIN-DR-01-50, Asset Retirement Obligation ("ARO") costs were excluded because (1) DEO already charges depreciation to a separate regulatory asset account, and (2) ARO costs have been removed from rate base in previous rate cases.
- Line 21: Per the response to LARKIN-DR-01-50, Business Unit 75027 was excluded in error.
- Line 22: See below.
- Line 23: Per the response to LARKIN-DR-01-50, projects prior to 2013 were excluded because the CEP deferral was approved for 2013 and forward. While the projects listed on line 23 were placed into service after 2013, the Company took a conservative approach and chose not to defer the costs of these projects since the start date was prior to 2013.
- Line 24: Per the response to LARKIN-DR-01-50, the Company did not identify the additional excluded items embedded in the "Other" category.

With regard to the 2018 Retirement On-Top entry in the amount of $13,558,319, this relates to the 2018 retirement adjustment discussed above and broken out in Exhibit 6-1. According to the response to LARKIN-DR-01-50, this On-Top entry was excluded because only data from PowerPlan (DEO's plant accounting system) is queried to identify CEP projects. The exhibit below reconciles the difference between the $13,871,438 shown in Exhibit 6-1 above and the $13,558,319 On-Top Entry.

### Exhibit 6-3. Reconciliation of 2018 On-Top Entry

| **Description** | **Amount** |
|---|---|
| LARKIN-DR-01-40 Attachment | $ (13,871,438) |
| LARKIN-DR-01-001 Attachment H | $ (13,558,319) |
| Difference | $ (313,119) |
| | |
| Intangibles - Acct 20300 Inadvertently Excluded | $ (6,560) |
| Manufactured - Accts 20500 & 21100 | $ (306,558) |
| Unexplained Difference | $ (1) |
| Total | $ (313,119) |
| Source: LARKIN-DR-01-85 | |

The response to LARKIN-DR-01-85 stated that the $13,558,319 On-Top entry was excluded from the 2018 CEP costs of $90,051,676 as On-Top entries have historically been excluded from CEP deferral calculations. In addition, the Company chose to exclude common plant from CEP due to the complexity of tracking allocated assets with various annual allocation factors.[22]

Conclusion

Based on the foregoing, including the Company's explanations for the discrepancies discussed above, we are satisfied that the Company's historical plant records are accurate.

As discussed in Chapter 9 of this report, we are recommending adjustments which impact the CEP plant balances, which in turn, impact the total Company plant balances. The impacts of our recommended CEP-related adjustments to the total Company plant balances are shown on Attachment LA-2.

## Detailed Transactional Testing

For the period 2013 through 2018, the Company provided a list of 3,216 work orders, which are identified by Project ID number in its response to LARKIN-DR-01-35. Of the 3,216 total work orders, 1,737 were CEP-related as shown in the exhibit below:

**Exhibit 6-4. Summary of Project ID Work Orders**

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|
| CEP-Related Projects | 146 | 199 | 266 | 474 | 319 | 333 | 1,737 |
| Non-CEP Projects | 395 | 386 | 258 | 157 | 122 | 161 | 1,479 |
| Total Projects | 541 | 585 | 524 | 631 | 441 | 494 | 3,216 |
| Source: LARKIN-DR-01-35 | | | | | | | |

Using the list of Project ID work orders summarized above, we selected a sample of project work orders in accordance to the sampling guidelines discussed below.

### *Audit Sampling*

Larkin used the guidance provided in the American Institute of Certified Public Accountants Audit Guide-Audit Sampling dated March 1, 2014 ("AICPA Audit Sampling Guide" or "Sampling Guide"). Paragraphs 3.96 and 4.07 of the AICPA Audit Sampling guide listed a number of key items that are commonly documented for audit samples. Each of these items is discussed below.

[22] See the response to LARKIN-DR-01-50(d).

### ***The objectives of the test and the accounts and assertions affected.***

The objectives of this audit test are to ascertain whether the balances recorded by DEO for the CEP expenditures have been appropriately recorded and the costs relate to the CEP and are reasonable and prudent with respect to the capital expenditures that qualify as CEP. This objective is thus deeper than merely matching the amount of the vendor invoice with the amount recorded by DEO in the general ledger. The detail of the capital expenditures need to be reviewed, with an understanding of how it relates to the CEP, and whether the costs are necessary, reasonable, and prudent.

### ***The definition of the population and the sampling unit, including how the auditor considered the completeness of the population.***

The Sample Guide at paragraph 4.06 indicates that:

> The population consists of the items constituting the account balance or class of transactions of interest subject to audit sampling. It is best practice for the auditor to determine at the beginning of the sampling application that the population from which he or she selects the sample is appropriate for the specific audit objective, because sample results can be projected only to the population from which the sample was selected.

The Sample Guide at paragraph 4.07 includes the following guidance about testing debit and credit balance items:

> Because the nature of the transactions resulting in debit balances, credit balances, and zero balances typically differ, the audit considerations might also differ because the risks and relevant assertions may differ. Therefore, the auditor usually considers whether the population to be sampled should include all those items together. For example, a retailer's accounts-receivable balance may include both debit and credit balances. The debit balances may result from customer sales on credit, whereas the credit balances might result from advance payments or credit memos and therefore represent liabilities. The audit objectives and assertions for testing those debit and credit balances might be different (for example, the auditor might be more concerned about completeness of credit balances versus existence for the debit balances). If the amount of credit balances is significant, the auditor might find it more effective and efficient to perform separate tests of the debit balances and the credit balances. In that case, the debit and credit balances might be defined as separate populations for the purpose of audit sampling.

The AICPA Audit Sampling Guide at paragraph 4.13 states that:

> A sampling unit is any of the individual elements that constitute the population. The auditor identifies a sampling unit for a particular audit sampling application. A sampling unit might be a customer account balance, an individual transaction,

or an individual entry within a transaction (for example, an individual line item included on a sales invoice)

The Sampling Guide at paragraph 4.14 indicates that the effectiveness and efficiency in relation to the objective of the test should be considered, and the ease of applying alternative procedures may also be a consideration.

### ***The definition of a misstatement.***

A misstatement is defined as a CEP expenditure amount in the project ID listings provided by DEO which cannot be verified to selected invoices or other documentation. A misstatement also includes vendor dollars recorded by DEO to the CEP which are determined to not be necessary and/or determined to be unreasonable for the CEP expenditures.

### ***The risk of incorrect acceptance or level of desired assurance (confidence).***

AU section 350, Audit Sampling (AICPA, Professional Standards), discusses the specific terms and risk of assessing control risk too low (when sampling for tests of controls) and risk of incorrect acceptance (for substantive testing). Paragraph 1.289(a) of the Sampling Guide, indicates that in the case of a test of details, there is a risk that a material misstatement does not exist when, in fact, it does. The auditor is primarily concerned with this type of erroneous conclusion because it affects audit effectiveness and is more likely to lead to an inappropriate audit opinion.

### ***The risk of incorrect rejection, if used.***

The risk of incorrect rejection for substantive tests refers to a situation where a test of details suggests that a material misstatement exists when, in fact, it does not. This type of erroneous conclusion affects audit efficiency because it would usually lead to additional work to establish that inclusion conclusions were incorrect. (See, e.g., paragraph 1.289(b) of the Sampling Guide.)

### ***Estimated and tolerable misstatement.***

The AICPA Professional Standards at AU-C section 530, Audit Sampling suggests that the auditor examine separately those items of high risk or for which accepting some sampling risk is not justified. According to paragraph .A15 of AU-C section 530, “the auditor might first separately examine those items deemed to be of relatively high risk and then use audit sampling … to form an estimate of some characteristic of the remaining population.” For example, individually material items or high risk items might be selected and tested 100 percent before sampling the remainder.

Paragraph 6.17 of the Sample Guide states that:

Items in the population with negative balances require special consideration, usually because they have different risk characteristics. One way is to exclude them from the selection process and test them separately. Another approach is to change the sign of the negative items and add them to the positive population before selection, thereby testing the entire population in one sample. The latter approach is typically used only when there are few negative items and few or no misstatements expected, as the evaluation of misstatements involving negative items that were included in the population may necessitate the assistance of a statistical sampling specialist to interpret the results. Some auditors therefore use only the former approach.

***<u>The audit sampling technique used.</u>***

The sampling technique used involved stratifying the population by the dollar amounts of the CEP-related project IDs (work orders). To facilitate the verification of work orders charged to CEP expenditures for each year 2013 through 2018, the population of work orders was stratified each year into the following groups by work order dollar amounts:

1) Work orders ranging between 60%-70% of the total CEP expenditures for each year (see below) were all selected for review.
2) Work orders between $100,000 and $2.6 million.
3) Work orders between $10,000 and $100,000.
4) Work orders below $10,000 and credit up to -$10,000.
5) Work orders showing credits of -$10,000 or more. All (i.e., 100%) of the credit balance items of more than $10,000 were selected for review.

With regard to category 1, the percentage of work orders selected for each year 2013 through 2018 were as follows:

### Exhibit 6-5. Percentage of Work Orders Selected For Sampling - 2013 through 2018

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| Work Orders Selected for Sample | $ 15,271,964 | $ 16,572,912 | $ 25,837,584 | $ 40,778,619 | $ 49,796,410 | $ 58,253,757 |
| Total Work Orders | $ 21,836,708 | $ 26,323,191 | $ 42,285,969 | $ 68,466,517 | $ 77,798,257 | $ 95,136,703 |
| Percentage of Work Order Selected | 70% | 63% | 61% | 60% | 64% | 61% |

For categories 1 and 5, all work orders (a 100% sample based on auditor judgment) were selected for review. For categories 2, 3 and 4, work orders were randomly selected from each of those populations by applying a random-number generator in Excel to the listing of CEP-related work orders provided by DEO.

For each year 2013 through 2018, we requested that the Company provide the following information for each Project ID work order selected in our sample:

- A detailed description, scope, and objective of the work, including service area location and any other identifiers, such as budget mapping.
- Work order justification and approval at the highest approval level available based on the nature of the work order.
- Estimated in-service date and actual in-service date.
- 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 10%.
- 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 codes descriptions would include such information as payroll, contractor charges, overheads, other allocations, materials and supplies, transportation, and employee expenses.
- Supporting detail for retirements, cost of removal and salvage, if applicable, charged or credited to plant. Provide the description, units, amount, and date recorded.

The Company provided the Project ID work orders from our selected samples for each year in its responses to LARKIN-DR-01-64 (2013); LARKIN-DR-01-65 (2014); LARKIN-DR-01-66 (2015); LARKIN-DR-01-67 (2016); LARKIN-DR-01-68 (2017); and LARKIN-DR-01-69 (2018).

Based on our review of the Project ID work order detail provided in the responses listed above, Larkin is satisfied that the Company's work order system is generally functioning as intended. However, as discussed below, there have been problems with projects being properly unitized once they are completed and placed into service.

## Insurance Recoveries

The Company has not had any significant distribution or general plant events that resulted in an insurance claim recovery of $50,000 or greater during the period 2013 through 2018 nor were there any pending distribution or general plant insurance claims as of December 31, 2018 that are recorded or accrued that would be charged to capital.[23]

## Unitization Backlog

In its response to LARKIN-DR-01-37(g), the Company described its unitization process as follows:

> CEP assets are unitized using the same unitization process as other assets. Unitization is a cost allocation process which provides costs and quantities for individual retirement units charged to a capital project. Unitization occurs for

[23] See the response to LARKIN-DR-01-61.

> projects which have been moved from work in progress-CWIP account 107 to completed construction-not classified-account 106; and are closed for all charges. The cost of an asset is derived from actual charges. The costs are allocated (break down) to the utility accounts using the latest "as-built" or the latest "estimate" on the project. The resulting unitization journal moves the project cost from the completed construction-not classified account 106 to the completed construction-classified account 101-Plan t in service.

Upon reviewing the work order detail (identified by Project ID number) that was provided in response to LARKIN-DR-01-35, we noted that for each year 2013 through 2018, there were many completed projects that have not been unitized. In response to our inquiry for why so many projects have not been unitized, in its response to LARKIN-DR-01-70, the Company provided the following explanation:

> The unitization process entails manual touchpoints in order to finalize the projects constructed and/or retired, and ensure the reasonableness of our asset records. Historically, this activity has fallen behind due to either lack of staffing focus on this effort, or overcoming other setbacks such as system conversions. In 2019, the Central Project Accounting group began a coordinated effort to address the lagging unitizations and we achieved more unitizations in 2019 than what was achieved in the preceding 4 years (2015-2018). This also exceeded the unitization amounts accomplished in 2014 when Duke employed a significant focus to catch up the unitization backlog. We will continue this focus and execution in 2020 and beyond in order to address the remainder of the backlog.

We recommend that the Company continue its efforts to address the unitization backlog discussed above in order for the Company to properly reflect completed projects that are in-service as unitized.

## Field Inspections and Table Top Reviews

For the field inspections and table top reviews, Larkin selected four projects, several of which had multiple assets. The following criteria were used for the field inspection and/or table top review:

- The assets were operational (used and useful) and providing service to DEO's ratepayers.
- 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 Larkin and Staff with detailed answers to questions about the work.
- Problems identified during the process of construction were identified and discussed.

- The project was not overbuilt.

The four projects selected for field inspections and/or table top reviews included (1) the Dicks Creek Project, (2) the Kellogg Eastern Gas Operations Center, (3) Line A000b, and (4) Line D000b.

The physical onsite field inspections for Dicks Creek and the Eastern Gas Ops Center were scheduled to be conducted by Larkin and the Commission Staff on Monday, March 16, 2020. However, due to the COVID-19, on March 14, 2020, management at DEO restricted anyone other than Company personnel to be on its premises, thus the onsite field visit was cancelled. As the COVID-19 pandemic worsened over the weeks that followed, resulting in statewide stay-home orders (for both Michigan and Ohio), Larkin, Staff, and the Company discussed ways in which the onsite field visits could be conducted remotely. Through these discussions, it was ultimately determined that the most efficient manner in which to conduct the field inspections for Dicks Creek and the Eastern Gas Ops Center, in lieu of physically visiting these facilities, was through a combination of (1) table top reviews and review of as-built diagrams using Microsoft Team Meetings, and (2) a member of DEO personnel conducting walkthroughs of both Dicks Creek and the Eastern Gas Ops Center while filming the walkthroughs using his cell phone, which was viewable to Larkin and Staff using Microsoft Team Meetings. As it relates to Line A000b and Line D000b, since both of these projects are essentially underground with no portion of either viewable, the review of these projects were conducted via table top reviews and a review of the as-built documentation using Microsoft Team Meetings.

The table top reviews/reviews and the video walkthroughs were conducted on April 9-10, 2020. A discussion of each of the four projects selected for field inspections is in the section below.

*Dicks Creek Project (consists of two separate Project ID work orders)*

**Type of Inspection:** Video onsite field visit and table top reviews of as-built diagrams and work orders

**Location**: 632 Todhunter Road, Monroe, OH 45050

**First Project ID Number**: G8160 - STA 120 Dicks Creek Reg Sta Replace

**Project Description**: Replace gas heater, 1st and 2nd stage regulation/piping, add filter/separator; abandon gas plant connections.

**Project Cost**: $12,487,188

**In-Service Date**: 2018

**Second Project ID Number**: R1489 - Dicks Creek SCADA

**Project Description**: Install SCADA and Odorizer building with 4,000 gallon odorant tank. Nes station RTU. Civil design build cement pads.

**Project Cost**: $1,905,809

**In-Service Date**: 2018

During the table top review held on April 9, 2020, the Company stated that the Dicks Creek project, which was approved in the 2013-2014 time period, was related to replacing a gas heater, two regulator pressure skids (one at 438 psi and the other at 225 psi), installing a new filter separator, installing a new odorant tank and installing an ultrasonic metering skid. The facility that was replaced was an older propane peak shaving plant which had an undersized heater for the volume of gas flowing through. The Company stated that the driver for this project, as determined by Integrity Management, was to separate propane from natural gas and increasing capacity through the station.

The Company stated that project was approved in during the 2013-2014 time frame on a Delegation of Authority ("DOA") basis and that final approval was signed off on by the Company's Vice President. The Issued For Construction ("IFC") was approved on May 16, 2017.[24]

As noted above, a second project built in conjunction with Dicks Creek is identified by Project ID number R1489 and relates to installing a SCADA[25] system to be used exclusively for natural gas.

As previously discussed, the Company provided a comparison of its budgeted CEP expenditures to the actual CEP expenditures for each year 2013 through 2018.[26] For 2018, the budget to actual comparison for distribution improvement reflected a total unfavorable variance of $26.5 million. The response to LARKIN-DR-01-49 stated that the $26.5 million variance was mainly driven by work on the Dicks Creek project, which had significant delays in 2018. We requested that DEO identify and explain these significant delays. In its supplemental response to LARKIN-DR-01-49, the Company stated that the in-service date for Dicks Creek was pushed out to September 2018 for the following reasons:

- The tie-in work began in Spring 2018 as planned, however the tie-ins were completed with in-company resources and the tie-ins were performed sequentially and not in parallel. This partly contributed to the delay until September 2018.
- During tie-in planning, tie-in to pipeline LP05 was excavated at the planned tie-in point. This pipe was listed as 12" on the IFC prints. However, upon excavation at the tie-in point it was discovered as 8". System planning requested the 8" segment (approx. 200') of LP05 within the station be replaced so this station outlet was 12: without the existing 8" bottleneck. This caused additional pipeline work at the end of the project to construct, hydrotest, and tie-in new piping.

Based on the Company's responses above regarding the delays with Dicks Creek construction, we requested that DEO identify and provide copies of any change orders associated with the project. In its confidential responses to LARKIN-DR-01-103 and LARKIN-DR-01-158, the

[24] The IFC means that the drawings and specifications have been approved by the local governing agencies and that these are the plans by which the project will be constructed.
[25]SCADA is an acronym for supervisory control and data acquisition, a computer system for gathering and analyzing real time data.
[26] See the response to LARKIN-DR-01-49.

Company provided the requested change order documentation, which we reviewed. [redacted]

Dicks Creek Video Walkthrough

As noted above, due to the COVID-19 pandemic, travel to Ohio for an onsite field visit planned for March 16, 2020 was cancelled. Therefore, on April 10, 2020, a member of DEO conducted a video walkthrough of the Dicks Creek facility, which we were able to view through Microsoft Team Meetings.

The video walkthrough initially covered the equipment at the Dicks Creek station inlet, [redacted]

[redacted]

[27] See the confidential response to LARKIN-DR-01-146.

The video walkthrough proceeded to the filter separator, [redacted]

[redacted]

The video walkthrough proceeded to the heater, [redacted]

[redacted]

The video walkthrough proceeded to the first stage pressure regulation skid, [redacted]

[redacted]

[redacted]

The video walkthrough proceeded to the intermediate station piping and valves, [redacted]

[redacted]

[redacted]

The photograph below shows a closer view of the odorant tank and RTU and odorant pump building. [redacted]

[redacted]

The photographs below show different angles of the ultrasonic metering skid. [redacted]

[redacted]

The outlet of the meter skid which leads to the second stage pressure regulation skid is [redacted]

The video walkthrough proceeded to the second stage pressure regulation skid [redacted]

[redacted]

This portion of the video walkthrough also included seeing the outlet of the second stage skid, which included [redacted]

The video walkthrough proceeded to a flare [redacted]

The video walkthrough of Dicks Creek concluded with viewing three large buildings on the premises, [redacted]

Conclusion

The Dicks Creek facility and equipment is used and useful and prudent. However, according to the work order detail provided in response to LARKIN-DR-01-69, neither Project ID number G8160 nor R1489 were unitized. Therefore, we recommend that the Company continue its efforts to address the unitization backlog previously discussed in order to get this project, and all other completed projects that are in-service, properly unitized.

*Kellogg Eastern Gas Operations Center (consists of two separate Project ID work orders)*

**Type of Inspection:** Video onsite field visit and table top reviews of as-built diagrams and work orders

**Location**: 4612 Kellogg Ave, Cincinnati, OH 45226

**First Project ID Number**: T1666 - EGOC New Eastern Gas Ops Center

**Project Description**: EGOC New Eastern Gas Ops Center - Building Only

**Project Cost**: $16,844,341

**In-Service Date**: 2017

**Second Project ID Number**: P6956 - 4612 Kellogg Ave. Land Purchase

**Project Description**: Purchase of 6.9 acres located at 4612 Kellogg Avenue in Cincinnati, Ohio for relocation of existing Gas Operations facility on River Road in Cincinnati. LU #1668170 - includes building which was demolished.

**Project Cost**: $296,177

**In-Service Date**: 2017

During the table top discussion that was conducted on April 9, 2020, the Company stated that the Eastern Gas Ops Center project was initiated to replace an aging outdated facility (see additional discussion below). According to DEO, the Eastern Gas Ops Center houses different groups for DEO's gas operations, including: gas field crews, technical crews, sales, work management, welding group, and management staff. The interior of the Eastern Gas Ops Center facility is comprised of the following areas:

- Sixteen work spaces (cubicles)
- Eight enclosed offices
- Three conference rooms

- Employee fitness room
- Men’s' and women’s' locker rooms
- Break area
- Warehouse space which includes truck storage space, storage shelves for large items, storage space for materials and a weld shop for fabrication and grinding

The exterior of the Eastern Gas Ops Center includes a large parking lot, a truck storage canopy, and a large materials storage area (see additional discussion below).

The primary driver for constructing the Eastern Gas Ops Center was that the existing facility was a peak shaving plant that had been built in the 1890's as a coal gasification facility and as such, there are still coal tar pits on the site that need to be environmentally remediated. As a result of these environmental remediation efforts, the DEO personnel at the coal shaving plant were relocated to the Eastern Gas Ops Center, which is approximately 10 miles from the peak shaving plant. The Company stated that while the majority of the old site has been remediated, there are portions of the facility that cannot be remediated because it is an active peak shaving plant. To address the remaining remediation issue as it relates to the peak shaving plant, the Company currently has a separate central corridor project pending in which DEO wants to construct a high pressure distribution line, which will run from north to south. DEO stated that it was in the process of getting the project approved by the Ohio Power Siting Board. Based upon receiving this approval, the Company hopes to start construction on this separate line project in early 2021 with the goal of having it in-service by late 2021. Once this new pipeline is in-service, the Company wants to run it for at least a year to make sure it functions properly. Once this new line if proven to function as intended, the Company intends to complete the remediation and ultimately retire the peak shaving plant.

As noted in the summary above, the Eastern Gas Ops Center was broken into two projects. Specifically, with Project ID number P6956, the Company purchased a 6.9 acre tract of land at 4612 Kellogg Avenue in Cincinnati, Ohio[28] on which it built the Eastern Gas Ops Center. Part of the cost of this land purchase included the demolition of an existing shed type building that was on the premises. Project ID number T1666 was related to the construction of the new building.

During the table top discussion on April 9, 2020, the Company stated that from a geographical perspective, the land is located near the Ohio River and sits next to Lunken Airport. DEO stated that the land is located in a flood zone, but that the new building was built up higher than the flood zone and includes a floodwall. In response to our inquiry as to why it would construct the building by a flood zone, the Company stated that prior to the building being constructed, the land was prepped so that the building would be above flood level. DEO stated that in the event the flooding is high enough to shut down Kellogg Road, there is a secondary entrance [redacted] hat is not subject to flooding.

[28] According to the supplemental response to LARKIN-DR-01-164(b), the original owner of the land was TNC Properties, LLC.

The Eastern Gas Ops Center serves the eastern portion of its Ohio gas operations exclusively and is run using three scheduled shifts for its employees, all of whom are Ohio-based. However, the Ohio-based crews can respond to emergency situations (e.g., grade 1 pipe leaks) in Kentucky, including fixing such leaks and then monitoring to ensure that gas is not still leaking after the repairs have been made. Company personnel in Kentucky can also respond to emergency situations in Ohio as well.

During the table top reviews, we asked the Company to identify specific problems that the construction of the Eastern Gas Ops Center facility addressed. In response to our inquiry, the Company indicated the following:

- Relocating the crews that had previously been stationed at the peak shaving plant due to this older facility being environmental remediated (discussed above).
- The Eastern Gas Ops Center is a permanent location.
- The Eastern Gas Ops Center provides back office support.
- The Eastern Gas Ops Center provides gas marketing support.

Upon reviewing the work order detail for Project ID number P6956, which was for the purchase of the 6.9 acres on which the facility was constructed, we noted a large credit in the amount of $16,260,426, which was offset against the $296,177 purchase price for the land for a net credit in the amount of $15,964,249. Upon our inquiry, the Company stated that the Eastern Gas Ops Center was originally set up as a single project with the costs of the land and the costs of the building under one project ID number. However, for FERC accounting, it was necessary to set up a separate project ID (i.e., work order) for the land purchase exclusively. Therefore, the Company posted a journal entry to move the costs associated with constructing the Eastern Gas Ops Center facility from Project ID number P6956 to Project ID number T1666. Upon reviewing the work order detail for Project ID number T1666, we noted many costs shown as positive amounts that matched the credit amounts listed in the work order detail for Project ID number P6956.

<u>Eastern Gas Ops Center Video Walkthrough</u>

On April 10, 2020, a member of DEO conducted a video walkthrough of the Eastern Gas Ops Center, which we were able to view through Microsoft Team Meetings. At the start of the video walkthrough, the Company employee conducting the walkthrough entered the building from its main entrance off of Kellogg Avenue, [redacted]

[redacted]

The interior video walkthrough began in the main lobby then proceeded to the conference rooms, one of which was a small room for team meetings while a larger conference room[29] (with 128 seating capacity) is used for things such as meetings with outside contractors. The larger conference room is [redacted]

[29] The Company stated that the larger conference room can be split into two separate rooms with an accordion style partition.

[redacted]

The video walkthrough also included a view of the workspaces and enclosed offices.  The cubicles in the workstations are used by work management personnel while the closed offices are for management and supervisors.  In terms of number of employees at the Eastern Gas Ops Center, the Company stated that this facility has [redacted] view of the workstations and enclosed offices [redacted]

[redacted]

[redacted]

[redacted] s currently kept locked by corporate security due to the COVID-19 shutdown [redacted] n lieu of the video walkthrough going inside the employee fitness room, in its confidential supplemental response to LARKIN-DR-01-164, the Company provided the following diagram of the fitness room:

[redacted] 1,106 square feet and contains various [redacted]

[redacted]

[redacted]

According to the supplemental response to LARKIN-DR-01-164(d), the costs of the employee fitness center are part of the overall costs of the Eastern Gas Ops Center and thus are included in the CEP deferral and proposed rider. As discussed in further detail in Chapter 9, we are recommending that the portion of the Eastern Gas Ops Center costs that relates to the employee fitness room be removed from recoverable CEP costs.

From the employee fitness room, the video walkthrough proceeded to the warehouse area. [redacted]

The Company stated that the square footage of the [redacted] square feet[30] and is comprised of [redacted] EO stated that meter testing is performed at its Queensgate facility.

From the warehouse, the video walkthrough proceeded outside into a large fenced-in area in the back of the facility, [redacted]

[30] See the supplemental response to LARKIN-DR-01-164.

[redacted]

This area included bins filled with [redacted] urther away from the building on the north side is a [redacted]

The photograph below is of the north side of the Eastern Gas Ops Center building.

[redacted]

[redacted] he north side of the building contains additional [redacted] is of the south side of the building.  DEO stated that it [redacted]

[redacted]

[redacted]

Conclusion

The Eastern Gas Ops Center is used and useful and prudent. However, as discussed in further detail in Chapter 7, we recommend that the costs of the Eastern Gas Ops Center that relate to the employee fitness center (i.e., the construction costs of the fitness center portion of the building and the exercise equipment) be removed from the recoverable CEP expenditures. In our view, these types of costs are not an appropriate use of ratepayer funds. In addition, according to the work order detail provided in response to LARKIN-DR-01-68, Project ID number T1666 was unitized in March 2018 and Project ID number P6956 was unitized in April 2018. While these projects were unitized, this process occurred in the year following the Eastern Gas Ops Center being placed into service. Therefore, we recommend that the Company continue its efforts to address the unitization backlog previously discussed in order to get all other completed projects that are in-service, properly unitized.

*Line A000b*

**Type of Inspection:** Table Top Review using As-Built Diagram and work order

**Location**: Liberty Twp., Butler County, Ohio (per as-built diagram)

**Project ID Number**: S5948 - Line A000b, Seg 5020 Replacement

**Project Description**: INT 10932026 Line A000b, Seg 5020 Replacement, Replace 2000' of Line A000b with new 20" steel.

**Project Cost**: $3,201,481

**In-Service Date**: 2018

During the table top discussion that was conducted on April 9, 2020, the Company stated that the Line A000b project ("Line A") was related to replacing 2,000 feet of 18 inch pipe that had been installed in the 1950's by DEO's predecessor company, Cincinnati Gas & Electric, with 20 inch steel pipe. The Company stated that its Integrity Management Group made the decision to replace the 18 inch pipe due to [redacted] n addition, this 2,000 foot section of pipe was the only part of the DEO system to have 18 inch pipe, which the Company considered to be an odd diameter. Therefore, the Integrity Management Group decided to replace it with the 20 inch continuous steel pipe to be consistent with the other pipe on the same easement. As shown on page 1 of the as-built diagram for Line A, which was provided in the confidential response to LARKIN-DR-01102, the new pipe was [redacted]

It is important to note while there were no issues with the old 18 inch pipe from a leak perspective, the Integrity Management Group was uncomfortable with keeping 18 inch [redacted] pipe of an [redacted] so the decision was made to replace it with the 20 inch steel pipe. The old 18 inch pipe was retired in place. We requested that the Company identify and provide the risk rankings prepared by the Integrity Management Group, which ranked the risk associated the18 inch pipe that was involved with the Line A pipe replacement project, including showing in detail how the risk of that pipe was determined, and how that risk was compared and evaluated in comparison to the risks associated with other pipeline segments on Duke Energy Ohio's natural gas distribution system. In its response to LARKIN-DR-01-163, the Company stated:

[redacted]

The response to LARKIN-DR-01-163 included what DEO stated was a recent dashboard which showed the relative risk of the feeder lines (high pressure distribution). This dashboard is replicated in the exhibit below:

### Exhibit 6-6. Feeder Line Risk Management Dashboard for Line A000b

[redacted]

As shown in the exhibit above, Line A000b was the [redacted] risk ranked feeder line in the system. The Company explained that the factors listed below are used to calculate feeder risk:[31]

- Use GIS data to find each factor
- Use the data factors to get a likelihood of failure score and a consequence of failure score
- Multiply the likelihood and consequence to get a risk of failure score
- Look at the sum of all segments for a particular pipeline to get the total risk score for that feeder line

The Company provided the following breakdown of the risk related to Line A000b:

[31] See the response to LARKIN-DR-01-163.

**Exhibit 6-7. Summary of the Breakdown of Risk Related to Line A000b**

[redacted]

The Company's Integrity Management Group summarized the risk ranking with Line A000b as follows:

[redacted]

In addition to the breakdown shown in the exhibit above, the Integrity Management Group's risk ranking for Line A000b included the following likelihood of breakdown by component:

**Exhibit 6-8. Risk of Breakdown By Component Related to Line A000b**

[redacted]

According to the work order detail that was provided in response to LARKIN-DR-01-69, the Line A project was not a blanket project, but rather an individual project. The Line A project has not been unitized as of the date of the response to LARKIN-DR-01-69. As previously discussed, in its response to LARKIN-DR-01-70, the Company stated that its unitization process has fallen behind historically due to either a lack of staff focusing on unitization or because of delays caused by system conversions. Beginning in 2019, the Central Project Accounting Group initiated a coordinated effort to address the unitization backlog which resulted in more unitizations in 2019 than was achieved during the period 2015 through 2018. DEO contends that it will continue to focus on addressing the unitization backlog in 2020 and beyond.

Since Line A is essentially completely underground, there was no way for DEO personnel to conduct a video walkthrough of the line nor were any photographs of Line A provided for the same reason. Therefore, we relied upon the table top discussion with DEO, the as-built diagram and work order detail for our review of this project.

<u>Conclusion</u>

Line A000b was installed, is used and useful, and prudent. However, according to the work order detail provided in response to LARKIN-DR-01-69, the Line A000b project has not yet been unitized. Therefore, we recommend that the Company continue its efforts to address the unitization backlog previously discussed in order to get this project, and all other completed projects that are in-service, properly unitized.

*<u>Line D</u>*

**Type of Inspection:** Table Top Review using As-Built Diagram

**Location**: City of Cincinnati, Hamilton County, Ohio (per as-built diagram)

**Project ID Number**: R0984 - WP27 Engineering for D replace

**Project Description**:WP27 Engineering for "D" replacement eMax 8075968 CDC

**Project Cost**: $4,883,418

**In-Service Date**: 2018

During the table top discussion that was conducted on April 9, 2020, the Company stated that the Line D000b project was related to replacing three miles of 20 inch and 24 inch pipe that was installed in 1948, with 20 inch and 24 inch pipe that has steel covered coating. The Company stated that slightly more than 50% of the old pipe was replaced with the 24 inch steel pipe with the remainder being 20 inch pipe. The Integrity Management Group decided to replace the older pipe as it was spiral welded and there was a concern that it could rupture if subjected to pressure testing. Similar to the pipe replaced by the Line A project, the old spiral welded pipe was also retired in place.

As shown on page 1 of the as-built diagram for Line D, which was provided in the Company's response to LARKIN-DR-01-101, the new pipe was [redacted]

According to the work order detail that was provided in response to LARKIN-DR-01-69, the Line D project was not a blanket project, but rather an individual project, which was unitized in November 2019.

Similar to Line A, since Line D is underground, there was no way for DEO personnel to conduct a video walkthrough of the line nor were any photographs of Line D provided for the same reason. Therefore, we relied upon the table top discussion with DEO, the as-built diagram and work order detail for our review of this project.

Conclusion

Equipment reviewed is confirmed to be installed, used and useful and prudent. According to the work order detail provided in response to LARKIN-DR-01-69, the Line D project was unitized in November 2019. While this project was unitized, this process occurred in the year following it being placed into service. Therefore, we recommend that the Company continue its efforts to address the unitization backlog previously discussed in order to get all other completed projects that are in-service, properly unitized.

## Capital Spending and Cost Containment

Capital Spending

The Company has identified the following criteria for designating capital projects and/or assets as CEP related:[32]

- The capital project is set up in DEO's gas delivery business segment.
- The capital project has charges incurred after January 2013.
- The capital project is not a service line replacement nor does it qualify as Rider AMPR or Rider AU projects.
- The capital project is not manufactured production plant.
- The capital project is recorded in plant in-service accounts (i.e., FERC account 106 - Plant In-Service Not Classified or FERC account 101 - Plant In-Service Classified.
- The capital asset is placed into service with the utility accounts associated with Gas Distribution Plant, General Plant, or Intangible Plant.

We requested that DEO explain how the deferred CEP assets are moved to utility plant in-service once the deferral has been established. In its response to LARKIN-DR-01-38, the Company stated that the CEP assets are in plant in-service accounts 106 and/or 101 and that there is no entry to record the deferral of CEP assets.

In terms of retirements, in its response to LARKIN-DR-01-38, DEO stated that the retirement of CEP assets follows the same methodology as with other assets. Specifically, the retirement of an asset is performed at the same time the new replacement asset is placed into service, or when an asset is no longer used for utility operations. The retirements are performed using the Work Management feeder system for gas distribution plant, or specially performed for intangible and general plant. The specific journal entry to record retirement is to debit FERC account 108 -

[32] See the response to LARKIN-DR-01-37(a).

Accumulated Provision for Depreciation and to credit FERC account 101 - Plant In-Service Classified.[33]

DEO's CEP capital spending has increased significantly since the inception of the CEP in 2013 as shown in the exhibit below:

### Exhibit 6-9. Summary of CEP capital spending and Percentage Change

| Budget Category | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 | Total CEP Plant in Service |
|---|---|---|---|---|---|---|---|
| Distribution Improvement | $ 17,677,711 | $ 22,792,060 | $ 37,018,650 | $ 46,362,944 | $ 64,219,840 | $ 89,519,414 | $ 277,590,619 |
| Information Technology | $ - | $ 851 | $ 452,331 | $ 3,550,915 | $ 15,348,312 | $ 532,262 | $ 19,884,671 |
| Total CEP In-Service Activity - Net Assets | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 |
| Percentage Increase | | 28 94% | 64 40% | 33 21% | 59 41% | 13 18% | |
| Source: Schedule J - CEP Additional Supporting Schedules Supporting the Application, Schedule 4 | | | | | | | |

As shown in the exhibit above, the CEP expenditures have increased in each subsequent year, with the largest percentage increases occurring from 2014 to 2015 and from 2016 to 2017. We requested that DEO explain why its CEP expenditures increased by the percentages shown in the exhibit above. In its response to LARKIN-DR-01-47(a), the Company stated that in 2013 and 2014, a large amount of non-Rider AMRP and non-Rider AU projects did not qualify for the CEP deferral due to them being placed into service and/or begun prior to 2013. In addition, upon the Rider AMRP and Rider AU projects slowing down and/or stopping altogether in 2014 and 2015, the annual budget funding became available for projects that were outside of those two riders, which increased the percentage of CEP projects.

<u>Budget to Actual Variance Analysis</u>

For each year 2013 through 2018, we requested that the Company provide a comparison of its budgeted CEP expenditures to the actual CEP expenditures included in the Company's filing and to provide explanations for any variances between the budgeted and actual amounts of CEP expenditures. In its response to LARKIN-DR-01-49, the Company provided the requested comparison for each year.

The budget to actual CEP expenditures for 2013 are shown in the exhibit below:

### Exhibit 6-10. Summary of 2013 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 31,600,000 | $ 21,877,330 | $ 9,722,670 |
| Information Technology | $ 2,000,000 | $ - | $ 2,000,000 |
| Compliance with Rules, Regulations and Orders | $ 200,000 | $ - | $ 200,000 |
| Total CEP Investment | $ 33,800,000 | $ 21,877,330 | $ 11,922,670 |
| Source: LARKIN-DR-01-49 | | | |

[33] See the response to LARKIN-DR-01-37(c).

As shown in the exhibit above, for distribution improvement, the Company had a favorable variance of $9,722,670, which the Company stated was mainly due to a combination of a reduction in public improvement relocation projects and projects that were carried over to 2014. For Information Technology, the Company had a favorable variance of $2,000,000, which the Company stated related to a delay in starting information technology projects. No explanation was provided for the $200,000 favorable variance for Compliance with Rules, Regulations and Orders. For 2013, the overall budget to actual comparison was a favorable variance totaling $11,922,670.

The budget to actual CEP expenditures for 2014 are shown in the exhibit below:

### Exhibit 6-11. Summary of 2014 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 45,900,000 | $ 26,307,679 | $ 19,592,321 |
| Information Technology | $ 3,600,000 | $ 851 | $ 3,599,149 |
| Compliance with Rules, Regulations and Orders | $ 2,000,000 | $ - | $ 2,000,000 |
| Total CEP Investment | $ 51,500,000 | $ 26,308,530 | $ 25,191,470 |
| Source: LARKIN-DR-01-49 | | | |

As shown in the exhibit above, for distribution improvement, the Company had a favorable variance of $19,592,321, which the Company stated was mainly driven by the cancellation and delay of significant projects as well as various projects carried over to 2015. For Information Technology, the Company had a favorable variance of $3,599,149, which the Company stated related to planned project carryover to 2015. For Compliance with Rules, Regulations and Orders, the Company had a favorable variance of $2,000,000, which the Company stated was mainly due to project timing. For 2014, the overall budget to actual comparison was a favorable variance totaling $25,191,470.

The budget to actual CEP expenditures for 2015 are shown in the exhibit below:

### Exhibit 6-12. Summary of 2015 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 56,800,000 | $ 40,683,326 | $ 16,116,674 |
| Information Technology | $ 5,400,000 | $ 452,331 | $ 4,947,669 |
| Compliance with Rules, Regulations and Orders | $ 3,000,000 | $ 1,681,921 | $ 1,318,079 |
| Total CEP Investment | $ 65,200,000 | $ 42,817,578 | $ 22,382,422 |
| Source: LARKIN-DR-01-49 | | | |

As shown in the exhibit above, for distribution improvement, the Company had a favorable variance of $16,116,674, which the Company stated was mainly driven by the cancellation and delay of significant projects as well as various projects carried over to 2016. For Information Technology, the Company had a favorable variance of $4,947,669, which the Company stated related to planned project carryover to 2016. For Compliance with Rules, Regulations and

Orders, the Company had a favorable variance of $1,318,079, which the Company stated was mainly due to project timing. For 2015, the overall budget to actual comparison was a favorable variance totaling $22,382,422.

The budget to actual CEP expenditures for 2016 are shown in the exhibit below:

### Exhibit 6-13. Summary of 2016 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 60,800,000 | $ 62,833,451 | $ (2,033,451) |
| Information Technology | $ 3,800,000 | $ 4,472,237 | $ (672,237) |
| Compliance with Rules, Regulations and Orders | $ 3,100,000 | $ 1,160,829 | $ 1,939,171 |
| Total CEP Investment | $ 67,700,000 | $ 68,466,517 | $ (766,517) |
| Source: LARKIN-DR-01-49 | | | |

As shown in the exhibit above, for distribution improvement, the Company had an unfavorable variance of $2,033,451, which the Company stated was mainly driven by increased spend on expansion projects. For Information Technology, the Company had an unfavorable variance of $672,237, which the Company stated was mainly driven by project timing. For Compliance with Rules, Regulations and Orders, the Company had a favorable variance of $1,939,171, which the Company stated was mainly due to project timing. For 2016, the overall budget to actual comparison was an unfavorable variance totaling $766,517.

The budget to actual CEP expenditures for 2017 are shown in the exhibit below:

### Exhibit 6-14. Summary of 2017 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 64,700,000 | $ 71,096,101 | $ (6,396,101) |
| Information Technology | $ 2,100,000 | $ 15,359,485 | $ (13,259,485) |
| Compliance with Rules, Regulations and Orders | $ 1,200,000 | $ 767,989 | $ 432,011 |
| Total CEP Investment | $ 68,000,000 | $ 87,223,575 | $ (19,223,575) |
| Source: LARKIN-DR-01-49 | | | |

As shown in the exhibit above, for distribution improvement, the Company had an unfavorable variance of $6,396,101, which the Company stated was mainly due to the new Eastern Gas Ops Center building spend in 2017, which was partially offset by under-spending on Public Improvement projects and M&R station projects, which had more in budgeted placeholders versus what was placed into service in 2017. For Information Technology, the Company had an unfavorable variance of $13,259,485, which the Company stated was due to additional costs and an extended schedule for the Enable Project.[34] For Compliance with Rules, Regulations and Orders, the Company had a favorable variance of $432,011, which the Company stated was

[34] The Enable Project is discussed in detail in Chapter 8 of this report.

mainly due to project timing. For 2017, the overall budget to actual comparison was an unfavorable variance totaling $19,223,575.

The budget to actual CEP expenditures for 2018 are shown in the exhibit below:

### Exhibit 6-15. Summary of 2018 Budget to Actual Variances

| Category | Capital Budget | Actual Additions | Total Variance |
|---|---|---|---|
| Distribution Improvement | $ 68,100,000 | $ 94,566,061 | $ (26,466,061) |
| Information Technology | $ - | $ 570,642 | $ (570,642) |
| Compliance with Rules, Regulations and Orders | $ 1,200,000 | $ - | $ 1,200,000 |
| Total CEP Investment | $ 69,300,000 | $ 95,136,703 | $ (25,836,703) |

Source: LARKIN-DR-01-49

As shown in the exhibit above, for distribution improvement, the Company had an unfavorable variance of $26,466,061, which the Company stated was mainly driven by work on the Dicks Creek Station, which had significant delays into 2018. This Dicks Creek variance was partially offset by the Mason Station project due to Central Corridor project delays. In addition, there were significant costs related to AMI in Ohio as well as Line D, which had significant trailing charges in 2018 although it was placed into service in December 2017. For Information Technology, the Company had an unfavorable variance of $570,642, which the Company stated was related to trailing charges on the Enable Project as well as the DEE vehicle network project. For Compliance with Rules, Regulations and Orders, the Company had a favorable variance of $1,200,000, which the Company stated was mainly driven by the Line D and Line A000b projects. Both of the line projects were budgeted under this category, but the actual expenditures were captured in the Distribution Improvement category. For 2018, the overall budget to actual comparison was an unfavorable variance totaling $25,836,703.

The exhibit below provides a summary of the budget to actual variances on CEP expenditures over the 2013 through 2018:

### Exhibit 6-16. Summary of 2013 - 2018 Budget to Actual Variances

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|
| Distribution Improvement | $ 9,722,670 | $ 19,592,321 | $ 16,116,674 | $ (2,033,451) | $ (6,396,101) | $ (26,466,061) | $ 10,536,052 |
| Information Technology | $ 2,000,000 | $ 3,599,149 | $ 4,947,669 | $ (672,237) | $ (13,259,485) | $ (570,642) | $ (3,955,547) |
| Comp. with Rules, Regs. and Orders | $ 200,000 | $ 2,000,000 | $ 1,318,079 | $ 1,939,171 | $ 432,011 | $ 1,200,000 | $ 7,089,261 |
| Total Budget to Actual Variances | $ 11,922,670 | $ 25,191,470 | $ 22,382,422 | $ (766,517) | $ (19,223,575) | $ (25,836,703) | $ 13,669,766 |

Note: Positive amounts reflect favorable variances and negative amounts reflect unfavorable variances

As shown in the exhibit above, during the overall the 2013-2018 period, (1) the budget to actual comparison for the distribution improvement projects was a favorable variance of $10,536,052; (2) the budget to actual comparison for the information technology projects was an unfavorable variance of $3,955,547; and (3) the budget to actual comparison for the Compliance with Rules, Regulations and Orders projects was a favorable variance of $7,089,261 for an overall favorable variance of $13,669,766 over the six-year period.

Conclusion

As noted above, from 2013 through 2015, all three categories of the Company's CEP expenditures were significantly under budget, resulting in favorable variances for each of those years.

For 2016, the Company exceeded its budgeted CEP expenditures in distribution improvement and information technology categories of CEP expenditures, but the resulting unfavorable variances were relatively modest given the magnitude of the overall budgeted CEP capital expenditures.

For both 2017 and 2018, the Company exceeded its budgeted CEP expenditures by a significant amount.  For 2017, the unfavorable variance was primarily driven by cost overruns associated with the Eastern Gas Ops Center and the Enable Project.  For 2018, the unfavorable variance was primarily driven by cost overruns and delays associated with the Dicks Creek Station project.  As previously discussed in this chapter, the Eastern Gas Ops Center and Dicks Creek Station were the subject of table top reviews and video walkthroughs conducted by Company personnel.  The Enable Project is discussed in detail in Chapter 7 of this report.

Based on the foregoing, it appears that if not for the cost overruns and delays associated with large projects, including the Eastern Gas Ops Center and Enable Project in 2017 and Dicks Creek Station in 2018 (all of which are discussed in detail in Chapters 6 and 7 of this report), the budget to actual analysis for those years would have been more in line with the previous years of the audit period (2013-2016), thus Larkin is satisfied that the CEP-related construction activity was not unreasonable.

**Causes for Increased Non-AMRP and Non-Rider AU Spending**

As previously discussed in this chapter, in its response to LARKIN-DR-01-35, the Company provided a listing of its project work orders for the period April 1, 2012 through December 31, 2018.  The project work orders included in this listing were designated as either CEP, AMRP, AU, or non-rider related (i.e., not CEP, AMRP, nor AU).  The non-rider related projects are discussed in this section.  The exhibit below provides a summary of the non-rider related projects for the period 2013 through 2018, which coincides with the CEP program costs:

## Exhibit 6-17. Summary of Non-Rider Related Capital Projects For 2013-2018

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|
| Intangible Plant | $ 325,379 | $ 1,044,975 | $ 1,495,406 | $ 20,667,978 | $ (16,134,242) | $ 7,636,594 | $ 15,036,089 |
| Increase/(Decrease) by Year | | $ 719,596 | $ 450,430 | $ 19,172,572 | $ (36,802,220) | $ 23,770,836 | |
| Production Plant | $ 1,156,069 | $ 95,731 | $ 165,100 | $ 472,056 | $ 92 | $ 1,691,285 | $ 3,580,333 |
| Increase/(Decrease) by Year | | $ (1,060,338) | $ 69,369 | $ 306,957 | $ (471,964) | $ 1,691,193 | |
| Distribution Plant | $ 6,552,106 | $ 2,185,946 | $ 1,030,015 | $ 2,117,701 | $ 4,679 | $ 12,384 | $ 11,902,830 |
| Increase/(Decrease) by Year | | $ (4,366,160) | $ (1,155,931) | $ 1,087,686 | $ (2,113,022) | $ 7,705 | |
| General Plant | $ 25,317,128 | $ 12,284,690 | $ 6,957,527 | $ 8,801,720 | $ 38,894,970 | $ 15,121,632 | $ 107,377,668 |
| Increase/(Decrease) by Year | | $ (13,032,438) | $ (5,327,163) | $ 1,844,193 | $ 30,093,250 | $ (23,773,338) | |
| | | | | | | | |
| Total Non-Rider Expenditures | $ 33,350,682 | $ 15,611,342 | $ 9,648,047 | $ 32,059,455 | $ 22,765,499 | $ 24,461,895 | $ 137,896,921 |
| Total Increase/(Decrease) by Year | | $ (17,739,339) | $ (5,963,295) | $ 22,411,408 | $ (9,293,956) | $ 1,696,396 | |
| Source: LARKIN-DR-01-35 | | | | | | | |

As shown above, the non-rider related projects are broken out by (1) intangible plant; (2) production plant; (3) distribution plant; and (4) general plant. For each category of plant, the amount of non-rider related capital expenditures fluctuated significantly during the period 2013 through 2018.

A discussion of each plant category is below with a focus on the years in which the non-rider related capital expenditures significantly increased over the prior year.

Intangible Plant

As shown in the exhibit, capital expenditures increased significantly from 2013 to 2014 and from 2015 to 2016.

The increase from 2013 to 2014 was primarily driven by two projects related to what is referred to as an EPIS Upgrade (Project ID numbers EGISUPGSO and PCTA214) with costs totaling $626,891 and a project related to IVR Software and Licenses (Project ID number PCTAIVRSW)with costs totaling $252,570 with the overall costs of these three projects totaling $879,461.

The increase from 2015 to 2016 was primarily driven by Project ID number P6956, which shows costs related to the land purchase at 4612 Kellogg Avenue, which as discussed above is where the Eastern Gas Ops Center is located. During the table top review of the Eastern Gas Ops Center on April 9, 2020, the Company stated that the Eastern Gas Ops Center was originally set up as a single project with the costs of the land and the costs of the building under one project ID number. However, for FERC accounting, it was necessary to set up a separate project ID (i.e., work order) for the land purchase exclusively. As such, the large decrease between 2016 and 2017 is primarily driven by a credit amount of $16,260,426, which reflects reversing the 4612 Kellogg Avenue land purchase from intangible plant in 2017.

Production Plant

The increase from 2015 to 2016 was primarily driven by two projects. Project ID number K4108, which has the description "Replace Compressor RTU at East Work" had costs totaling $208,306 and Project ID number Q3810, which has the description "had costs totaling $101,389.

The increase from 2017 to 2018 is primarily driven by two projects. Project ID number P8052, which has the description "Replace Shutdown and Isolation Valve" had costs totaling $915,767 and Project ID number T7915 had the description "East Works 4' Vap Line Replacement" had costs totaling $774,860.

Distribution Plant

The increase from 2015 to 2016 was primarily by Project ID number G8170, which had the description "Mason Normac Replacement", had costs totaling $920,823.

The increase from 2017 to 2018 was primarily driven by Project ID number G1545, which has the description "EMAX 1243678 130A S Marshall", had costs totaling $13,487.

General Plant

The large increase from 2016 to 2017 was driven by several projects in 2017, which are summarized in the exhibit below:

## Exhibit 6-18. Summary of Large Non-Rider Related Capital Projects For 2017

| FERC Account | Project ID Number | Project Description | Rider | WO Completion Date | In-Service Date | Unitization Date | Work Type | Blanket Project | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 390 | OHF15053B | OH-4MA-Annex-Elev Equip | Non Rider Related | 201709 | 2017 | 201805 | additions | N | $ 2,306,677 |
| 390 | OHP140713 | Office Renovations @ Little Miami | Non Rider Related | 201710 | 2017 | 201907 | Replacement | N | $ 2,989,488 |
| 390 | OMW150215 | AHU#4 Replacement at 4th & Main | Non Rider Related | 201704 | 2017 | 201804 | Replacement | N | $ 3,032,320 |
| 390 | OMW160100 | Ops Center Renovation | Non Rider Related | 201711 | 2017 | not_unitized | Replacement | N | $ 4,608,834 |
| 390 | OMW16029A | Dana Ops Center Renovation | Non Rider Related | 201712 | 2017 | 201803 | additions | N | $ 5,949,307 |
| 390 | OMW16029B | Dana Ops Center Renovation Phase 2 | Non Rider Related | 201708 | 2017 | 201805 | additions | N | $ 1,660,743 |
| 390 | OMW16029C | Dana Ops Center Renovation Phase 3 | Non Rider Related | 201703 | 2017 | 201803 | Replacement | N | $ 3,238,781 |
| 390 | OSTW10006 | Annex Renovation | Non Rider Related | 201709 | 2017 | 201805 | Replacement | N | $ 3,667,084 |
| 391 | OSTW10006 | Annex Renovation | Non Rider Related | 201709 | 2017 | 201805 | Replacement | N | $ 1,872,488 |
| 397 | OMW16029C | Dana Ops Center Renovation Phase 3 | Non Rider Related | 201703 | 2017 | 201803 | Replacement | N | $ 924,208 |
| | | | | | | | | | $ 30,249,931 |

Source: LARKIN-DR-01-35

As shown in the exhibit above, five of the projects were related to the Dana Ops Center renovation with costs totaling $16,384,874. In addition, the Annex Renovation had costs totaling $5,539,573 with the three remaining projects totaling $8,328,485.

Conclusion

For each category of plant, the amount of non-rider related capital expenditures fluctuated significantly during the period 2013 through 2018 as shown in Exhibit6-17 above. On an overall basis, the only years in which there was net increase in non-rider related capital expenditures was 2016 and 2018 with decreases in the other years. In addition, the years in which there were significant increases in capital costs, they typically related to individual projects rather than an influx of several projects. On that basis, we conclude that the non-rider related capital expenditures during the period 2013 through 2018 were reasonable and prudent.

Cost Containment

Labor costs are a major contributor to the CEP project costs. Specifically, as discussed above in the section of our report in which we sampled project work orders, labor costs, and outside contractor labor costs in particular, comprise a significant portion of the costs included in the CEP projects. As such, we requested that the Company provide its written guidelines and/or policies and procedures regarding the use of outside contractors rather than using internal labor on its non-AMRP and non-Rider AU capital expenditures (i.e., CEP costs). In its response to LARKIN-DR-01-14, the Company stated:

> There are no written guidelines and/or policies and procedures regarding the use of outside contractors vs. Company personnel as it relates to non-Rider AMRP and non-Rider AU capital expenditures. Generally, internal crews will work projects if the pipe is 100 feet long in length or less. If the work requires specialized knowledge or the pipe is greater than 100 feet in length, the Company will have one our contractors perform the work. This is an internal guideline for gas but there is nothing in writing.[35]

We asked the Company to explain the basis of it employing outside contractors to perform work on projects in which the pipe is greater than 100 feet in length and how that criteria was determined. In its response to LARKIN-DR-01-30, the Company stated that it uses the 100 feet length from an efficiency standpoint. If the pipe is 100 feet or less, internal resources are typically used for the engineering and construction of projects. Specifically, the Company will design, order materials and install and prepare as-built diagrams on the back-end, which can be accomplished in a short time frame (i.e., 30-45 days from beginning to end). However, if it is necessary to hire an outside contractor, the process typically takes three months from beginning to end.

In terms of other criteria used by DEO in determining whether to have outside contractors perform work on projects rather than internal labor (such as for projects that do not involve pipe), in its response to LARKIN-DR-01-30, the Company stated:

> The Company typically will bid out most new regulator station installations to contractors due to volume of work. The regulator, reliefs, heater startups and Remote Terminal Unit telemetry equipment point to point (SCADA verifications) are set up and completed by our Technical Field Operations (TFO) Gas System Operation crews due to Operator Qualification requirements. TFO Management also writes the Work Authorization Permits to gas up new stations once Maximum Allowable Operating Pressure (Engineering provides this data with new station designs) verification have been verified by Major Project Teammates.

According to the response to LARKIN-DR-01-113, the TFO Gas System Operations is comprised of Gas Technical Services, Gas Measurement Center, Gas System Operations Mechanics, and Management Staff. During the telephone interview conducted on January 24, 2020, the Company stated that the TFO group is involved with some capital work, but primarily focuses on O&M inspection work. Major Projects Teammates are discussed below.

With regard to cost containment strategies as it relates to the use of outside contractors, the Company competitively bids out work that consists of street improvements, main replacements, pressure improvements, and main extensions (8,000 feet or less and eight inches in diameter or less) for distribution main. DEO stated that there are four contractors that perform this work. In addition, the Company has set pricing for this type of work established in blanket contracts.

[35] The response to LARKIN-DR-01-16 indicated that this also applies to the use of internal labor on projects.

Specifically, if it is greater than 8,000 feet or greater than eight inches in diameter, the job is bid out to a pool of approved contractors.[36] The Ohio Service Line Replacement Program is also bid out with set pricing in place. However, as noted above, costs related to the Ohio Service Line Replacement Program are currently not included in CEP. During the January 24, 2020 telephone interview, the Company stated that it typically uses external crews on blanket projects.

We asked DEO to explain the basis for the Company's practice of competitively bidding out work to the four outside contractors referenced above to work on projects in which main extensions are 8,000 feet or less and to explain how and when this criteria was determined. In its response to LARKIN-DR-01-31, the Company stated that the criteria is based on reviewing historical project data. Specifically, DEO stated that 85% of its distribution projects are 8,000 feet or less. The contractors used by the Company are large enough to efficiently perform work of this size and they give the Company the best pricing. DEO indicated that the most recent review was completed in July 2019 with projects dating back to 2015. The four contractors are AMS Construction, RLA Utilities, KS Energy, and Premier. The set pricing relates only to these four contractors, although there was an initial open bid pricing process with several contractors.AMS Construction, RLA Utilities, and KS Energy focus on mains and services while Premier focuses on the Service Line Replacement Program.[37]

In the event a project falls outside the scope of blanket projects (i.e. greater than 8,000 feet for distribution mains), the Company indicated it has an approved bidder list that is managed by its sourcing group who works in conjunction with the operations group in an open-bid process. For distribution main projects that are greater than 8,000 feet, in addition to the four contractors listed above, the Company also identified Infrasource, Miller Pipeline, and Intren as being on the approved bidders list.

As it relates to Major Projects, we asked the Company to explain the criteria used for projects bid out, contracted by, and supervised by the Major Projects Group. In its response to LARKIN-DR-01-110, the Company stated:

> Natural Gas Major Projects was created in early 2017 shortly after the acquisition of Piedmont Natural Gas. The organization was formed during the integration of both companies to align with best practices. At that time, we competitively bid (to at least 3 approved bidders) every project for both Engineering and Construction services or we followed our sourcing policy requiring a VP to sign off on any contract that wasn't competitively bid and cost more than $250,000. We would then evaluate the bids based on Cost, Schedule, Project Execution Plan, Organization & Key Personnel, Corporate Responsibility and Safety. Major project competitively bids out on every project they manage, so there are no blanket contracts for engineering and construction.

[36] See the response to LARKIN-DR-01-15.
[37] See the response to LARKIN-DR-01-31.

The staffing of the Major Projects group is comprised of the following personnel: Project Manager, Project Engineer, Implementation Superintendent, Project Controls, QA Analyst, and Land Agent.[38]

In addition to the foregoing, the Company has a robust RFP process for both blanket work orders and major individual projects.[39]

In terms of cost containment strategies that DEO has in place pursuant to the use of internal labor, the Company stated that internal labor is managed on a project by project basis depending on deliverables and is monitored through the approval of timesheets.[40] Specifically, supervisors and managers direct the work of internal labor with respect to which projects are worked on and how resources are allocated based on the annual budget and specific work scope of each Company crew. In addition, charges by internal labor on the timesheets are approved by each manager on a semi-monthly basis or every two weeks depending on whether the employee is exempt or non-exempt. Factors including weather, compliance due dates, or customer needs can determine an employee's work schedule.[41] During the January 24, 2020 telephone interview, the Company stated that internal labor is typically more available to perform operations and management type work.

<u>Conclusion</u>
Based on the foregoing, Larkin concludes that DEO has implemented effective cost containment strategies with regard to the use of outside contractors and internal labor.

## Incremental Revenue Offset

As part of its CEP revenue requirement calculation, the Company included a line item on Company Exhibit J, Schedule No. 1, which it referred to as Cumulative Offset for Incremental Revenue. This revenue offset, in a credit amount of $18,930,741 is included as an offset to the, deferred regulatory assets on Schedule No. 1 and represents the incremental revenues associated with the CEP investments and treated as an offset to deferred expenses. The Company's revenue offset of $18,930,741 is summarized on Exhibit J, Schedule 8 and replicated in the exhibit below:

### Exhibit 6-19. Summary of DEO's Incremental Offset to Revenue

| Rate Category | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 |
|---|---|---|---|---|---|---|
| Rate RS / RFT / RSLI | $ (986,239) | $ (2,797,652) | $ (5,043,990) | $ (7,939,172) | $ (11,838,788) | $ (16,835,653) |
| Rate GS / FT Small | $ (56,999) | $ (56,999) | $ (56,999) | $ (56,999) | $ (56,999) | $ (56,999) |
| Rate GS / FT Large | $ - | $ - | $ (1,875,220) | $ (2,038,089) | $ (2,038,089) | $ (2,038,089) |
| Rate IT | $ - | $ - | $ - | $ - | $ - | $ - |
| Total Incremental Revenue - (Increase) | $ (1,043,238) | $ (2,854,651) | $ (6,976,209) | $ (10,034,260) | $ (13,933,876) | $ (18,930,741) |
| Source: Exhibit J, Schedule 8 from DEO's Filing | | | | | | |

[38] See the response to LARKIN-DR-01-111.
[39] See the responses to LARKIN-DR-01-109 and LARKIN-DR-01-110.
[40] See the response to LARKIN-DR-01-17.
[41] See the response to LARKIN-DR-01-32.

The Company's detailed calculations for each year 2013 through 2018 are shown on Exhibit J, Workpapers 8.1 through 8.6, respectively. Specifically, for each year, using the baseline number of customers from DEO's last rate case (Case No. 12-1685-GA-AIR) the Company's revenue offset is based on the monthly changes in customer counts (from the actual number of bills) for each of the rate classes shown in the exhibit above. The Company then multiplied the difference between the baseline and actual customers by the fixed monthly rate for cost recovery[42] for each rate class to determine the annual increase/(decrease) in revenue.

For each year 2013 through 2018, using the data from our sample selections previously discussed, we asked the Company whether any of the projects from our sample that were designated as "additions" were related to adding new customers and whether they were revenue generating. In each of its responses to LARKIN-DR-01-151 through LARKIN-DR-01-156 (with each response representing the period 2013-2018), the Company provided attachments which indicated that several projects in each year were related to adding new customers and were revenue generating. We have summarized the number of new customers and the costs of those projects in the exhibit below:

### Exhibit 6-20. Summary of New Customers and Revenue Producing CEP Projects For 2013-2018

| Year | Number of New Customers | Total of Revenue Producing Projects |
|---|---|---|
| 2013 | 11 | $ 296,443 |
| 2014 | 256 | $ 564,944 |
| 2015 | 170 | $ 765,506 |
| 2016 | 72 | $ 1,559,668 |
| 2017 | 132 | $ 824,247 |
| 2018 | 31 | $ 486,439 |
| Total | 672 | $ 4,497,248 |

Source: LARKIN-DR-01-151 through 156

As shown in the exhibit, the number of new customers from the projects designated as additions totaled 672 during the period 2013 through 2018 and the project costs totaled $4,497,248.

<u>Conclusion</u>

In our view, the Company's methodology for applying the incremental revenue offset to deferred CEP expenses is reasonable. We are not recommending any adjustments to remove revenue generating CEP investments.

[42] DEO's Schedule 8 workpapers state that the fixed cost rates were derived by removing the equity return and taxes from the rates derived in Case No. 12-1685-GA-AIR.

# 7 ENABLE PROJECT

## Enable Project Costs

In a PowerPoint presentation dated March 2018, the Company described the Enable Project as a process-centric effort to standardize the highly disparate processes within each business unit to accomplish the following:

- Drive higher levels of productivity and efficiency equating to ~$75 million in annual value.
- Better define the needed information systems.
- Deploy the needed information systems and consistent processes.
- Create measurable, sustainable value for all affected business units.

In addition, the Company's presentation indicated that Enable project's objective is to drive sustainable, organizational value through improved efficiency and optimized performance by (1) overseeing 20 million assets; (2) managing 500,000 inventory items; (3) having more than 17,000 users; (4) transacting $5.6 billion in goods and services; (5) executing 1.3 million work orders; and (6) controlling $1 billion in inventory.

With regard to the specific functions and/or modules of the Enable system used by DEO's gas operations, in its response to LARKIN-DR-01-131, the Company stated:

> As part of the Enable Project, a suite of tools that manages the work, assets, resources and inventory was implemented for the gas business. The major types of work managed through this suite of tools includes construction, maintenance and inspections. In general, these work types follow the same flow through the suite of tools. Work is initiated in the Work Request Tool via the customer systems; the work order is set up in the Maximo system and continually attributed as the work order progresses. The work order then triggers engineers to design the work in the Gas Integration Manager (GIM) tool, to schedule the work to crews in Asset & Resource Management (ARM) Scheduler, and initiate requisition of materials in Maximo. The work order from Maximo then appears in the Field Mobile Application for crews to perform and subsequently complete the work, and when the work order is closed the information posts to systems of record including financial systems and the Geographic Information Systems (GIS) mapping system.

The Enable system was initially placed into service on August 7, 2017 and has a 10-year useful life.[43]

The Enable Project was a Duke Energy initiative to review and upgrade information technology over several of its business units. The Enable project affected several Duke Energy business units including: Transmission, Distribution, Vegetation Management, Fossil/Hydro Operations, Gas Operations, Supply Chain, and Fleet Operations.[44]

The total Enable Project costs that were charged across the impacted Duke Energy business units are shown in the exhibit below:

### Exhibit 7-1. Summary of Enable Project Costs Charged to all Duke Energy Business Units

| Description | 2015 | 2016 | 2017 | 2018 | Grand Total |
|---|---|---|---|---|---|
| Enable Project Costs Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 |
| Source: LARKIN-DR-01-157 | | | | | |

From 2015 and 2018, Enable Project costs totaling $236,024,436 were charged to Duke Energy's impacted business units. The amount of these costs that were allocated to DEO's gas utility are discussed below.

For each year 2013 through 2018, we had requested that DEO provide a comparison of its budgeted CEP expenditures to the actual CEP expenditures and to provide explanations for any variances. In its response to LARKIN-DR-01-49, the Company provided the requested budget to actual comparisons. For the period ending December 31, 2017, the DEO gas utility's budget to actual analysis indicated an unfavorable variance totaling $13,259,485 related to information technology. In its explanation for this large variance, the Company stated that it was due to additional costs and extended schedule related to the Enable project.

In order to obtain a better understanding of the $13.3 million variance noted above, we requested additional information regarding the reasons for this variance. In its supplemental response to LARKIN-DR-01-49, the Company stated:

> Enable was initially budgeted at the enterprise level. There was no specific budget for gas operations. Initially, gas operations was going to receive a partial implementation as compared to electric but at a later point in the project, the scope was expanded to include additional processes. Ohio Gas operations was assigned 5.43% which is calculated as Ohio Gas meters as a percentage of Duke Energy total enterprise meters, which is in accordance with the Company's meter-based CAM.

During the January 31, 2020 interviews, the Company stated that the allocation of the Enable Project was based on customer counts. We requested that the Company provide the calculations

[43] See the response to LARKIN-DR-01-131.
[44] This information was contained in DEO's Enable Overview PowerPoint presentation dated March 2018.

of the allocation of the Enable project's cost among Duke Energy's various entities/business units, including the 5.43% noted in the passage above for DEO's gas utility operations. In its response toLARKIN-DR-01-115, the Company explained that the allocation of the Enable project was determined using the "DEMS" operating unit from the 2014 version of the Company's Cost Allocation Manual ("CAM"), which allocates costs based on meters across Duke Energy's business units. Specifically, the Enable Project costs were allocated among the Company's eight business units listed in the exhibit below:

### Exhibit 7-2. Summary of Duke Energy Business Units

| Business Unit | Business Unit No. | Percentage |
|---|---|---|
| Power Delivery | 20017 | 31.52% |
| Carolinas | 50126 | 19.09% |
| Florida | 50226 | 21.71% |
| DEO Electric | 75023 | 8.97% |
| Kentucky - Electric | 75084 | 1.78% |
| Indiana - Electric | 75115 | 10.26% |
| Kentucky - Gas | 75086 | 1.24% |
| DEO Gas | 75026 | 5.43% |
| | Total | 100.00% |

Source: LARKIN-DR-01-115

As shown in the exhibit, Business Unit 75026, which reflects the 5.43% allocation noted in the passage above relates to the Company's Ohio gas distribution utility. The exhibit below shows the Enable projects/applications costs that were allocated to DEO's gas utility:

### Exhibit 7-3. Enable Project Costs Allocated to DEO's Gas Utility

| EF Project ID Description | Fiscal Year 2015 | Fiscal Year 2016 | Fiscal Year 2017 | Fiscal Year 2018 | Grand Total |
|---|---|---|---|---|---|
| **Software** | | | | | |
| ArcGIS / ESRI | $ 53,145 | $ 303,871 | $ 293,360 | $ 11,531 | $ 661,908 |
| ARM Scheduler | $ 82,384 | $ 156,404 | $ 370,514 | $ 15,294 | $ 624,595 |
| Centralized Design Tool | $ 18,826 | $ 119,078 | $ 213,895 | $ 11,501 | $ 363,301 |
| ECOM Data Hub | $ 17,131 | $ 107,204 | $ 238,485 | $ 7,084 | $ 369,905 |
| EGIS (EGIS, Job Mgr, GSDS) | $ 292,604 | $ 620,031 | $ 1,168,222 | $ 36,068 | $ 2,116,925 |
| Expert Designer | $ 81,667 | $ 116,235 | $ 268,223 | $ 23,200 | $ 489,325 |
| Maximo | $ 691,525 | $ 1,499,574 | $ 1,997,688 | $ 87,058 | $ 4,275,845 |
| Mobility | $ 355,021 | $ 809,899 | $ 1,456,679 | $ 46,674 | $ 2,668,273 |
| PowerPlan | $ 20,630 | $ 130,915 | $ 29,784 | $ - | $ 181,330 |
| WMSP, WRT, and AST | $ 45,444 | $ 147,364 | $ 341,112 | $ 12,654 | $ 546,575 |
| **Software Total** | $ 1,658,378 | $ 4,010,576 | $ 6,377,963 | $ 251,064 | $ 12,297,982 |
| | | | | | |
| **Hardware** | | | | | |
| ArcGIS / ESRI | $ 38 | $ 2 | $ 1,004 | $ 0 | $ 1,044 |
| ARM Scheduler | $ 30 | $ 1 | $ 87 | $ 0 | $ 119 |
| Centralized Design Tool | $ - | $ - | $ 53 | $ 0 | $ 53 |
| ECOM Data Hub | $ - | $ 476 | $ 1,789 | $ 0 | $ 2,266 |
| EGIS (EGIS, Job Mgr, GSDS) | $ 1,777 | $ 936 | $ 604 | $ 1 | $ 3,318 |
| Expert Designer | $ 214 | $ 9 | $ 56 | $ 0 | $ 280 |
| Maximo | $ 2,165 | $ 7,729 | $ 14,173 | $ 2 | $ 24,068 |
| Mobility | $ 8,602 | $ 126,383 | $ 351,931 | $ 5 | $ 486,921 |
| WMSP, WRT, and AST | $ - | $ - | $ 76 | $ 0 | $ 76 |
| **Hardware Total** | $ 12,826 | $ 135,537 | $ 369,772 | $ 9 | $ 518,145 |
| | | | | | |
| **Grand Total** | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 |

Source: LARKIN-DR-01-157(g)

As shown in the exhibit above, Enable project software costs allocated to DEO's gas operations totaled $12,297,982 and the hardware related costs totaled $518,145 for an overall total of $12,816,127 charged to DEO's gas distribution utility.

According to the response to LARKIN-DR-01-157(h), for each year 2015 through 2018, the amounts shown above were based on using the 5.43% allocation factor from the 2014 CAM. The exhibit below shows how the Company applied the 5.43% allocation factor in determining the Enable Projects costs to be charged to DEO's gas distribution utility:

## Exhibit 7-4. Enable Project Costs Allocated to DEO's Gas Utility - Per Company

| Description | 2015 | 2016 | 2017 | 2018 | Grand Total |
|---|---|---|---|---|---|
| Enable Project Costs Charged Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 |
| Multiplied by 5 43% from the 2014 CAM | 5 43% | 5 43% | 5 43% | 5 43% | |
| Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 |
| Source: LARKIN-DR-01-157 | | | | | |

As shown above, the Company applied the 5.43 % 2014 CAM allocation factor to the total Company Enable Project costs to derive the portion allocated to DEO's gas distribution utility. The calculations provided by the Company did not separate the total Company software and hardware costs.

We disagree with the Company's methodology of allocating Enable Project costs to DEO's gas distribution utility based on the 2014 CAM 5.43% allocation factor. We recommend that the recoverable Enable project costs in CEP be based on the CAM percentage allocation applicable to DEO as updated each year through 2018. According to the response to LARKIN-DR-01-157, the CAM allocations to DEO's gas utility were 5.41%, 5.34%, and 5.30% for 2015, 2016, and 2017, respectively. The exhibit below shows how the Enable Project costs would have been allocated to DEO's gas distribution utility if the CAM percentage allocation had been updated each year:

## Exhibit 7-5. Enable Project Costs Allocated to DEO's Gas Utility - As Recommended

| Description | 2015 | 2016 | 2017 | 2018 | Grand Total |
|---|---|---|---|---|---|
| Enable Project Costs Charged Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 |
| Multiplied by Each Year's CAM Allocation Factor for DEO Gas | 5 43% | 5 41% | 5 34% | 5 30% | |
| Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 |
| Per Company Using 5 43% in Each Year | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 |
| Difference | $ - | $ (15,271) | $ (111,841) | $ (6,011) | $ (133,123) |
| Source: LARKIN-DR-01-157 Supplemental | | | | | |

As shown above, by using the annual updated CAM allocation percentages, the total Enable Project costs allocated to DEO's gas distribution utility is $12,683,004, or $133,123 less than the Company's amount of $12,816,127.[45] As discussed in further detail in Chapter 9 of this report, we recommend that the allocation of Enable Project costs to DEO's gas distribution utility be calculated using the annual updated CAM percentages.

[45] Note 1 on the LARKIN-DR-01-157 Supplemental Attachment states that due to the complexity of Enable charging and the timing of the CAM spreadsheet, updating the percentage each year would require using the prior year's CAM.

## Enable Project Budget Overruns and Change Orders

As discussed above, for the period ending December 31, 2017, the Company's budget to actual analysis resulted in an unfavorable variance totaling $13,259,485 which the Company indicated was due to additional costs and an extended schedule for the Enable project.

To understand what caused the budget overruns on this project, we requested that DEO identify and provide a complete copy of each change order for the Enable Project. In its response to LARKIN-DR-01-105, the Company provided 131 confidential attachments. While some of these attachments were the original Bids and/or Statements of Work from the various vendors that worked on the Enable Project, the vast majority of these attachments were change orders for the project. The change orders provided totaled [redacted]

[redacted]

[46] The 131 voluminous confidential attachments to LARKIN-DR-01-105 were provided on a CD, which Larkin received on April 17, 2020. In addition, problems were initially encountered with opening the files, but this was eventually resolved.

Exhibit 7-6. [redacted]

[redacted]

[redacted]

Conclusion

Larkin did not perform a management audit. As it relates to the significant budget overruns with regard to the Enable Project, based on the information we reviewed, we found that DEO had documentation to support the Enable Project costs. We did not find imprudence. As such, we are not recommending any adjustments nor are we making a finding of imprudence. However, given the magnitude of the actual costs of this project, and the change orders in excess of $31 million, we recommend that the costs of the Duke Energy Enable Project be subject to ongoing regulatory scrutiny. Specifically, due to the sheer volume of costs associated with this project, coupled with the fact that they were allocated across several of Duke Energy's business units (in addition to DEO's gas utility), our opinion is that ongoing and additional regulatory scrutiny of the Duke Energy Enable Project costs charged to DEO may be warranted.

# 8 METERS AND COMMUNICATION EQUIPMENT

This chapter of our report discusses the following topics as it relates to AMI meters and related communication equipment:

- The costs associated with AMI meter module replacements from 2013, 2014 and 2015 that should have been included in Rider AU
- Rider AU costs excluded from CEP
- An "Unretirement" in the amount of $23,065,474
- Gas Meters Installed and Retired
- Replacement of gas meter communication equipment

## AMI Meter Module Replacements

In order to determine which meter-related projects should have been included in Rider AU versus CEP, we asked the Company to distinguish between (1) costs that are includable in Rider AU, and (2) costs that it included in the CEP.  In its response to LARKIN-DR-01-78, DEO stated that Rider AU costs were distinguished through certain project class codes that were assigned to Smart Grid projects and that Rider AU costs were only distinguished through 2015 since that was conclusion of the Smart Grid initiative.  We requested further clarification of the criteria DEO used to identify projects to include in Rider AU and those to include in the CEP.

Upon reviewing the listing of the Company's CEP-related project work orders (previously discussed in Chapter 6), we noted several projects in each year 2013 through 2018, which appeared to relate to the replacement of meters and/or for AMI as shown in the exhibit below:

## Exhibit 8-1. AMI Module Projects Included in CEP

| FERC Account | Project ID Number | Project Description | Rider | Work Order Completion Date | In-Service Date | Unitization Date | Work Type | Blanket Project | Charges |
|---|---|---|---|---|---|---|---|---|---|
| | | **2013 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201212 | 2013 | 200412 | Replacement | Y | $ 308,408 46 |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201312 | 2013 | 200412 | Replacement | Y | $ 22,400 06 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201303 | 2013 | not_unitized | Replacement | Y | $ 890 46 |
| | | **2014 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201312 | 2014 | 200412 | Replacement | Y | $ 151,791 21 |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201412 | 2014 | 200412 | Replacement | Y | $ 5,032 13 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201401 | 2014 | not_unitized | Replacement | Y | $ 879 77 |
| | | **2015 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201412 | 2015 | 200412 | Replacement | Y | $ 172,989 03 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201504 | 2015 | not_unitized | Replacement | Y | $ 31 27 |
| | | **2016 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 1,388,723 09 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201601 | 2016 | 201708 | Replacement | Y | $ 277,589 94 |
| 376 | R1488 | AMRP 2015 Small Segments | CEP | 201511 | 2016 | not_unitized | Replacement | N | $ 257,321 63 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 243,820 16 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201601 | 2016 | 201910 | Replacement | Y | $ 232,515 98 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 73,363 15 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201610 | 2016 | 201910 | Replacement | Y | $ 65 60 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201610 | 2016 | 201708 | Replacement | Y | $ 19 78 |
| 387 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201610 | 2016 | 201708 | Replacement | Y | $ 15 12 |
| 376 | P7607 | AMRP 2015 Small Segments Jan-Jul | CEP | 201507 | 2016 | not_unitized | Replacement | N | $ (103,377 99) |
| | | **2017 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 2,573,139 31 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 193,803 64 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 141,246 87 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | 107,589 12 |
| 394 | SGOGPGMTR | Smart Grid Ohio Gap Gas Meter | CEP | 201501 | 2017 | 201512 | additions | Y | 90,161 20 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201705 | 2017 | 201910 | Replacement | Y | 29,873 10 |
| 387 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | 15,291 31 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201708 | 2017 | 201708 | Replacement | Y | 14,851 59 |
| | | **2018 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 2,634,723 83 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 170,062 70 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 144,539 25 |
| 380 | CMSTRCAR | Curb to Meter for Streetcar Project | CEP | 201405 | 2018 | not_unitized | Replacement | N | 11,849 45 |

Source: LARKIN-DR-01-35

We requested that DEO explain why these projects were included in the CEP expenditures rather than in Rider AU. The Company's response to LARKIN-DR-01-72 stated that the projects cited as relating to meters were blanket projects used to purchase and install meters. In addition, the response to LARKIN-DR-01-72, stated that Rider AU covered investments were specifically related to Smart Grid. The gas utility meters were not removed or replaced with smart meters. Rather, communication devices were added to the existing meters.

As part of the response to LARKIN-DR-01-72, the Company stated that for 2013, 2014 and 2015, project additions identified by Project ID number AMIMODCHG should have been included in Rider AU, but that this project was not labeled properly so these projects were not captured in Rider AU. DEO included them in CEP because they relate to infrastructure for gas operations, and had not been included in Rider AU, due to the incorrect labeling. These three projects are summarized in the exhibit below:

**Exhibit 8-2. AMI Module Projects That Should Have Been Included in Rider AU**

| Year | FERC Account | Project ID Number | Project Description | Rider | Work Order Completion Date | In-Service Date | Unitization Date | Work Type | Blanket Project | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 381 | AMIMODCHG | AMI Module Install/Remove | CEP | March 2013 | 2013 | Not Unitized | Replacement | Y | $ 890 46 |
| 2014 | 381 | AMIMODCHG | AMI Module Install/Remove | CEP | January 2014 | 2014 | Not Unitized | Replacement | Y | $ 879 77 |
| 2015 | 381 | AMIMODCHG | AMI Module Install/Remove | CEP | April 2015 | 2015 | Not Unitized | Replacement | Y | $ 31 27 |
| | | | | | | | | | Total | $ 1,801 50 |
| Source: LARKIN-DR-01-35 | | | | | | | | | | |

The three AMI projects that should have been included in Rider AU totaled $1,802. Because these projects should have been included in Rider AU, but were not due to improper labeling by the Company, we have removed the costs associated with these three projects from CEP plant in-service as shown on Attachment LA-1, Schedule 9. For this adjustment, because of the small plant adjustment amount, we did not attempt to reflect the impacts to deferred or annualized depreciation expense, or the PISCC, which would be even smaller.

## Rider AU Costs Excluded from CEP

The Company provided a reconciliation of the components of its historical plant records (i.e., by rider and other exclusions), including amounts designated as relating to CEP and Rider AU.[47] For Rider AU, the reconciliation included the following amounts for the period April through December 2012 as well as calendar years 2013 through 2015:

**Exhibit 8-3. Rider AU Costs Excluded from CEP**

| Description | Apr-Dec 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| Rider AU | $ 12,416,689 | $ 23,333,565 | $ 5,033,648 | $ (151,995) |
| Less Rider AU Common | $ (5,531,194) | $ (8,291,903) | $ (2,796,044) | $ 2,580 |
| Less Rider AU Acct 17001 | $ (866,164) | $ (7,988,510) | $ (675,242) | $ 2,518 |
| Net Rider AU | $ 6,019,331 | $ 7,053,152 | $ 1,562,362 | $ (146,897) |
| Source: LARKIN-DR-01-001(h) Attachment | | | | |

As shown in the exhibit above, the Company's historical plant records included Rider AU related projects netting to $6.019 million (2012 from April-December), $7.053 million (2013), $1.562 million (2014), and a credit amount of $146,897 (2015).

In LARKIN-DR-01-84, we requested further clarification of the criteria DEO used to identify projects to include in Rider AU and those amounts included in the CEP, including:

- The criteria used by DEO to identify amounts in Rider AU for the period March through December 2012 and for each year 2013 and 2014.

[47] This reconciliation, which was provided in the response to LARKIN-DR-01-001 as Attachment H, is discussed in more detail in Chapter 6 of this report.

- For each year 2015 through 2018, we asked DEO what work orders and costs have been included in CEP that prior to December 31, 2014 would have been included in Rider AU.
- We asked DEO to explain what caused the Company to cease treating work orders and costs as belonging in Rider AU starting on January 1, 2015.
- We asked DEO to explain whether there is any difference in the carrying charges or return that was applied to amounts in Rider AU and the CEP for any of the years 2013 through 2015.

With regard to the first bullet point above, in its response to LARKIN-DR-01-84, the Company stated that it identified projects as Rider AU through 2015. Specifically, project class codes were used to identify projects' in-service expenditures that would be used in Rider AU.[48]

Regarding the second bullet point above, the Company stated that no work orders for costs incurred during the period 2015 through 2018 were included in Rider AU because the Commission authorized DEO to include costs related to the initial AMI deployment in Rider AU, and that this initial deployment was completed in 2014.

Regarding the third bullet point above, and pursuant to the previous statement, the Company stopped including expenditures in Rider AU because the Smart Grid project had been completed. The Company stated it was only authorized to include the costs of the initial AMI deployment in Rider AU.

Finally, with regard to the fourth bullet point above, DEO stated that there were no differences in the carrying charges or return for Rider AU or CEP during the period 2013 through 2015.

## The "Top End" $23,065,474 "Unretirement"

The aforementioned reconciliation (from the response to LARKIN-DR-01-001) of the components of DEO's historical plant records by rider and other exclusions that was referenced above included the following line item for 2015: "Reconciling Item - 381/2810, 2811/Meters" in the amount of $23,065,474.

We noted that this amount was included as an adjustment to the Company's 2015 reported FERC Form 2 amounts as shown in an attachment that was provided with DEO's response LARKIN-DR-01-004.[49]

In its response to LARKIN-DR-01-24, the Company stated that the $23,065,474 was for a journal entry related to the retirement of smart grid meters that was not recorded in PowerPlan.

[48] Also see the response to LARKIN-DR-01-78.

[49] LARKIN-DR-01-004 requested the Company's detailed monthly general ledger data for its plant accounts for the period 2012 through 2018.

We requested additional information regarding this journal entry and in its response to LARKIN-DR-01-88 the Company stated:

> The Company has performed additional research on this item and needs to update the description of the purpose of the entry that was provided in LARKIN-DR-01-001 and LARKIN-DR-01-24. In December 2015, $23M of gas meters were incorrectly retired in PowerPlan, the fixed asset system. This was discovered through the close process, after any updates in the subledger could be made for December 2015 accounting. As such, an on-top entry was recorded to reverse the retirement that processed in PowerPlan. The original incorrect entry that PowerPlan recorded was a debit to Account 108 - Accumulated Depreciation and a credit to Account 101 - Plant in Service. The correcting on-top entry was a debit to Account 101 and a credit to Account 108 to reverse the PowerPlan activity. As such, the entry is needed to reconcile the PowerPlan data to the General Ledger and FERC Form as of December 31, 2015. An "Unretirement" entry was processed in PowerPlan in January 2016 and the "on-top" entry was also reversed in January 2016. As such, the reconciling item was no longer needed as of December 31, 2016.
>
> In previous Data Requests, this on-top has incorrectly been described as a retirement entry, but it is really an "un-retirement". Additionally, while the entry references "SG" which typically indicates Smart Grid, the incorrect retirements and associated reversal were not related to smart grid meters. The incorrect retirement was of gas meters. The Smart Grid initiative did not involve actual meter assets, but instead involved communication modules added to meters.

In addition to the foregoing passage, in its response to LARKIN-DR-01-88, the Company stated that none of the on-top entry for the $23,065,474 "un-retirement" was included in the CEP investment for 2015,[50] or in Rider AU (since it related to normal gas meters and not Smart Grid meters). In addition, none of this amount was allocated to common plant. We confirmed that this was not included in CEP costs.

We recommend that Staff be aware of this unusual "un-retirement" entry and, as needed, make follow-up inquiries in future DEO rate cases to determine whether and how it is impacting DEO's rate base.

## Gas Meters Installed and Retired

In order to obtain clarity on whether and how DEO meter costs are allocated to the Company's electric and gas utility operations, we asked that, for portions of DEO's Ohio service territory that include the provision of both electric utility service and gas distribution service, if there are any costs related to the electric utility AMI or smart meter program, or related investment in

[50] Also see the response to LARKIN-DR-01-138, which stated that the transaction type (i.e., PPRTRV-URET) used to book this "unretirement" was excluded from the CEP additions and retirements.

communications equipment charged or allocated to DEO's gas utility operations during the period 2012 through 2018. In its response to LARKIN-DR-01-89, the Company stated:

> A part of the electric utility AMI or smart meter program included costs that were charged to Common utility plant accounts. A portion of these Common costs were allocated to Gas Operations through inclusion in Rider AU costs for 2012-2015. All other costs that did not go through the AU will get included in rate base during the next gas rate case. Depreciation Expense on Common projects is allocated between Electric and Common based on an allocation percentage that is based on FERC Form 1 data. Generally, approximately 40% is allocated to Gas operations.

A summary of the costs that were included in Rider AU for 2012 through 2015 is shown in the exhibit below:

### Exhibit 8-4. Costs Included in Rider AU

| 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|
| $ 2,835,210 | $ 12,959,400 | $ 3,641,519 | $ (5,098) |

Source: LARKIN-DR-01-89

During the telephone interviews with DEO personnel, the Company stated that the CEP expenditures do not include any allocations for common plant.

During our review of the 2013 project work orders that were provided in response to LARKIN-DR-01-35, we noted two projects under ID number 20064 which had the description "To Include All Labor Materials And" in the amounts of $93,874 and $46,937.

Upon our inquiry as to what this project related to, in its response to LARKIN-DR-01-73, the Company stated that this was a blanket project to install gas analog meters in 2013 and was designated as CEP since meters are part of the infrastructure for gas operations. These meters were not included in Rider AU as they were not smart gas modules that were installed for purposes of AMI.

In its response to LARKIN-DR-01-135, DEO explained that the term "analog meter" applies only to electric meters and that all gas meters in DEO's system are diaphragm meters (see additional discussion below). In addition, the Company's response stated that Project ID 20064 was a blanket work order used to record gas meter costs in 2013 and that there are no smart meters installed on the Company's gas system.

The exhibit below shows (1) the total gas meters in service in each year 2012-2018;(2) the net number of gas meters installed, retired or replaced in each year 2013-2018; and (3) the incremental cost of the gas meters installed in each year 2013-2018:

**Exhibit 8-5. Summary of Meters in Service, Net Installs, Retirements and Replacements and Meter Costs**

| Description | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| Total Meters in service | 452,966 | 452,292 | 453,127 | 454,695 | 457,084 | 459,524 | 461,370 |
| Net Installs, Retirements, Replacements | (674) | 835 | 1,568 | 2,389 | 2,440 | 1,846 | |
| End of Year Meters in Service | 452,292 | 453,127 | 454,695 | 457,084 | 459,524 | 461,370 | 461,370 |
| Cost of Gas Meters Installed | | $ 641,367 | $ 641,367 | $ 2,324,966 | $ 2,328,118 | $ 3,329,430 | $ 3,668,230 |
| Average Cost Per Installed Meter | | $ 1.42 | $ 1.41 | $ 5.09 | $ 5.07 | $ 7.22 | $ 7.95 |
| Source: LARKIN-DR-91 and LARKIN-DR-01-135; average cost per meter calculated by dividing cost by end-of-year installed meters. | | | | | | | |

As shown in the exhibit above, with the exception of 2013, the net number of meters installed, retired, or replaced increased each year.

According to the response to LARKIN-DR-01-161, the reasons for the installation of new gas utility meters in each year are not tracked, but such reasons would have been due to (1) serving new customers; (2) increasing load on a customer's premises; (3) system improvements; (4) obsolescence; (5) replacing defective meters. The costs shown in the exhibit relate to the total net cost of gas meter installs, retirements and replacements, which are recorded in Company account 281 - Meters (FERC Account 381).[51]

We had requested that DEO provide a breakout between (1) the installed meters, retired meters, and meters replaced, and (2) the costs associated with the net installs, retirements and replacements. In its response to LARKIN-DR-01-161(e) the Company stated that the data is not available to separate the quantity between the meter installations, retirements, or replacements. In addition, with regard to breaking out the costs, the Company stated:

> From an accounting perspective, when a new meter is installed at a new customer location, an addition is recorded on the books. When a meter a customer location is replaced, a retirement is recorded for the meter removed from the location and an addition is recorded for the meter that is installed to replace the previous meter. If a meter is removed from a customer location and is not replaced with another meter, then only a meter retirement is processed. The costs of additions and retirements were provided in DR-01-135. This data is from the fixed asset system.[52]

The meter costs indicated in the response to LARKIN-DR-01-135 are shown in the exhibit above. As for what is included in CEP from 2013 through 2018, only the incremental costs relating to the meters installed and old meters retired would be included in CEP (to the extent they were not part of Rider AU or booked to Common utility accounts.[53]

[51] According to LARKIN-DR-01-161(c), these amounts exclude the related labor costs, which are recorded in Company account 282 - Meter Installations (FERC Account 382).
[52] See the response to LARKIN-DR-01-161(f).
[53] See the response to LARKIN-DR-01-161(g).

As it relates to gas meter retirements, the exhibit below shows (1) the number of gas diaphragm meters retired in each year 2013-2018, and (2) the original cost of the gas diaphragm meters that were retired in each year 2013-2018.

### Exhibit 8-6. Summary of Meter Retirements and Associated Costs

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| Quantity of Gas Meters Retired | (5,982) | (5,736) | (31,432) | (235,845) | (53,507) | (20,475) |
| Original Cost of Gas Meters Retired | $ (354,295) | $ (443,552) | $ (1,594,546) | $ (11,556,377) | $ (3,502,660) | $ (1,482,044) |
| | | | | | | |
| Average Cost of Meters Retired | $ 59.23 | $ 77.33 | $ 50.73 | $ 49.00 | $ 65.46 | $ 72.38 |
| Source: LARKIN-DR-01-135; average cost of meters retired calculated by Larkin | | | | | | |

As shown above, the number of gas meter retirements increased substantially from 2014 to 2015 and then increased by a very large amount in 2016 before gradually decreasing in 2017 and 2018.

We requested that DEO explain the reason(s) why the gas meters were retired (e.g., meters reaching the end of their useful lives, meters were defective and failed, thus had to be replaced, the meter technology was obsolete, etc.). However, in its response to LARKIN-DR-01-161(l), the Company merely stated that retirements are processed in the fixed asset system when meters are no longer installed in the field. In addition, DEO stated that meters can be removed from customer locations for a variety of reasons, including meters being defective or failing, or after an extensive period of inactivity.

The original cost of the retirements noted in the exhibit above are included in Exhibit J, Schedule 4 - Monthly CEP Investments from the Company's filing.[54] According to the response to LARKIN-DR-01-37(c), the accounting entry to record the retirement of a CEP project is to debit FERC account 108 - Accumulated Provision for Depreciation and to credit FERC account 101 - Plant In-Service Classified.

The high number of gas meter retirements in years after DEO completed its smart meter deployment could warrant further investigation.

## Replacement of Gas Meter Communication Equipment

In order to obtain an overall understanding of the Company's Ohio gas distribution system Advanced Meter Infrastructure ("AMI") systems, we requested that the Company explain the AMI systems it has installed for Ohio gas distribution utility, including a description of changes to the AMI equipment for (1) retirements, and (2) replacements that have occurred during each year in the period 2013 through 2018. In its response to LARKIN-DR-01-92, the Company stated that it implemented an initial AMI deployment for its electric and gas systems between 2008 and 2014 and that it has been recovering the costs of this initial deployment through a combination of base rates and through Rider AU. In addition, the Company is currently in the process of replacing the original AMI equipment from the initial deployment (which ended in

[54] See the response to LARKIN-DR-010161(m).

2014) with new assets which are included in the CEP. According to the response to LARKIN-DR-01-93, DEO stated that the majority of its residential gas AMI meters installed during the initial deployment (i.e., 2008-2014) were wirelessly connected to a communication node device for data backhaul to the Company. In 2012, DEO began deploying a wireless mesh AMI system primarily for its small commercial customers, which enabled the gas AMI modules to communicate wirelessly to electric AMI meters and then to communication devices for data backhaul. However, in 2017 and 2018, the Company began replacing communication node devices and the connected electric and gas AMI meters with the wireless mesh AMI system.

On page 3 of the Direct Testimony of Company witness Donald L. Schneider, Jr. dated March 16, 2017 in Case No. 17-32-EL-AIR, Mr. Schneider stated that the Company has two AMI metering environments, which include node and mesh environments.[55] Specifically, the node environment is comprised of Echelon electric meters, Badger gas communication modules and communication nodes, originally manufactured by Ambient, but which was subsequently acquired by Ericsson. In addition, the mesh environment is comprised of Itron electric meters, Itron gas communications module, Itron range extenders, and Cisco Connected Grid Routers ("CGRs").

We asked the Company to explain how it distinguishes between (1) gas analog meters; (2) "smart" meters; (3) Smart Grid meters; (4) AMI meters; (5) "normal" meters; and (6) any other types of meters on the DEO gas utility system. In its response to LARKIN-DR-01-139 stated the following:

> For Duke Energy Ohio Gas, all meters on the system are diaphragm meters and are not considered "smart" meters. Starting in 2008, the Smart Grid initiatives added "smart" gas communication modules to the gas meters so that they could communicate with the Smart Grid network. These modules were recorded in Utility Account 397 - Communication Equipment (Company account 297). The gas meters themselves did not change as part of this initiative. All costs related to meters are recorded within Utility Accounts 381 - Meters and 382 - Meter Installations (Company accounts 281 and 282).

As of each year-end December 31, 2012 through December 31, 2018, we requested that DEO identify and provide specific information concerning its AMI communications equipment, including: (1) a description of gas AMI communications equipment installed by type; (2) the cost of gas AMI communications equipment installed by type; (3) for each year 2013-2018, gas AMI equipment (other than meters) retired by type and the reason(s) for such retirements; and (4) for each year 2013-2018, gas AMI equipment (other than meters) purchased in total and by type of equipment. In its confidential response to LARKIN-DR-01-94(a), the Company stated:

[55] In its responses to LARKIN-DR-01-92 and LARKIN-DR-01-93, DEO referred to Mr. Schneider's Direct Testimony in Case No. 17-32-EL-AIR for an outline of the Company's business plan for replacing the communications node devices.

[redacted]

[redacted]

We requested that DEO explain why its AMI technology on the gas meters was changed. In its response to LARKIN-DR-01-129, the Company explained that all of its legacy Badger AMI gas modules are being changed as part of the transition from the originally deployed Echelon/Badger/Ambient AMI solution to the Company's current standard AMI solution called Itron Openway. DEO cited the following three factors as reasons for this change:[57]

- The Ambient communication nodes use 2G technology. Verizon has indicated that it will end 2G communication at some point in 2022.

- The new customer billing system called Customer Connect, which is scheduled to be deployed in Ohio during the third quarter of 2022, will not be integrated with the Energy Data Management System ("EDMS") and all of the Echelon and Badger meter data reads go through EMDS.

- The Company is deploying a single AMI solution across all of its jurisdictions in order to take advantage of efficiencies and to consolidate customer programs.

The exhibit below shows the costs that DEO incurred by year for its current communication nodes:

[56] As discussed previously in Chapter 6, the project ID numbers (work orders) for each year 2013 through 2018 were provided in DEO's response to LARKIN-DR-01-35.
[57] See the response to LARKIN-DR-01-129(a).

## Exhibit 8-7. Summary of Meter Communication Node Costs

| Project ID Number | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Z3020 - Badger | $ 4,164,303 | $ 2,469,031 | $ 7,894,957 | $ 8,738,173 | $ (13,772,941) | $ 2,985,689 | $ 12,925 | | | | | $ 12,492,137 |
| | | | | | | | | | | | | |
| SGGASMTR - Badger | $ - | $ - | $ 473,520 | $ 3,078,438 | $ (2,630,969) | $ 462,078 | $ 146,740 | $ (52,224) | $ - | $ - | $ - | $ 1,477,583 |
| | | | | | | | | | | | | |
| SGOGPGMOD - Itron | $ - | $ - | $ - | $ - | $ 431,120 | $ 3,736,117 | $ 232,065 | $ (148,892) | | | | $ 4,250,410 |
| | | | | | | | | | | | | |
| SGOGPGMTR - Itron | $ - | $ - | $ - | $ - | $ 13,110 | $ 509,500 | $ 118,799 | $ (10,026) | $ - | $ 90,161 | $ - | $ 721,544 |
| | | | | | | | | | | | | |
| SG000584G - Itron | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 3,965,480 | $ 3,524,130 | $ 7,489,610 |
| Source: LARKIN-DR-01-129 | | | | | | | | | | | | |

As shown in the exhibit above, the costs associated with Project ID number Z3020, which related to the Badger AMI gas modules, totaled $12,492,137 between 2008 and 2014. Of this amount, the Company recorded $5,785,959 in FERC Account 381 - Meters and $6,706,178 in FERC Account 397 - Communications. According to the response to LARKIN-DR-01-129(f), Project ID Z3020 related to the installation of (1) Echelon electric meters, (2) Badger gas modules, and (3) Ambient communication modes. DEO stated that the costs for these modules were not recorded separately.

The costs associated with Project ID number SGGASMTR, which also related to the Badger AMI gas modules, totaled $1,477,583 between 2010 and 2015 all of which was recorded in FERC Account 381 - Meters. Similar to Project ID Z3020, the response to LARKIN-DR-01-129(f) indicated that Project ID SGGASMTR also covered the installation of the Echelon electric meters, Badger gas modules, and Ambient communication nodes.

The costs associated with Project ID number SGOGPGMOD, which related to the Itron Openway deployment, totaled $4,250,411 between 2012 and 2015 all of which was recorded in FERC Account 397 - Communications. According to the response to LARKIN-DR-01-129(g), Project ID number SGOGPGMOD related to the Itron Openway gap deployment to replace meters, modules, and CGRs that were not covered in the initial Echelon deployment.

The costs associated with Project ID number SGOGPGMTR, which also related to the Itron Openway deployment, totaled $721,544 between 2012 and 2015. Of this amount, the Company recorded $631,383 in FERC Account 381 - Meters and $90,161 in FERC Account 397 - Communications. Similar to Project ID SGOGPGMOD, the response to LARKIN-DR-01-129(g) indicated that Project ID SGOGPGMTR also related to the Itron Openway deployment to replace meters, modules, and connected grid routers ("CGRs") that had not been included in the initial Echelon deployment.

Finally, the costs associated with Project ID number SG000584G, which related to converting Echelon electric meters and Badger gas modules to Itron Openway, totaled $7,489,610 between 2017 and 2018 (see additional discussion below). Of this amount, the Company recorded $33,357 in FERC Account 381 - Meters and $7,456,253 in FERC Account 397 - Communications. According to LARKIN-DR-01-129(g), Project ID number SG000584G converted some of the Echelon electric meters and Badger gas modules to Itron Openway for the purpose of clearing nodes.

In order to determine whether the projects listed in the exhibit above are included in the CEP expenditures, for each year 2013 through 2018, we compared the Project ID numbers discussed above to the work order detail that was provided in LARKIN-DR-01-35. The results of this review are summarized in the exhibit below:

**Exhibit 8-8. Summary of Meter Communication Equipment Projects**

| Project ID Number | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total | Rider* |
|---|---|---|---|---|---|---|---|---|
| Z3020 | $ 2,985,689 | $ 12,925 | $ - | $ - | $ - | $ - | $ 2,998,614 | AU |
| SGGASMTR | $ 462,078 | $ 146,740 | $ (52,224) | $ - | $ - | $ - | $ 556,594 | NR |
| SGOGPGMOD | $ 3,736,117 | $ 232,065 | $ (148,892) | $ - | $ - | $ - | $ 3,819,290 | AU |
| SGOGPGMTR | $ 509,500 | $ 118,799 | $ (10,026) | $ - | $ 90,161 | $ - | $ 708,434 | NR & CEP |
| SG000584G | $ - | $ - | $ - | $ - | $ - | $ 7,489,610 | $ 7,489,610 | CEP |

Notes/Source:
Amounts from LARKIN-DR-01-129
* The "NR" designation indicates "Non-Rider Related" per the response to LARKIN-DR-01-35

As shown in the exhibit above, none of the costs associated with Project ID numbers Z3020, SGGASMTR or SGOGPGMOD were included in CEP expenditures.

With regard to Project ID number SGOGPGMTR, the Company indicated that the costs incurred in years 2013 through 2015 were non-Rider related, but that the $90,161 incurred in 2017 was included in the CEP expenditures.

For Project ID number SG000584G, according to the work order detail provided in LARKIN-DR-01-35, all of the $7,489,610 incurred was included in CEP in 2018, although the response to LARKIN-DR-01-129 indicated that $3,965,480 of that amount was incurred in 2017.

Based on what is reflected in the exhibit above, we requested confirmation from DEO that the $90,161 in 2017 and the costs totaling $7,489,610 in 2018 are the only costs included in Exhibit J, Schedule 4 - Monthly CEP Investments from the Company's filing. In its response to LARKIN-R-01-162(a), the Company stated:

> The three 2018 amounts totaling $7,489,610 for Project SG000584G are the only costs included in the CEP filing related to the Company changing the Badger AMI gas modules from the Echelon/Badger/Ambient AMI solution to the Itron Openway. As described in LARKIN-DR-01-93 Attachment page 12, the project was driven by Ericsson's decision to stop manufacturing the nodes, and higher than expected failure rates of the nodes. The 2017 amount of $90,161 for Project SGOGPGMTR is related to installation of the Itron Openway gas modules, however the project did not replace Badger AMI gas modules. Project SGOGPGMTR was for all of the customers accounts that were not included in the initial Echelon Badger deployment as described in LARKIN-DR-01-93 Attachment 8 and 9. The material included Itron Openway electric meters, Itron Openway gas modules, Cisco connected grid routers (CGRs), and Itron range extenders.

With regard to Project ID number SG000584G included in CEP for 2018, the bulk of the total cost of $7,489,610, i.e., $7,456,253 had the following description: "SG DEO AMI BC - Tech Transition - Gas. Communication nodes will be removed. OpenWay AMI meters will be installed."

The response to LARKIN-DR-01-77 explained that this project was included in CEP expenditures because it relates to gas infrastructure specific to the communication nodes used to transmit meter data to the smart grid network. In addition, the response to LARKIN-DR-01-77 stated:

> The original smart grid project involved installing communication modules on the gas meters that would communicate with the Echelon smart grid network; however, in 2017, DEO had to move to an Itron smart grid network because the Echelon network was no longer supported. the gas modules that were originally installed had to be replaced with Itron gas modules to function properly with the Itron network.

As discussed above, the Company's legacy Badger AMI gas modules are being changed as part of the transition from the originally deployed Echelon/Badger/Ambient AMI solution to the Company's current standard AMI solution called Itron Openway.

We asked DEO to identify, by year, the costs for the communication nodes that were removed. In its response to LARKIN-DR-01-129, the Company indicated communication nodes were removed in 2015 and 2016 only as summarized in the exhibit below:

**Exhibit 8-9. Summary of Meter Communication Equipment Removed by Project**

| Project ID Number | FERC Account | 2015 | 2016 | Total |
|---|---|---|---|---|
| Z3020 | 381 | $ (372,363) | $ - | $ (372,363) |
| SGGASMTR | 381 | $ (17,454,706) | $ 16,322,006 | $ (1,132,700) |
| SGGASMTR | 381 | $ (6,635,473) | $ 5,610,769 | $ (1,024,704) |
| SGGASMTR | 382 | $ (502,408) | $ - | $ (502,408) |
| SGGASMTR | 382 | $ (242,277) | $ - | $ (242,277) |
| SGOGPGMTR | 381 | $ (147,806) | $ - | $ (147,806) |
| Total | | $ (25,355,033) | $ 21,932,775 | $ (3,422,258) |

Source: LARKIN-DR-01-129

As shown in the exhibit above, for 2015, the removal of the communication nodes resulted in an overall credit amount of $25,355,033, while 2016 reflects an overall positive charge amount of $21,932,775 for a net credit amount totaling $3,422,258. The Company stated that as part of the transition from the Echelon/Badger/Ambient AMI solution to the Itron Openway AMI solution, the removed communication nodes are being replaced with CGRs.[58]

We requested that DEO (1) explain why the 2016 retirement amounts for the removed communication nodes were positive, and (2) whether the removal of the communication nodes are reflected in the CEP.

In its response to LARKIN-DR-01-162(d), the Company stated that the positive retirement amounts in 2016 were driven by the "un-retirement" that was previously discussed and that the related transaction was recorded as a debit to plant in-service and a credit to accumulated depreciation, thus reversing the impacts of the retirement recorded in error in 2015. In addition, since the un-retirement was processed as part of Project SGGASMTR, it was not included in CEP.

The response to LARKIN-DR-01-77 indicates that the work to replace the communication nodes did not commence until 2017.

We requested that DEO explain why it removed communication nodes in 2015 and 2016. In its response to LARKIN-DR-01-162(b), the Company stated that it employs an auto-retirement process for FERC account 397 - Communication Equipment rather than recording a specific retirement each time communication related items are replaced. In other words, the assets recorded in FERC account 397 are accounted for as retirements at the end of their expected useful life, which is 15 years for DEO gas, even if the communications equipment is actually removed and replaced before the end of the 15-year period, as appears to have been the case with some of the DEO gas utility meter communication modules..

As it relates to the estimated useful life of the DEO gas AMI system, the response to LARKIN-DR-01-130(b) indicated that the Badger AMI gas module, which was installed as part of the Echelon/Badger/Ambient AMI solution, was expected by the Company to have a 20-year life. This is based on the life expectancy of the internal battery. In addition, the Ambient communications node (also installed pursuant to the Echelon/Badger/Ambient AMI solution) was expected by the Company to have a 10-year useful life. Finally, the Itron Openway (the AMI solution DEO is changing to) was designed for a 20-year life.[59]

In terms of the components of the DEO gas AMI system that are shared with the electric AMI system, the response to LARKIN-DR-01-130(c) stated that both the Echelon/Badger/Ambient AMI solution and the Itron AMI solution use the Ambient node and the Cisco Connected Grid Router, respectively, as a shared device for electric and gas. However, the Echelon/Badger/Ambient AMI solution has a separated head-end system for gas data, but the Itron AMI solution uses a common head-end system for both gas and electric. In addition, both of these AMI solutions use a Meter Data Management ("MDM") system, which is common to gas and electric. These shared assets are recorded as common assets whereby depreciation

[58] See the response to LARKIN-DR-01-129(e).
[59] See the response to LARKIN-DR-01-130(b).

expense is allocated between gas and electric based on allocation factors (e.g., ratio of gross plant for gas and electric).

As discussed above, the Company has explained that the reason it is changing its communication nodes from the Echelon network to the Itron Openway network is because the Echelon network is no longer supported. Against this backdrop, we have identified a concern regarding the systems' compatibility with 5G wireless technology.[60] Pursuant to this concern, we asked the Company to explain whether the currently installed DEO gas AMI system is compatible with wireless 5G technology. In its response to LARKIN-DR-01-130(a), the Company stated:

> The Badger Gas AMI system requires a communication backhaul (Ambient communications node), and the currently deployed communication backhaul is not compatible with 5G wireless. The Itron Gas AMI system also requires a communication backhaul (Connected Grid Router - CGR), which is 4G technology. From what we know today, these are not 5G compatible. To the best of our knowledge, there is not a readily available 5G modem that could be used in the CGRs, so we cannot definitively answer this question "yes" or "no".

The foregoing response was troubling because it left open the question of whether it will be necessary for DEO to upgrade and/or replace its meter communication nodes again and before the expiration of their currently expected useful life in the event the Itron Openway AMI solution is not compatible with 5G.

The communication node in the current Echelon/Badger/Ambient AMI solution has a 3G wireless modem that is not 5G compatible and will no longer be supported by the end of 2022.[61]

In the event the Itron OpenWay is not 5G compatible, we asked the Company how it plans to address this issue when the current 3G technology sunsets in 2022. In its response to LARKIN-DR-01-162 the Company stated:

> Itron's OpenWay solution uses cellular communications on its OpenWay CENTRON LTE meters and OpenWay Connected Grid Routers (CGRs). All of the OpenWay LTE meters in service utilize 4G modems and Verizon's 4G network, and are not impacted by Verizon's 3G end of life. Likewise, the majority of the OpenWay CGRs leverage 4G modems and 4G network and are not impacted by the 3G network end of life. Remaining 3G CGRs will be updated with 4G modems or replaced with 4G CGRs by the end of Q3 2020. The 4G modems in both Itron's OpenWay CENTRON meters and OpenWay CGRs will be supported by Verizon's 4G LTE network until, at a minimum, 2030. These modems are not 5G capable, but are backwards compatible with Verizon's 5G network. Itron will introduce a 5G compatible cellular solution for possible

[60] 5G is the fifth generation of wireless communication standards.
[61] See the response to LARKIN-DR-01-130(e).

deployment on the Company's network in 2021. This new meter will operate on Verizon's 4G Cat-M1 network, and will be "5G Ready".

Conclusion

Larkin did not perform a management audit. As it relates to the issues pertaining to the gas meters installed, retired, or replaced during the period 2013 through 2018, coupled with the replacement of the gas meter communication nodes, based on the information we reviewed, we found that DEO had documentation for CEP-includable costs and did not find imprudence. As such, we are not recommending adjustments for DEO's gas meters costs nor are we making a finding of imprudence or unreasonableness. However, due to the complexities surrounding these issues, the significant costs involved, and the apparent replacement of meters and related communications equipment prior to the end of its expected useful life, we recommend that the Company's AMI meters and related communication devices continue to be subject to ongoing regulatory scrutiny. Specifically, due to the level of costs associated with the meters and related communication equipment, coupled with the potential for additional meters and/or communication equipment needing to be replaced prior to the existing equipment being fully depreciated, as well as the impact on DEO's electric utility (in addition to the gas utility), our opinion is that this area warrants ongoing regulatory scrutiny of these costs.

# 9 ADJUSTMENTS TO DUKE ENERGY OHIO'S CEP COSTS

## Incentive and Stock-Based Compensation

We are recommending adjustments to remove a net amount of $775,173 from CEP costs for the earnings portion of incentive compensation and stock-based compensation, and related impacts on depreciation and ADIT. PISCC is also reduced by $142,980 related to this adjustment.

As part of our review of the costs associated with DEO's CEP expenditures for the period 2013 through 2018, Larkin asked the Company whether any costs for incentive compensation and/or stock-based compensation have been charged to the CEP related capital expenditures or to other costs. Specifically, we asked DEO to identify by amount and account, the amounts of incentive compensation and/or stock-based compensation included in CEP expenditures for each of the following periods: March 31, 2012, December 31, 2012, December 31, 2013, December 31, 2014, December 31, 2015, December 31, 2016, December 31, 2017, and December 31, 2018. In addition, we asked DEO to identify and quantify any amounts of incentive and/or stock-based compensation that relates to the Company's stock price, dividends or financial goals.

In its response to LARKIN-DR-01-022, the Company stated that incentive compensation is recorded to a project by resource type and that the resource type detail is available when such costs are still reflected in construction work in progress ("CWIP"). However, upon the CEP projects being unitized, they are unitized in total rather than by resource type. As a result, DEO has to make manual calculations in order to determine the amounts of incentive compensation and stock-based compensation included in CEP plant in-service. The exhibit below summarizes the resource types that are associated with incentive compensation and the percentage of each resource type that relates to DEO's earnings:

### Exhibit 9-1. Summary of Resource Types for Incentive and Stock-Based Compensation

| Resource Type | Percentage Related to Earnings |
|---|---|
| 18400 - Incentives Allocated | 30% |
| 18401 Incentives Allocated-Union | 30% |
| 1E002 - Exec Short Term Incentive | 50% |
| 1E200 - Phantom Stock | 100% |
| 1E202 - Performance Award | 75% |

Source: LARKIN-DR-01-022

As shown in the exhibit above, the percentage of resource types 18400 and 18401that relate to DEO's earnings is 30%. It should be noted that the response to LARKIN-DR-01-022 indicated that the 30% of incentive compensation related to the Company's earnings was prior to 2018. In response to our inquiry as to what percentage of resource types 18400 and 18401were related to DEO's earnings during 2018, in its response to LARKIN-DR-01-148, the Company stated that the response to LARKIN-DR-01-022 should have stated that the 30% related to earnings prior to 2019. The percentage of resource types 1E002, 1E200 and 1E202 that are related to the Company's earnings are 50%, 100% and 75%, respectively. In addition, according to the response to LARKIN-DR-01-29(j), resource types 1E200 - Phantom Stock and 1E202 - Performance Award are stock-based and are part of DEO's Long-Term Incentive Program.

In its response to LARKIN-DR-01-29, the Company indicated that the amounts (by resource type) in the exhibit below reflect DEO's estimates of the unadjusted earnings-based incentive compensation that are included in the CEP deferral:

### Exhibit 9-2. Earnings Based Incentive Compensation andStock-Based Compensation Included in CEP Plant In-Service

| Resource Type | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| 18400 - Incentives Allocated | $ 50,266 | $ 45,913 | $ 31,532 | $ 28,541 | $ 64,329 | $ 13,595 |
| 18401 Incentives Allocated-Union | $ 67,155 | $ 58,203 | $ 58,596 | $ 52,137 | $ 42,332 | $ 50,626 |
| 1E002 - Exec Short Term Incentive | $ 324 | $ 1,964 | $ (931) | $ 203 | $ 929 | $ 40 |
| 1E200 - Phantom Stock | $ 1,741 | $ 6,840 | $ (2,560) | $ 609 | $ 1,709 | $ 106 |
| 1E202 - Performance Award | $ 57 | $ 421 | $ (71) | $ 17 | $ 4 | |
| Total | $ 119,543 | $ 113,340 | $ 86,567 | $ 81,507 | $ 109,303 | $ 64,367 |
| | | | | | | |
| Cumulative Total | $ 119,543 | $ 232,882 | $ 319,449 | $ 400,957 | $ 510,259 | $ 574,626 |

Source: LARKIN-DR-01-29

As shown in the exhibit above, the Company's CEP expenditures included incentive compensation totaling $119,543 (2013), $113,340 (2014), $86,567 (2015), $81,507 (2016), $109,303 (2017), and $64,367 (2018) for a cumulative total of $574,626 as of December 31, 2018.

We had asked about incentive compensation included in CEP expenditures from 2012. In its response to LARKIN-DR-01-29, the Company stated that the CEP deferral only included CEP in-service projects started and placed into service after 2013.

According to the response to LARKIN-DR-01-76, the amounts of incentive compensation listed above are embedded in the electronic version of Exhibit J - Additional Schedules Supporting the Application on the tab titled "WP4.1 - Assets by FERC" from the Company's filing.

The Company stated that incentive compensation is recorded to CEP projects by resource type when such costs are recorded to CWIP. Pursuant to this, we asked DEO to quantify the amount of incentive compensation it recorded to retirement work in progress ("RWIP"). Specifically, we asked the Company for the total amount of incentive compensation recorded to RWIP as well as the portion related to earnings-based incentives. In its response to LARKIN-DR-01-117, the Company identified the following amounts of total incentive compensation and the portion related to earnings-based incentives:

**Exhibit 9-3. RWIP Earning Based Incentive Compensation**

| Year | Total RWIP Incentive Compensation | RWIP Earnings Based Incentive Compensation |
|---|---|---|
| 2013 | $ 108,823 | $ 32,647 |
| 2014 | $ 101,597 | $ 30,479 |
| 2015 | $ 126,617 | $ 37,985 |
| 2016 | $ 103,676 | $ 31,103 |
| 2017 | $ 120,438 | $ 36,131 |
| 2018 | $ 146,109 | $ 43,833 |
| Total | $ 707,260 | $ 212,178 |

Source: LARKIN-DR-01-117

As shown in the exhibit above, during the period 2013 through 2018, the Company recorded total incentive compensation of $707,260 and incentive compensation related to earnings-based incentives totaling $212,178. However, the Company stated that RWIP was inadvertently not offset against accumulated depreciation in its Rider CEP application. Therefore, there was zero impact of RWIP (including the related incentive compensation) in the CEP deferrals in DEO's filing.[62] We have not made an adjustment to include RWIP (net of earnings-based incentive and stock-based compensation) in CEP, but it would not be unreasonable to do so since it is related to CEP and was inadvertently omitted from inclusion by DEO.

The Company provided descriptions of its incentive compensation plans (by resource type) in its response to LARKIN-DR-01-29, which are discussed below.

<u>Resource Types 18400 - Incentives Allocated and 18401 - Incentives Allocated-Union</u>

The incentive compensation plan that relates to these two resource types is the Short-Term Incentive Plan ("STIP"), which is available to all employees at DEO.[63] The response to LARKIN-DR-01-29 states that the STIP program promotes a corporate culture that is performance-oriented and is based on goals, including corporate goals and individual goals. Specifically, all of DEO's employees under the STIP are subject to the following corporate and individual goals:

- Corporate Component - The corporate goals include Earnings Per Share, O&M Expense control, Reliability, Safety/Environmental, Customer Satisfaction and Safety.
- Team or Individual Component - Business unit ("team") or individual goals are typically lower-level tactical and operational goals that provide more specific direction for employees. Almost all employees have a component of their incentive assigned to team goals while executives typically have individual goals.
- Safety Component - As an added focus on safety and to reinforce the Company's zero tolerance for controllable work-related employee fatalities, fewer life altering injuries,

[62] See the response to LARKIN-DR-01-117(c).
[63] See the response to LARKIN-DR-01-148.

and no significant operational events, the STIP program rewards all employees, exempt and non-exempt, with an additional 5 percent of their short-term incentive payout, if more stringent goals are met.

Resource Type 1E002 - Executive Short-Term Incentive

According to the response to LARKIN-DR-01-29, prior to 2016, the Company's executives participated in the Cash Equity Incentive Plan ("CEIP"), which was a sub-plan of the Duke Energy Short-Term Incentive Plan, but that starting with the 2016 plan year, executive short-term incentive compensation was covered by the Duke Energy STIP discussed above. The CEIP was the plan in effect for the period 2013 through 2015, and similar to the STIP discussed above, the CEIP was intended to reward performance based on the achievement of corporate, individual and/or team goals. Specifically, the CEIP included the following goals:

- Target opportunity was expressed as a percentage of base pay.
- Performance is measured based on corporate goals (50%), team goals (25%), and individual goals (25%).
- Corporate Component - Corporate measures include adjusted diluted earnings per share, an operations and maintenance cost-control measure, and a composite of several reliability measures.
- Team Component - CEIP participants had a component of their incentive aligned and operational, team or functional goals.
- Individual Component - CEIP participants had an incentive component aligned with individual performance. An employee's overall rating on his or her annual performance appraisal was a factor in the payout for this component.
- Safety Component - an enterprise-wide safety goal and penalty applied based on the number of serious injuries and fatalities ("SIF's"). This measure focused on incident severity, including serious injuries for employees and work-related fatalities for employees and contractors.
- Performance period is a calendar year. At the end of the performance period, performance will be assessed on each measure/goal to determine the goal accomplishment level.

Resource Type 1E200 - Phantom Stock

According to the response to LARKIN-DR-01-29, phantom stock for DEO's incentive purposes is actually restricted stock and is a form of stock-based compensation. Restricted stock units vest according to an installment-based vesting schedule over a period of generally three years while the employee continues employment with Duke Energy. Upon the shares vesting, they are placed in the employee's brokerage account less any shares that were used to pay for taxes on the vested amount.

Resource Type 1E202 - Performance Award

Phantom stock, as discussed above, is actually restricted stock, which, along with the performance award, represents stock-based compensation. In its response to LARKIN-DR-01-29, the Company provided a confidential copy of its 2018 Executive Long-Term Incentive Plan ("LTIP"). As they represent stock-based compensation, Resource types 1E200 - Phantom Stock (restricted stock) and 1E202 - Performance Award are discussed in the LTIP as discussed below.

As discussed on page 1 of the 2018 LTIP, the Company's LTIP consists of stock-based awards for restricted stock units (RSUs) and performance shares. In addition, on page 1 of the 2018 LTIP it states that [redacted]

[redacted]

As noted above, the amounts for incentive compensation included in CEP projects that are identified by the resource types noted above are initially recorded to CWIP prior to those CEP projects being placed into plant in-service. Once a project is placed into service, the incentive compensation charges are not allocated by resource type.[64]

During the telephone interview conducted on January 31, 2020, the Company stated that the manual calculations of incentive compensation include related overhead allocations for payroll taxes and fringe benefits. We requested that DEO provide a listing of all overheads (i.e., labor loadings, etc.) and any other indirect items that were charged to the CEP-related work orders and to include a description of the types of charges and how they were applied. In its response to LARKIN-DR-01-62 provided the requested listing of overheads by resource type, indirect cost type (i.e., overheads), whether it is an allocation or a loader, and the calculation methodology for each indirect cost type. Included in this listing were the indirect cost types for payroll taxes and fringe benefits, both of which are described below.

For payroll taxes, which is classified as a loader (rather than an allocation), the resource type is 1825X and has the following description:

> Payroll taxes include state unemployment, federal unemployment, social security and Medicare. Payroll taxes are accrued as they are incurred. Actual payroll taxes are charged to the appropriate payroll tax account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of payroll tax between operating and capital projects as well as among Affiliates.

For fringe benefits, which is also classified as a loader, the resource type is 1835X and has the following description:

> Fringe benefits are employee benefits such as retirement, and medical and dental insurance. These costs are generally accrued as they are earned. Actual fringe benefit costs are charged to the appropriate administrative and general FERC account. These costs are then allocated via a loading factor that is based on labor. This allows the proper distribution of fringe benefits between operating and capital projects as well as among Affiliates.

In its response to LARKIN-DR-01-124, the Company confirmed that resource types 1825X (payroll taxes) and 1835X (fringe benefits) are allocated to DEO Gas based on payroll dollars, which includes the resource types listed above for incentive compensation and stock-based compensation.

[64] See the response to LARKIN-DR-01-76(b).

The amounts for incentive and stock-based compensation (including the related payroll taxes and fringe benefits) are initially included in the costs of CEP projects by resource type and recorded to CWIP prior to those CEP projects being placed into service.

We requested that the Company identify where the gross plant incentives, payroll tax impacts, and fringe benefits are reflected in its filing. In its response to LARKIN-DR-01-149, the Company stated:

> See LARKIN-D01-149 Attachment. As part of a negotiated settlement in Case No. 17-0032-EL-AIR the Company agreed to make a similar adjustment with Rider DCI. It is the Company's position that incentive costs are appropriately included within capital assets as per Generally Accepted Accounting Principles but, if under similar circumstances as in the settlement previously mentioned above, the Company would create a single new line item (#8 in LARKIN-DR-01-149 Attachment) as an offset to Plant In-Service for the total adjustment and add a schedule (Schedule 13 in LARKIN-DR-01-149 Attachment) to the filing to provide a quarterly breakdown of the capitalized incentives being removed and calculate the depreciation and accumulated deferred income taxes specifically related to those incentives.

The costs for incentive compensation and stock-based compensation, including the related overheads (i.e., payroll taxes and fringe benefits), that were charged to the CEP expenditures for each year of the 2013-2018 review period, which were provided in the supplemental response to LARKIN-DR-01-22,aresummarized in the exhibit below:

### Exhibit 9-4. Payroll Tax and Fringe Benefit Impacts of Earnings Based Incentive Compensation and Stock-Based Compensation

| | | Quarterly Spend (Capital) | | | | | |
|---|---|---|---|---|---|---|---|
| **Description** | Period | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Gross Plant Incentives | Q1 | $23,958 | $23,793 | $16,046 | $14,093 | $12,577 | $13,076 |
| | Q2 | $29,385 | $22,637 | $21,150 | $27,087 | $27,553 | $8,607 |
| | Q3 | $24,427 | $30,185 | $25,232 | $14,419 | $45,564 | $23,858 |
| | Q4 | $41,774 | $36,724 | $24,139 | $25,908 | $23,608 | $18,825 |
| Cumulative Gross Plant Incentives | | $119,543 | $232,882 | $319,449 | $400,957 | $510,259 | $574,626 |
| Payroll Tax Rate | | 7.69% | 7.10% | 7.39% | 7.48% | 7.05% | 6.34% |
| Payroll Tax Impact | | $9,193 | $8,047 | $6,397 | $6,097 | $7,706 | $4,081 |
| Cumulative Payroll Tax Impact | | $9,193 | $17,240 | $23,637 | $29,734 | $37,440 | $41,521 |
| Fringe Benefit Rate | | 51.15% | 28.95% | 34.38% | 24.32% | 20.45% | 24.82% |
| Fringe Benefit Impact | | $61,146 | $32,812 | $29,762 | $19,823 | $22,352 | $15,976 |
| Cumulative Fringe Benefit | | $61,146 | $93,958 | $123,720 | $143,542 | $165,895 | $181,870 |
| Total Cumulative Gross Plant Incentives | | $189,882 | $344,080 | $466,806 | $574,233 | $713,594 | $798,017 |
| Source: LARKIN-DR-01-22 Supplemental | | | | | | | |

It should be noted that the cumulative amounts of incentive and stock-based compensation expense for the 2013-2018 period comprise what is reflected in the CEP plant in-service in the Company's filing. In other words, the 2018 cumulative amounts for (1) gross plant incentives of

$574,626; (2) payroll tax impacts of $41,521; and (3) fringe benefits of $181,870, for an overall total of $798,017, is what is included in DEO's CEP related revenue requirement in Exhibit J, Schedule No. 1.

The amounts from Company Schedule 13 (from the response to LARKIN-DR-01-149) which show the quarterly breakdown of the capitalized incentives described in the passage above are summarized in the following exhibit:

### Exhibit 9-5. Quarterly Breakdown of Earnings Based Incentive Compensation and Stock-Based Compensation and Impacts to Depreciation, Accumulated Depreciation and ADIT

| Description | Period | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) |
| Gross Plant Incentives | Q1 | $ (38,054) | $ (32,371) | $ (22,749) | $ (18,575) | $ (16,036) | $ (17,151) |
| | Q2 | $ (46,675) | $ (30,797) | $ (29,984) | $ (35,701) | $ (35,130) | $ (11,289) |
| | Q3 | $ (38,800) | $ (41,067) | $ (35,771) | $ (19,004) | $ (58,095) | $ (31,292) |
| | Q4 | $ (66,353) | $ (49,963) | $ (34,222) | $ (34,147) | $ (30,101) | $ (24,691) |
| Cumulative Gross Plant Incentives | | $ (189,882) | $ (344,080) | $ (466,806) | $ (574,233) | $ (713,594) | $ (798,017) |
| Depreciation Expense | Q1 | $ (121) | $ (344) | $ (519) | $ (651) | $ (761) | $ (866) |
| | Q2 | $ (148) | $ (394) | $ (587) | $ (796) | $ (1,021) | $ (1,168) |
| | Q3 | $ (123) | $ (377) | $ (621) | $ (795) | $ (1,039) | $ (1,323) |
| | Q4 | $ (211) | $ (580) | $ (847) | $ (1,064) | $ (1,268) | $ (1,442) |
| Accumulated Depreciation | Q1 | $ 121 | $ 947 | $ 2,818 | $ 5,523 | $ 8,939 | $ 13,133 |
| | Q2 | $ 269 | $ 1,341 | $ 3,405 | $ 6,319 | $ 9,959 | $ 14,301 |
| | Q3 | $ 392 | $ 1,718 | $ 4,026 | $ 7,114 | $ 10,999 | $ 15,624 |
| | Q4 | $ 603 | $ 2,298 | $ 4,873 | $ 8,178 | $ 12,267 | $ 17,066 |
| Accumulated Deferred Income Tax | Q1 | $ 50 | $ 383 | $ 1,106 | $ 2,088 | $ 3,245 | $ 4,581 |
| | Q2 | $ 110 | $ 538 | $ 1,322 | $ 2,365 | $ 3,580 | $ 4,935 |
| | Q3 | $ 161 | $ 686 | $ 1,554 | $ 2,640 | $ 3,924 | $ 5,353 |
| | Q4 | $ 247 | $ 914 | $ 1,865 | $ 3,004 | $ 4,327 | $ 5,777 |
| Total Adjustment to Net Rate Base | Q1 | $ (189,711) | $ (342,750) | $ (462,882) | $ (566,621) | $ (701,410) | $ (780,303) |
| | Q2 | $ (189,502) | $ (342,201) | $ (462,079) | $ (565,549) | $ (700,054) | $ (778,781) |
| | Q3 | $ (189,329) | $ (341,676) | $ (461,227) | $ (564,479) | $ (698,672) | $ (777,040) |
| | Q4 | $ (189,032) | $ (340,868) | $ (460,068) | $ (563,050) | $ (697,000) | $ (775,173) |
| Source: LARKIN-DR-01-149 | | | | | | | |

For each year 2013 through 2018, after factoring in the related depreciation expense, accumulated depreciation, and ADIT, the cumulative total adjustment amount of $775,173 shown for the fourth quarter of 2018 reflects the amount that DEO referred to as the single new line item to be offset against plant in-service in the Company's CEP revenue requirement calculation. As shown in the exhibit above, the methodology the Company used for calculating the incentive-based offset to CEP plant in-service factors in depreciation expense, accumulated depreciation and ADIT. Therefore, in its response to LARKIN-DR-01-160(a), DEO confirmed that the individual line items for depreciation and ADIT in its CEP revenue requirement calculation (i.e., Exhibit J, Schedule No. 1) should not also be adjusted to calculate the impact of removing the earnings-based incentive and stock-based compensation from CEP plant in-service.

The Company's approach appears to be reasonable. We have reflected this adjustment for purposes of removing earnings-based incentive and stock-based compensation from the CEP expenditures.

With regard to the incentive compensation amounts under resource types 18400, 18401 and 1E002, the basis for our recommendation is that incentive compensation expense that is tied to a utility's financial performance should not be borne by ratepayers. Specifically, the portion of incentive compensation expense that is directly attributable to meeting financial performance goals, such as net income or earnings per share, is not properly recoverable from ratepayers for several reasons. First, if the financial goals are set properly, achieving the necessary performance should be self-supporting. That is, measures that achieve additional cost savings, improves sales, or otherwise improves financial results of the Company should provide the income necessary to fund the awards. Second, the payouts for financial goal achievement can be distinguished from incentive compensation that is measured for improving the quality of service, efficiency, or safety goals. Finally, the incentive to improve financial performance is not necessarily consistent with ratepayers' interests.

With regard to the stock-based compensation expense amounts under resource types 1E200 and 1E202, the basis for our recommendation is that stock-based compensation expenses for performance shares and RSUs should not be charged to DEO's ratepayers. The cost of these stock-based compensation programs is incurred to improve the Duke Energy financial performance for the benefit of shareholders, not to improve customer service or meet other regulated utility service requirements. In fact, the objectives of maximizing shareholder value on the one hand and minimizing costs to ratepayers on the other hand, are generally opposed to each other. In addition, the hypothetical stock performance pursuant to the performance shares should not be considered expense for ratemaking purposes because dividends are considered in the determination of the required return on common equity and stock performance is a component of shareholder return.

<u>Impact on PISCC Deferral</u>

Since the amounts of earnings-based incentive and stock-based compensation are embedded in Exhibit J on the tab "WP4.1 - Assets by FERC" (per the response to LARKIN-DR-01-76), it appeared to Larkin that the PISCC deferral should also be adjusted to reflect the impact of removing the earnings-based incentive and stock-based compensation from CEP plant in-service. In its response to LARKIN-DR-01-160(b), the Company disagreed where it stated:

> The practice of including earnings based incentives in capital projects is in accordance with GAAP and FERC accounting guidelines. There has been no stipulation or Commission order to modify our accounting practices to remove earnings based capitalized incentives from past CEP deferrals or gross plant balances in general. The Stipulation and Order and Opinion in Case No. 17-0032-EL-AIR required the Company to remove capitalized incentives from assets included in Rider DCI and Rider PF. It did not retroactively adjust past gross plant balances or regulatory assets. Therefore, the removal of earnings based incentives should not be reflected in the PISCC deferral amount of $29,592,179.

Despite the Company's position on this matter as discussed in the passage above, for transparency purposes, DEO provided an attachment in its response to LARKIN-DR-01-160(c) which reflects a calculation of the impact of the retroactive removal of earnings-based incentive and stock-based compensation from the PISCC deferral. As shown on that attachment, the Company's calculation decreases the PISCC deferral by $142,980.

Larkin recommends that the impact of removing the earnings-based incentive and stock-based compensation from the assets included in CEP expenditures should also have a related impact on the PISCC deferral amount. As noted above, the earnings-based incentive and stock-based compensation amounts previously discussed are embedded in Exhibit J on the tab "WP4.1 - Assets by FERC. The calculation of the PISCC deferral in Exhibit J, Schedule 6 from the Company's filing is derived in part by the amounts shown on WP4.1 - Assets by FERC. Therefore, in our view, the PISCC deferral should be adjusted to reflect the impact of removing the earnings-based incentive and stock-based compensation from CEP plant in-service.

Conclusion

We recommend that the cumulative amounts of incentive and stock-based compensation totaling $775,173 (after factoring in the related depreciation, accumulated depreciation, and ADIT) for the period 2013 through 2018 be removed from the CEP rider. In addition, we recommend that the Company's calculation reflecting the impact of removing the earnings-based incentive and stock-based compensation on the PISCC deferral in the amount of $142,980 also be adopted. Our recommended adjustments are shown on Attachment LA-1, Schedule 3.

## Property Taxes

We are recommending an adjustment for deferred and annualized property taxes related to correcting an error that was identified during the review process.

As discussed on page 4 of the direct testimony of Company witness Jay Brown, the Company's Rider CEP revenue requirement shown on Exhibit J, Schedule No. 1 is comprised of an annualized return on rate base and also provides for annualized operating expenses. Specifically, the CEP rate base includes the CEP deferral regulatory asset, a portion of which includes cumulative deferred property tax balance for eligible CEP investments of $13,046,753 and the operating expenses include annualized property tax expense totaling $5,705,526. These amounts are summarized on Exhibit J, Schedule 7 and the underlying calculations for these amounts are reflected on Company workpapers 7.1 through 7.15 from the Company's filing.

We reviewed workpapers 7.1 through 7.15 and noted that the amounts for the additions and retirements on Company workpapers WP4.1 - Assets by FERC and WP4.2 - Retirements by FERC for each year 2013 through 2018 flow through to property tax workpapers 7.1 through 7.15 depending on the year of the CEP plant additions and plant retirements. These amounts are then multiplied by three different percentages in order to derive the amounts of deferred property taxes regulatory asset as well as the annualized property tax expense. The three percentages include (1) the "percent good", (2) a valuation percentage, and (3) DEO's average personal property tax rate. With regard to the "percent good", Note 1 on the property tax workpapers states that these percentages are from the Ohio Department of Taxation Annual Natural Gas

Property Tax Report on Schedule C(2). With regard to the valuation percentage, Note 2 on the Company's workpapers states that this percentage, which is 25% in each year 2013-2018, is also from the Ohio Department of Taxation Annual Natural Gas Property Tax Report on Schedule G. Finally, with regard to DEO's average personal property tax rate, the response to LARKIN-DR-01-51(d) states in part:

> These rates are determined by using the Gas Property assessed value for each tax year multiplied by the most recent tax rates available from the Ohio Department of Taxation at the time of the request. Once a tax value is determined by each district the total tax is summed up, the summation of tax is divided by total assessed value to get the average tax rate for Ohio gas assets that year.

Our review of the Company's property tax calculation workpapers raised questions about the percentages used for the "percent good" as well as the average personal property tax rates used by DEO in its computations of the deferred property tax regulatory asset and annualized property tax expense included in its revenue requirement. Specifically, as to the "percent good" percentages used, we noted that these percentages fluctuated between 98.3%, 95.0% and 91.7% for the distribution improvement plant additions[65] depending on the year in which the property taxes were calculated. Pursuant to our inquiry about these fluctuations between years, in its response to LARKIN-DR-01-51(a), the Company stated in part:

> The percentages should fluctuate due to when the CEP investments took place and should follow the schedules on pages Schedule C - Distribution on the Ohio Department of Taxation Annual Natural Gas Property Tax Reports.

However, in its response to LARKIN-DR-01-51(b), the Company indicated the Excel workpapers in which the "percent good" percentages are reflected were not updated in error and that they should have been updated for each current year. In addition, with regard to the average personal property tax rates used by DEO, the passage above from the response to LARKIN-DR-01-51(d) explains how those average rates are determined. However, the Company stated that, similar to the "percent good" percentages, the average personal property tax rates were not updated in error and the year in which the property tax was expensed should use the average rate for the corresponding year.

To correct for these errors, the Company provided updated "percent good" and average personal property tax rates to use in calculating the deferred property tax regulatory asset as well as the annualized property tax expense. The exhibit below replicates Attachment 7 from the response to LARKIN-DR-01-51, and shows the rates used in the Company's filing and the updated amounts that should have been used:

[65] For each year 2013 through 2018, the "percent good" used for retirements was 15%, which was derived from the Ohio Department of Taxation Annual Natural Gas Property Tax Reports.

## Exhibit 9-6. Summary of Corrected Property Tax Rates

| Company Workpaper | Description | Percent Good | Percent Good (Updated) | DEO Avg. Personal Property Tax Rate | DEO Avg. Gas Personal Property Tax Rate (Updated) |
|---|---|---|---|---|---|
| WP 7 1 | 2013 CEP Investments - Property Taxes Expensed in 2014 | 98 3% | 98 3% | 9 7713% | 9 7713% |
| WP 7 2 | 2013 CEP Investments - Property Taxes Expensed in 2015 | 95 0% | 95 0% | 9 7713% | 9 8358% |
| WP 7 3 | 2013 CEP Investments - Property Taxes Expensed in 2016 | 91 7% | 91 7% | 9 8358% | 9 8863% |
| WP 7 4 | 2013 CEP Investments - Property Taxes Expensed in 2017 | 91 7% | 88 3% | 9 8358% | 10 1944% |
| WP 7 5 | 2013 CEP Investments - Property Taxes Expensed in 2018 | 91 7% | 85 0% | 9 8358% | 10 1956% |
| WP 7 6 | 2014 CEP Investments - Property Taxes Expensed in 2015 | 98 3% | 98 3% | 9 7713% | 9 8358% |
| WP 7 7 | 2014 CEP Investments - Property Taxes Expensed in 2016 | 95 0% | 95 0% | 9 8358% | 9 8863% |
| WP 7 8 | 2014 CEP Investments - Property Taxes Expensed in 2017 | 91 7% | 91 7% | 9 8358% | 10 1944% |
| WP 7 9 | 2014 CEP Investments - Property Taxes Expensed in 2018 | 91 7% | 88 3% | 9 8358% | 10 1956% |
| WP 7 10 | 2015 CEP Investments - Property Taxes Expensed in 2016 | 98 3% | 98 3% | 9 8358% | 9 8863% |
| WP 7 11 | 2015 CEP Investments - Property Taxes Expensed in 2017 | 95 0% | 95 0% | 9 8358% | 10 1944% |
| WP 7 12 | 2015 CEP Investments - Property Taxes Expensed in 2018 | 95 0% | 91 7% | 9 8358% | 10 1956% |
| WP 7 13 | 2016 CEP Investments - Property Taxes Expensed in 2017 | 98 3% | 98 3% | 9 8358% | 10 1944% |
| WP 7 14 | 2016 CEP Investments - Property Taxes Expensed in 2018 | 98 3% | 95 0% | 9 8358% | 10 1956% |
| WP 7 15 | 2017 CEP Investments - Property Taxes Expensed in 2018 | 98 3% | 98 3% | 9 8358% | 10 1956% |

Source: LARKIN-DR-01-51(7) Attachment

As shown in the exhibit above, the updated "percent good" percentages and the average personal property tax rates are substantially different than the percentages/rates reflected in the Company's filing. We compared the updated "percent good" percentages to the corresponding Ohio Department of Taxation Annual Natural Gas Property Tax Reports. No exceptions were noted. In addition, we reviewed the annual calculations of each average personal property tax rates which were provided in LARKIN-DR-01-51(8) Attachment through LARKIN-DR-01-51(12) Attachment. We conclude that these calculations are reasonable.

Using the updated percentages for the "percent good" and the updated average personal property tax rates, we recalculated the deferred property tax regulatory asset, which is compared to the Company's calculation from its filing as shown in the exhibit below:

## Exhibit 9-7. Deferred Property Tax Expense Adjustment

| | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 |
|---|---|---|---|---|---|---|
| **Per Larkin** | | | | | | |
| Distribution Improvement - Deferred Property Taxes | $ - | $ 508,954 | $ 1,626,811 | $ 3,707,679 | $ 7,312,983 | $ 12,554,735 |
| Information Technology - Deferred Property Taxes | $ - | $ - | $ 21 | $ 11,031 | $ 130,523 | $ 627,350 |
| Total CEP - Deferred Property Taxes | $ - | $ 508,954 | $ 1,626,832 | $ 3,718,710 | $ 7,443,506 | $ 13,182,085 |
| **Per Company Filing** | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 |
| Distribution Improvement - Deferred Property Taxes | $ - | $ 509,951 | $ 1,621,109 | $ 3,704,813 | $ 7,214,597 | $ 12,433,247 |
| Information Technology - Deferred Property Taxes | $ - | $ - | $ 20 | $ 10,974 | $ 126,630 | $ 613,506 |
| Total CEP - Deferred Property Taxes | $ - | $ 509,951 | $ 1,621,129 | $ 3,715,787 | $ 7,341,227 | $ 13,046,753 |
| **Adjustment to Property Tax Regulatory Asset** | | | | | | |
| Distribution Improvement - Deferred Property Taxes | $ - | $ - | $ 5,702 | $ 2,866 | $ 98,386 | $ 121,488 |
| Information Technology - Deferred Property Taxes | $ - | $ - | $ 1 | $ 57 | $ 3,893 | $ 13,844 |
| Total CEP - Deferred Property Taxes | $ - | $ - | $ 5,703 | $ 2,923 | $ 102,279 | **$ 135,332** |

As shown in the exhibit above, our recalculated deferred property tax regulatory asset totals $13,182,085. When compared to the amount from the Company's filing of $13,046,753, our recommended adjustment increases the deferred property tax regulatory asset by $135,332.

In addition, the updated percentages for the "percent good" and the updated average personal property tax rates, we recalculated the annualized property tax expense, which is compared to the Company's calculation from its filing as shown in the exhibit below:

## Exhibit 9-8. Annualized Property Tax Expense Adjustment

| Per Larkin | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 |
|---|---|---|---|---|---|---|
| Distribution Improvement - Annualized Property Tax Expe | $ - | $ - | $ - | $ - | $ - | $ - |
| Information Technology - Annualized Property Tax Expen | $ - | $ - | $ - | $ - | $ - | $ - |
| Total CEP - Annualized Property Tax Expense | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | |
| **Per Company Filing** | | | | | | |
| Distribution Improvement - Annualized Property Tax Expe | $ - | $ 509,951 | $ 1,111,158 | $ 2,083,704 | $ 3,509,784 | $ 5,218,650 |
| Information Technology - Annualized Property Tax Expen | $ - | $ - | $ 20 | $ 10,954 | $ 115,656 | $ 486,876 |
| Total CEP - Annualized Property Tax Expense | $ - | $ 509,951 | $ 1,111,178 | $ 2,094,658 | $ 3,625,440 | $ 5,705,526 |
| | | | | | | |
| **Adjustment to Property Tax Regulatory Asset** | | | | | | |
| Distribution Improvement - Annualized Property Tax Expe | $ - | $ (509,951) | $(1,111,158) | $(2,083,704) | $(3,509,784) | $ (5,218,650) |
| Information Technology - Annualized Property Tax Expen | $ - | $ - | $ (20) | $ (10,954) | $ (115,656) | $ (486,876) |
| Total CEP - Annualized Property Tax Expense | $ - | $ (509,951) | $(1,111,178) | $(2,094,658) | $(3,625,440) | **$ (5,705,526)** |

As shown in the exhibit above, our recalculated annualized property tax expense totals $5,738,579. When compared to the amount from the Company's filing of $5,705,526, our recommended adjustment increases the annualized property tax expense by $33,053.

Our adjustments to the deferred property tax regulatory asset and annualized property tax expense is shown on Attachment LA-1, Schedule 4.

## Eastern Gas Operations Center Employee Fitness Room

We are recommending that costs for a fitness room at the Company's Eastern Gas Ops Center be removed from CEP costs. In our view, the costs associated with the employee fitness center are not an appropriate use of ratepayer funds.

As discussed in Chapter 6, on April 10, 2020, using Microsoft Team Meetings, Larkin and Staff participated in a video walkthrough by DEO personnel of the Company's Eastern Gas Ops Center. A portion of this walkthrough centered on the employee fitness room.

With regard to the employee fitness room and related equipment, we requested that DEO provide the following information: (1) how much of the cost for Project ID T1666 relates to the fitness room; (2) the actual or approximate square footage of the employee fitness room; (3) an itemization of the types of equipment and furniture in the fitness room; and (4) the cost of the equipment and furniture in the fitness room.

In its response to LARKIN-DR-01-164, the Company stated that [redacted]

We recommend that the costs of the Eastern Gas Ops Center facility that relate to the employee fitness center (i.e., the fitness center related construction costs and the cost of the exercise equipment) be removed from recoverable CEP expenditures.

The Company supplemented the response to LARKIN-DR-01-164 in order to quantify the [redacted]

[redacted] Our recommended adjustments to remove the costs of the employee fitness center are shown on AttachmentLA-1, Schedule 5.

## Correction of Errors in CEP Filing

We are recommending the following adjustments for corrections to DEO's CEP filing:

- Net Plant In-Service: ($557,570)
- Deferred Depreciation Expense: ($46,350)
- Deferred Tax - Liberalized Depreciation: ($72,876)
- Post In-Service Carrying Cost: ($118,293)

As discussed in Chapter 6, the Company provided an overall listing of its project work detail for each year of the 2013-2018 review period in its response to LARKIN-DR-01-35. This comprehensive work order listing included all of the Company's projects during that period, including projects related to (1) CEP, (2) AMRP, (3) Rider AU, and (4) non-Rider related projects. Accordingly, we compared the projects designated as CEP-related from the project work order listing to what the Company reflected in its Rider CEP filing for its CEP investments during the 2013-2018 review period. Specifically, using the information from Company Exhibit J, Schedule 4 - Monthly CEP Investments, we compared the gross CEP assets (i.e., CEP net in-service assets plus adding back retirements) to the total CEP-related projects from the work order listing as shown in the exhibit below:

### Exhibit 9-9. Comparison of Gross CEP Assets to CEP-Related Projects from Work Orders

| Line No. | Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|
| 1 | Total CEP In-Service Activity - Net Assets | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 |
| 2 | Add Back Retirements | $ 4,199,618 | $ 3,515,619 | $ 5,346,597 | $ 18,552,658 | $ 7,655,424 | $ 5,085,027 | $ 44,354,944 |
| 3 | Total CEP In-Service Activity - Gross Assets | $ 21,877,330 | $ 26,308,530 | $ 42,817,578 | $ 68,466,517 | $ 87,223,575 | $ 95,136,703 | $ 341,830,234 |
| 4 | 2013-2018 Work Order Total for CEP | $ 21,836,708 | $ 26,323,191 | $ 42,285,969 | $ 68,466,517 | $ 77,798,257 | $ 95,136,703 | $ 331,847,345 |
| 5 | Difference | $ 40,622 | $ (14,661) | $ 531,609 | $ - | $ 9,425,319 | $ (0) | $ 9,982,889 |

Source: Lines 1&2 from Exhibit J, Schedule 4 - Monthly CEP Investments; Line 4 from LARKIN-DR-01-35 Attachment

As shown in the exhibit above, the comparison of the CEP investments from the Company's Rider CEP filing to the CEP-related project work orders reflected variances of $40,622, $14,661, $531,609, and $9,425,319 in 2013, 2014, 2015, and 2017, respectively. We asked DEO to explain and reconcile these discrepancies.

In its response to LARKIN-DR-01-75, DEO stated that the large discrepancy noted for 2017 related to projects that were incorrectly labeled in the response to LARKIN-DR-01-35 and that they should have been designated as CEP. The Company provided the reconciliation in the exhibit below for these projects, which DEO stated were caused by incorrect data filtering methods, which resulted in the understatement of the 2017 CEP work order total.

### Exhibit 9-10. Summary of 2017 Projects That Should Have Been Included in CEP Plant In-Service

| 2017 Project ID | Amount | |
|---|---|---|
| ARCGS | $ | 650,376 |
| ARMS | $ | 609,301 |
| ECOMS | $ | 362,821 |
| EGISS | $ | 2,080,857 |
| EXPDS | $ | 466,126 |
| MAXS | $ | 4,188,787 |
| PPS | $ | 181,330 |
| SDDTS | $ | 351,800 |
| WRTS | $ | 533,921 |
| Total | $ | 9,425,319 |

Source: LARKIN-DR-01-75

As shown in the exhibit, the projects listed total the variance of $9,425,319 noted in Attachment LA-1 above for 2017.

With regard to the variances of $40,622, $14,661, $531,609 noted for 2013, 2014 and 2015, the Company stated that these discrepancies were related to activities that were incorrectly included in the CEP plant balances. In its response to LARKIN-DR-01-136, DEO clarified that the following adjustments should be made to Exhibit J, Schedule 4 - Monthly CEP Investments:

- For 2013, the CEP balances should be decreased by $40,622.
- For 2014, the CEP balances should be increased by $14,661.
- For 2015, the CEP balances should be decreased by $531,609.

In its response toLARKIN-DR-01-159, the Company confirmed that there should be corresponding adjustments to accumulated depreciation, ADIT and the PISCC. For each year 2013 through 2015, the exhibit below summarizes the fallout impacts of adjusting the net CEP plant balances for these three items:

### Exhibit 9-11. Impacts of Adjusting CEP Plant Balances on Deferred Depreciation, Deferred Taxes and PISCC

| Description | 2013 | | 2014 | | 2015 | | Total | |
|---|---|---|---|---|---|---|---|---|
| Net Plant in Service | $ | (40,622) | $ | 14,661 | $ | (531,609) | $ | (557,570) |
| Deferred Depreciation Expense | $ | (4,266) | $ | 1,218 | $ | (43,284) | $ | (46,332) |
| Deferred Tax - Liberalized Depreciation | $ | (5,750) | $ | 1,994 | $ | (69,120) | $ | (72,876) |
| Post In-Service Carrying Cost | $ | (10,805) | $ | 3,237 | $ | (110,724) | $ | (118,293) |

Source: LARKIN-DR-01-159

As shown in the exhibit above, in addition to the aforementioned adjustments to net plant in-service, for deferred depreciation expense, the impact of the error corrections are a reduction of $4,266 (2013), an increase of $1,218 (2014), and a decrease of $43,284 (2015) for an overall decrease of $46,332.[66] The impact of the error corrections also decreased annualized depreciation by $11,622 as shown on Attachment LA-1, Schedule 6.

For Deferred Tax - Liberalized Depreciation, the impact of the error corrections is a decrease of $5,750 (2013), an increase of $1,994 (2014), and a decrease of $69,120 (2015) for an overall decrease of $72,876.

For PISCC, the impact of the error corrections a decrease of $10,805 (2013), an increase of $3,237 (2014), and a decrease of $110,724 (2015), for an overall decrease of $118,293.

We reflected the adjustments noted above, on Attachment LA-1, Schedule 6.

## Composite Depreciation Rate Excluding Negative Net Salvage for Amortization of CEP Regulatory Assets

As previously discussed, we disagree with the Company's use of the 2.54% composite depreciation rate (based on 2015 FERC Form 2 data) for calculating the amortization of regulatory assets.

The 2.54% rate includes the impact of negative net salvage. As such, it is not a reasonable methodology for determining an estimate of the useful life of the CEP assets, or by which to calculate the amortization of regulatory assets.

Larkin, in consultation with Staff, recommends using a 2.25% rate because this rate excludes the impact of negative net salvage and is therefore a better estimate of the average useful life of the CEP assets. The 2.25% rate is shown on Exhibit LA-1, Schedule 7. We applied the 2.25% rate to the adjusted regulatory asset balance. This results in an adjusted amortization of regulatory assets amount of $1,007,416, which is $135,122 lower than the $1,142,538 that DEO proposed.

## Enable Project - Allocation of Costs to DEO Gas Utility

As discussed in Chapter 7, we disagree with the Company's methodology of allocating Enable Project costs to DEO's gas distribution utility which was based on the 2014 CAM 5.43% allocation factor for all years.

We recommend that the recoverable Enable project costs in CEP be based on the CAM percentage allocation applicable to the DEO gas utility for each year. According to the response to LARKIN-DR-01-157, the CAM allocations to DEO's gas utility were 5.41%, 5.34%, and 5.30% for 2015, 2016, and 2017, respectively. The exhibit below shows how the Enable Project costs would have been allocated to DEO's gas distribution utility if the CAM percentage allocation had been updated each year:

[66] The calculations for this adjustment on Attachment LA-1, Schedule 6 resulted in a slight rounding difference, thus the total decrease to deferred depreciation expense on that schedule is $46,350.

## Exhibit 9-12. Impact of Using Annual Updated CAM Allocation Rates For Enable Project Costs Allocated to DEO Gas Distribution Utility

| Description | 2015 | 2016 | 2017 | 2018 | Grand Total |
|---|---|---|---|---|---|
| Enable Project Costs Charged Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 |
| Multiplied by Each Year's CAM Allocation Factor for DEO Gas | 5 43% | 5 41% | 5 34% | 5 30% | |
| Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 |
| Per Company Using 5 43% in Each Year | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 |
| Difference | $ - | $ (15,271) | $ (111,841) | $ (6,011) | $ (133,123) |
| Source: LARKIN-DR-01-157 Supplemental | | | | | |

As shown above, by using the annual updated CAM allocation percentages, the total Enable Project costs allocated to DEO's gas distribution utility is $12,683,004, or $133,123 less than the Company's amount of $12,816,127.

As shown on Attachment LA-1, Schedule 8, the result of our recommendation decreases CEP plant in-service by $133,123, deferred depreciation expense by $18,467, annualized depreciation expense by $13,852 and PISCC by $9,443.

## AMI Meter Modules

As discussed in Chapter 8, in its response to LARKIN-DR-01-72, the Company stated that for 2013, 2014 and 2015, project additions identified by Project ID number AMIMODCHG should have been included in Rider AU, but these projects were not captured in Rider AU because they were not labeled properly. DEO included them in CEP because they relate to infrastructure for gas operations. We have removed the costs associated with these three projects from CEP plant in-service as shown on Attachment LA-1, Schedule 9. For this adjustment, because of the small plant adjustment amount, we did not attempt to reflect the impacts to deferred or annualized depreciation expense, or the PISCC, which would be even smaller.

# Duke Energy Ohio - Gas
# Case No. 19-0791-GA-ALT
# Attachment LA-1
# Accompanying the Report of Larkin & Associates PLLC



| Number | Description | No. of Pages | Confidential | Exhibit Page No. |
|---|---|---|---|---|
| | **Revenue Requirement Summary Schedules** | | | |
| 1 | Revenue Requirement Calculation | 1 | No | 2 |
| 2 | Summary of Adjustments | 1 | Yes | 3 |
| | | | | |
| | **Adjustment Schedules** | | | |
| 3 | Remove Earnings Based Portion of Incentive and Stock-Based Compensation | 2 | No | 4-5 |
| 4 | Property Tax Expense | 1 | No | 6 |
| 5 | Eastern Gas Operation Center - Employee Fitness Room | 2 | Yes | 7-8 |
| 6 | Correction of Errors to CEP Plant Balances | 3 | No | 9-11 |
| 7 | Calculation of Composite Depreciation Rate | 1 | No | 12 |
| 8 | Enable Project Allocation Factor | 2 | No | 13-14 |
| 9 | AMI Meter Modules Included in CEP in Error | 1 | No | 15 |
| | | | | |
| | Total Pages (Including Contents Page) | 15 | | |

**Duke Energy Ohio**
**Capital Expenditure Program**
**Revenue Requirement Calculation**

**Attachment LA-1**
**Schedule No. 1**
**Page 1 of 1**

| Line | Description | Company Reference | Company Total (A) | Adjustments (B) | Adjusted (C) = (A) + (B) |
|---|---|---|---|---|---|
| | **Plant In-Service** | | | | |
| 1 | Additions | Schedule No. 4 Ln 9 (Sum of 2013 - 2018) | $ 341,830,234 | $ (898,452) | $ 340,931,782 |
| 2 | Original Cost Retired | Schedule No. 4 Ln 15 (Sum of 2013 - 2018) | $ 44,354,944 | $ - | $ 44,354,944 |
| 3 | Total Plant In-Service | | $ 297,475,290 | $ (898,452) | $ 296,576,838 |
| | **Less: Accumulation Provision for Depreciation** | | | | |
| 4 | Depreciation Expense | Schedule Nos. 5a & 5b | $ 21,273,627 | $ (71,992) | $ 21,201,635 |
| 5 | 2012 Rate Case Depreciation Offset | Schedule No. 11 Ln 5 | $ 225,989,904 | $ - | $ 225,989,904 |
| 6 | Original Cost Retired | Schedule No. 4 Ln 15 (Sum of 2013 - 2018) | $ 44,354,944 | $ - | $ 44,354,944 |
| 7 | Total Accumulated Provision for Depreciation | | $ (202,908,587) | $ 71,992 | $ (202,836,595) |
| 8 | **Net Plant In-Service** | Ln 3 + Ln 7 | $ 94,566,703 | $ (826,461) | $ 93,740,242 |
| | **Regulatory Assets** | | | | |
| 9 | Deferred Depreciation Expense | Schedule No. 3 Ln 1 | $ 21,273,627 | $ (71,992) | $ 21,201,635 |
| 10 | Post in Service Carrying Costs | Schedule No. 3 Ln 2 | $ 29,592,179 | $ (288,978) | $ 29,303,201 |
| 11 | Property Tax | Schedule No. 3 Ln 3 | $ 13,046,753 | $ 135,332 | $ 13,182,085 |
| 12 | Cumulative Offset for Incremental Revenue | Schedule No. 3 Ln 4 | $ (18,930,741) | $ - | $ (18,930,741) |
| 13 | Total Regulatory Assets | | $ 44,981,818 | $ (225,637) | $ 44,756,181 |
| | **Accumulated Deferred Income Taxes** | | | | |
| 14 | Accumulated Deferred Income Tax on Post in Service Carrying Costs | Line 10 x 21% | $ (6,214,358) | $ 60,685 | $ (6,153,672) |
| 15 | Accumulated Deferred Income Tax on Property Tax | Line 11 x 21% | $ (2,739,818) | $ (28,420) | $ (2,768,238) |
| 16 | Accumulated Deferred Income Tax on Cumulative Offset for Incremental Revenue | Line 12 x 21% | $ 3,975,456 | $ - | $ 3,975,456 |
| 17 | Accumulated Deferred Income Tax on Liberalized Depreciation | Schedule 12 Ln 6 | $ (36,809,812) | $ 72,876 | $ (36,736,936) |
| 18 | Total Accumulated Deferred Income Taxes | | $ (41,788,532) | $ 105,141 | $ (41,683,390) |
| 19 | Less: Earnings Based Capitalized Incentives Impact on Rate Base | | | $ (775,173) | $ (775,173) |
| 20 | **Net Rate Base** | | $ 97,759,989 | $ (1,722,130) | $ 96,037,860 |
| 21 | Approved Pre-tax Rate of Return | | 9.16% | 9.16% | 9.16% |
| 22 | **Annualized Return on Rate Base** | Line 20 x Line 21 | $ 8,954,815 | $ (157,747) | $ 8,797,068 |
| | **Operating Expenses** | | | | |
| 23 | Total Regulatory Assets | Line 13 Above | $ 44,981,818 | | $ 44,756,181 |
| 24 | Composite Depreciation Rate | | 2.54% | | 2.25% |
| 25 | Amortization of Regulatory Assets | Line 23 x Line 24 | $ 1,142,538 | $ (135,122) | $ 1,007,416 |
| 26 | Annualized Depreciation | Schedule 5a & Schedule 5b | $ 9,093,544 | $ (29,779) | $ 9,063,765 |
| 27 | Annualized Property Tax Expense | Schedule 7 | $ 5,705,526 | $ 33,053 | $ 5,738,579 |
| 28 | Total Annualized Operating Expenses | | $ 15,941,608 | $ (131,848) | $ 15,809,760 |
| 29 | **Total Revenue Requirement** | Sum Ln 22 - 28 | $ 24,896,423 | $ (289,595) | $ 24,606,828 |
| | **Allocation %** | | | | |
| 30 | Rate RS / RFT / RSLI | Case No. 12-1685-GA-AIR, Schedule E-3.2f, page 7 of 14 | 72.35% | | 72.35% |
| 31 | Rate GS / FT Small | | 7.46% | | 7.46% |
| 32 | Rate GS / FT Large | | 15.62% | | 15.62% |
| 33 | Rate IT | | 4.57% | | 4.57% |
| 34 | **Total Allocation** | | 100.00% | | 100.00% |
| | **Annual Revenue Requirement** | | | | |
| 35 | Rate RS / RFT / RSLI / RFTLI | Ln 29 x Ln 30 | $ 18,011,940 | $ (209,514.73) | $ 17,802,425 |
| 36 | Rate GS / FT Small | Ln 26 x Ln 31 | $ 1,858,070 | $ (21,613.05) | $ 1,836,457 |
| 37 | Rate GS / FT Large | Ln 26 x Ln 32 | $ 3,888,199 | $ (45,227.50) | $ 3,842,971 |
| 38 | Rate IT / GGIT | Ln 26 x Ln 33 | $ 1,138,215 | $ (13,239.70) | $ 1,124,975 |
| 39 | **Total Annual Revenue Requirement** | Sum Ln 32 - 35 | $ 24,896,423 | $ (289,595) | $ 24,606,828 |
| | **Annual Bills Issued** | | | | |
| 40 | Rate RS / RFT / RSLI / RFTLI | Schedule 3 Ln 25 | 4,836,307 | | 4,836,307 |
| 41 | Rate GS / FT Small | Schedule 3 Ln 26 | 255,797 | | 255,797 |
| 42 | Rate GS / FT Large | Schedule 3 Ln 27 | 85,973 | | 85,973 |
| 43 | Rate IT / GGIT | Schedule 3 Ln 28 | 881 | | 881 |
| | **Estimated Monthly Rate Impact** | | | | |
| 44 | Rate RS / RFT / RSLI / RFTLI | Ln 35 ÷ Ln 40 | $ 3.72 | $ (0.04) | $ 3.68 |
| 45 | Rate GS / FT Small | Ln 36 ÷ Ln 41 | $ 7.26 | $ (0.08) | $ 7.18 |
| 46 | Rate GS / FT Large | Ln 37 ÷ Ln 42 | $ 45.23 | $ (0.53) | $ 44.70 |
| 47 | Rate IT / GGIT | Ln 38 ÷ Ln 43 | $ 1,291.96 | $ (15.03) | $ 1,276.93 |

Notes and Source:
Col. A: Exhibit J, Schedule 1 from the Company's CEP filing
Col. B: Schedule 2

**Duke Energy Ohio**
**Capital Expenditure Program**
**Summary of Adjustments**



| Line No. | Description | Total Adjustments | Remove Earnings Based Portion of Incentive and Stock-Based Compensation Sch. 3 | Property Tax Expense Sch. 4 | Eastern Gas Operation Center - Employee Fitness Room Sch. 5 | Correction of Errors to CEP Plant Balances Sch. 6 | Impact of Using ASL Composite Depreciation Rate Sch. 7 | Enable Project Allocation Sch. 8 | Remove AMI Meter Modules Included in CEP in Error Sch. 9 |
|---|---|---|---|---|---|---|---|---|---|
| | **Plant In-Service** | | | | | | | | |
| 1 | Additions | [redacted] | | | [redacted] | $ (557,570) | | $ (133,123) | $ (1,802) |
| 2 | Original Cost Retired | - | | | | | | | |
| 3 | Total Plant In-Service | [redacted] | $ - | $ - | [redacted] | $ (557,570) | $ - | $ (133,123) | $ (1,802) |
| | **Less Accumulation Provision for Depreciation** | | | | | | | | |
| 4 | Depreciation Expense | [redacted] | | | [redacted] | ($46,350) | | $ (18,467) | |
| 5 | 2012 Rate Case Depreciation Offset | $ - | | | | | | | |
| 6 | Original Cost Retired | $ - | | | | | | | |
| 7 | Total Accumulated Provision for Depreciation | [redacted] | $ - | $ - | [redacted] | $ 46,350 | $ - | $ 18,467 | $ - |
| 8 | Less: Earnings Based Capitalized Incentives | $ (775,173) | $ (775,173) | | | | | | |
| 9 | **Net Plant In-Service** | [redacted] | ($775,173) | $ - | [redacted] | $ (511,220) | $ - | $ (114,656) | $ (1,802) |
| | **Regulatory Assets** | | | | | | | | |
| 10 | Deferred Depreciation Expense | [redacted] | | | [redacted] | $ (46,350) | | $ (18,467) | |
| 11 | Post in Service Carrying Costs | | $ (142,980) | | | $ (118,293) | | $ (9,443) | |
| 12 | Property Tax | $ 135,332 | | $ 135,332 | | | | | |
| 13 | Cumulative Offset for Incremental Revenue | $ - | | | | | | | |
| 14 | Total Regulatory Assets | [redacted] | $ (142,980) | $ 135,332 | [redacted] | $ (164,643) | $ - | $ (27,910) | $ - |
| | **Accumulated Deferred Income Taxes** | | | | | | | | |
| 15 | Accumulated Deferred Income Tax on Post in Service Carrying Costs | [redacted] | $ 30,026 | $ - | [redacted] | $ 24,842 | | $ 1,983 | |
| 16 | Accumulated Deferred Income Tax on Property Tax | $ (28,420) | $ - | $ (28,420) | $ - | $ - | | | |
| 17 | Accumulated Deferred Income Tax on Cumulative Offset for Incremental Revenue | $ - | $ - | $ - | $ - | $ - | | | |
| 18 | Accumulated Deferred Income Tax on Liberalized Depreciation | $ 72,876 | | | | $ 72,876 | | | |
| 19 | Total Accumulated Deferred Income Taxes | [redacted] | $ 30,026 | $ (28,420) | [redacted] | $ 97,718 | $ - | $ 1,983 | $ - |
| 20 | **Net Rate Base** | [redacted] | $ (888,128) | $ 106,912 | [redacted] | $ (578,144) | $ - | $ (140,583) | $ (1,802) |
| 21 | Approved Pre-tax Rate of Return | 9.16% | 9.16% | 9.16% | 9.16% | 9.16% | 9.16% | 9.16% | 9.16% |
| 22 | **Annualized Return on Rate Base** | [redacted] | $ (81,353) | $ 9,793 | [redacted] | $ (52,958) | $ - | $ (12,877) | $ (165) |
| | **Operating Expenses** | | | | | | | | |
| 23 | Amortization of Regulatory Assets - Note A | $ (135,122) | $ - | $ - | $ - | $ - | $ (135,122) | | |
| 24 | Annualized Depreciation | [redacted] | | | [redacted] | $ (11,622) | | $ (13,852) | |
| 25 | Annualized Property Tax Expense | $ 33,053 | | $ 33,053 | | | | | |
| 26 | Total Annualized Operating Expenses | [redacted] | $ - | $ 33,053 | [redacted] | $ (11,622) | $ (135,122) | $ (13,852) | $ - |
| 27 | **Total Revenue Requirement** | [redacted] | $ (81,353) | $ 42,846 | [redacted] | $ (64,580) | $ (135,122) | $ (26,729) | $ (165) |

Notes and Source:
A: The impact of our adjustments on the amortization of regulatory assets is shown on Schedule 1 - Revenue Requirement (lines 23-25)

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based Portion of Incentive and Stock-Based Compensation**



| Line No. | Description | Period | 2013 (A) | 2014 (B) | 2015 (C) | 2016 (D) | 2017 (E) | 2018 (F) |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Plant Incentives | Q1 | $ (38,054) | $ (32,371) | $ (22,749) | $ (18,575) | $ (16,036) | $ (17,151) |
| 2 | | Q2 | $ (46,675) | $ (30,797) | $ (29,984) | $ (35,701) | $ (35,130) | $ (11,289) |
| 3 | | Q3 | $ (38,800) | $ (41,067) | $ (35,771) | $ (19,004) | $ (58,095) | $ (31,292) |
| 4 | | Q4 | $ (66,353) | $ (49,963) | $ (34,222) | $ (34,147) | $ (30,101) | $ (24,691) |
| 5 | Cumulative Gross Plant Incentives | | $ (189,882) | $ (344,080) | $ (466,806) | $ (574,233) | $ (713,594) | $ (798,017) |
| 6 | Depreciation Expense | Q1 | $ (121) | $ (344) | $ (519) | $ (651) | $ (761) | $ (866) |
| 7 | | Q2 | $ (148) | $ (394) | $ (587) | $ (796) | $ (1,021) | $ (1,168) |
| 8 | | Q3 | $ (123) | $ (377) | $ (621) | $ (795) | $ (1,039) | $ (1,323) |
| 9 | | Q4 | $ (211) | $ (580) | $ (847) | $ (1,064) | $ (1,268) | $ (1,442) |
| 10 | Accumulated Depreciation | Q1 | $ 121 | $ 947 | $ 2,818 | $ 5,523 | $ 8,939 | $ 13,133 |
| 11 | | Q2 | $ 269 | $ 1,341 | $ 3,405 | $ 6,319 | $ 9,959 | $ 14,301 |
| 12 | | Q3 | $ 392 | $ 1,718 | $ 4,026 | $ 7,114 | $ 10,999 | $ 15,624 |
| 13 | | Q4 | $ 603 | $ 2,298 | $ 4,873 | $ 8,178 | $ 12,267 | $ 17,066 |
| 14 | Accumulated Deferred Income Tax | Q1 | $ 50 | $ 383 | $ 1,106 | $ 2,088 | $ 3,245 | $ 4,581 |
| 15 | | Q2 | $ 110 | $ 538 | $ 1,322 | $ 2,365 | $ 3,580 | $ 4,935 |
| 16 | | Q3 | $ 161 | $ 686 | $ 1,554 | $ 2,640 | $ 3,924 | $ 5,353 |
| 17 | | Q4 | $ 247 | $ 914 | $ 1,865 | $ 3,004 | $ 4,327 | $ 5,777 |
| 18 | Total Adjustment to Net Rate Base | Q1 | $ (189,711) | $ (342,750) | $ (462,882) | $ (566,621) | $ (701,410) | $ (780,303) |
| 19 | | Q2 | $ (189,502) | $ (342,201) | $ (462,079) | $ (565,549) | $ (700,054) | $ (778,781) |
| 20 | | Q3 | $ (189,329) | $ (341,676) | $ (461,227) | $ (564,479) | $ (698,672) | $ (777,040) |
| 21 | | Q4 | $ (189,032) | $ (340,868) | $ (460,068) | $ (563,050) | $ (697,000) | **$ (775,173)** |

Notes and Source
Cols. A-F: Amounts from the response to LARKIN-DR-01-149

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based Portion of Incentive and Stock-Based Compensation**
**Impact on PISCC deferral**



| Line No. | Description | | Quarterly Spend (Capital) 2013 (A) | 2014 (B) | 2015 (C) | 2016 (D) | 2017 (E) | 2018 (F) |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Plant Incentives | Q1 | (38,054) | (32,371) | (22,749) | (18,575) | (16,036) | (17,151) |
| 2 | | Q2 | (46,675) | (30,797) | (29,984) | (35,701) | (35,130) | (11,289) |
| 3 | | Q3 | (38,800) | (41,067) | (35,771) | (19,004) | (58,095) | (31,292) |
| 4 | | Q4 | (66,353) | (49,963) | (34,222) | (34,147) | (30,101) | (24,691) |
| 5 | Cummulative EBCI | | (189,882) | (344,080) | (466,806) | (574,233) | (713,594) | (798,017) |
| 6 | Long Term Debt Rate | | 5.32% | | | | | |
| 7 | Annual PISCC | | (5,051) | (14,203) | (21,570) | (27,692) | (34,256) | (40,209) |
| 8 | Cumulative PISCC | | (5,051) | (19,254) | (40,824) | (68,515) | (102,772) | **(142,980)** |

Notes and Source
Cols. A-F: Amounts from the response to LARKIN-DR-01-160

**Duke Energy Ohio**
**Capital Expenditure Program**
**Property Tax Expense**



| Line No. | Description | 12/31/2013 (A) | 12/31/2014 (B) | 12/31/2015 (C) | 12/31/2016 (D) | 12/31/2017 (E) | 12/31/2018 (F) |
|---|---|---|---|---|---|---|---|
| | **Property Tax Regulatory Asset** | | | | | | |
| | **Per Larkin** | | | | | | |
| 1 | Distribution Improvement - Deferred Property Taxes | $ - | $ 508,954 | $ 1,626,811 | $ 3,707,679 | $ 7,312,983 | $ 12,554,735 |
| 2 | Information Technology - Deferred Property Taxes | $ - | $ - | $ 21 | $ 11,031 | $ 130,523 | $ 627,350 |
| 3 | Total CEP - Deferred Property Taxes | $ - | $ 508,954 | $ 1,626,832 | $ 3,718,710 | $ 7,443,506 | $ 13,182,085 |
| | **Per Company Filing** | | | | | | |
| 4 | Distribution Improvement - Deferred Property Taxes | $ - | $ 509,951 | $ 1,621,109 | $ 3,704,813 | $ 7,214,597 | $ 12,433,247 |
| 5 | Information Technology - Deferred Property Taxes | $ - | $ - | $ 20 | $ 10,974 | $ 126,630 | $ 613,506 |
| 6 | Total CEP - Deferred Property Taxes | $ - | $ 509,951 | $ 1,621,129 | $ 3,715,787 | $ 7,341,227 | $ 13,046,753 |
| | **Adjustment to Property Tax Regulatory Asset** | | | | | | |
| 7 | Distribution Improvement - Deferred Property Taxes | $ - | $ - | $ 5,702 | $ 2,866 | $ 98,386 | $ 121,488 |
| 8 | Information Technology - Deferred Property Taxes | $ - | $ - | $ 1 | $ 57 | $ 3,893 | $ 13,844 |
| 9 | Total CEP - Deferred Property Taxes | $ - | $ - | $ 5,703 | $ 2,923 | $ 102,279 | **$ 135,332** |
| | **Annualized Property Tax Expense** | | | | | | |
| | **Per Larkin** | 12/31/2013 | 12/31/2014 | 12/31/2015 | 12/31/2016 | 12/31/2017 | 12/31/2018 |
| | Distribution Improvement - Annualized Property Tax Expense | $ - | $ 508,954 | $ 1,117,857 | $ 2,080,868 | $ 3,605,304 | $ 5,241,752 |
| | Information Technology - Annualized Property Tax Expense | $ - | $ - | $ 21 | $ 11,010 | $ 119,492 | $ 496,827 |
| | Total CEP - Annualized Property Tax Expense | $ - | $ 508,954 | $ 1,117,878 | $ 2,091,878 | $ 3,724,796 | $ 5,738,579 |
| | **Per Company Filing** | | | | | | |
| | Distribution Improvement - Annualized Property Tax Expense | $ - | $ 509,951 | $ 1,111,158 | $ 2,083,704 | $ 3,509,784 | $ 5,218,650 |
| | Information Technology - Annualized Property Tax Expense | $ - | $ - | $ 20 | $ 10,954 | $ 115,656 | $ 486,876 |
| | Total CEP - Annualized Property Tax Expense | $ - | $ 509,951 | $ 1,111,178 | $ 2,094,658 | $ 3,625,440 | $ 5,705,526 |
| | **Adjustment to Property Tax Regulatory Asset** | | | | | | |
| | Distribution Improvement - Annualized Property Tax Expense | $ - | $ (997) | $ 6,699 | $ (2,836) | $ 95,520 | $ 23,102 |
| | Information Technology - Annualized Property Tax Expense | $ - | $ - | $ 1 | $ 56 | $ 3,836 | $ 9,951 |
| | Total CEP - Annualized Property Tax Expense | $ - | $ (997) | $ 6,700 | $ (2,780) | $ 99,356 | **$ 33,053** |

Notes and Source:
Cols. A-F: See Schedule 4 workpapers

**Duke Energy Ohio**
**Capital Expenditure Program**
**Eastern Gas Operation Center - Employee Fitness Room**



| Line No. | Description | Amount (A) | Reference |
|---|---|---|---|
| 1 | Remove Employee Fitness Room Construction Costs | [redacted] | A |
| 2 | Remove Employee Fitness Room Equipment | | A |
| 3 | Total Adjustment to Remove Employee Fitness Room Costs | | |
| 4 | Adjustment to Deferred Depreciation Expense | [redacted] | B |
| 5 | Adjustment to Annualized Depreciation Expense* | [redacted] | C |
| 6 | Adjustment to Post In-Service Carrying Costs | [redacted] | B |

Notes and Source:
A: Amounts from the supplemental response to LARKIN-DR-01-164
B: See page 2
C: See Depreciation Workpaper

**Duke Energy Ohio**
**Capital Expenditure Program**
**Eastern Gas Operation Center - Employee Fitness Room**



| Line No. | Description | Cumulative Total | Rate | Apr 2017 | May 2017 | Jun 2017 | Jul 2017 | Aug 2017 | Sep 2017 | Oct 2017 | Nov 2017 | Dec 2017 | Jan 2018 | Feb 2018 | Mar 2018 | Apr 2018 | May 2018 | Jun 2018 | Jul 2018 | Aug 2018 | Sep 2018 | Oct 2018 | Nov 2018 | Dec 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | ( R) | (S) | (T) | (U) | (W) | (V) |
| 1 | Fitness Center Cost | [redacted] | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Calculated Depreciation | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Calculated PISCC | | | | | | | | | | | | | | | | | | | | | | | |

Notes and Source
Cols. A-V: Amounts from the supplemental response to LARK N-DR-01-164

**Duke Energy Ohio**
**Capital Expenditure Program**
**Correction of Errors to CEP Plant Balances**



| Line No. | Description | 2013 CEP Plant Balances (A) | 2014 CEP Plant Balances (B) | 2015 CEP Plant Balances (C) | Total Adjustment (D) | Reference |
|---|---|---|---|---|---|---|
| 1 | Adjustment to Net Plant Balances | $ (40,622) | $ 14,661 | $ (531,609) | $ (557,570) | Line 10 |
| 2 | Adjustment to Deferred Depreciation Expense | | | | $ (46,350) | Depr Workpaper |
| 3 | Adjustment to Annualized Depreciation Expense | | | | $ (11,622) | Depr Workpaper |
| 4 | Adjustment to Deferred Tax - Liberalized Depreciation | | | | $ 72,876 | Page 2 |
| 5 | Adjustment to Post In-Service Carrying Costs | | | | $ (118,293) | Page 3 |

Notes and Source
Line 1: The deriva ion of these amounts is shown below.

| Line No. | Description | 2013 | 2014 | 2015 | Total | Reference |
|---|---|---|---|---|---|---|
| 6 | Total CEP In-Service Activity - Net Assets | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | | Exh. J, Sch. 4 |
| 7 | Add Back Retirements | $ 4,199,618 | $ 3,515,619 | $ 5,346,597 | | Exh. J, Sch. 4 |
| 8 | Total CEP In-Service Activity - Gross Assets | $ 21,877,330 | $ 26,308,530 | $ 42,817,578 | | |
| 9 | 2013-2018 Work Order Total for CEP | $ 21,836,708 | $ 26,323,191 | $ 42,285,969 | | LARKIN-DR-01-35 |
| 10 | Difference (see below for additional detail) | $ 40,622 | $ (14,661) | $ 531,609 | $ 557,570 | |

The response to LARK N-DR-01-75 states that the variances shown on line 10 were caused by incorrect data filtering methods, which resulted in an under/overstatement in the CEP work order totals. The breakout of each variance, by project number, is shown below.

| Line No. | Description | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| 11 | Project No. 20062 | $ 18,753 | $ 9,980 | |
| 12 | Project No. 20063 | $ 21,869 | | |
| 13 | Project No. G9141 | | $ (26,212) | |
| 14 | Project No. G9870 | | $ 1,568 | |
| 15 | Project No. G6985 | | | $ (4,095) |
| 16 | Project No. G8592 | | | $ (279,308) |
| 17 | Project No. G9106 | | | $ 809,305 |
| 18 | Project No. H1006 | | | $ (6,921) |
| 19 | Project No. H1123 | | | $ 14,499 |
| 20 | Project No. H1360 | | | $ 1,107 |
| 21 | Project No. H1647 | | | $ (7,925) |
| 22 | Project No. H1667 | | | $ 21,534 |
| 23 | Project No. H1676 | | | $ (5,135) |
| 24 | Project No. H1711 | | | $ 505 |
| 25 | Project No. I1110 | | | $ (11,957) |
| 26 | Total | $ 40,622 | $ (14,663) | $ 531,609 |

Attachment LA-1
Case No. 19-0791-GA-ALT
Page 10 of 15

**Duke Energy Ohio**
**Capital Expenditure Program**
**Correction of Errors to CEP Plant Balances**
**Deferred Tax - Liberalized Depreciation**

**Attachment LA-1**
**Schedule No. 6**
**Page 2 of 3**

| Line No. | Descrip ion | | 2013 (A) | 2014 (B) | 2015 (C) | 2016 (D) | 2017 (E) | 2018 (F) | Total (G) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant Additions (excluding Land) | | $ 21,877,330 | $ 26,308,530 | $ 42,817,578 | $ 68,466,517 | $ 86,927,435 | $ 93,776,160 | $ 340,173,550 |
| 2 | Depreciaion Expense - Plant | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 3 | MACRS Depr/Amort (Calculated Below) | | $ 11,346,482 | $ 14,548,870 | $ 23,794,105 | $ 39,280,166 | $ 56,790,223 | $ 29,177,944 | $ 174,937,790 |
| 4 | Difference Between Book Depr & Tax Depr | | $ (11,346,482) | $ (14,548,870) | $ (23,794,105) | $ (39,280,166) | $ (56,790,223) | $ (29,177,944) | $ (174,937,790) |
| 5 | Federal Income Tax Rate | | 21% | 21% | 21% | 21% | 21% | 21% | 21% |
| 6 | Adjusted Deferred Tax-Liberalized Deprecia ion | | $ (2,382,761) | $ (3,055,263) | $ (4,996,762) | $ (8,248,835) | $ (11,925,947) | $ (6,127,368) | $ (36,736,936) |
| 7 | Original Deferred Tax - Liberalized Deprecia ion | | $ (2,387,186) | $ (3,053,973) | $ (5,054,849) | $ (8,253,026) | $ (11,929,823) | $ (6,130,954) | $ (36,809,812) |
| 8 | Adjustment to Deferred Tax - Liberalized Depreciation | | $ 4,425 | $ (1,289) | $ 58,086 | $ 4,191 | $ 3,877 | $ 3,586 | **$ 72,876** |
| 9 | | 2013 | $ 11,346,482 | | | | | | $ 11,346,482 |
| 10 | | 2014 | $ 819,713 | $ 13,729,157 | | | | | $ 14,548,870 |
| 11 | | 2015 | $ 750,441 | $ 1,072,463 | $ 21,971,201 | | | | $ 23,794,105 |
| 12 | | 2016 | $ 688,550 | $ 957,364 | $ 1,692,481 | $ 35,941,772 | | | $ 39,280,166 |
| 13 | | 2017 | $ 632,616 | $ 860,763 | $ 1,516,953 | $ 3,280,728 | $ 50,499,163 | | $ 56,790,223 |
| 14 | | 2018 | $ 585,450 | $ 778,178 | $ 1,370,746 | $ 3,028,031 | $ 5,064,626 | $ 18,350,912 | $ 29,177,944 |
| 15 | | 2019 | $ 542,892 | $ 723,428 | $ 1,255,969 | $ 2,445,763 | $ 4,802,824 | $ 7,575,338 | $ 17,346,214 |
| 16 | | 2020 | $ 498,896 | $ 674,037 | $ 1,151,039 | $ 1,893,159 | $ 3,346,793 | $ 6,484,337 | $ 14,048,260 |
| 17 | | 2021 | $ 486,745 | $ 600,905 | $ 1,057,375 | $ 1,751,968 | $ 1,932,478 | $ 5,606,597 | $ 11,436,067 |
| 18 | | 2022 | $ 486,641 | $ 564,706 | $ 968,907 | $ 1,628,185 | $ 1,762,395 | $ 4,913,779 | $ 10,324,613 |
| 19 | | 2023 | $ 486,745 | $ 564,586 | $ 938,884 | $ 1,478,701 | $ 1,628,705 | $ 4,583,689 | $ 9,681,309 |
| 21 | | 2025 | $ 486,745 | $ 564,586 | $ 938,884 | $ 1,416,627 | $ 1,499,034 | $ 3,639,133 | $ 8,545,008 |
| 22 | | 2026 | $ 486,641 | $ 564,706 | $ 938,693 | $ 1,416,914 | $ 1,498,804 | $ 3,184,691 | $ 8,090,449 |
| 23 | | 2027 | $ 486,745 | $ 564,586 | $ 938,884 | $ 1,416,627 | $ 1,499,034 | $ 3,184,044 | $ 8,089,919 |
| 24 | | 2028 | $ 475,437 | $ 564,706 | $ 938,693 | $ 1,416,914 | $ 1,498,804 | $ 3,184,691 | $ 8,079,245 |
| 25 | | 2029 | $ 464,341 | $ 551,463 | $ 938,884 | $ 1,416,627 | $ 1,499,034 | $ 3,184,044 | $ 8,054,393 |
| 26 | | 2030 | $ 464,237 | $ 538,466 | $ 895,326 | $ 1,416,914 | $ 1,498,804 | $ 3,184,691 | $ 7,998,438 |
| 27 | | 2031 | $ 464,341 | $ 538,345 | $ 852,165 | $ 1,347,468 | $ 1,499,034 | $ 3,184,044 | $ 7,885,396 |
| 28 | | 2032 | $ 464,237 | $ 538,466 | $ 851,974 | $ 1,278,618 | $ 1,261,283 | $ 3,184,691 | $ 7,579,269 |
| 29 | | 2033 | $ 232,171 | $ 538,345 | $ 852,165 | $ 1,278,331 | $ 1,024,072 | $ 3,036,598 | $ 6,961,682 |
| 30 | | 2034 | | $ 269,233 | $ 851,974 | $ 1,278,618 | $ 1,023,843 | $ 2,889,850 | $ 6,313,518 |
| 31 | | 2035 | | | $ 426,083 | $ 1,278,331 | $ 1,024,072 | $ 2,889,203 | $ 5,617,689 |
| 32 | | 2036 | | | | $ 639,309 | $ 1,023,843 | $ 2,889,850 | $ 4,553,002 |
| 33 | | 2037 | | | | | $ 512,036 | $ 2,889,203 | $ 3,401,239 |
| 34 | | 2038 | | | | | | $ 1,444,925 | $ 1,444,925 |
| 35 | | Total | $ 21,836,708 | $ 26,323,193 | $ 42,285,969 | $ 68,466,517 | $ 86,927,435 | $ 93,776,160 | $ 339,615,983 |

Notes and Source:
Cols. A-C: Corrected amounts from he response to LARKIN-DR-01-159
Cols. D-F: Amounts from Exhibit J, Schedule 12 from DEO's filing

**Duke Energy Ohio**
**Capital Expenditure Program**
**Correction of Errors to CEP Plant Balances**
**Post In-Service Carrying Costs**

**Attachment LA-1**
**Schedule No. 6**
**Page 3 of 3**

| Line No. | Description | December 2013 | November 2014 | December 2014 | January 2015 | June 2015 | August 2015 | Grand Total |
|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 1 | 27603 - Gas Mains - Dist Lines/Plas | | $ (26,212) | $ 1,568 | $ 529,997 | | $ 1,107 | $ 506,461 |
| 2 | 27605 - Gas Mains - Feeder Lines/St | | | | | $ 505 | | $ 505 |
| 3 | 28100 - Meters | $ (133,198) | | $ (87,096) | | | | $ (220,293) |
| 4 | 28101 - Leased Meters | $ 151,950 | | $ 97,076 | | | | $ 249,026 |
| 5 | 28300 - House Regulators | $ (531,673) | | | | | | $ (531,673) |
| 6 | 28301 - House Regulators Leased | $ 553,542 | | | | | | $ 553,542 |
| 7 | Grand Total | $ 40,622 | $ (26,212) | $ 11,548 | $ 529,997 | $ 505 | $ 1,107 | $ 557,568 |
| | | | | | | | | |
| 8 | Month of Adjustment | Dec-2013 | Nov-2014 | Dec-2014 | Jan-2015 | Jun-2015 | Aug-2015 | Total |
| 9 | Monthly Rate | 0.44% | 0.44% | 0.44% | 0.44% | 0.44% | 0.44% | |
| 10 | Months | 60 | 49 | 48 | 47 | 42 | 40 | |
| 11 | PISCC adjustment | $ (10,805) | $ 5,694 | $ (2,458) | $ (110,434) | $ (94) | $ (196) | $ (118,293) |

Notes and Source:
Amounts above from the response to LARKIN-DR-01-159

**Duke Energy Ohio** | **Attachment LA-1**
**Capital Expenditure Program** | **Schedule No. 7**
**Calculation of Composite Depreciation Rate** | **Page 1 of 1**

FERC ACCT / COMPANY ACCT / ACCOUNT TITLE
Direct Weighting Method

| Line No. | Description | CEP $'s | Case No. 12-1685-GA-AIR Authorized Accrual Rate | Average Service Life | Dollars Weighted |
|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) = AxC |
| | **Distribution Plant** | | | | |
| 1 | 374 / 2740 / Land | $ 1,656,720 | | | |
| 2 | 374 / 2741 / Rights of Way | $ (2,668) | 1.54% | 65 | $ (173,410) |
| 3 | 374 / 2742 / City Gate Check Station | | | | |
| 4 | 375 / 2750 / Structures & Improvements | $ 17,482,414 | 2.09% | 55 | $ 961,532,772 |
| 5 | 27601 - Gas Mains - Dist Lines/Cast | $ (69,225) | 2.72% | 46 | $ (3,184,344) |
| 6 | 27602 - Gas Mains - Dist Lines/Stee | $ 20,199,255 | 1.87% | 67 | $ 1,353,350,079 |
| 7 | 27603 - Gas Mains - Dist Lines/Plas | $ 65,371,311 | 2.08% | 60 | $ 3,922,278,679 |
| 8 | 27605 - Gas Mains - Feeder Lines/St | $ 32,371,195 | 1.87% | 67 | $ 2,168,870,054 |
| 9 | 27607 - Capex Gas Mains - Dist Stee | $ 665,240 | 1.87% | 67 | $ 44,571,074 |
| 10 | 27608 - Capex Gas Mains - Dist Plas | $ 798,137 | 2.08% | 60 | $ 47,888,200 |
| 11 | 378 / 2780 / System Meas. & Reg. Station Equipment - General | $ 24,331,612 | 2.35% | 49 | $ 1,192,248,985 |
| 12 | 378 / 2781 / System Meas. & Reg. Station Equipment - Electronic | $ 2,330,725 | 7.00% | 15 | $ 34,960,869 |
| 13 | 378 / 2782 / District Regulating Equipment | $ 1,786,290 | 2.40% | 48 | $ 85,741,940 |
| 14 | 379 / 2790 / Meas. & Reg - City Gate | $ 1,113,061 | 6.67% | 15 | $ 16,695,908 |
| 15 | 28001 - Services - M-C C Iron & C | $ (1,805,405) | 3.11% | 37 | $ (66,800,001) |
| 16 | 28002 - Services - M- C Steel | $ 1,945,262 | 2.88% | 40 | $ 77,810,466 |
| 17 | 28003 - Services - M-C Plastic | $ 64,300,923 | 3.59% | 32 | $ 2,057,629,538 |
| 18 | 28005 - Capex Services M-C Plastic | $ 14,852 | 3.59% | 32 | $ 475,251 |
| 19 | 28006 - Services C-M Plastic | $ 40,033,351 | 3.59% | 32 | $ 1,281,067,222 |
| 20 | 28007 - Capex Services C-M Plastic | $ - | | | $ - |
| 21 | 28008 - Services C-M Steel | $ 1,163,546 | 2.88% | 40 | $ 46,541,835 |
| 22 | 381 / 2810, 2811 / Meters | $ (6,764,136) | 2.22% | 45 | $ (304,386,109) |
| 23 | 381 / 2812 / Utility of the Future Meters | $ - | | | |
| 24 | 382 / 2820, 2821 / Meter Installations | $ (886,267) | 2.00% | 50 | $ (44,313,340) |
| 25 | 383 / 2830, 2831 / House Regulators | $ (1,036,739) | 2.00% | 50 | $ (51,836,970) |
| 26 | 384 / 2840, 2841 / House Regulator Installations | $ 75,069 | 2.00% | 50 | $ 3,753,434 |
| 27 | 385 / 2850 / Large Industrial Meas. & Reg. Equipment | $ 15,089 | 2.63% | 40 | $ 603,576 |
| 28 | 385 / 2851 / Large Industrial Meas. & Reg. Equipment - Comm | | | | |
| 29 | 387 / 2870 / Other Equipment - Other | | | | |
| 30 | 387 / 2871 / Street Lighting Equipment | $ (120,401) | 2.67% | 45 | $ (5,418,037) |
| 31 | 388 / / Gas ARO | | | | |
| | **General Plant & Intangible** | | | | |
| 32 | 000 / 2030 / Miscellaneous Intangible Plant | $ 9,810,837 | Various | 5 | $ 49,054,186 |
| 33 | 000 / 20301 / Miscellaneous Intangible Plant-Enable | $ 9,629,709 | Various | 5 | $ 48,148,546 |
| 34 | 389 / 2890 / Land | | | | |
| 35 | 390 / 2900 / Structures & Improvements | $ (288,800) | 3.33% | 30 | $ (8,663,993) |
| 36 | 391 / 2910 / Office Furniture & Equipment | | | | |
| 37 | 391 / 2911 / Electronic Data Processing Equipment | $ 444,124 | 20.00% | 5 | $ 2,220,622 |
| 38 | 392 / 2920 / Transportation Equipment | | | | |
| 39 | 392 / 2921 / Trailers | | | | |
| 40 | 394 / 2940 / Tools, Shop & Garage Equipment | $ 4,194,274 | 4.00% | 25 | $ 104,856,840 |
| 41 | 395 / 2950 / Laboratory Equipment | $ (54,460) | 6.67% | 15 | $ (816,903) |
| 42 | 396 / 2960 / Power Operated Equipment | $ 1,005,255 | 6.36% | 11 | $ 11,057,806 |
| 43 | 397 / 2970 / Communication Equipment | $ 7,765,141 | 6.67% | 15 | $ 116,477,118 |
| 44 | 398 / 2980 / Miscellaneous Equipment | | | | |
| 45 | Total General Plant | $ 297 475 290 | | | $ 13 142 241 893 |
| 46 | | $ (1 656 720) | | | 44.426697 ASL |
| 47 | | $ 295 818 570 | | | |
| | | | | | 2.25 % |

Notes and Source
The calculations above were provided by PUCO Staff

**Duke Energy Ohio**
**Capital Expenditure Program**
**Enable Project Allocation Factor**



| Line No. | Description | 2015 (A) | 2016 (B) | 2017 (C) | 2018 (D) | Total (E) | Reference |
|---|---|---|---|---|---|---|---|
| 1 | Total Charged to DE Ohio Gas Delivery | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 | |
| 2 | Divided by 5.43% (2014 CAM Allocation % Used) | 5.43% | 5.43% | 5.43% | 5.43% | | |
| 3 | Total Charged Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 | L1 / L2 |
| 4 | Multiplied by % from Each Year's CAM - Note A | 5.43% | 5.41% | 5.34% | 5.30% | | |
| 5 | Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 | L3 x L4 |
| 6 | Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 | Line 5 |
| 7 | Total Charged to DE Ohio Gas Delivery | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 | Line 1 |
| 8 | Difference in Allocation Methods | $ - | $ (15,271) | $ (111,841) | $ (6,011) | $ (133,123) | L6 - L7 |
| 9 | Adjustment to Deferred Depreciation Expense | | | | | $ (18,467) | Page 2 |
| 10 | Adjustment to Annualized Depreciation Expense | | | | | $ (13,852) | Depr Workpaper, p2 |
| 11 | Adjustment to Post In-Service Carrying Costs | | | | | $ (9,443) | Page 2 |

Notes and Source
Cols. A-E: Amounts from the supplemental response to LARKIN-DR-01-157

Note A: According to the response to LARKIN-DR-01-157, due to the complexity of Enable charging and the timing of the CAM spreadsheet, updating the percentage each year requires using the prior year's CAM

**Duke Energy Ohio**
**Capital Expenditure Program**
**Enable Project Allocation Factor**



| Line No. | Description | Cumulative Total | Rate | Aug 2017 | Sep 2017 | Oct 2017 | Nov 2017 | Dec 2017 | Jan 2018 | Feb 2018 | Mar 2018 | Apr 2018 | May 2018 | Jun 2018 | Jul 2018 | Aug 2018 | Sep 2018 | Oct 2018 | Nov 2018 | Dec 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | ( R) | (S) |
| 1 | Enable Project Software | (127,741) | | $ (127,741) | | | | | | | | | | | | | | | | |
| 2 | Calculated Depreciation - FERC 303 | (17,032) | 10.00% | | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) |
| 3 | Enable Project Hardware | (5,382) | | $ (5,382) | | | | | | | | | | | | | | | | |
| 4 | Calculated Depreciation - FERC 391 | (1,435) | 20.00% | | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) |
| 5 | Total Calculated Depreciation | (18 467) | | | | | | | | | | | | | | | | | | |
| 6 | Calculated PISCC | (9 443) | 5.32% | $ (133,123) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) |

Notes and Source
Amounts on lines 7-9 below are from the response to LARKIN-DR-35

| Line | Description | FERC Account | Enable Project Costs | Percentage |
|---|---|---|---|---|
| 7 | Miscellaneous Intangible Plant | 303 | $ 12,297,982 | 95.96% |
| 8 | Electronic Data Processing | 391 | $ 518 136 | 4.04% |
| 9 | Total Enable Project Costs in CEP | | $ 12 816 118 | 100.00% |
| 10 | Difference in Allocation Methods | | $ (133,123) | |
| 11 | Percentage of Enable Project to FERC 303 | | 95.96% | |
| 12 | Difference in Allocation Methods to FERC 303 | | $ (127 741) | |
| 13 | Difference in Allocation Methods | | $ (133,123) | |
| 14 | Percentage of Enable Project to FERC 391 | | 4.04% | |
| 15 | Difference in Allocation Methods to FERC 391 | | $ (5 382) | |

**Duke Energy Ohio**
**Capital Expenditure Program**
**AMI Meter Modules Included in CEP in Error**



| Line No. | **Project Description** | Year (A) | FERC Account (B) | Project ID Number (C) | Work Order Completion Date (D) | Work Type (E) | Amount (F) |
|---|---|---|---|---|---|---|---|
| 1 | AMI Module Install/Remove | 2013 | 381 | AMIMODCHG | March 2013 | Replacement | $ (890) |
| 2 | AMI Module Install/Remove | 2014 | 381 | AMIMODCHG | January 2014 | Replacement | $ (880) |
| 3 | AMI Module Install/Remove | 2015 | 381 | AMIMODCHG | April 2015 | Replacement | $ (31) |
| | | | | | | | $ (1,802) |

Notes and Source
Cols. A-F: The amounts above are from the responses to LARKIN-DR-01-35 and LARKIN-DR-01-72

# Duke Energy Ohio - Gas
# Case No. 19-0791-GA-ALT
# Attachment LA-2
# Total Company Plant and Depreciation Reserve Balances



| Number | Description | No. of Pages | Confidential | Exhibit Page No. |
|---|---|---|---|---|
| | **Plant In-Service and Depreciation Reserve Schedules** | | | |
| 1 | Plant In-Service By Accounts and Subaccounts | 2 | Yes | 2-3 |
| 2 | Accumulated Depreciation and Amortization | 2 | Yes | 4-5 |
| | | | | |
| | **Adjustment Schedules** | | | |
| 3 | Eastern Gas Operation Center - Employee Fitness Room | 2 | Yes | 6-7 |
| 4 | Enable Project Allocation Factor | 2 | No | 8-9 |
| 5 | Remove Earnings Based CEP Related Incentive and Stock-Based Compensation | 2 | No | 10-11 |
| 6 | Remove Earnings Based Non-CEP Incentive and Stock-Based Compensation | 2 | No | 12-13 |
| | | | | |
| | Total Pages (Including Contents Page) | 13 | | |

**Duke Energy Ohio - Total Company**
**Plant In-Service By Accounts and Subaccounts**
**As of December 31, 2018**

**Attachment LA-2**
**Schedule 1**
**Page 1 of 2**

| Line No. | FERC Account Number | Company Account Number | Account Title | Total Company Amount | Recommended Adjustments | Adjusted Total Company Amount | Allocation Percentage | Adjusted Total |
|---|---|---|---|---|---|---|---|---|
| | | | | (A) | (B) | (C) | (D) | (E) |
| | | | **Manufactured Production Plant** | | | | | |
| 1 | 304 | 2040 | Land and Land Rights | $ 474,358 | $ 6 | $ 474,364 | 100% | $ 474,364 |
| 2 | 304 | 2041 | Rights of Way | $ 4,147 | $ - | $ 4,147 | 100% | $ 4,147 |
| 3 | 305 | 2050 | Structures & Improvements | $ 5,275,043 | $ (3,860) | $ 5,271,184 | 100% | $ 5,271,184 |
| 4 | 311 | 2110 | Liquefied Petroleum Gas Equipment | $ 13,237,049 | $ (4,412) | $ 13,232,637 | 100% | $ 13,232,637 |
| 5 | 320 | 2200 | Other Equipment | $ 144,194 | $ (297) | $ 143,896 | 100% | $ 143,896 |
| 6 | | | Total Manufactured Gas Production Plant | $ 19,134,791 | $ (8,563) | $ 19,126,228 | | $ 19,126,228 |
| | | | **Distribution Plant** | | | | | |
| 7 | 374 | 2740 | Land and Land Rights | $ 2,664,021 | $ (6,595) | $ 2,657,425 | 100% | $ 2,657,425 |
| 8 | 374 | 2741 | Rights of Way | $ 8,868,619 | $ 292 | $ 8,868,911 | 100% | $ 8,868,911 |
| 9 | 374 | 2742 | City Gate Check Station | $ 3,663 | $ - | $ 3,663 | 100% | $ 3,663 |
| 10 | 375 | 2750 | Structures & Improvements | $ 18,732,489 | $ (250,773) | $ 18,481,716 | 100% | $ 18,481,716 |
| 11 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | $ 4,804,331 | $ 6,577 | $ 4,810,908 | 100% | $ 4,810,908 |
| 12 | 376 | 2762, 65, 67, 69 | Mains - Steel | $ 494,220,451 | $ (268,732) | $ 493,951,719 | 100% | $ 493,951,719 |
| 13 | 376 | 2763, 2768 | Mains - Plastic | $ 773,628,950 | $ (421,263) | $ 773,207,687 | 100% | $ 773,207,687 |
| 14 | 378 | 2780 | System Meas. & Reg. Station Equipment | $ 37,121,227 | $ (52,760) | $ 37,068,467 | 100% | $ 37,068,467 |
| 15 | 378 | 2781 | System Meas. & Reg. Station Equip-Electronic | $ 8,184,188 | $ (11,076) | $ 8,173,112 | 100% | $ 8,173,112 |
| 16 | 378 | 2782 | District Regulating Equipment | $ 6,305,762 | $ (4,010) | $ 6,301,752 | 100% | $ 6,301,752 |
| 17 | 379 | 2790 | Meas. & Reg.- City Gate | $ 3,632,273 | $ (8,779) | $ 3,623,493 | 100% | $ 3,623,493 |
| 18 | 380 | 2801 | Services- Cast Iron & Copper | $ 4,110,530 | $ 7,806 | $ 4,118,336 | 100% | $ 4,118,336 |
| 19 | 380 | 2802, 2804, 2808 | Services-Steel | $ 24,802,473 | $ (17,271) | $ 24,785,202 | 100% | $ 24,785,202 |
| 20 | 380 | 2803, 05, 06, 07 | Services-Plastic | $ 553,191,382 | $ (415,547) | $ 552,775,834 | 100% | $ 552,775,834 |
| 21 | 381 | 2810,2811 | Meters | $ 40,076,717 | $ 14,411 | $ 40,091,128 | 100% | $ 40,091,128 |
| 22 | 381 | 2812 | Utility of the Future Meters | $ 25,879 | $ (52) | $ 25,828 | 100% | $ 25,828 |
| 23 | 382 | 2820,2821 | Meter Installations | $ 27,122,879 | $ 5,110 | $ 27,127,989 | 100% | $ 27,127,989 |
| 24 | 383 | 2830,2831 | House Regulators | $ 22,744,670 | $ 2,702 | $ 22,747,371 | 100% | $ 22,747,371 |
| 25 | 384 | 2840,2841 | House Regulator Installations | $ 16,889,144 | $ (196) | $ 16,888,948 | 100% | $ 16,888,948 |
| 26 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | $ 2,820,996 | $ (48) | $ 2,820,948 | 100% | $ 2,820,948 |
| 27 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | $ 728,946 | $ - | $ 728,946 | 100% | $ 728,946 |
| 28 | 387 | 2870 | Other Equipment - Other | $ 299,591 | $ (231) | $ 299,360 | 100% | $ 299,360 |
| 29 | 387 | 2871 | Street Lighting Equipment | $ 1,132,638 | $ (1,078) | $ 1,131,560 | 100% | $ 1,131,560 |
| 30 | 388 | | Gas ARO | $ 13,105,258 | $ (22,871) | $ 13,082,387 | 100% | $ 13,082,387 |
| 25 | | | Total Distribution Plant | $ 2,065,217,077 | $ (1,444,385) | $ 2,063,772,691 | | $ 2,063,772,690 |
| | | | **General Plant** | | | | | |
| 26 | 000 | 2030 | Miscellaneous Intangible Plant | $ 38,535,480 | $ (57,277) | $ 38,478,203 | 100% | $ 38,478,203 |
| 27 | 000 | 20301 | Miscellaneous Intangible Plant-Enable | $ 9,629,709 | $ (152,835) | $ 9,476,874 | 100% | $ 9,476,874 |
| 28 | 389 | 2890 | Land | $ - | $ - | $ - | 100% | $ - |
| 29 | 390 | 2900 | Structures & Improvements | $ 1,743,587 | $ 1,073 | $ 1,744,660 | 100% | $ 1,744,660 |
| 30 | 391 | 2910 | Office Furniture & Equipment | $ 374,759 | $ (4,935) | $ 369,824 | 100% | $ 369,824 |
| 31 | 391 | 2911 | Electronic Data Processing Equipment | $ 2,841,734 | $ (3,551) | $ 2,838,183 | 100% | $ 2,838,183 |
| 32 | 392 | 2920 | Transportation Equipment | $ 2,697,193 | $ (6,964) | $ 2,690,229 | 100% | $ 2,690,229 |
| 33 | 392 | 2921 | Trailers | $ 475,441 | $ 440 | $ 475,881 | 100% | $ 475,881 |
| 34 | 394 | 2940 | Tools, Shop & Garage Equipment | $ 12,426,179 | $ (11,238) | $ 12,414,941 | 100% | $ 12,414,941 |
| 35 | 395 | 2950 | Laboratory Equipment | $ 9,512 | $ 117 | $ 9,629 | 100% | $ 9,629 |
| 36 | 396 | 2960 | Power Operated Equipment | $ 66,838 | $ 397 | $ 67,235 | 100% | $ 67,235 |
| 37 | 397 | 2970 | Communication Equipment | $ 43,400,908 | $ (40,761) | $ 43,360,147 | 100% | $ 43,360,147 |
| 38 | 398 | 2980 | Miscellaneous Equipment | $ 41 970 | $ (109) | $ 41 861 | 100% | $ 41 861 |
| 39 | | | Total General Plant | $ 112 243 310 | $ (275 644) | $ 111 967 666 | | $ 111 967 667 |
| 40 | | | Total Gas Plant | $ 2 196 595 178 | $ (1 728 592) | $ 2 194 866 585 | | $ 2 194 866 585 |
| | | | **Common Plant** | | | | | |
| 41 | | 370 | Common AMI Meters | $ 78,660 | $ 5,259 | $ 83,919 | 100% | $ 83,919 |
| 42 | | 3010 | Organization | $ 60,936 | $ - | $ 60,936 | 100% | $ 60,936 |
| 43 | | 1030 | Miscellaneous Intangible Plant | $ 50,088,343 | $ 150,500 | $ 50,238,843 | 100% | $ 50,238,843 |
| 44 | | 1890 | Land and Land Rights | $ 2,241,719 | $ (313) | $ 2,241,406 | 100% | $ 2,241,406 |
| 45 | | 1891 | Rights of Way | $ 37,969 | $ - | $ 37,969 | 100% | $ 37,969 |
| 46 | | 1900 | Structures & Improvements | $ 203,544,186 | $ (175,584) | $ 203,368,602 | 100% | $ 203,368,602 |
| 47 | | 1910 | Office Furniture & Equipment | $ 10,014,274 | $ (15,383) | $ 9,998,891 | 100% | $ 9,998,891 |
| 48 | | 1911 | Electronic Data Processing | $ 130,625 | $ 1,801 | $ 132,426 | 100% | $ 132,426 |
| 49 | | 1920 | Transportation Equipment | $ 735,331 | $ (1,694) | $ 733,637 | 100% | $ 733,637 |
| 50 | | 1921 | Trailers | $ (688,110) | $ 3,029 | $ (685,081) | 100% | $ (685,081) |
| 51 | | 1930 | Stores Equipment | $ 469,805 | $ (639) | $ 469,166 | 100% | $ 469,166 |
| 52 | | 1940 | Tools, Shop & Garage Equipment | $ 2,708,934 | $ (885) | $ 2,708,049 | 100% | $ 2,708,049 |
| 53 | | 1950 | Laboratory Equipment | $ (0) | $ 61 | $ 61 | 100% | $ 61 |
| 54 | | 1960 | Power Operated Equipment | $ 111,852 | $ 110 | $ 111,962 | 100% | $ 111,962 |
| 55 | | 1970 | Communication Equipment | $ 95,565,793 | $ (68,028) | $ 95,497,766 | 100% | $ 95,497,766 |
| 56 | | 1980 | Miscellaneous Equipment | $ 1,046,650 | $ (1,577) | $ 1,045,073 | 100% | $ 1,045,073 |
| 57 | | 1990, 1991 | ARO Common General plant | $ 151 797 | $ (136) | $ 151 662 | 100% | $ 151 662 |
| 58 | | | Total Common Plant | $ 366,298,764 | $ (103,479) | $ 366,195,285 | | $ 366,195,287 |
| 59 | | 34 90% | Common Plant Allocated to Gas | $ 127,838,269 | $ (36,114) | $ 127,802,155 | 100% | $ 127,802,155 |
| 60 | | | Total Gas Plant Including Allocated Common | $ 2,324,433,447 | $ (1,764,706) | $ 2,322,668,740 | | $ 2,322,668,740 |

Notes and Source:
Col. A: Amounts from Exhibit I, Schedule B-2.1 from the Company's filing
Col. B: Page 2 of this schedule

**Duke Energy Ohio**
**Capital Expenditure Program**
**Plant In-Service Summary of Adjustments**

**Attachment LA-2**
**Schedule 1**
**Page 2 of 2**

| Line No. | FERC Account Number | Company Account Number | Account Title | Eastern Gas Operations Center - Employee Fitness Room | Enable Project Allocation | Remove Earnings Based Portion of Incentive and Stock-Based Compensation For CEP | Remove Earnings Based Portion of Incentive and Stock-Based Compensation Non-CEP | Recommended Adjustments |
|---|---|---|---|---|---|---|---|---|
| | | | | (1) | (2) | (3) | (4) | (5) |
| | | | **Manufactured Production Plant** | | | | | |
| 1 | 304 | 2040 | Land and Land Rights | | | | $ 6 | $ 6 |
| 2 | 304 | 2041 | Rights of Way | | | | $ - | $ - |
| 3 | 305 | 2050 | Structures & Improvements | | | | $ (3,860) | $ (3,860) |
| 4 | 311 | 2110 | Liquefied Petroleum Gas Equipment | | | | $ (4,412) | $ (4,412) |
| 5 | 320 | 2200 | Other Equipment | | | | $ (297) | $ (297) |
| 6 | | | Total Manufactured Gas Production Plant | $ - | $ - | $ - | $ (8 563) | $ (8 563) |
| | | | **Distribution Plant** | | | | | |
| 7 | 374 | 2740 | Land and Land Rights | | | $ (4,317) | $ (2,278) | $ (6,595) |
| 8 | 374 | 2741 | Rights of Way | | | $ 7 | $ 285 | $ 292 |
| 9 | 374 | 2742 | City Gate Check Station | | | $ - | $ - | |
| 10 | 375 | 2750 | Structures & Improvements | [redacted] | | $ (45,556) | $ 741 | [redacted] |
| 11 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | | | $ 180 | $ 6,397 | $ 6,577 |
| 12 | 376 | 2762, 65, 67, 69 | Mains - Steel | | | $ (138,724) | $ (130,008) | $ (268,732) |
| 13 | 376 | 2763, 2768 | Mains - Plastic | | | $ (172,427) | $ (248,836) | $ (421,263) |
| 14 | 378 | 2780 | System Meas. & Reg. Station Equipment | | | $ (63,404) | $ 10,644 | $ (52,760) |
| 15 | 378 | 2781 | System Meas. & Reg. Station Equip-Electronic | | | $ (6,073) | $ (5,002) | $ (11,076) |
| 16 | 378 | 2782 | District Regulating Equipment | | | $ (4,655) | $ 644 | $ (4,010) |
| 17 | 379 | 2790 | Meas. & Reg.- City Gate | | | $ (2,900) | $ (5,879) | $ (8,779) |
| 18 | 380 | 2801 | Services- Cast Iron & Copper | | | $ 4,705 | $ 3,102 | $ 7,806 |
| 19 | 380 | 2802, 2804, 2808 | Services-Steel | | | $ (8,101) | $ (9,170) | $ (17,271) |
| 20 | 380 | 2803, 05, 06, 07 | Services-Plastic | | | $ (271,917) | $ (143,630) | $ (415,547) |
| 21 | 381 | 2810,2811 | Meters | | | $ 17,626 | $ (3,215) | $ 14,411 |
| 22 | 381 | 2812 | Utility of the Future Meters | | | $ - | $ (52) | $ (52) |
| 23 | 382 | 2820,2821 | Meter Installations | | | $ 2,309 | $ 2,800 | $ 5,110 |
| 24 | 383 | 2830,2831 | House Regulators | | | $ 2,702 | $ - | $ 2,702 |
| 25 | 384 | 2840,2841 | House Regulator Installations | | | $ (196) | $ (0) | $ (196) |
| 26 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | | | $ (39) | $ (9) | $ (48) |
| 27 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | | | $ - | $ - | $ - |
| 28 | 387 | 2870 | Other Equipment - Other | | | $ - | $ (231) | $ (231) |
| 29 | 387 | 2871 | Street Lighting Equipment | | | $ 314 | $ (1,392) | $ (1,078) |
| 30 | 388 | | Gas ARO | | | | $ (22 871) | $ (22 871) |
| 25 | | | Total Distribution Plant | [redacted] | $ - | $ (690 468) | $ (547 960) | [redacted] |
| | | | **General Plant** | | | | | |
| 26 | 000 | 2030 | Miscellaneous Intangible Plant | | | $ (25,565) | $ (31,711) | $ (57,277) |
| 27 | 000 | 20301 | Miscellaneous Intangible Plant-Enable | | ($127,741) | $ (25,093) | $ (0) | $ (152,835) |
| 28 | 389 | 2890 | Land | | | | $ - | $ - |
| 29 | 390 | 2900 | Structures & Improvements | | | $ 753 | $ 321 | $ 1,073 |
| 30 | 391 | 2910 | Office Furniture & Equipment | | ($5,382) | | $ 447 | $ (4,935) |
| 31 | 391 | 2911 | Electronic Data Processing Equipment | | | $ (1,157) | $ (2,394) | $ (3,551) |
| 32 | 392 | 2920 | Transportation Equipment | | | | $ (6,964) | $ (6,964) |
| 33 | 392 | 2921 | Trailers | | | | $ 440 | $ 440 |
| 34 | 394 | 2940 | Tools, Shop & Garage Equipment | | | $ (10,930) | $ (309) | $ (11,238) |
| 35 | 395 | 2950 | Laboratory Equipment | | | $ 142 | $ (25) | $ 117 |
| 36 | 396 | 2960 | Power Operated Equipment | | | $ (2,620) | $ 3,016 | $ 397 |
| 37 | 397 | 2970 | Communication Equipment | | | $ (20,235) | $ (20,526) | $ (40,761) |
| 38 | 398 | 2980 | Miscellaneous Equipment | | | | $ (109) | $ (109) |
| 39 | | | Total General Plant | $ - | $ (133 123) | $ (84 706) | $ (57 815) | $ (275 644) |
| 40 | | | Total Gas Plant | [redacted] | $ (133 123) | $ (775 173) | $ (614 338) | [redacted] |
| | | | **Common Plant** | | | | | |
| 41 | | 0 | Common AMI Meters | | | | $ 5,259 | $ 5,259 |
| 42 | | 0 | Organization | | | | $ - | $ - |
| 43 | | 1030 | Miscellaneous Intangible Plant | | | | $ 150,500 | $ 150,500 |
| 44 | | 1890 | Land and Land Rights | | | | $ (313) | $ (313) |
| 45 | | 1891 | Rights of Way | | | | $ - | $ - |
| 46 | | 1900 | Structures & Improvements | | | | $ (175,584) | $ (175,584) |
| 47 | | 1910 | Office Furniture & Equipment | | | | $ (15,383) | $ (15,383) |
| 48 | | 1911 | Electronic Data Processing | | | | $ 1,801 | $ 1,801 |
| 49 | | 1920 | Transportation Equipment | | | | $ (1,694) | $ (1,694) |
| 50 | | 1921 | Trailers | | | | $ 3,029 | $ 3,029 |
| 51 | | 1930 | Stores Equipment | | | | $ (639) | $ (639) |
| 52 | | 1940 | Tools, Shop & Garage Equipment | | | | $ (885) | $ (885) |
| 53 | | 1950 | Laboratory Equipment | | | | $ 61 | $ 61 |
| 54 | | 1960 | Power Operated Equipment | | | | $ 110 | $ 110 |
| 55 | | 1970 | Communication Equipment | | | | $ (68,028) | $ (68,028) |
| 56 | | 1980 | Miscellaneous Equipment | | | | $ (1,577) | $ (1,577) |
| 57 | | 1990, 1991 | ARO Common General plant | | | | $ (136) | $ (136) |
| 58 | | | Total Common Plant | $ - | $ - | $ - | $ (103 479) | $ (103 479) |
| 59 | | 34 90% | Common Plant Allocated to Gas | | | | | $ (36 114) |
| 60 | | | Total Gas Plant Including Allocated Common | | | | | $ (1 764 706) |

Notes and Source:
Col. 1: Schedule 3
Col. 2: Schedule 4
Col. 3: Schedule 5
Col. 4: Schedule 6

**Duke Energy Ohio - Total Company**
**Accumulated Depreciation and Amortization**
**As of December 31, 2018**



| Line No. | FERC Account Number | Company Account Number | Account Title | Total Company Plant Investment (A) | Total Company Accumulated Depreciation (B) | Recommended Adjustments (C) | Adjusted Total Company Accumulated Depreciation (D) | Allocation (E) | Adjusted Total Company Accumulated Depreciation (F) |
|---|---|---|---|---|---|---|---|---|---|
| | | | **Manufactured Production Plant** | | | | | | |
| 1 | 304 | 2040 | Land and Land Rights | $ 474,364 | $ (1,991) | | $ (1,991) | 100% | $ (1,991) |
| 2 | 304 | 2041 | Rights of Way | $ 4,147 | $ 4,148 | | $ 4,148 | 100% | $ 4,148 |
| 3 | 305 | 2050 | Structures & Improvements | $ 5,271,184 | $ 3,765,529 | | $ 3,765,529 | 100% | $ 3,765,529 |
| 4 | 311 | 2110 | Liquefied Petroleum Gas Equipment | $ 13,232,637 | $ 5,789,409 | | $ 5,789,409 | 100% | $ 5,789,409 |
| 5 | 320 | 2200 | Other Equipment | $ 143,896 | $ 34,582 | | $ 34,582 | 100% | $ 34,582 |
| 6 | | 108 | Retirement Work in Progress | $ - | $ (17,369) | | $ (17,369) | 100% | $ (17,369) |
| 7 | | | Total Manufactured Gas Production Plant | $ 19,126,228 | $ 9,574,308 | $ - | $ 9,574,308 | | $ 9,574,308 |
| | | | **Distribution Plant** | | | | | | |
| 8 | 374 | 2740 | Land and Land Rights | $ 2,657,425 | $ 3,385 | | $ 3,385 | 100% | $ 3,385 |
| 9 | 374 | 2741 | Rights of Way | $ 8,868,911 | $ 1,898,232 | | $ 1,898,232 | 100% | $ 1,898,232 |
| 10 | 374 | 2742 | City Gate Check Station | $ 3,663 | $ 287 | | $ 287 | 100% | $ 287 |
| 11 | 375 | 2750 | Structures & Improvements | $ 18,481,716 | $ 1,283,444 | [redacted] | $ 1,276,270 | 100% | $ 1,276,270 |
| 12 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | $ 4,810,908 | $ 1,579,343 | | $ 1,579,343 | 100% | $ 1,579,343 |
| 13 | 376 | 2762, 65, 67, 69 | Mains - Steel | $ 493,951,719 | $ 196,688,157 | | $ 196,688,157 | 100% | $ 196,688,157 |
| 14 | 376 | 2763, 2766, 2768 | Mains - Plastic | $ 773,207,687 | $ 179,492,754 | | $ 179,492,754 | 100% | $ 179,492,754 |
| 15 | 378 | 2780 | System Meas. & Reg. Station Equipment | $ 37,068,467 | $ 3,373,516 | | $ 3,373,516 | 100% | $ 3,373,516 |
| 16 | 378 | 2781 | System Meas. & Reg. Station Equipment-Elec | $ 8,173,112 | $ 5,265,458 | | $ 5,265,458 | 100% | $ 5,265,458 |
| 17 | 378 | 2782 | District Regulating Equipment | $ 6,301,752 | $ 2,582,431 | | $ 2,582,431 | 100% | $ 2,582,431 |
| 18 | 379 | 2790 | Meas. & Reg.- City Gate Station | $ 3,623,493 | $ 1,113,446 | | $ 1,113,446 | 100% | $ 1,113,446 |
| 19 | 380 | 2801 | Services- Cast Iron & Copper | $ 4,118,336 | $ 5,782,538 | | $ 5,782,538 | 100% | $ 5,782,538 |
| 20 | 380 | 2802,2804, 2804 | Services-Steel | $ 24,785,202 | $ 10,711,851 | | $ 10,711,851 | 100% | $ 10,711,851 |
| 21 | 380 | 2803,05, 06, 07 | Services-Plastic | $ 552,775,834 | $ 180,950,208 | | $ 180,950,208 | 100% | $ 180,950,208 |
| 22 | 381 | 2810,2811 | Meters | $ 40,091,128 | $ (3,755,689) | | $ (3,755,689) | 100% | $ (3,755,689) |
| 23 | 381 | 2812 | Utility of the Future Meters | $ 25,828 | $ 3,839 | | $ 3,839 | 100% | $ 3,839 |
| 24 | 382 | 2820,2821 | Meter Installations | $ 27,127,989 | $ 11,358,326 | | $ 11,358,326 | 100% | $ 11,358,326 |
| 25 | 383 | 2830,2831 | House Regulators | $ 22,747,371 | $ 4,138,524 | | $ 4,138,524 | 100% | $ 4,138,524 |
| 26 | 384 | 2840,2841 | House Regulator Installations | $ 16,888,948 | $ 6,112,209 | | $ 6,112,209 | 100% | $ 6,112,209 |
| 27 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | $ 2,820,948 | $ 1,994,371 | | $ 1,994,371 | 100% | $ 1,994,371 |
| 28 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | $ 728,946 | $ 612,114 | | $ 612,114 | 100% | $ 612,114 |
| 29 | 387 | 2870 | Other Equipment - Other | $ 299,360 | $ 236,814 | | $ 236,814 | 100% | $ 236,814 |
| 30 | 387 | 2871 | Street Lighting Equipment | $ 1,131,560 | $ 496,304 | | $ 496,304 | 100% | $ 496,304 |
| 31 | | 108 | Retirement Work in Progress | | $ (29,282,945) | | $ (29,282,945) | 100% | $ (29,282,945) |
| 32 | 388 | | Gas ARO | $ 13,082,387 | $ 3,652,293 | | $ 3,652,293 | 100% | $ 3,652,293 |
| 33 | | | Total Distribution Plant | $ 2,063,772,690 | $ 586,291,210 | [redacted] | $ 586,284,036 | | $ 586,284,036 |
| | | | **General Plant** | | | | | | |
| 34 | 000 | 2030 | Miscellaneous Intangible Plant | $ 38,478,203 | $ 23,420,208 | | $ 23,420,208 | 100% | $ 23,420,208 |
| 35 | 000 | 20301 | Miscellaneous Intangible Plant-Enable | $ 9,476,874 | $ 1,270,673 | $ (17,032) | $ 1,253,641 | 100% | $ 1,253,641 |
| 36 | 389 | 2890 | Land | $ - | $ - | | $ - | 100% | $ - |
| 37 | 390 | 2900 | Structures & Improvements | $ 1,744,660 | $ 810,567 | | $ 810,567 | 100% | $ 810,567 |
| 38 | 391 | 2910 | Office Furniture & Equipment | $ 369,824 | $ 174,047 | | $ 174,047 | 100% | $ 174,047 |
| 39 | 391 | 2911 | Electronic Data Processing Equipment | $ 2,838,183 | $ 1,001,148 | $ (1,435) | $ 999,713 | 100% | $ 999,713 |
| 40 | 392 | 2920 | Transportation Equipment | $ 2,690,229 | $ 495,561 | | $ 495,561 | 100% | $ 495,561 |
| 41 | 392 | 2921 | Trailers | $ 475,881 | $ 428,396 | | $ 428,396 | 100% | $ 428,396 |
| 42 | 394 | 2940 | Tools, Shop & Garage Equipment | $ 12,414,941 | $ 5,094,730 | | $ 5,094,730 | 100% | $ 5,094,730 |
| 43 | 395 | 2950 | Laboratory Equipment | $ 9,629 | $ (47,103) | | $ (47,103) | 100% | $ (47,103) |
| 44 | 396 | 2960 | Power Operated Equipment | $ 67,235 | $ 1,733 | | $ 1,733 | 100% | $ 1,733 |
| 45 | 397 | 2970 | Communication Equipment | $ 43,360,147 | $ 17,029,853 | | $ 17,029,853 | 100% | $ 17,029,853 |
| 46 | 398 | 2980 | Miscellaneous Equipment | $ 41,861 | $ 11,664 | | $ 11,664 | 100% | $ 11,664 |
| 47 | | 108 | Retirement Work in Progress | $ - | $ (115,172) | | $ (115,172) | 100% | $ (115,172) |
| 48 | | | Total General Plant | $ 111,967,667 | $ 49,576,304 | $ (18,467) | $ 49,557,837 | | $ 49,557,838 |
| 49 | | | Total Gas Plant | $ 2,194,866,585 | $ 645,441,823 | $ (25,642) | $ 645,416,181 | | $ 645,416,181 |
| | | | **Common Plant** | | | | | | |
| 50 | | 1900 | Structures & Improvements | $ 83,919 | | | $ - | 100% | $ - |
| 51 | | 1910 | Office Furniture & Equipment | $ 60,936 | | | $ - | 100% | $ - |
| 52 | | 1030 | Miscellaneous Intangible Plant | $ 50,238,843 | $ 49,852,772 | | $ 49,852,772 | 100% | $ 49,852,772 |
| 53 | | 1890 | Land and Land Rights | $ 2,241,406 | $ 106,000 | | $ 106,000 | 100% | $ 106,000 |
| 54 | | 1891 | Rights of Way | $ 37,969 | $ - | | $ - | 100% | $ - |
| 55 | | 1900 | Structures & Improvements | $ 203,368,602 | $ 46,804,957 | | $ 46,804,957 | 100% | $ 46,804,957 |
| 56 | | 1910 | Office Furniture & Equipment | $ 9,998,891 | $ 3,190,377 | | $ 3,190,377 | 100% | $ 3,190,377 |
| 57 | | 1911 | Electronic Data Processing | $ 132,426 | $ (72,053) | | $ (72,053) | 100% | $ (72,053) |
| 58 | | 1920 | Transportation Equipment | $ 733,637 | $ 115,516 | | $ 115,516 | 100% | $ 115,516 |
| 59 | | 1921 | Trailers | $ (685,081) | $ 1,477 | | $ 1,477 | 100% | $ 1,477 |
| 60 | | 1930 | Stores Equipment | $ 469,166 | $ 179,081 | | $ 179,081 | 100% | $ 179,081 |
| 61 | | 1940 | Tools, Shop & Garage Equipment | $ 2,708,049 | $ 877,498 | | $ 877,498 | 100% | $ 877,498 |
| 62 | | 1950 | Laboratory Equipment | $ 61 | $ (0) | | $ (0) | 100% | $ - |
| 63 | | 1960 | Power Operated Equipment | $ 111,962 | $ 62,658 | | $ 62,658 | 100% | $ 62,658 |
| 64 | | 1970 | Communication Equipment | $ 95,497,766 | $ 38,879,405 | | $ 38,879,405 | 100% | $ 38,879,405 |
| 65 | | 1980 | Miscellaneous Equipment | $ 1,045,073 | $ 256,427 | | $ 256,427 | 100% | $ 256,427 |
| 66 | | 1990, 1991 | Retirement Work in Progress - ARO | $ 151,662 | $ 381,831 | | $ 381,831 | 100% | $ 381,831 |
| 67 | | 108 | Retirement Work in Progress | $ - | $ (955,274) | | $ (955,274) | 100% | $ (955,274) |
| 68 | | | Total Common Plant | $ 366,050,432 | $ 139,680,672 | $ - | $ 139,680,672 | | $ 139,680,672 |
| | | | Common Plant Allocated to Gas | | | | | | |
| 69 | | 34.90% | Original Cost | $ 127,838,269 | | | | | |
| 70 | | 34.90% | Reserve | | $ 48,748,555 | | $ 48,748,555 | 100% | $ 48,748,555 |
| 71 | | | Total Gas Plant Including Allocated Common | $ 2,322,704,854 | $ 694,190,378 | $ (25,642) | $ 694,164,736 | | $ 694,164,736 |

Notes and Source:
Cols. A-B: Amounts from Exhibit I, Schedule B-3 from the Company's filing
Col. C: Page 2 of this schedule

**Duke Energy Ohio**
**Capital Expenditure Program**
**Accumulated Depreciation and Amortization Summary of Adjustments**



| Line No. | FERC Account Number | Company Account Number | Account Title | Eastern Gas Operations Center - Employee Fitness Room | Enable Project Allocation | Remove Earnings Based Portion of Incentive and Stock-Based Compensation For CEP | Remove Earnings Based Portion of Incentive and Stock-Based Compensation Non-CEP | Recommended Adjustments |
|---|---|---|---|---|---|---|---|---|
| | | | | (1) | (2) | (3) | (4) | (5) |
| | | | **Manufactured Production Plant** | | | | | |
| 1 | 304 | 2040 | Land and Land Rights | | | | | $ - |
| 2 | 304 | 2041 | Rights of Way | | | | | $ - |
| 3 | 305 | 2050 | Structures & Improvements | | | | | $ - |
| 4 | 311 | 2110 | Liquefied Petroleum Gas Equipment | | | | | $ - |
| 5 | 320 | 2200 | Other Equipment | | | | | $ - |
| 6 | | | Total Manufactured Gas Production Plant | $ - | | $ - | $ - | $ - |
| | | | **Distribution Plant** | | | | | |
| 7 | 374 | 2740 | Land and Land Rights | | | | | $ - |
| 8 | 374 | 2741 | Rights of Way | | | | | $ - |
| 9 | 374 | 2742 | City Gate Check Station | | | | | $ - |
| 10 | 375 | 2750 | Structures & Improvements | [redacted] | | | | [redacted] |
| 11 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | | | | | $ - |
| 12 | 376 | 2762, 65, 67, 69 | Mains - Steel | | | | | $ - |
| 13 | 376 | 2763, 2768 | Mains - Plastic | | | | | $ - |
| 14 | 378 | 2780 | System Meas. & Reg. Station Equipment | | | | | $ - |
| 15 | 378 | 2781 | System Meas. & Reg. Station Equip-Electronic | | | | | $ - |
| 16 | 378 | 2782 | District Regulating Equipment | | | | | $ - |
| 17 | 379 | 2790 | Meas. & Reg.- City Gate | | | | | $ - |
| 18 | 380 | 2801 | Services- Cast Iron & Copper | | | | | $ - |
| 19 | 380 | 2802, 2804, 2808 | Services-Steel | | | | | $ - |
| 20 | 380 | 2803, 05, 06, 07 | Services-Plastic | | | | | $ - |
| 21 | 381 | 2810,2811 | Meters | | | | | $ - |
| 22 | 381 | 2812 | Utility of the Future Meters | | | | | $ - |
| 23 | 382 | 2820,2821 | Meter Installations | | | | | $ - |
| 24 | 383 | 2830,2831 | House Regulators | | | | | $ - |
| 25 | 384 | 2840,2841 | House Regulator Installations | | | | | $ - |
| 26 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | | | | | $ - |
| 27 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | | | | | $ - |
| 28 | 387 | 2870 | Other Equipment - Other | | | | | $ - |
| 29 | 387 | 2871 | Street Lighting Equipment | | | | | $ - |
| 30 | 388 | | Gas ARO | | | | | $ - |
| 25 | | | Total Distribution Plant | [redacted] | | $ - | $ - | [redacted] |
| | | | **General Plant** | | | | | |
| 26 | 000 | 2030 | Miscellaneous Intangible Plant | | | | | $ - |
| 27 | 000 | 20301 | Miscellaneous Intangible Plant-Enable | | ($17,032) | | | $ (17,032) |
| 28 | 389 | 2890 | Land | | | | | $ - |
| 29 | 390 | 2900 | Structures & Improvements | | | | | $ - |
| 30 | 391 | 2910 | Office Furniture & Equipment | | ($1,435) | | | $ (1,435) |
| 31 | 391 | 2911 | Electronic Data Processing Equipment | | | | | $ - |
| 32 | 392 | 2920 | Transportation Equipment | | | | | $ - |
| 33 | 392 | 2921 | Trailers | | | | | $ - |
| 34 | 394 | 2940 | Tools, Shop & Garage Equipment | | | | | $ - |
| 35 | 395 | 2950 | Laboratory Equipment | | | | | $ - |
| 36 | 396 | 2960 | Power Operated Equipment | | | | | $ - |
| 37 | 397 | 2970 | Communication Equipment | | | | | $ - |
| 38 | 398 | 2980 | Miscellaneous Equipment | | | | | $ - |
| 39 | | | Total General Plant | $ - | $ (18,467) | $ - | $ - | $ (18,467) |
| 40 | | | Total Gas Plant | [redacted] | $ (18 467) | $ - | $ - | [redacted] |
| | | | **Common Plant** | | | | | |
| 41 | | 0 | Common AMI Meters | | | | | $ - |
| 42 | | 0 | Organization | | | | | $ - |
| 43 | | 1030 | Miscellaneous Intangible Plant | | | | | $ - |
| 44 | | 1890 | Land and Land Rights | | | | | $ - |
| 45 | | 1891 | Rights of Way | | | | | $ - |
| 46 | | 1900 | Structures & Improvements | | | | | $ - |
| 47 | | 1910 | Office Furniture & Equipment | | | | | $ - |
| 48 | | 1911 | Electronic Data Processing | | | | | $ - |
| 49 | | 1920 | Transportation Equipment | | | | | $ - |
| 50 | | 1921 | Trailers | | | | | $ - |
| 51 | | 1930 | Stores Equipment | | | | | $ - |
| 52 | | 1940 | Tools, Shop & Garage Equipment | | | | | $ - |
| 53 | | 1950 | Laboratory Equipment | | | | | $ - |
| 54 | | 1960 | Power Operated Equipment | | | | | $ - |
| 55 | | 1970 | Communication Equipment | | | | | $ - |
| 56 | | 1980 | Miscellaneous Equipment | | | | | $ - |
| 57 | | 1990, 1991 | ARO Common General plant | | | | | $ - |
| 58 | | | Total Common Plant | $ - | | $ - | $ - | $ - |
| 59 | | 34 90% | Common Plant Allocated to Gas | | | | | $ - |
| 60 | | | Total Gas Plant Including Allocated Common | | | | | $ (25 642) |

Notes and Source:
Col. 1: Schedule 3
Col. 2: Schedule 4

**Duke Energy Ohio**
**Capital Expenditure Program**
**Eastern Gas Operation Center - Employee Fitness Room**

**Attachment LA-2**
**Schedule No. 3**
**Page 1 of 2**

| Line No. | Description | Amount (A) |
|---|---|---|
| 1 | Remove Employee Fitness Room Construction Costs | [redacted] |
| 2 | Remove Employee Fitness Room Equipment | |
| 3 | Total Adjustment to Remove Employee Fitness Room Costs | |
| 4 | Adjustment to Deferred Depreciation Expense | [redacted] |
| 5 | Adjustment to Annualized Depreciation Expense | [redacted] |
| 6 | Adjustment to Post In-Service Carrying Costs | [redacted] |

Notes and Source:
Col. A: See Attachment LA-1, Schedule 5, page 1

**Duke Energy Ohio**
**Capital Expenditure Program**
**Eastern Gas Operation Center - Employee Fitness Room**



| Line No. | Description | Cumulative Total | Rate | Apr 2017 | May 2017 | Jun 2017 | Jul 2017 | Aug 2017 | Sep 2017 | Oct 2017 | Nov 2017 | Dec 2017 | Jan 2018 | Feb 2018 | Mar 2018 | Apr 2018 | May 2018 | Jun 2018 | Jul 2018 | Aug 2018 | Sep 2018 | Oct 2018 | Nov 2018 | Dec 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | ( R) | (S) | (T) | (U) | (W) | (V) |
| 1 | Fitness Center Cost | [redacted] | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Calculated Depreciation | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Calculated PISCC | | | | | | | | | | | | | | | | | | | | | | | |

Notes and Source
Col. A: See Attachment LA-1, Schedule 5, page 2

**Duke Energy Ohio**
**Capital Expenditure Program**
**Enable Project Allocation Factor**



| Line No. | Description | 2015 (A) | 2016 (B) | 2017 (C) | 2018 (D) | Total (E) | Reference |
|---|---|---|---|---|---|---|---|
| 1 | Total Charged to DE Ohio Gas Delivery | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 | |
| 2 | Divided by 5.43% (2014 CAM Allocation % Used) | 5.43% | 5.43% | 5.43% | 5.43% | | |
| 3 | Total Charged Across All Business Units | $ 30,777,252 | $ 76,355,683 | $ 124,267,684 | $ 4,623,818 | $ 236,024,436 | L1 / L2 |
| 4 | Multiplied by % from Each Year's CAM - Note A | 5.43% | 5.41% | 5.34% | 5.30% | | |
| 5 | Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 | L3 x L4 |
| 6 | Total Charged to DE Ohio Gas Delivery If % Updated Each Year | $ 1,671,205 | $ 4,130,842 | $ 6,635,894 | $ 245,062 | $ 12,683,004 | Line 5 |
| 7 | Total Charged to DE Ohio Gas Delivery | $ 1,671,205 | $ 4,146,114 | $ 6,747,735 | $ 251,073 | $ 12,816,127 | Line 1 |
| 8 | Difference in Allocation Methods | $ - | $ (15,271) | $ (111,841) | $ (6,011) | $ (133,123) | L6 - L7 |
| 9 | Adjustment to Deferred Depreciation Expense | | | | | $ (18,467) | Page 2 |
| 10 | Adjustment to Annualized Depreciation Expense | | | | | $ (13,852) | Depr Workpaper, p2 |
| 11 | Adjustment to Post In-Service Carrying Costs | | | | | $ (9,443) | Page 2 |

Notes and Source
Cols. A-E: See Attachment LA-1, Schedule 8, page 1

Note A: According to the response to LARKIN-DR-01-157, due to the complexity of Enable charging and the timing of the CAM spreadsheet, updating the percentage each year requires using the prior year's CAM

**Duke Energy Ohio**
**Capital Expenditure Program**
**Enable Project Allocation Factor**



| Line No. | Description | Cumulative Total | Rate | Aug 2017 | Sep 2017 | Oct 2017 | Nov 2017 | Dec 2017 | Jan 2018 | Feb 2018 | Mar 2018 | Apr 2018 | May 2018 | Jun 2018 | Jul 2018 | Aug 2018 | Sep 2018 | Oct 2018 | Nov 2018 | Dec 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) | ( R) | (S) |
| 1 | Enable Project Software | (127,741) | | $ (127,741) | | | | | | | | | | | | | | | | |
| 2 | Calculated Depreciation - FERC 303 | (17,032) | 10.00% | | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) | (1,065) |
| 3 | Enable Project Hardware | (5,382) | | $ (5,382) | | | | | | | | | | | | | | | | |
| 4 | Calculated Depreciation - FERC 391 | (1,435) | 20.00% | | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) | (90) |
| 5 | Total Calculated Depreciation | (18,467) | | | | | | | | | | | | | | | | | | |
| 6 | Calculated PISCC | (9 443) | 5.32% | $ (133,123) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) | (590) |

Notes and Source
Cols. A-S: See Attachment LA-1, Schedule 8, page 2

| Line No. | Description | FERC Account | Enable Project Costs | Percentage |
|---|---|---|---|---|
| 7 | Miscellaneous Intangible Plant | 303 | $ 12,297,982 | 95 96% |
| 8 | Electronic Data Processing | 391 | $ 518 136 | 4.04% |
| 9 | Total Enable Project Costs in CEP | | $ 12 816 118 | 100.00% |
| 10 | Difference in Allocation Methods | | $ (133,123) | |
| 11 | Percentage of Enable Project to FERC 303 | | 95 96% | |
| 12 | Difference in Allocation Methods to FERC 303 | | $ (127 741) | |
| 13 | Difference in Allocation Methods | | $ (133,123) | |
| 14 | Percentage of Enable Project to FERC 391 | | 4.04% | |
| 15 | Difference in Allocation Methods to FERC 391 | | $ (5 382) | |

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based CEP Related Incentive and Stock-Based Compensation**



| Line No. | FERC Account Number | Company Account Number | Account Title | Cumula ive Net CEP Plant Per Company | Ratio | Estimated Allocation of Earnings Based CEP Related Incentive and Stock-Based Compensation |
|---|---|---|---|---|---|---|
| | | | | (A) | (B) | (C) |
| | | | **Distribution Plant** | | | |
| 1 | 374 | 2740 | Land and Land Rights | $ 1,656,720 | 0.56% | $ (4,317) |
| 2 | 374 | 2741 | Rights of Way | $ (2,668) | 0.00% | $ 7 |
| 3 | 374 | 2742 | City Gate Check Station | $ - | 0.00% | $ - |
| 4 | 375 | 2750 | Structures & Improvements | $ 17,482,414 | 5.88% | $ (45,556) |
| 5 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | $ (69,225) | -0.02% | $ 180 |
| 6 | 376 | 2762, 65, 67, 69 | Mains - Steel | $ 53,235,690 | 17 90% | $ (138,724) |
| 7 | 376 | 2763, 2766, 2768 | Mains - Plas ic | $ 66,169,448 | 22 24% | $ (172,427) |
| 8 | 378 | 2780 | System Meas. & Reg. Station Equipment | $ 24,331,612 | 8.18% | $ (63,404) |
| 9 | 378 | 2781 | System Meas. & Reg. Station Equipment-Elec | $ 2,330,725 | 0.78% | $ (6,073) |
| 10 | 378 | 2782 | District Regulating Equipment | $ 1,786,290 | 0.60% | $ (4,655) |
| 11 | 379 | 2790 | Meas. & Reg. - City Gate | $ 1,113,061 | 0.37% | $ (2,900) |
| 12 | 380 | 2801 | Services- Cast Iron & Copper | $ (1,805,405) | -0.61% | $ 4,705 |
| 13 | 380 | 2802,2804, 2808 | Services-Steel | $ 3,108,808 | 1.05% | $ (8,101) |
| 14 | 380 | 2803,05, 06, 07 | Services-Plastic | $ 104,349,125 | 35 08% | $ (271,917) |
| 15 | 381 | 2810,2811 | Meters | $ (6,764,136) | -2.27% | $ 17,626 |
| 16 | 381 | 2812 | U ility of the Future Meters | $ - | 0.00% | $ - |
| 17 | 382 | 2820,2821 | Meter Installations | $ (886,267) | -0.30% | $ 2,309 |
| 18 | 383 | 2830 | House Regulators | $ (1,036,739) | -0.35% | $ 2,702 |
| 19 | 384 | 2840 | House Regulator Installa ions | $ 75,069 | 0.03% | $ (196) |
| 20 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | $ 15,089 | 0.01% | $ (39) |
| 21 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | $ - | 0.00% | $ - |
| 22 | 387 | 2870 | Other Equipment - Other | $ - | 0.00% | $ - |
| 23 | 387 | 2871 | Street Lighting Equipment | $ (120,401) | -0.04% | $ 314 |
| 24 | 390 | 2900 | Structures & Improvements | $ (288,800) | -0.10% | $ 753 |
| 25 | 394 | 2940 | Tools, Shop & Garage Equipment | $ 4,194,274 | 1.41% | $ (10,930) |
| 26 | 395 | 2950 | Laboratory Equipment | $ (54,460) | -0.02% | $ 142 |
| 27 | 396 | 2960 | Power Operated Equipment | $ 1,005,255 | 0.34% | $ (2,620) |
| 28 | 397 | 2970 | Communication Equipment | $ 7,765,141 | 2.61% | $ (20,235) |
| 29 | | | Total CEP Distribution Plant | $ 277 590,619 | | $ (723,357) |
| | | | **General Plant** | | | |
| 30 | 391 | 2911 | Electronic Data Processing | $ 444,124 | 0.15% | $ (1,157) |
| 31 | | 2030 | Miscellaneous Intangible Plant | $ 9,810,837 | 3.30% | $ (25,565) |
| 32 | | 20310 | Miscellaneous Intangible Plant - Enable | $ 9,629,709 | 3.24% | $ (25,093) |
| 33 | | | Total CEP General Plant | $ 19,884,671 | | $ (51,816) |
| 34 | | | CEP Plant In-Serivce | $ 297,475,290 | 100.00% | $ (775,173) |

Notes and Source:
Col. A: Amounts reflect the net of Exhibit J, Workpapers WP4.1 - Assets by FERC and WP4.2 - Retirements by FERC

| | | |
|---|---|---|
| 33 | Earnings Based Adjustment to Incentive and Stock-Based Compensation | $ (775,173) |

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based CEP Related Incentive and Stock-Based Compensation**



| Line No. | Description | Period | 2013 (A) | 2014 (B) | 2015 (C) | 2016 (D) | 2017 (E) | 2018 (F) |
|---|---|---|---|---|---|---|---|---|
| 1 | Gross Plant Incentives | Q1 | $ (38,054) | $ (32,371) | $ (22,749) | $ (18,575) | $ (16,036) | $ (17,151) |
| 2 | | Q2 | $ (46,675) | $ (30,797) | $ (29,984) | $ (35,701) | $ (35,130) | $ (11,289) |
| 3 | | Q3 | $ (38,800) | $ (41,067) | $ (35,771) | $ (19,004) | $ (58,095) | $ (31,292) |
| 4 | | Q4 | $ (66,353) | $ (49,963) | $ (34,222) | $ (34,147) | $ (30,101) | $ (24,691) |
| 5 | Cumulative Gross Plant Incentives | | $ (189,882) | $ (344,080) | $ (466,806) | $ (574,233) | $ (713,594) | $ (798,017) |
| 6 | Depreciation Expense | Q1 | $ (121) | $ (344) | $ (519) | $ (651) | $ (761) | $ (866) |
| 7 | | Q2 | $ (148) | $ (394) | $ (587) | $ (796) | $ (1,021) | $ (1,168) |
| 8 | | Q3 | $ (123) | $ (377) | $ (621) | $ (795) | $ (1,039) | $ (1,323) |
| 9 | | Q4 | $ (211) | $ (580) | $ (847) | $ (1,064) | $ (1,268) | $ (1,442) |
| 10 | Accumulated Depreciation | Q1 | $ 121 | $ 947 | $ 2,818 | $ 5,523 | $ 8,939 | $ 13,133 |
| 11 | | Q2 | $ 269 | $ 1,341 | $ 3,405 | $ 6,319 | $ 9,959 | $ 14,301 |
| 12 | | Q3 | $ 392 | $ 1,718 | $ 4,026 | $ 7,114 | $ 10,999 | $ 15,624 |
| 13 | | Q4 | $ 603 | $ 2,298 | $ 4,873 | $ 8,178 | $ 12,267 | $ 17,066 |
| 14 | Accumulated Deferred Income Tax | Q1 | $ 50 | $ 383 | $ 1,106 | $ 2,088 | $ 3,245 | $ 4,581 |
| 15 | | Q2 | $ 110 | $ 538 | $ 1,322 | $ 2,365 | $ 3,580 | $ 4,935 |
| 16 | | Q3 | $ 161 | $ 686 | $ 1,554 | $ 2,640 | $ 3,924 | $ 5,353 |
| 17 | | Q4 | $ 247 | $ 914 | $ 1,865 | $ 3,004 | $ 4,327 | $ 5,777 |
| 18 | Total Adjustment to Net Rate Base | Q1 | $ (189,711) | $ (342,750) | $ (462,882) | $ (566,621) | $ (701,410) | $ (780,303) |
| 19 | | Q2 | $ (189,502) | $ (342,201) | $ (462,079) | $ (565,549) | $ (700,054) | $ (778,781) |
| 20 | | Q3 | $ (189,329) | $ (341,676) | $ (461,227) | $ (564,479) | $ (698,672) | $ (777,040) |
| 21 | | Q4 | $ (189,032) | $ (340,868) | $ (460,068) | $ (563,050) | $ (697,000) | **$ (775,173)** |

Notes and Source
Cols. A-F: See Attachment LA-1, Schedule 3

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based Non-CEP Incentive and Stock-Based Compensation**



| Line No. | FERC Account Number | Company Account Number | Account Title | Total Company Plant Balances 12/31/2012 (A) | Total Company Plant Balances 12/31/2018 (B) | Difference (C) | Ratio of Difference (D) | Estimated Non-CEP Adjustment to Incentive and Stock-Based Compensation |
|---|---|---|---|---|---|---|---|---|
| | | | **Manufactured Production Plant** | | | | | |
| 1 | 304 | 2040 | Land and Land Rights | $ 476,528 | $ 474,358 | $ (2,170) | 0.00% | $ 6 |
| 2 | 304 | 2041 | Rights of Way | $ 4,147 | $ 4,147 | $ - | 0.00% | $ - |
| 3 | 305 | 2050 | Structures & Improvements | $ 3,793,938 | $ 5,275,043 | $ 1,481,105 | 0.27% | $ (3,860) |
| 4 | 311 | 2110 | Liquefied Petroleum Gas Equipment | $ 11,543,916 | $ 13,237,049 | $ 1,693,134 | 0.31% | $ (4,412) |
| 5 | 320 | 2200 | Other Equipment | $ 30,095 | $ 144,194 | $ 114,099 | 0.02% | $ (297) |
| 6 | | | Total Manufactured Gas Production Plant | $ 15,848,624 | $ 19,134,791 | $ 3,286,168 | | $ (8,563) |
| | | | **Common Plant** | | | | | |
| 7 | | 0 | Common AMI Meters | $ 2,096,785 | $ 78,660 | $ (2,018,125) | -0.37% | $ 5,259 |
| 8 | | 0 | Organization | $ 60,936 | $ 60,936 | $ - | 0.00% | $ - |
| 9 | | 1030 | Miscellaneous Intangible Plant | $ 107,843,246 | $ 50,088,343 | $ (57,754,903) | -10.56% | $ 150,500 |
| 10 | | 1890 | Land and Land Rights | $ 2,121,647 | $ 2,241,719 | $ 120,072 | 0.02% | $ (313) |
| 11 | | 1891 | Rights of Way | $ 37,969 | $ 37,969 | $ - | 0.00% | $ - |
| 12 | | 1900 | Structures & Improvements | $ 136,163,238 | $ 203,544,186 | $ 67,380,948 | 12.32% | $ (175,584) |
| 13 | | 1910 | Office Furniture & Equipment | $ 4,111,003 | $ 10,014,274 | $ 5,903,272 | 1.08% | $ (15,383) |
| 14 | | 1911 | Electronic Data Processing | $ 821,780 | $ 130,625 | $ (691,155) | -0.13% | $ 1,801 |
| 15 | | 1920 | Transportation Equipment | $ 85,311 | $ 735,331 | $ 650,019 | 0.12% | $ (1,694) |
| 16 | | 1921 | Trailers | $ 474,273 | $ (688,110) | $ (1,162,383) | -0.21% | $ 3,029 |
| 17 | | 1930 | Stores Equipment | $ 224,695 | $ 469,805 | $ 245,110 | 0.04% | $ (639) |
| 18 | | 1940 | Tools, Shop & Garage Equipment | $ 2,369,186 | $ 2,708,934 | $ 339,748 | 0.06% | $ (885) |
| 19 | | 1950 | Laboratory Equipment | $ 23,250 | $ (0) | $ (23,250) | 0.00% | $ 61 |
| 20 | | 1960 | Power Operated Equipment | $ 153,899 | $ 111,852 | $ (42,046) | -0.01% | $ 110 |
| 21 | | 1970 | Communication Equipment | $ 69,459,906 | $ 95,565,793 | $ 26,105,887 | 4.77% | $ (68,028) |
| 22 | | 1980 | Miscellaneous Equipment | $ 441,453 | $ 1,046,650 | $ 605,197 | 0.11% | $ (1,577) |
| 23 | | 1990, 1991 | ARO Common General plant | $ 99 735 | $ 151 797 | $ 52 062 | 0.01% | $ (136) |
| 24 | | | Total Common Plant | $ 326,588,312 | $ 366,298,764 | $ 39,710,453 | | $ (103,479) |
| 25 | | | Manufactured Gas Production Plant | $ 15,848,624 | $ 19,134,791 | $ 3,286,168 | 0.60% | $ (8,563) |
| 26 | | 34.90% | Common Plant Allocated to Gas | $ 113,979,321 | $ 127,838,269 | $ 13,858,948 | 2.53% | $ (36,114) |
| 27 | | | Total Distribution and General - see page 2 | $ 1,647,517,117 | $ 2,177,460,388 | $ 529,943,271 | 96 87% | $ (1,380,948) [A] |
| 28 | | | Total From Schedule B-2.1 | $ 1,777,345,062 | $ 2,324,433,448 | $ 547,088,386 | 100.00% | $ (1,425,625) |

Notes and Source
Cols. A-B: Amounts from Exhibit I, Workpaper WPB-2 3 from DEO's SFR filing

| | | | |
|---|---|---|---|
| 29 | | | Line 28<br>$ 547 088 386 |
| | Estimated Non-CEP Earnings Based Incentive and Stock-Based Compensation | $ (775,173) x | $ 297,475,290 = $ (1,425,625) |
| | | Sch. 5, page 1<br>Col. C | Sch. 5, page 1<br>Col. A |

[A]: See allocation to plant accounts on page 2

Attachment LA-2
Case No. 19-0791-GA-ALT
Page 13 of 13

**Duke Energy Ohio**
**Capital Expenditure Program**
**Remove Earnings Based Non-CEP Incentive and Stock-Based Compensation**

**Attachment LA-2**
**Schedule 6**
**Page 2 of 2**

| Line No. | FERC Account Number | Company Account Number | Account Title | Total Company Plant Balances 12/31/2012 (A) | Total Company Plant Balances 12/31/2018 (B) | Difference (C) | Ratio of Difference (D) | Estimated Allocation of Earnings Based CEP Related Incentive and Stock-Based Compensation (E) | Less Estimated Incentive and Stock-Based Compensation in CEP Plant (F) | Estimated Earnings Based Incentive and Stock-Based Compensation in Non-CEP Accounts (G) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Distribution Plant** | | | | | | | |
| 1 | 374 | 2740 | Land | $ 133,008 | $ 2,664,021 | $ 2,531,013 | 0.46% | $ (6,595) | $ (4,317) | $ (2,278) |
| 2 | 374 | 2741 | Rights of Way | $ 8,980,609 | $ 8,868,619 | $ (111,990) | -0.02% | $ 292 | $ 7 | $ 285 |
| 3 | 374 | 2742 | City Gate Check Station | $ 3,663 | $ 3,663 | $ - | 0.00% | $ - | $ - | $ - |
| 4 | 375 | 2750 | Structures & Improvements | $ 1,534,498 | $ 18,732,489 | $ 17,197,991 | 3.14% | $ (44,815) | $ (45,556) | $ 741 |
| 5 | 376 | 2761, 2764 | Mains - Cast Iron & Copper | $ 7,328,447 | $ 4,804,331 | $ (2,524,116) | -0.46% | $ 6,577 | $ 180 | $ 6,397 |
| 6 | 376 | 2762, 65, 67, 69 | Mains - Steel | $ 391,093,612 | $ 494,220,451 | $ 103,126,839 | 18.85% | $ (268,732) | $ (138,724) | $ (130,008) |
| 7 | 376 | 2763, 2768 | Mains - Plastic | $ 611,967,740 | $ 773,628,950 | $ 161,661,210 | 29.55% | $ (421,263) | $ (172,427) | $ (248,836) |
| 8 | 378 | 2780 | System Meas. & Reg. Station Equipment - General | $ 16,874,426 | $ 37,121,227 | $ 20,246,801 | 3.70% | $ (52,760) | $ (63,404) | $ 10,644 |
| 9 | 378 | 2781 | System Meas. & Reg. Station Equipment - Electronic | $ 3,933,889 | $ 8,184,188 | $ 4,250,298 | 0.78% | $ (11,076) | $ (6,073) | $ (5,002) |
| 10 | 378 | 2782 | District Regulating Equipment | $ 4,766,775 | $ 6,305,762 | $ 1,538,987 | 0 28% | $ (4,010) | $ (4,655) | $ 644 |
| 11 | 379 | 2790 | Meas. & Reg - City Gate | $ 263,232 | $ 3,632,273 | $ 3,369,041 | 0.62% | $ (8,779) | $ (2,900) | $ (5,879) |
| 12 | 380 | 2801 | Services- Cast Iron & Copper | $ 7,106,296 | $ 4,110,530 | $ (2,995,766) | -0.55% | $ 7,806 | $ 4,705 | $ 3,102 |
| 13 | 380 | 2802, 2804, 2808 | Services-Steel | $ 18,174,607 | $ 24,802,473 | $ 6,627,867 | 1 21% | $ (17,271) | $ (8,101) | $ (9,170) |
| 14 | 380 | 2803, 05, 06, 07 | Services-Plastic | $ 393,723,747 | $ 553,191,382 | $ 159,467,634 | 29.15% | $ (415,547) | $ (271,917) | $ (143,630) |
| 15 | 381 | 2810,2811 | Meters | $ 45,606,905 | $ 40,076,717 | $ (5,530,188) | -1.01% | $ 14,411 | $ 17,626 | $ (3,215) |
| 16 | 381 | 2812 | Utility of the Future Meters | $ 6,069 | $ 25,879 | $ 19,810 | 0.00% | $ (52) | $ - | $ (52) |
| 17 | 382 | 2820, 2821 | Meter Installations | $ 29,083,834 | $ 27,122,879 | $ (1,960,955) | -0.36% | $ 5,110 | $ 2,309 | $ 2,800 |
| 18 | 383 | 2830, 2831 | House Regulators | $ 23,781,409 | $ 22,744,670 | $ (1,036,739) | -0.19% | $ 2,702 | $ 2,702 | $ - |
| 19 | 384 | 2840, 2841 | House Regulator Installations | $ 16,814,075 | $ 16,889,144 | $ 75,069 | 0.01% | $ (196) | $ (196) | $ (0) |
| 20 | 385 | 2850 | Large Industrial Meas. & Reg. Equipment | $ 2,802,486 | $ 2,820,996 | $ 18,510 | 0.00% | $ (48) | $ (39) | $ (9) |
| 21 | 385 | 2851 | Large Industrial Meas. & Reg. Equipment - Comm | $ 728,946 | $ 728,946 | $ - | 0.00% | $ - | $ - | $ - |
| 22 | 387 | 2870 | Other Equipment - Other | $ 210,891 | $ 299,591 | $ 88,700 | 0.02% | $ (231) | $ - | $ (231) |
| 23 | 387 | 2871 | Street Lighting Equipment | $ 718,965 | $ 1,132,638 | $ 413,673 | 0.08% | $ (1,078) | $ 314 | $ (1,392) |
| 24 | 388 | | Gas ARO | $ 4,328,442 | $ 13,105,258 | $ 8,776,816 | 1.60% | $ (22,871) | | $ (22,871) |
| 25 | | | Total Distribution Plant | $ 1,589,966,573 | $ 2,065,217,077 | $ 475,250,504 | | $ (1,238,427) | $ (690,468) | $ (547,960) |
| | | | **General Plant** | | | | | | | |
| 26 | 000 | 2030 | Miscellaneous Intangible Plant | $ 16,555,356 | $ 38,535,480 | $ 21,980,124 | 4.02% | $ (57,277) | $ (25,565) | $ (31,711) |
| 27 | 000 | 20301 | Miscellaneous Intangible Plant-Enable | $ - | $ 9,629,709 | $ 9,629,709 | 1.76% | $ (25,093) | $ (25,093) | $ (0) |
| 28 | 389 | 2890 | Land | $ - | $ - | $ - | 0.00% | $ - | | $ - |
| 29 | 390 | 2900 | Structures & Improvements | $ 2,155,534 | $ 1,743,587 | $ (411,946) | -0.08% | $ 1,073 | $ 753 | $ 321 |
| 30 | 391 | 2910 | Office Furniture & Equipment | $ 546,203 | $ 374,759 | $ (171,444) | -0.03% | $ 447 | | $ 447 |
| 31 | 391 | 2911 | Electronic Data Processing Equipment | $ 1,479,011 | $ 2,841,734 | $ 1,362,723 | 0 25% | $ (3,551) | $ (1,157) | $ (2,394) |
| 32 | 392 | 2920 | Transportation Equipment | $ 24,590 | $ 2,697,193 | $ 2,672,603 | 0.49% | $ (6,964) | | $ (6,964) |
| 33 | 392 | 2921 | Trailers | $ 644,188 | $ 475,441 | $ (168,747) | -0.03% | $ 440 | | $ 440 |
| 34 | 394 | 2940 | Tools, Shop & Garage Equipment | $ 8,113,493 | $ 12,426,179 | $ 4,312,686 | 0.79% | $ (11,238) | $ (10,930) | $ (309) |
| 35 | 395 | 2950 | Laboratory Equipment | $ 54,460 | $ 9,512 | $ (44,948) | -0.01% | $ 117 | $ 142 | $ (25) |
| 36 | 396 | 2960 | Power Operated Equipment | $ 219,039 | $ 66,838 | $ (152,201) | -0.03% | $ 397 | $ (2,620) | $ 3,016 |
| 37 | 397 | 2970 | Communication Equipment | $ 27,758,671 | $ 43,400,908 | $ 15,642,237 | 2 86% | $ (40,761) | $ (20,235) | $ (20,526) |
| 38 | 398 | 2980 | Miscellaneous Equipment | $ - | $ 41 970 | $ 41 970 | 0.01% | $ (109) | | $ (109) |
| 39 | | | Total General Plant | $ 57,550,544 | $ 112,243,311 | $ 54,692,767 | | $ (142,521) | $ (84,706) | $ (57,815) |
| 40 | | | Total Distribution and General Plant | $ 1,647,517,117 | $ 2,177,460,388 | $ 529,943,271 | 96 87% | $ (1,380,948) [A] | $ (775,173) | $ (605,775) |

Notes and Source:
Cols. A-B: Amounts from Exhibit I, Workpaper WPB-2.3 from DEO's SFR filing
Col. C: Col. B - Col. A
Col. F: See Schedule 3, page 3
Col. G: Col. E - Col. F

[A]: Distribution and General amount from page 1

# Attachment LA-3: Data Request Listing

**Case No. 19-0791-GA-ALT**
**Plant in Service and Capital Spending Prudence Audit**
**Of Duke Energy Ohio, Inc. (Natural Gas)**

**Set 1 - Submitted on November 8, 2019**

As it applies to the review period, March 31, 2012 through December 31, 2018, please provide the following information and documents:

LA-DR-01-01. Refer to the electronic version of Exhibit I from the Company's Standard Filing Requirements (SFR) at the tab titled "WPB-2.3" Please provide the Company's historical plant records to which the amounts shown on WPB-2.3 can be traced to for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.

a. For each period indicated, please provide the requested plant information by individual account and sub-account.
b. Pursuant to part "a", identify the non-AMRP and non-Rider AU related plant in service as well as CEP-related expenditures and investments on an account by account basis.
c. For the historical plant records requested above, please include a breakdown between all additions, retirements, transfers and/or reclassifications (by account) that have occurred from March 31, 2012 through December 31, 2018.

LA-DR-01-02. Refer to the electronic version of Exhibit I from the Company's SFRs at the tab titled "WPB-3.3." Please provide the Company's historical depreciation reserve records for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018:

a. For each period indicated, please provide the requested depreciation reserve balance information by individual account and sub-account.
b. Pursuant to part "a", identify the non-AMRP and non-Rider AU related depreciation reserve balances as well as CEP-related depreciation reserve balances on an account by account basis.
c. For the historical depreciation reserve records requested above, please include a breakdown between all accruals, salvage, retirements, cost of removal and transfers and/or reclassifications (by account) that have occurred from March 31, 2012 through December 31, 2018.

LA-DR-01-03. Refer to the electronic version of Exhibit I from the Company's SFRs at the tab titled "Sch._B-3.2_Proposed."

a. Were the depreciation rates shown under column F - Current Accrual Rate" authorized by the Commission? If so, cite by Order date and docket.

b. Pursuant to part "a", if the depreciation rates that are reflected on the "Sch._B-3.2 Proposed" tab on Exhibit I were not authorized by the Commission, show how they were derived.

c. To the extent they're not reflected on the "Sch._B-3.2 Proposed" tab on Exhibit I, please provide the depreciation rates that were authorized during the period March 31, 2012 through December 31, 2018.

d. Were the depreciation rates shown on the "Sch._B-3.2 Proposed" tab under column F developed in a depreciation study? If so, provide a copy of that depreciation study. If not, explain fully why not.

LA-DR-01-04. Please provide the detailed monthly general ledger information for each year, 2012 through 2018, for each account identified in response to LA-DR-1.

LA-DR-01-05. Please provide the detailed monthly general ledger information for each year, 2012 through 2018, for each account identified in response to LA-DR-2.

LA-DR-01-06. Please provide the Company's continuing property records for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.

LA-DR-01-07. Please provide the Company's recorded depreciation expense that was associated with the CEP plant in-service assets for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.

LA-DR-01-08. Please provide the Company's recorded property tax expense by account that was associated with the CEP plant in-service assets for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.

LA-DR-01-09. Please provide the Company's capital budgeting and planning activities, including (1) forecasting methods, (2) risk assessment practices, and (3) prioritization methods for addressing risk.

LA-DR-01-10. Please provide the Company's capitalization policies that were in effect during the period March 31, 2012 through December 31, 2018.

LA-DR-01-11. Please provide the Company's Cost Allocation Manual(s) (CAM), or any other documentation that relates to the Company's cost allocation methodologies, that were in effect (including any changes that were implemented) during the period March 31, 2012 through December 31, 2018.

LA-DR-01-12. Please provide the Company's written guidelines and/or policies and procedures related to capital spending (i.e., plant additions, new construction, plant replacement and plant retirements) during the period March 31, 2012 through December 31, 2018.

LA-DR-01-13. Please provide any depreciation studies that were performed on behalf of the Company from which the depreciation rates in effect from March 31, 2012 through December 31, 2018 were based.

a. Please provide the relevant Commission Order(s) that approved the depreciation rates that were in effect between March 31, 2012 and December 31, 2018.

LA-DR-01-14. Please provide the Company's written guidelines and/or policies and procedures regarding the use of outside contractors (versus using Company personnel) as it relates to non-AMRP and non-Rider AU capital expenditures in general and specifically to during the period March 31, 2012 through December 31, 2018.

LA-DR-01-15. Did the Company have any cost containment strategies in place pursuant to the use of outside contractors as it relates to non-AMRP and non-Rider AU capital expenditures in general and specifically to during the period March 31, 2012 through December 31, 2018? Explain fully.

LA-DR-01-16. Please provide the Company's written guidelines and/or policies and procedures regarding the use of internal labor as it relates to non-AMRP and non-Rider AU capital expenditures in general and specifically to during the period March 31, 2012 through December 31, 2018.

LA-DR-01-17. Did the Company have any cost containment strategies in place pursuant to the use of internal labor as it relates to non-AMRP and non-Rider AU capital expenditures and assets during the period March 31, 2012 through December 31, 2018? Explain fully.

LA-DR-01-18. Please identify and provide all pertinent testimony and workpapers that were filed by DEO and/or any other intervenors pursuant to the establishment of the CEP and the deferral of the post in-service carrying costs (PISCC) for the period March 31, 2012 through December 31, 2018.

LA-DR-01-19. Please provide all of the Company's CEP related schedules reflecting the CEP formula, including but not limited to the Excel versions of Schedules 1-9 (and associated workpapers) that were filed on May 14, 2019, which relate to PISCC, depreciation expense, property tax expense and incremental revenue (pursuant to Case No. 13-2417-GA-UNC).

LA-DR-01-20. Please identify the Company personnel who are most familiar with each of the following aspects of CEP for the period March 31, 2012 through December 31, 2018:

a. Capital expenditure budgeting
b. Accounting
c. Depreciation
d. Ratemaking and cost recovery

LA-DR-01-21. Please identify all internal audits associated with the following for the period March 31, 2012 through December 31, 2018:

a. CEP
b. Capital expenditures
c. Continuing property records
d. Capitalization of costs
e. Accounting for overhead costs
f. Property taxes

LA-DR-01-22. Was any cost for incentive compensation or stock-based compensation charged to the CEP related capital expenditures or other costs?

a. If so, identify by amount and account, such incentive compensation or stock-based compensation included in the CEP for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.
b. Are any of the amounts identified in response to part "a" related to DEO's stock price, dividends or financial goals? If so, please identify, quantify and explain fully.

LA-DR-01-23. Was any cost for Supplemental Executive Retirement Program (SERP) expense charged to the CEP related capital expenditures or other costs?

a. If so, identify by amount and account, such SERP costs included in the CEP for each of the following periods: 3/31/2012, 12/31/2012, 12/31/2013, 12/31/2014, 12/31/2015, 12/31/2016, 12/31/2017 and 12/31/2018.

## Set 2 - Submitted on November 27, 2019

LA-DR-01-24. General Ledger Detail. Refer to the response to LARKIN-DR-01-004.

a. Referring to the tab titled "Recon DR-4" on the attachment to this response, please explain fully and in detail the nature of the adjustment in the amount of $4,983,541 in 2014 that is shown under the column "Adjustments - booked GL only".

b. Referring to the tab titled "Recon DR-4" on the attachment to this response, please explain fully and in detail the nature of the adjustment in the amount of $23,065,474 in 2015 that is shown under the column "Adjustments to FERC Page Gas & Common".

c. Referring to the tab titled "Recon DR-4" on the attachment to this response, please explain fully and in detail the variance in the amount of $111,003 that is between the amounts reflected in the Company's 2012 FERC Form 1 and on WPB-2.3 for 2012 in the Company's SFR filing.

d. For each year 2012 through 2018, please identify the accounting system that the Company used for its general ledger function.

LA-DR-01-25. General Ledger Detail. Refer to the response to LARKIN-DR-01-005.

a. Referring to the tab titled "Recon DR-5" on the attachment to this response, please explain fully and in detail the nature of the adjustment in the amount of $97,413 in 2014 that is shown under the column "Adjustments - booked GL only".

b. Referring to the tab titled "Recon DR-5" on the attachment to this response, please explain fully and in detail the nature of each of the adjustments from April 1, 2012 through December 31, 2018 that total $32,503,104 and which are shown under the column "Adjustments to FERC Page Gas & Common".

c. Referring to the tab titled "Recon DR-5" on the attachment to this response, please explain fully and in detail the variance in the amount of $17,052 that is between the amounts reflected in the Company's 2018 FERC Form 1 and on WPB-2.3 for 2018 in the Company's SFR filing.

LA-DR-01-26. Depreciation Expense. Refer to the response to LARKIN-DR-01-007 and Exhibit J - Additional Schedules Supporting the Application.

a. Referring to Exhibit J on the tab titled SCH 5a - Def Dep - Dist Impr, please explain fully and in detail why there was $0 depreciation expense reflected as of March 31, 2012 and December 31, 2012.

b. Referring to Exhibit J on the tab titled SCH 5b - Def Dep - Info Tech, please explain fully and in detail why there was $0 depreciation expense as of March 31, 2012, December 31, 2012, December 31, 2013 and December 31, 2014.

LA-DR-01-27. Property Tax Expense. Refer to the response to LARKIN-DR-01-008 and Exhibit J - Additional Schedules Supporting the Application.

a. Referring to Exhibit J on the tab titled SCH 7 - Deferred Property Tax, please explain fully and in detail why there was $0 property tax expense reflected as of March 31, 2012, December 31, 2012 and December 31, 2013.

**<u>Set 3 - Submitted on December 13, 2019</u>**

LA-DR-01-28. Internal Audit Reports. Refer to the response to LARKIN-DR-01-021, which indicated that for the period March 31, 2012 through December 31, 2018, there were no internal audits conducted that related to (1) CEP, (2) capital expenditures, (3) continuing property records, (4) capitalization of costs, (5) accounting for overhead costs, and (5) property taxes.

a. Please provide a listing of all internal audits that were conducted by or of the Company in each year 2012 through 2019.

b. Please provide a listing of all internal audits that were conducted by or of any affiliates that charge costs to the Company in each year 2012 through 2019.

c. Please provide a listing of all of the Company's SOX compliance audits on internal controls that were conducted in each year 2012 through 2019.

d. Please provide a listing of all FERC audits that were conducted on the Company in each year 2012 through 2019.

LA-DR-01-29. Incentive Compensation. Refer to the response to LARKIN-DR-01-022.

a. Referring to the LARKIN-DR-01-022 Attachment, for 2013 please breakout each quarterly amount of incentive compensation shown (which totals $119,543) between the resource types listed in the response to LARKIN-DR-01-022.

b. Referring to the LARKIN-DR-01-022 Attachment, for 2014 please breakout each quarterly amount of incentive compensation shown (which totals $232,882) between the resource types listed in the response to LARKIN-DR-01-022.

c. Referring to the LARKIN-DR-01-022 Attachment, for 2015 please breakout each quarterly amount of incentive compensation shown (which totals $319,449) between the resource types listed in the response to LARKIN-DR-01-022.

d. Referring to the LARKIN-DR-01-022 Attachment, for 2016 please breakout each quarterly amount of incentive compensation shown (which totals $400,957) between the resource types listed in the response to LARKIN-DR-01-022.

e. Referring to the LARKIN-DR-01-022 Attachment, for 2017 please breakout each quarterly amount of incentive compensation shown (which totals $510,259) between the resource types listed in the response to LARKIN-DR-01-022.

f. Referring to the LARKIN-DR-01-022 Attachment, for 2018 please breakout each quarterly amount of incentive compensation shown (which totals $574,626) between the resource types listed in the response to LARKIN-DR-01-022.

g. Why was there no amount of incentive compensation charged to CEP related capital expenditures in 2012?

h. Please explain fully and in detail the Exec Short Term Incentive plan.

i. Please explain fully and in detail Phantom Stock.

j. Are any of the resource types listed in the response to LARKIN-DR-01-022 related to stock-based compensation? Explain fully.

LA-DR-01-30. Outside Contractors. Refer to the response to LARKIN-DR-01-014.

a. What is the basis for the Company's practice of employing outside contractors (versus using internal labor) to perform work on projects in which the pipe is greater than 100 feet in length and how was this 100 foot criteria determined? Explain fully.

b. Please explain fully and in detail all other criteria used by the Company (i.e., on projects which do not involve pipe) in determining whether to have internal crews work on capital projects or to have outside contractors work on such projects.

LA-DR-01-31. Outside Contractors. Refer to the response to LARKIN-DR-01-015.

a. What is the basis for the Company's practice of competitively bidding out work to four outside contractors to perform work on projects in which main extensions are 8,000 feet or less (for distribution mains)? In addition, how and when was this criteria determined? Explain fully.

b. Pursuant to the work described in part "a", please list the four outside contractors that the Company selects from and explain how these four contractors "won the right" to perform such work.

c. Please explain fully and in detail all other competitive bidding criteria used by the Company (other than the 8,000 feet or less for distribution mains criteria) in selecting outside contractors to work on CEP related projects.

d. Please quantify and elaborate in detail on the Company's statement that "we have set pricing for this work established in blanket contracts." Does this set pricing relate only to those four specific contractors, or to all outside contractors? Explain fully.

e. For those distribution main projects which are greater than 8,000 feet, please provide a list of the approved outside contractors that such projects are bid out to.

f. Please quantify the set pricing that is in place as it relates to the Ohio Service Line Replacement Program to replace copper and bare steel services.

g. Pursuant to part "d", when was the Ohio Service Line Replacement Program established and how does it impact the CEP program?

LA-DR-01-32. Internal Labor. Refer to the response to LARKIN-DR-01-017. As it relates to cost containment strategies for internal labor, please elaborate in detail on the Company's statement that "internal labor is managed project by project depending on deliverables and monitored through the approval of timesheets.

LA-DR-01-33. General Ledger Detail. Refer to the response to LARKIN-DR-01-004 and WPB-2.3a from the Company's SFR filing. We had requested that the Company provide its detailed monthly general ledger information for the gross additions, retirements and transfers listed on WPB-2.3a for each year 2012 through 2018. However, what was provided on the LARKIN-DR-01-004 Attachment appears to only be summary information for the following accounts:

| Account Number | Description |
|---|---|
| 101000 | Property, Plant, & Equipment |
| 101150 | Common Plant in Service |
| 101499 | Asset Retirement Obligations |
| 102100 | Electric Plant Purchased |
| 106000 | Comp Const Unclassified |
| 106102 | CCNC - Common |

a. For each account listed the table above and for each year 2012 through 2018, please provide the granular transaction general ledger detail which sums to the monthly amounts shown on the "GL BALANCE-PIS" tab on the LARKIN-DR-01-004 Attachment.

b. Referring to the LARKIN-DR-01-004 Attachment at the tab titled "Recon DR 4", please explain fully and in detail why the amounts recorded in the general ledger (and reported on page 200, line 8 of DEO's FERC Form 2) are different than the amounts reflected on

WPB-2.3a from the Company's filing (and reported on page 201, line 8 of DEO's FERC Form 2).

c. Please confirm that the amounts reflected on WPB-2.3a from the Company's filing will be reflected in the granular general ledger detail requested in part "a" above. If not confirmed, explain fully why not.

LA-DR-01-34. General Ledger Detail. Refer to the response to LARKIN-DR-01-005 and WPB-3.3a from the Company's SFR filing. We had requested that the Company provide its detailed monthly general ledger information for the depreciation reserve accruals, retirements and transfers listed on WPB-3.3a for each year 2012 through 2018. However, what was provided on the LARKIN-DR-01-005 Attachment appears to only be summary information for the following accounts:

| Account Number | Description |
|---|---|
| 108000 | Accumulated DD&A-PP&E |
| 108101 | Accum DD&A- Common PP&E |
| 108151 | Common Accum Dep - COR |
| 108301 | Accum Depreciation COR |
| 108499 | ARO Asset Accum Depreciation |
| 108552 | Non-Reg Plant in Svc Res Adj |
| 108600 | SCHM Retirement Wip |
| 108620 | RWIP - Reg Liab |
| 111100 | Acc Prov-Amor Plt In Ser |
| 111110 | Common Accum Amort |
| 111503 | Accum Amort - DENA |
| 115001 | Pur Acctg-Amort Pp&E |
| 115150 | Common Accum Dep-Pur Adj |

a. For each account listed the table above and for each year 2012 through 2018, please provide the granular transaction general ledger detail which sums to the monthly amounts shown on the "GL BALANCE-RESERVE" tab on the LARKIN-DR-01-005 Attachment.

b. Referring to the LARKIN-DR-01-005 Attachment at the tab titled "Recon DR 5", please explain fully and in detail why the amounts recorded in the general ledger (and reported on page 200, line 14 of DEO's FERC Form 2) are different than the amounts reflected on WPB-3.3a from the Company's filing (and reported on page 201, line 14 of DEO's FERC Form 2).

c. Please confirm that the amounts reflected on WPB-3.3a from the Company's filing will be reflected in the granular general ledger detail requested in part "a" above. If not confirmed, explain fully why not.

LA-DR-01-35. Work Order System. Refer to the capitalization policies that were provided in the confidential response to LARKIN-DR-01-010. Using the LARKIN-DR-01-010(e) confidential attachment as an example, the 2018 capitalization guidelines states the following at page 159: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Please provide in Excel format a list of all monthly work orders put in service by year, starting April 1, 2012 through December 31, 2018. Please identify the work orders as either IRP or CEP. 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, Growth, Support Services, Information Technology, etc.).
e. Work Order construction completion 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.

LA-DR-01-36. Work Order System. For each year 2012 through 2018 that the lists of work orders requested in LA-DR-35, 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. Please explain and reconcile any discrepancies. Identify, quantify and explain each reconciling item.

LA-DR-01-37. 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 retirements of a CEP project.

d. The accounting entry or entries to record the retirement of a non-CEP project, where the replacement is a CEP project.

e. The accounting entry or entries to record PISCC, depreciation expense on the closed assets, and incremental property taxes.

f. The accounting entries to retire a CEP project.

g. How CEP deferred projects are unitized.

LA-DR-01-38. Work Order Accounting. Please explain fully and in detail how the deferred CEP assets are moved to utility plant in service once the proper deferral has been established. Include the following accounting treatments:

a. How the proper accumulated depreciation reserve balance is determined. Adjusting the depreciation reserve based on using a composite rate of depreciation versus a FERC 300-account based depreciation rate.

b. How the assets are identified and categorized by FERC 300 account.

c. How retirements are identified and charged to the proper FERC 300 account reserve.

LA-DR-01-39. Work Order System. Please state whether the items listed on WPB-2.3a are included in the work order listing that was requested in LA-DR-35. If not, explain fully why not.

LA-DR-01-40. Historical Plant Records. Refer to the 2018 historical plant records provided in response to LARKIN-DR-01-001, WPB-2.3a and the table below.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| Account Number | Description | Per WPB-2.3a | Per Retirements in Plant Records (LA-DR-1) | Difference |
|---|---|---|---|---|
| | **Common - General Plant** | | | |
| 19000 | Structures and Improvements | $ (5,786,363) | $ (1,593,070) | $ (4,193,293) |
| 19100 | Office Furniture and Equipment | $ (350,839) | $ (38,313) | $ (312,526) |
| 19700 | Communication Equipment | $ (1,197,179) | $ (477,600) | $ (719,579) |
| 19800 | Miscellaneous Equipment | $ (8,586) | $ - | $ (8,586) |
| | | | | |
| | **Gas Distribution Plant** | | | |
| 27401 | Rights of Way | $ (111,953) | $ - | $ (111,953) |
| 27500 | Structures and Improvements | $ 61,317 | $ - | $ 61,317 |
| | | | | |
| 27602 | Gas Mains - Dist Lines/Steel | | $ (328,492) | |
| 27605 | Gas Mains - Feeder Lines/St | | $ (198,754) | |
| | Total | $ (6,992,006) | $ (527,246) | $ (6,464,760) |
| | | | | |
| 27603 | Gas Mains - Dist Lines/Plas | $ (3,775,204) | $ (462,832) | $ (3,312,372) |
| 27800 | System Meas & Reg Station | $ (2,525,235) | $ (62,562) | $ (2,462,673) |
| 27801 | System M&R St. Electronic | $ (460,749) | $ - | $ (460,749) |
| 27802 | District Regulating Equipment | $ (405,506) | $ - | $ (405,506) |
| 27900 | Meas & Reg Sta Equip - City | $ (124,142) | $ (15,579) | $ (108,563) |
| | | | | |
| 28003 | Services - M-C Plastic | | $ (1,111,235) | |
| 28006 | Services C-M Plastic | | $ (282,533) | |
| | Total | $ (1,403,513) | $ (1,393,769) | $ (9,744) |
| | | | | |
| 28500 | Ind Meas & Reg St Equipment | $ (3,204) | $ - | $ (3,204) |
| | | | | |
| | **Gas - General Plant** | | | |
| 29000 | Structures and Improvements | $ (2,140) | $ - | $ (2,140) |
| 29100 | Office Furniture & Equipment | $ (181,031) | $ (30,740) | $ (150,291) |
| 29500 | Laboratory Equipment | $ (1,396) | $ - | $ (1,396) |
| 29700 | Communication Equipment | $ (3,652) | $ - | $ (3,652) |
| | | | | |
| | **Gas - Intangible Plant** | | | |
| 20300 | Miscellaneous Intangibles Pl | $ (6,560) | $ - | $ (6,560) |
| | | | | |
| | **Gas - Manufactured Plant** | | | |
| 20500 | Structures and Improvements | $ (39,372) | $ - | $ (39,372) |
| 21100 | Liquified Petroleum Gas Equip | $ (864,254) | $ (597,070) | $ (267,184) |

As shown in the table above, a number of significant differences were noted between the retirements listed in the 2018 plant records provided in the LARKIN-DR-01-001(g) Attachment and the retirements listed for 2018 on WPB-2.3a.

a. Please explain and reconcile these discrepancies. Identify, quantify and explain each reconciling item.

**Set 4 - Submitted on January 8, 2020**

LA-DR-01-41. Internal Audit Reports. Refer to the response to LARKIN-DR-01-021 and the confidential table below.

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

a. Please provide copies of the internal audit reports listed in the table above.

LA-DR-01-42. Rate of Return. Refer to Exhibit J - CEP Additional Schedules Supporting the Application, Schedule 1, line 20. Note A states: "Approved Pre-Tax Rate of Return set per Stipulation in Case No. 12-1685-GA-AIR. Upon the Tax Cut and Jobs Act of 2017 becoming law the Pre-Tax Rate of Return has been adjusted to reflect a reduction of the Corporate tax rate from 35% to 21%."

a. Based on Note A, please show how the 9.16% pre-tax rate of return was derived. Show detailed calculations.

LA-DR-01-43. Original Cost Retired. Refer to Exhibit J - CEP Additional Schedules Supporting the Application, Schedule 1, lines 2 and 6. Please explain fully and in detail why the original cost retired amount of $44,354,944 is reflected in both Plant in Service and Accumulation Provision for Depreciation.

LA-DR-01-44. Amortization of Regulatory Assets. Refer to Exhibit J - CEP Additional Schedules Supporting the Application, Schedule 1, line 22, which shows that the Amortization of Regulatory Assets amount of $1,142,538 was derived by multiplying the total regulatory assets of $44,981,818 by 2.54% and a reference to Note B. Note B states: "For purposes of this calculation Duke Energy Ohio used a composite depreciation rate calculated using data from the 2015 FERC Form 2."

a. Please show how the 2.54% composite depreciation rate was derived. Show detailed calculations.

b. Why did the Company use its 2015 FERC Form 2 data to calculate this composite depreciation rate as opposed to using (1) more recent FERC Form 2 data (e.g., from 2018), or (2) some other method of calculating an amortization rate.

c. Pursuant to part "b", please provide the composite depreciation rate using 2018 FERC Form 2 data. Show detailed calculations.

d. As soon the data is available, please provide the composite depreciation rate that would be derived using 2019 FERC Form 2 data. Show detailed calculations.

LA-DR-01-45. Major Additions or Replacements. Please provide a list with a description and total dollar amount of any major CEP additions and/or replacements placed into service during the period 2013 through 2018.

LA-DR-01-46. Timeline.

a. Please provide a timeline of major events that occurred from January 1, 2013 through December 31, 2018 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, system conversions, and upgrades.

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.

LA-DR-01-47. Refer to the response to LARKIN-DR-01-001, specifically the LARKIN-DR-01-001(h) Attachment and the table below, which lists the CEP projects included in the reconciliation that is on the Summary tab of the referenced attachment (and the net plant-in-service included in the Company's revenue requirement calculation per Schedule 1 of Exhibit J - Additional Schedules Supporting the Application).

| **Description** | **Year 2013** | **Year 2014** | **Year 2015** | **Year 2016** | **Year 2017** | **Year 2018** | **Ending Balance** |
|---|---|---|---|---|---|---|---|
| CEP Projects | 17,677,711 | 22,792,911 | 37,470,981 | 49,913,859 | 79,568,151 | 90,051,676 | 297,475,290 |
| % Increase | | 28.94% | 64.40% | 33.21% | 59.41% | 13.18% | |
| Source: LARKIN-DR-01-001(h) Attachment | | | | | | | |

a. Referring to the table above, please explain fully and in detail why the CEP expenditures increased by the percentages shown between 2013 and 2018.

b. For each year 2013 through 2018, please breakout the CEP expenditures in the table above by FERC account.

c. Please provide an explanation of the difference between CEP expenditures and non-AMRP and non-Rider AU capital expenditures.

d. How are CEP expenditures distinguished from non-AMRP and non-Rider AU capital expenditures in the Company's work management system? Explain fully.

e. How are CEP projects identified after placed in service in the plant account system?

f. How does the Company distinguish between Distribution and Transmission projects? In other words, what criteria does DEO use to determine whether its CEP expenditures are related to Distribution? Explain fully.

g. Referring to the LARKIN-DR-01-001(h) Attachment at the tab titled "Mains and Services", for each year 2013 through 2018, please reconcile the CEP related gross additions, retirements and transfers which total $224,998,440 to the CEP expenditures listed in the table above which total $297,475,290. Identify, quantify and explain each reconciling item.

LA-DR-01-48. For each year 2013 through 2018, please provide a summary of hazardous leaks per year for (1) mains, and (2) for service lines. Breakout by type of pipe material and by the following causes of failure: corrosion, equipment, excavation, materials and welds, natural forces, operations, and other outside forces.

a. For those leaks caused by excavation damages, please provide a breakout of such damages caused by (1) DEO hired contractors, (2) DEO internal labor, and (3) independent non-affiliated third party company excavations (such as, but not limited to, contractors installing fiber optic cable for telephone or cable companies).

b. For each of the excavation damaged-caused leaks that were caused by third-party nonaffiliated companies and their contractors, (1) identify the costs incurred by DEO related to the repair and/or replacement, (2) describe DEO's efforts to collect the costs from the party that was doing the excavation that caused the leak, (3) identify and quantify the amounts recovered by DEO from the nonaffiliated third party and/or contractor, and (4) show in detail how DEO accounted for (a) the amounts being sought for recovery and (b) the amounts actually recovered.

c. Pursuant to part "b", please provide a copy of DEO's procedures for identifying the party that caused excavation damage related leaks and for recouping the cost of repairs and/or replacement from the third party or contractor that was conducting the excavation.

LA-DR-01-49. Budget to Actual Variances. Refer to the electronic version of Exhibit J - CEP Additional Schedules Supporting the Application at the tab titled "SCH 4 - Monthly CEP Investments" and the table below.

| Budget Category | 12 Months Ended 12/31/2013 | 12 Months Ended 12/31/2014 | 12 Months Ended 12/31/2015 | 12 Months Ended 12/31/2016 | 12 Months Ended 12/31/2017 | 12 Months Ended 12/31/2018 | Total CEP Plant in Service |
|---|---|---|---|---|---|---|---|
| Distribution Improvement | $ 17,677,711 | $ 22,792,060 | $ 37,018,650 | $ 46,362,944 | $ 64,219,840 | $ 89,519,414 | $ 277,590,619 |
| Information Technology | $ - | $ 851 | $ 452 331 | $ 3 550 915 | $ 15 348 312 | $ 532 262 | $ 19 884 671 |
| Total CEP In-Service Activity - Net Assets | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 |

Source Schedule J - CEP Additional Supporting Schedules Supporting the Application, Schedule 4

a. For each year 2013 through 2018, please provide a comparison of the Company's budgeted CEP expenditures to the actual CEP expenditures that are reflected in the table above and provide explanations for any variances between the budgeted and actual amounts.

LA-DR-01-50. CEP Projects to Incremental Gas Plant in Service. Refer to the response to LARKIN-DR-01-001, specifically the Excel version of LARKIN-DR-01-001(h) Attachment and the table below.

| Description | Year 2013 | Year 2014 | Year 2015 | Year 2016 | Year 2017 | Year 2018 | Total |
|---|---|---|---|---|---|---|---|
| CEP Projects | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 |
| Incremental Gas Plant in Service | $ 100,768,771 | $ 89,447,347 | $ 82,267,149 | $ 85,659,204 | $ 77,916,397 | $ 97,170,571 | $ 533,229,439 |
| % of CEP Projects to Incremental Gas Plant in Service | 17 54% | 25 48% | 45 55% | 58 27% | 102 12% | 92 67% | 55 79% |
| Source: LARKIN-DR-01-001(h) Attachment | | | | | | | |

a. For the period 2013 through 2018, please explain fully and in detail the reasons for the fluctuations (in terms of the percentages reflected in the table above) in CEP projects to total incremental gas plant in service.

b. Referring to the summary tab in the LARKIN-DR-01-001(h) Attachment, please explain fully and in detail why the amounts listed on Excel rows 42-46 were excluded from the CEP expenditures.

c. Referring to the summary tab in the LARKIN-DR-01-001(h) Attachment, please explain fully and in detail what is embedded in the "Other" category at Excel row 47.

d. In addition to excluding production plant from Rider CEP (as indicated on Excel row 40), it also appears that the Company did not allocate any common plant to Rider CEP. Please confirm and explain fully why not. If not confirmed, identify where common plant has been included in Rider CEP.

LA-DR-01-51. Property Tax Expense. Refer to the electronic version of Exhibit J - CEP Additional Schedules Supporting the Application and the table below, which reflects the workpapers showing the Company's calculation of the estimated property tax deferrals for Distribution Improvement and Information Technology additions and retirements. With regard to the percentages shown under column A in the table below (which relate to Distribution Improvement additions), Note 1 on each of the referenced workpapers states: "Per Ohio Department of Taxation Annual Natural Gas Property Tax Report, Schedule C(2) for specific classes of plant."

**Case No. 19-0791-GA-ALT**
**Plant in Service and Capital Spending Prudence Audit**
**Of Duke Energy Ohio, Inc. (Natural Gas)**

| Company Workpaper | Description | % Good 2014 | DEO Avg. 2014 Personal Property Tax Rate |
|---|---|---|---|
| | | (A) | (B) |
| WP7.1 | 2013 CEP Investments - Property Taxes Expensed in 2014 | 98.3% | 9.7713% |
| WP7.2 | 2013 CEP Investments - Property Taxes Expensed in 2015 | 95.0% | 9.7713% |
| WP7.3 | 2013 CEP Investments - Property Taxes Expensed in 2016 | 91.7% | 9.8358% |
| WP7.4 | 2013 CEP Investments - Property Taxes Expensed in 2017 | 91.7% | 9.8358% |
| WP7.5 | 2013 CEP Investments - Property Taxes Expensed in 2018 | 91.7% | 9.8358% |
| WP7.6 | 2014 CEP Investments - Property Taxes Expensed in 2015 | 98.3% | 9.7713% |
| WP7.7 | 2013 CEP Investments - Property Taxes Expensed in 2016 | 95.0% | 9.8358% |
| WP7.8 | 2013 CEP Investments - Property Taxes Expensed in 2017 | 91.7% | 9.8358% |
| WP7.9 | 2013 CEP Investments - Property Taxes Expensed in 2018 | 91.7% | 9.8358% |
| WP7.10 | 2015 CEP Investments - Property Taxes Expensed in 2016 | 98.3% | 9.8358% |
| WP7.11 | 2015 CEP Investments - Property Taxes Expensed in 2017 | 95.0% | 9.8358% |
| WP7.12 | 2015 CEP Investments - Property Taxes Expensed in 2018 | 95.0% | 9.8358% |
| WP7.13 | 2016 CEP Investments - Property Taxes Expensed in 2017 | 98.3% | 9.8358% |
| WP7.14 | 2016 CEP Investments - Property Taxes Expensed in 2018 | 98.3% | 9.8358% |
| WP7.15 | 2017 CEP Investments - Property Taxes Expensed in 2018 | 98.3% | 9.8358% |

Source: Schedule J - CEP Additional Supporting Schedules Supporting the Application

a. Pursuant to Note 1, why do the percentages fluctuate between 98.3%, 95.0%, and 91.7% when each of the referenced workpapers list the same categories (e.g., lines 1-29 and lines 31-58 on each workpaper) of Distribution Improvement and Information Technology additions and retirements? Explain fully.

b. Why is "2014" indicated under the "% Good" column on each of the referenced workpapers despite different years of CEP investments being reflected on the workpapers?

c. For both the Distribution Improvement additions and retirements, please provide copies of the Ohio Department of Taxation Annual Natural Gas Property Tax Report(s), Schedule C(2) from which the "% Good" percentages noted in the table above (and the 15% shown for retirements) were derived.

d. Referring to column B in the table above, each of the referenced workpapers state that the property tax rates shown in column B are "Duke Energy Ohio's Average 2014 Personal Property Tax Rate". Based on the foregoing, (1) explain fully and in detail why two different rates (9.7713% and 9.8358%) are reflected as DEO's 2014 average personal property tax rate, and (2) why did the Company use the average 2014 average personal property tax rate for all years, including those unrelated to 2014? Explain fully.

e. Pursuant to part "d", please show how the 9.7713% and 9.8358% 2014 average personal property tax rates were derived. Show detailed calculations.

f. For each year 2015 through 2018, please provide DEO's average personal property tax rates and show how each rate was derived. Show detailed calculations.

LA-DR-01-52. Depreciation. Refer to the Direct Testimony of Company witness Brown and the electronic versions of (1) Exhibit I CEP Section A and B Schedules of Standard Filing Requirements at the tab titled "SCH_B-3.2_Proposed", and (2) Exhibit J - CEP Additional Schedules Supporting the Application at the tabs titled "SCH 5a - Def Dep - Distr Impr" and "SCH 5b - Def Dep - Info Tech". On page 7 (lines 16-18), Mr. Brown states: "Deferred expenses, such as deferred depreciation, deferred property taxes, and deferred post-in-service carrying costs, are amortized over the life of the underlying assets using current depreciation rates." In addition, Footnote 1 on Schedules 5a and 5b states "Utility Account specific depreciation rate approved in Case No. 12-1685-GA-AIR."

a. Please provide the relevant pages from the depreciation study (or other documentation) from Case No. 12-1685-GA-AIR, which reflects the Commission approved depreciation rates shown on Schedules 5a and 5b from Exhibit J.

b. Have depreciation rates been changed since the Commission's approval in Case No. 12-1685-GA-AIR?

c. If depreciation rates have been changed, please explain for each change, when the change was made, what the change was (i.e., new rates by FERC account), and whether it was approved by the Commission.

d. SCH 5b - Def Dep - Info Tech from Exhibit J indicates a depreciation rate of 20% for Miscellaneous Intangible Plant, but SCH_B-3.2_Proposed from Exhibit I indicates "Various" for Miscellaneous Intangible Plant. Please explain and reconcile this discrepancy.

## Set 5 - Submitted on January 10, 2020

LA-DR-01-53. Information Technology. Refer to the electronic version of Exhibit J - CEP Additional Schedules Supporting the Application at the tab titled "WP4.1 - Assets by FERC". With regard to Information Technology, the Company's filing reflects CEP expenditures in the following Company accounts: (1) 2911 - Electronic Data Processing, (2) 2030 -

Miscellaneous Intangible Plant, and (3) 20310 - Miscellaneous Intangible Plant - Enable.

a. Please describe fully and in detail how the investments in each of these accounts relate specifically to the CEP program.

b. Please confirm that the amounts deferred in these accounts fall under the following component of R.C. 4929.111: "any program to install, upgrade, or replace information technology systems." If not confirmed, explain fully why not.

c. If the response to part "b" is confirmed, explain in detail the information system(s) that were installed, upgraded or replaced during the period 2013 through 2018.

d. Pursuant to part "c", are the information systems(s) that were installed, upgraded or replaced during the period 2013 through 2018 related exclusively to CEP for DEO's natural gas operations, or are the system(s) also used by other divisions of DEO (e.g., electric operations)? Explain fully.

e. Pursuant to part "d", if the information systems are used by other divisions of DEO, please explain fully why the costs are included in CEP expenditures and provide a breakout (by percentage) of how the use of these systems are allocated among DEO's natural gas operations and other divisions.

LA-DR-01-54. Information Technology. Refer to the electronic version of Exhibit J - CEP Additional Schedules Supporting the Application at the tab titled "WP4.1 - Assets by FERC". With regard to Information Technology, the Company's filing reflects CEP expenditures in the following Company accounts: (1) 2911 - Electronic Data Processing, (2) 2030 - Miscellaneous Intangible Plant, and (3) 20310 - Miscellaneous Intangible Plant - Enable.

a. What is meant by Miscellaneous Intangible Plant - Enable? Explain fully.

b. The referenced workpaper indicates that amounts associated with Electronic Data Processing is recorded in FERC account 391. However, there is no FERC account designation for the aforementioned Miscellaneous Intangible Plant accounts. Please provide the FERC account(s) for these items.

c. Referring to the referenced workpaper, please explain fully and in detail the nature of the following Information Technology related CEP expenditures that occurred in August 2017: (1) $521,642 in Company account 2911, (2) $2,504,565 in Company account 2030, and (3) $8,417,983 in account 20310 for total CEP expenditures of $11,444,190.

LA-DR-01-55. CEP Deferral. Refer to (1) the electronic version of Exhibit J - CEP Additional Schedules Supporting the Application at the tab titled "WP4.1 - Assets by FERC", (2) page 4 (lines 5-6) of the Direct Testimony of Company witness Jay P. Brown, and (3) the Commission's Finding and Order dated October 1, 2014 in Case No. 13-2417-GA-UNC, *et al*. Page 11, Section 19 of the Commission's Finding and Order, which cites R.C. 4929.111, provides the criteria under which the CEP deferral may be implemented. The third such criteria states: "Any program reasonably and necessary to comply with any rules, regulations, or orders of the Commission or other governmental entity having jurisdiction."

a. For the period 2013 through 2018, are any of the deferred CEP expenditures listed on the referenced workpaper, for which the Company is requesting recovery, related to the criteria cited above from the Commission's Finding and Order? If not, explain fully why not.

b. If the answer to part "a" is "yes", please quantify and describe in detail each specific CEP investment (Distribution or Information Technology) listed on WP4.1 - Assets by FERC during the period 2013 through 2018 to which this criteria applies.

LA-DR-01-56. Outside Contractors. Refer to the responses to LARKIN-DR-01-014, LARKIN-DR-01-016 and LARKIN-DR-01-030. Please clarify whether these responses pertained to CEP expenditures during the period March 31, 2012 through December 31, 2018. If not, explain fully why not.

a. If the answer to the above is "no", please provide any written guidelines and/or policies or procedures regarding the use of outside contractors as it relates to CEP related expenditures during the period March 31, 2012 through December 31, 2018.

LA-DR-01-57. Outside Contractors. Refer to the response to LARKIN-DR-01-015. Please clarify whether this response pertains to CEP expenditures during the period March 31, 2012 through December 31, 2018. If not, explain fully why not.

a. If the answer to the above is "no", please explain whether the Company has any cost containment strategies in place pursuant to the use of outside contractors as it relates to CEP expenditures during the period March 31, 2012 through December 31, 2018.

LA-DR-01-58. Internal Labor. Refer to the responses to LARKIN-DR-01-017 and LARKIN-DR-01-032. Please clarify whether these responses pertained to CEP expenditures during the period March 31, 2012 through December 31, 2018. If not, explain fully why not.

a. If the answer to the above is "no", please explain whether the Company has any cost containment strategies in place pursuant to the use of internal labor as it relates to CEP expenditures during the period March 31, 2012 through December 31, 2018.

LA-DR-01-59. Tax Cut and Jobs Act of 2017 (TCJA). How has the TCJA effect been reflected in the Company's CEP revenue requirement? Quantify and explain fully.

LA-DR-01-60. AFUDC. For each year 2013 through 2018, please provide the AFUDC interest rate (debt and equity components) and show how it was derived. Show detailed calculations.

LA-DR-01-61. Insurance Recovery.

a. Have there been any significant events during the period 2013 through 2018 which resulted in an insurance claim recovery of $50,000 or greater related to Distribution or General plant? If so, (1) please provide a list of such events, (2) explain how each recovery was recorded on the Company's books, and (3) explain how it was reflected in the plant balances.

b. Are there any pending Distribution or General plant insurance claims as of December 31, 2018 that are not recorded or accrued that would be charged to capital? If so, please provide the type of recovery, estimated amount and when receipt of such recovery is expected.

LA-DR-01-62. Overhead and Indirect Costs. Please provide a list of all overheads (labor loadings, etc.) and any other indirect items charged to DEO CEP related work orders, including descriptions of the type of charge and how that charged item was applied (e.g., calculation with descriptions of factors used in the calculations).

LA-DR-01-63. Allocations. Refer to the electronic version of Exhibit I CEP Section A and B Schedules of Standard Filing Requirements and specifically the tabs titled "SCH_B-2.1" and "SCH_B-3.1". Both of these schedules indicate that 100% of DEO's investment is jurisdictional. To clarify, please confirm that none of the 300 series FERC accounts, including intangible plant (e.g., IT software) and general plant, are allocated to other DEO divisions (e.g., electric operations). If not confirmed, explain fully why not.

## Set 6 - Submitted on January 14, 2020

LA-DR-01-64. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2013 CEP projects.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200812 | 2013 | 200812 | Replacement | Y | $ | 5,907,986 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201301 | 2013 | 200812 | Replacement | Y | $ | 4,336,913 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201301 | 2013 | 201911 | Replacement | Y | $ | 2,819,775 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201301 | 2013 | 201910 | Replacement | Y | $ | 2,207,290 |
| 383 | 20063 | PURCHASE NEW GAS REGULATORS | CEP | 201212 | 2013 | 200412 | Replacement | Y | $ | 1,003,823 |
| 376 | G8592 | Chester Rd, Greenwood and Lippleman | CEP | 201304 | 2013 | 201501 | Replacement | N | $ | 192,273 |
| 376 | G9138 | Baltimore St & Girard Ave Corrosion | CEP | 201304 | 2013 | 201803 | Replacement | N | $ | 181,224 |
| 380 | 3MCNEW10 | Install New M-C 3" | CEP | 201301 | 2013 | 201611 | additions | Y | $ | 162,593 |
| 376 | G8870 | Old St Route 28 Slide Replacement | CEP | 201303 | 2013 | not_unitized | Replacement | N | $ | 144,480 |
| 376 | H0490 | Cooper Road Sidewalk Phase 2 | CEP | 201308 | 2013 | 201803 | Replacement | N | $ | 109,397 |
| 384 | 20064 | TO INCLUDE ALL LABOR MATERIALS AND | CEP | 201212 | 2013 | 200412 | Replacement | Y | $ | 93,874 |
| 378 | G9967 | Reg 402-Erie & Delta (Replace DR66) | CEP | 201311 | 2013 | not_unitized | Replacement | N | $ | 86,712 |
| 376 | H0167 | Cooper Rd Sidewalk PID 88828 | CEP | 201307 | 2013 | 201803 | Replacement | N | $ | 82,962 |
| 376 | G9974 | West Street Culvert Lebanon | CEP | 201306 | 2013 | 201803 | Replacement | N | $ | 81,767 |
| 378 | G9986 | Reg Station 207 Improvements | CEP | 201311 | 2013 | not_unitized | Replacement | N | $ | 57,637 |
| 376 | H0043 | Charity Street Bridge Replacement | CEP | 201306 | 2013 | 201804 | Replacement | N | $ | 47,489 |
| 382 | 20064 | TO INCLUDE ALL LABOR MATERIALS AND | CEP | 201212 | 2013 | 200412 | Replacement | Y | $ | 46,937 |
| 376 | G9206 | Kyles Station Rd at Yankee Rd Round | CEP | 201304 | 2013 | 201804 | Replacement | N | $ | 45,181 |
| 376 | G9427 | Jefferson, Willow & W Vorhees Readi | CEP | 201304 | 2013 | 201411 | Replacement | N | $ | 37,629 |
| 376 | H0300 | WAR-SR63/SR123 Connector | CEP | 201306 | 2013 | not_unitized | Replacement | N | $ | 35,437 |
| 376 | G8149 | STA 820 Inlet Piping | CEP | 201305 | 2013 | not_unitized | additions | N | $ | 33,944 |
| 376 | G8034 | GM emax 2941138 262 Main W | CEP | 201305 | 2013 | 201609 | additions | N | $ | 33,881 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201301 | 2013 | 201611 | additions | Y | $ | 31,352 |
| 376 | G8152 | STA 821 Inlet Piping | CEP | 201308 | 2013 | not_unitized | additions | N | $ | 30,684 |
| 376 | G9960 | Kleybolte Ave Normac Rpl | CEP | 201305 | 2013 | 201806 | Replacement | N | $ | 27,652 |
| 376 | G9108 | Disney Street | CEP | 201303 | 2013 | 201804 | Replacement | N | $ | 24,205 |
| 376 | G8150 | STA 820 Outlet Piping | CEP | 201305 | 2013 | not_unitized | additions | N | $ | 22,614 |
| 380 | 4CMNEW10 | Install New C-M 4" | CEP | 201301 | 2013 | 201911 | Replacement | Y | $ | 12,406 |
| 376 | H1237 | Rose Marie Main Replacement | CEP | 201312 | 2013 | not_unitized | Replacement | N | $ | 11,961 |
| 376 | H0664 | Liberty-Fairfield Rd Main Extension | CEP | 201310 | 2013 | 201609 | additions | N | $ | 11,540 |
| 380 | 4MCR10 | Replace M-C 4" - Ohio | CEP | 201302 | 2013 | 200812 | Replacement | Y | $ | 11,364 |
| 378 | H0284 | STA 637 Duck Creek - Pit Door Rpl | CEP | 201309 | 2013 | not_unitized | Replacement | N | $ | 11,353 |
| 380 | 6MCNEW10 | Install New M-C 6" | CEP | 201301 | 2013 | 201611 | additions | Y | $ | 11,324 |
| 380 | 4MCNEW10 | Install New M-C 4" | CEP | 201301 | 2013 | 201611 | Replacement | Y | $ | 10,235 |
| 376 | G9997 | MEA 6020 Kyles Station | CEP | 201309 | 2013 | 201406 | additions | N | $ | 9,280 |
| 376 | G9489 | 1 Letitia Amelia OH MEA | CEP | 201304 | 2013 | 201609 | additions | N | $ | 8,443 |
| 376 | H0512 | Install Main on Red Oak Ct | CEP | 201309 | 2013 | 201609 | additions | N | $ | 7,789 |
| 376 | H0617 | 6480 Hayes Rd Main Extension | CEP | 201310 | 2013 | 201609 | additions | N | $ | 7,469 |
| 380 | 3MCR10 | Replace M-C 3" - Ohio | CEP | 201301 | 2013 | 200812 | Replacement | Y | $ | 7,146 |
| 376 | G8153 | STA 821 Outlet Piping | CEP | 201308 | 2013 | not_unitized | Replacement | N | $ | 6,838 |
| 376 | G9078 | JT emax 3692484 Villages of Daybrk | CEP | 201303 | 2013 | 201609 | additions | N | $ | 6,420 |
| 376 | G9945 | JT 4025980 Carriage Hill Sec 6C | CEP | 201311 | 2013 | 201609 | additions | N | $ | 6,354 |
| 376 | 20075 | TO ACCUMULATE CREDITS TO PLANT FOR | CEP | 200901 | 2013 | 200107 | Replacement | Y | $ | (90,338) |

For each Project ID (work order) listed above, please provide the following information:

a. A detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).

b. Work Order justification and approval at the highest approval level available based on the nature of the work order.

c. Estimated in-service date and actual in-service date.

d. 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 10%.

e. 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, materials and supplies, transportation, and employee expenses.

f. 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:

- 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 Mark Dady or Ralph Smith directly at (734) 522-3420 or msdady@gmail.com and rsmithla@aol.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

LA-DR-01-65. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2014 CEP projects.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200812 | 2014 | 200812 | Replacement | Y | $ 6,396,177 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201401 | 2014 | 200812 | Replacement | Y | $ 3,761,314 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201401 | 2014 | 201910 | Replacement | Y | $ 2,635,014 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201401 | 2014 | 201911 | Replacement | Y | $ 1,687,633 |
| 383 | 20063 | PURCHASE NEW GAS REGULATORS | CEP | 201312 | 2014 | 200412 | Replacement | Y | $ 1,131,238 |
| 394 | 20073 | Purchase Gas Tools Blanket | CEP | 201001 | 2014 | 200408 | Replacement | Y | $ 961,536 |
| 376 | G8733 | CLE-SR 28-5 01/PID #87761 | CEP | 201402 | 2014 | not_unitized | Replacement | N | $ 602,758 |
| 376 | H0492 | HAM-CR 456-0 65 | CEP | 201405 | 2014 | not_unitized | Replacement | N | $ 456,653 |
| 376 | J0110 | Gest St | CEP | 201409 | 2014 | not_unitized | Replacement | N | $ 268,504 |
| 376 | H0848 | Stewart Rd Culvert Improvement | CEP | 201403 | 2014 | 201412 | Replacement | N | $ 157,298 |
| 376 | H0071 | Towne Blvd Widening | CEP | 201402 | 2014 | 201803 | Replacement | N | $ 124,945 |
| 376 | H0496 | HAM-128-0 00 PID #75890 | CEP | 201407 | 2014 | 201803 | Replacement | N | $ 106,816 |
| 376 | G9870 | Stock Ave CSO 012 Sewer Seperation | CEP | 201402 | 2014 | 201411 | Replacement | N | $ 100,819 |
| 376 | H0139 | Harrison Ave/Queen City Ave | CEP | 201311 | 2014 | 201803 | Replacement | N | $ 74,164 |
| 380 | 6MCNEW10 | Install New M-C 6" | CEP | 201403 | 2014 | 201611 | additions | Y | $ 70,106 |
| 376 | H0949 | JT emax 4298153 Carriage Hill Sec 7 | CEP | 201406 | 2014 | 201609 | additions | N | $ 57,826 |
| 376 | H0239 | West Chester Normac Replacement | CEP | 201312 | 2014 | 201803 | Replacement | N | $ 57,220 |
| 376 | G9250 | eMax 3550087 10100 Progress Way | CEP | 201303 | 2014 | 201609 | additions | N | $ 54,450 |
| 376 | G9989 | Improve Liberty Fairfield Road | CEP | 201310 | 2014 | 201803 | Replacement | N | $ 53,145 |
| 378 | H0001 | Reg Station #8L Improvements | CEP | 201408 | 2014 | not_unitized | Replacement | N | $ 52,013 |
| 376 | H1564 | JT 4341043 Oakley Commercial | CEP | 201412 | 2014 | not_unitized | additions | N | $ 51,647 |
| 376 | M2121 | Fifth St Reconstruction, City of Lo | CEP | 201408 | 2014 | not_unitized | Replacement | N | $ 51,247 |
| 376 | P6286 | Harrison Ave Improvements, Village | CEP | 201411 | 2014 | not_unitized | Replacement | N | $ 49,530 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201401 | 2014 | 201611 | additions | Y | $ 45,815 |
| 376 | H0424 | Al Neyer LLC Install 6" PL | CEP | 201403 | 2014 | 201609 | additions | N | $ 41,684 |
| 378 | H0002 | Reg Station #1M Improvements | CEP | 201407 | 2014 | not_unitized | Replacement | N | $ 31,484 |
| 380 | H1416 | 501 Race C-M | CEP | 201312 | 2014 | 201804 | additions | N | $ 30,527 |
| 376 | O7105 | Given Rd, Indian Hill MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 27,527 |
| 376 | G6985 | EMAX 3020988 Shaker Run 4B | CEP | 201408 | 2014 | 201502 | additions | N | $ 16,958 |
| 376 | H1510 | Ludlow Place Main Extension | CEP | 201404 | 2014 | not_unitized | additions | N | $ 16,805 |
| 376 | P6520 | Newtown Rd MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 15,010 |
| 376 | H0948 | JT emax 4298153 Carriage Hill Sec 5 | CEP | 201404 | 2014 | 201410 | additions | N | $ 14,549 |
| 376 | H4113 | JT 4767393 Sycamore Place Subd | CEP | 201405 | 2014 | 201609 | additions | N | $ 12,838 |
| 376 | H1006 | GM 4519899 Parks of Whitewater 2A | CEP | 201403 | 2014 | 201501 | additions | N | $ 12,195 |
| 376 | P6302 | Lynn St MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 11,927 |
| 376 | M2114 | JT 4857601 Windsor Estates Sec 3 | CEP | 201412 | 2014 | 201609 | additions | N | $ 11,436 |
| 376 | H0693 | JT emax 4420066 White Pillars Sec 3 | CEP | 201404 | 2014 | 201609 | additions | N | $ 11,212 |
| 376 | H1123 | Hunt Rd Main Extension | CEP | 201404 | 2014 | 201412 | additions | N | $ 11,195 |
| 376 | G9371 | JT emax 3814873 East Fork Crossing | CEP | 201312 | 2014 | 201609 | additions | N | $ 10,524 |
| 376 | H0231 | JT emax 4095788 Forest Glen Ph 2 | CEP | 201401 | 2014 | 201609 | additions | N | $ 10,393 |
| 376 | H0519 | JT emax 4323503 Woodbury Glen Subd | CEP | 201402 | 2014 | 201609 | additions | N | $ 8,255 |
| 376 | H1394 | JT 4620265 TRAILS OF SHAKER RUN ph4 | CEP | 201405 | 2014 | 201609 | additions | N | $ 7,991 |
| 376 | H0226 | JT emax 4172881 Knolls of Liberty | CEP | 201402 | 2014 | 201609 | additions | N | $ 7,182 |
| 376 | P6304 | Glen Willow Ln MEA | CEP | 201409 | 2014 | 201609 | additions | N | $ 6,893 |
| 380 | 6CMNEW10 | Install New C-M 6" | CEP | 201404 | 2014 | not_unitized | additions | Y | $ (13,088) |
| 376 | 20075 | TO ACCUMULATE CREDITS TO PLANT FOR | CEP | 200901 | 2014 | 200107 | Replacement | Y | $ (229,267) |

For each Project ID (work order) listed above, please provide the following information:

a. A detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).

b. Work Order justification and approval at the highest approval level available based on the nature of the work order.

c. Estimated in-service date and actual in-service date.

d. 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 10%.

e. 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.

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f. 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:

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LA-DR-01-66. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2015 CEP projects.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200912 | 2015 | 200812 | Replacement | Y | $ 7,129,967 |
| 376 | P6306 | Brent Spence Bridge Gas Main AM-01 | CEP | 201506 | 2015 | 201905 | Replacement | N | $ 5,319,534 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201501 | 2015 | 200812 | Replacement | Y | $ 3,440,471 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201501 | 2015 | 201910 | Replacement | Y | $ 2,733,791 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201501 | 2015 | 201911 | Replacement | Y | $ 2,115,448 |
| 376 | H1808 | Hilton - Davis Line "A" | CEP | 201510 | 2015 | 201907 | Replacement | N | $ 1,782,850 |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201504 | 2015 | not_unitized | Replacement | Y | $ 1,307,217 |
| 376 | P7220 | 20" HP Main Relocate on MLK | CEP | 201504 | 2015 | not_unitized | Replacement | N | $ 774,531 |
| 381 | INSREGREL | Install or Remove Regulator/Relief | CEP | 201504 | 2015 | not_unitized | Replacement | Y | $ 628,022 |
| 376 | Q2140 | REPLACE F/L 'EE' SEGMENT # 1100, CA | CEP | 201510 | 2015 | not_unitized | Replacement | N | $ 605,753 |
| 376 | G9887 | HAM-27-14 15 Part 1 PID 92555 | CEP | 201407 | 2015 | not_unitized | Replacement | N | $ 559,387 |
| 376 | P6196 | Monmouth Ave - Relocate Gas Pipe | CEP | 201501 | 2015 | 201911 | Replacement | N | $ 408,272 |
| 376 | P8043 | Greenshire Ph 1 Subdivison MEA | CEP | 201507 | 2015 | not_unitized | additions | N | $ 221,512 |
| 378 | K2103 | Zimmer Bypass | CEP | 201405 | 2015 | not_unitized | additions | N | $ 141,711 |
| 378 | H0035 | Reg 220 Improvements | CEP | 201412 | 2015 | not_unitized | Replacement | N | $ 134,580 |
| 376 | G9075 | MOD 506 Addition | CEP | 201409 | 2015 | not_unitized | additions | N | $ 134,014 |
| 376 | J9106 | White St, Lick Run Sewer Seperation | CEP | 201409 | 2015 | not_unitized | Replacement | N | $ 122,720 |
| 376 | O4141 | Dawson Rd | CEP | 201501 | 2015 | 201803 | Replacement | N | $ 112,545 |
| 378 | H1062 | REG 253 Modifications | CEP | 201501 | 2015 | not_unitized | Replacement | N | $ 83,396 |
| 376 | Q1124 | Rumpke Main Extension | CEP | 201507 | 2015 | 201609 | additions | N | $ 82,939 |
| 376 | G9687 | MOD 677 Addition Non-AMRP | CEP | 201411 | 2015 | not_unitized | Replacement | N | $ 77,374 |
| 376 | P8063 | Spring St, Bethel, OH 2" main repla | CEP | 201504 | 2015 | not_unitized | Replacement | N | $ 70,506 |
| 376 | Q8765 | AERONCA STREET MAIN REPLACEMENT | CEP | 201507 | 2015 | 201803 | Replacement | N | $ 67,739 |
| 376 | P7730 | West Tech Blvd MEA | CEP | 201505 | 2015 | 201609 | additions | N | $ 58,678 |
| 376 | P3103 | Elizabeth Dr, Batavia MEA | CEP | 201410 | 2015 | 201803 | additions | N | $ 54,320 |
| 376 | K5111 | Liberty Towne Center | CEP | 201505 | 2015 | not_unitized | additions | N | $ 53,103 |
| 376 | P7637 | Aston Rd MEA | CEP | 201504 | 2015 | 201609 | additions | N | $ 51,234 |
| 380 | 4CMNEW10 | Install New C-M 4" | CEP | 201501 | 2015 | 201911 | Replacement | Y | $ 45,946 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201501 | 2015 | 201611 | additions | Y | $ 43,944 |
| 376 | H0632 | Reg 404 - Inlet & Outlet | CEP | 201502 | 2015 | not_unitized | additions | N | $ 43,597 |
| 376 | R2896 | Compton Rd MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ 38,160 |
| 376 | P6145 | Morse Ave at Brandywine Dr - Bridge | CEP | 201412 | 2015 | 201804 | Replacement | N | $ 33,459 |
| 376 | O0130 | 800 W 5th St MEA | CEP | 201410 | 2015 | not_unitized | additions | N | $ 32,505 |
| 376 | Q3688 | Stonehouse Ln | CEP | 201511 | 2015 | not_unitized | Replacement | N | $ 28,970 |
| 376 | H1390 | STA 812 Outlet Piping | CEP | 201410 | 2015 | not_unitized | Replacement | N | $ 28,900 |
| 376 | R2897 | Potomac Ct MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ 27,954 |
| 376 | R2282 | Eastgate Brew and View Movie Theate | CEP | 201509 | 2015 | 201804 | Replacement | N | $ 24,167 |
| 376 | H1260 | MOD 476 Addition | CEP | 201412 | 2015 | not_unitized | Replacement | N | $ 20,060 |
| 376 | Q9760 | JT 7575703 Parks of Whitewater | CEP | 201509 | 2015 | not_unitized | additions | N | $ 19,732 |
| 376 | R0093 | Hoskins Ln MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ 19,498 |
| 376 | R0069 | JT 7611771 Birdhaven Subdivision | CEP | 201510 | 2015 | 201609 | additions | N | $ 19,304 |
| 376 | P7636 | Clermont Ln MEA | CEP | 201504 | 2015 | 201609 | additions | N | $ 12,628 |
| 376 | P6757 | T/L CG04 - Install Corrosion Monito | CEP | 201411 | 2015 | not_unitized | additions | N | $ 12,136 |
| 376 | P6495 | JT 6359913 Willows Bend Sect 3 | CEP | 201503 | 2015 | 201609 | additions | N | $ 11,046 |
| 376 | L2112 | N Norwood SP to IP Conversion | CEP | 201409 | 2015 | 201805 | Replacement | N | $ 10,410 |
| 376 | H0869 | JT emax 4347751 Falling Brook Ph 2 | CEP | 201401 | 2015 | not_unitized | additions | N | $ 8,048 |
| 376 | J7111 | JT 5039426 Skr Run PH 5A | CEP | 201503 | 2015 | 201609 | additions | N | $ 5,535 |
| 376 | P6848 | JT 6089412 Parks of Whitewater | CEP | 201504 | 2015 | 201609 | additions | N | $ 5,367 |
| 376 | M2103 | W Kemper Rd Rehab #2013045-000 | CEP | 201408 | 2015 | not_unitized | Replacement | N | $ (12,158) |
| 376 | R0730 | Sycamore Plaza Main Replacement | CEP | 201512 | 2015 | not_unitized | Replacement | N | $ (24,587) |

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c. Estimated in-service date and actual in-service date.

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e. 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, materials and supplies, transportation, and employee expenses.

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Notes:

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LA-DR-01-67. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2016 CEP projects.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200912 | 2016 | 200812 | Replacement | Y | $ 7,305,479 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201601 | 2016 | 201910 | Replacement | Y | $ 5,136,330 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201601 | 2016 | 201911 | Replacement | Y | $ 4,468,278 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201601 | 2016 | 200812 | Replacement | Y | $ 3,938,622 |
| 380 | MCSTRCAR | Main to Curb for Street Car Project | CEP | 201405 | 2016 | not_unitized | Replacement | N | $ 3,717,309 |
| 303 | SMARTPH1 | Gas Smart Implementation Phase 1 | CEP | 201512 | 2016 | 201706 | additions | N | $ 1,745,024 |
| 376 | I6117 | MOD 680 Harrison | CEP | 201512 | 2016 | not_unitized | Replacement | N | $ 1,723,940 |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 1,388,723 |
| 376 | R2219 | SR 52 CG75 Replacement | CEP | 201610 | 2016 | not_unitized | Replacement | N | $ 1,244,604 |
| 376 | O0129 | Pippen Rd Imps, C R NO 90 Compton | CEP | 201605 | 2016 | not_unitized | Replacement | N | $ 1,239,081 |
| 376 | R8276 | GO 10000389 Cargill Main Ext | CEP | 201608 | 2016 | not_unitized | additions | N | $ 1,224,185 |
| 376 | R0123 | CLE-171-4 89 PID 82582 | CEP | 201603 | 2016 | 201907 | Replacement | N | $ 1,201,833 |
| 394 | R2220 | Stopple equipment for gas pipelines | CEP | 201512 | 2016 | not_unitized | additions | N | $ 1,201,639 |
| 303 | MAOPSFTWR | Maximum Allowable Operating Pressur | CEP | 201609 | 2016 | not_unitized | additions | N | $ 1,162,892 |
| 376 | R9779 | STI 8363343 Yankee Rd | CEP | 201609 | 2016 | not_unitized | Replacement | N | $ 1,090,573 |
| 376 | R3656 | F/L XX00 Pressure Imp, Route 4 | CEP | 201606 | 2016 | not_unitized | Replacement | N | $ 1,027,811 |
| 376 | R0134 | CLE-CR3 AICHOLTZ RD CONNECTOR | CEP | 201606 | 2016 | 201905 | Replacement | N | $ 1,014,891 |
| 376 | P6168 | Pippin Rd C R 90 Improvements | CEP | 201610 | 2016 | not_unitized | Replacement | N | $ 947,406 |
| 376 | R5265 | STI 7632473 BUT-Oxford State Rd | CEP | 201607 | 2016 | not_unitized | Replacement | N | $ 893,884 |
| 376 | R9341 | STI 6295113 Columbia & Western Row | CEP | 201608 | 2016 | not_unitized | Replacement | N | $ 546,895 |
| 376 | R0944 | WP2 Pressure Test "V000" | CEP | 201508 | 2016 | 201710 | Replacement | N | $ 488,157 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201601 | 2016 | 201708 | Replacement | Y | $ 277,590 |
| 376 | R2759 | Sta 833 Outlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 152,586 |
| 376 | R2189 | Guerley Rd Main Relocation - MSD | CEP | 42328 | 2016 | 201910 | Replacement | N | $ 124,097 |
| 376 | R2675 | STA 834 INLET PIPING | CEP | 201511 | 2016 | not_unitized | additions | N | $ 87,612 |
| 376 | R7262 | GO 9879292 5658 Colonial Dr | CEP | 42522 | 2016 | 201803 | additions | N | $ 79,442 |
| 376 | R2677 | STA 834 OUTLET PIPING | CEP | 201511 | 2016 | not_unitized | additions | N | $ 78,664 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 73,363 |
| 380 | CMNEWS10 | 2" or less Steel new C-M | CEP | 201603 | 2016 | not_unitized | additions | Y | $ 57,514 |
| 376 | S1460 | GO 10048200 8665 Koszo Dr | CEP | 201607 | 2016 | 201803 | additions | N | $ 54,883 |
| 376 | H0838 | MOD 650 | CEP | 201510 | 2016 | not_unitized | Replacement | N | $ 52,297 |
| 378 | P9836 | SYSTEM STA 831 | CEP | 201512 | 2016 | not_unitized | additions | N | $ 51,786 |
| 376 | S9062 | STI 10903009 Cooper & Malsbary Conn | CEP | 201610 | 2016 | not_unitized | Replacement | N | $ 50,824 |
| 376 | R0732 | BUT-CULVERTS-FY2016, PID 88709 | CEP | 201601 | 2016 | 201803 | Replacement | N | $ 47,573 |
| 376 | R3318 | Station 831 Inlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 38,911 |
| 376 | S9579 | GO 10953504 Abington | CEP | 201611 | 2016 | 201803 | additions | N | $ 38,154 |
| 376 | S9915 | GO 11380408 Creemer St | CEP | 201611 | 2016 | 201804 | additions | N | $ 33,187 |
| 391 | PCTAIT82G | INT82G - GeoSpatial Data store | CEP | 201509 | 2016 | 201609 | additions | N | $ 32,708 |
| 391 | PCTAIT82F | INT82F-EGIS Web Tool | CEP | 201509 | 2016 | 201705 | additions | N | $ 30,723 |
| 376 | R0775 | SUMMIT ROAD LANDSLIDE STABILIZATION | CEP | 201509 | 2016 | not_unitized | Replacement | N | $ 28,162 |
| 380 | LMCNEWS10 | Greater than 2" M-C Steel | CEP | 201603 | 2016 | not_unitized | additions | Y | $ 27,659 |
| 376 | R0622 | JT 7971704 Terrace Ridge | CEP | 201601 | 2016 | 201609 | additions | N | $ 23,600 |
| 376 | R9336 | STI 8082097 N East Street | CEP | 201605 | 2016 | not_unitized | Replacement | N | $ 23,537 |
| 376 | R3319 | Station 831 Outlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 22,200 |
| 376 | S9628 | STI 11118448 High St Recon | CEP | 201611 | 2016 | not_unitized | Replacement | N | $ 13,400 |
| 378 | R1781 | System Sta 832 - Outlet | CEP | 201603 | 2016 | not_unitized | additions | N | $ 12,258 |
| 376 | R7170 | STI 9825792 Jackson Ave Impr | CEP | 201603 | 2016 | 201910 | Replacement | N | $ 11,983 |
| 376 | Q1852 | CARSON RD REHABILITIAION PROJECT | CEP | 201506 | 2016 | not_unitized | Replacement | N | $ 11,486 |
| 376 | J7114 | JT 5039499 Shaker Run PH 4E | CEP | 201510 | 2016 | 201609 | additions | N | $ 8,186 |
| 378 | I3104 | Bracken Sta 759 Odorizer Pump | CEP | 201407 | 2016 | not_unitized | additions | N | $ 7,361 |
| 376 | R1478 | JT 8127946 Gilmar Meadows | CEP | 201511 | 2016 | 201609 | additions | N | $ 7,226 |
| 376 | S9605 | GO 11220811 1008 Paxton Guinea | CEP | 201609 | 2016 | not_unitized | additions | N | $ 5,633 |
| 376 | G9968 | Reg 402 - Inlet & Outlet | CEP | 201311 | 2016 | not_unitized | Replacement | N | $ 5,158 |
| 376 | G9110 | MOD 593 | CEP | 201312 | 2016 | not_unitized | Replacement | N | $ 5,068 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201610 | 2016 | 201911 | Replacement | Y | $ 5,063 |
| 376 | H0262 | MOD 471 | CEP | 201412 | 2016 | not_unitized | Replacement | N | $ 5,056 |
| 376 | Q1132 | Beechmont Kroger Expansion | CEP | 201602 | 2016 | not_unitized | Replacement | N | $ (13,635) |
| 303 | SGMDMMM2S | SG MDM Mass Market Project 2 | CEP | 201411 | 2016 | 201611 | additions | N | $ (14,785) |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201601 | 2016 | 201611 | additions | Y | $ (27,819) |
| 376 | P7607 | AMRP 2015 Small Segments Jan-Jul | CEP | 201507 | 2016 | not_unitized | Replacement | N | $ (103,378) |
| 380 | CMSTRCAR | Curb to Meter for Streetcar Project | CEP | 201405 | 2016 | not_unitized | Replacement | N | $ (2,978,606) |

For each Project ID (work order) listed above, please provide the following information:

a. A detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).

b. Work Order justification and approval at the highest approval level available based on the nature of the work order.

c. Estimated in-service date and actual in-service date.

d. 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 10%.

e. 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, materials and supplies, transportation, and employee expenses.

a. 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:

- 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 Mark Dady or Ralph Smith directly at (734) 522-3420 or msdady@gmail.com and rsmithla@aol.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

LA-DR-01-68. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2017 CEP projects.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 375 | T1666 | EGOC New Eastern Gas Ops Center | CEP | 201612 | 2017 | 201803 | additions | N | $ | 16,844,341 |
| 376 | R0984 | WP27 Engineering for "D000b" replac | CEP | 201712 | 2017 | 201911 | Replacement | N | $ | 15,285,576 |
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200912 | 2017 | 200812 | Replacement | Y | $ | 5,466,662 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201701 | 2017 | 201910 | Replacement | Y | $ | 5,036,577 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201701 | 2017 | 200812 | Replacement | Y | $ | 3,603,972 |
| 380 | MCNEWP10 | New M-C Plastic 2 inch and Under OH | CEP | 201701 | 2017 | 201911 | Replacement | Y | $ | 3,559,282 |
| 303 | PCTAIT85B | INT85B CTA MWMS Consolidation | CEP | 201704 | 2017 | not_unitized | additions | N | $ | 2,554,286 |
| 376 | J9108 | Harrison MOD 685 | CEP | 201712 | 2017 | 201909 | Replacement | N | $ | 1,570,464 |
| 376 | S8885 | STI 7121405 City of Mason | CEP | 201701 | 2017 | not_unitized | Replacement | N | $ | 330,657 |
| 374 | P6956 | 4612 Kellogg Ave Land Purchase | CEP | 201610 | 2017 | 201804 | additions | N | $ | 296,177 |
| 376 | T1946 | RPL 11687191 Orchard St Repl | CEP | 201705 | 2017 | not_unitized | Replacement | Y | $ | 124,440 |
| 376 | T1665 | GO 11853643 3888 Stillwell Beckett | CEP | 201704 | 2017 | not_unitized | additions | N | $ | 117,905 |
| 376 | T7852 | RPL 20928269 Linton Rd | CEP | 201711 | 2017 | not_unitized | Replacement | N | $ | 109,331 |
| 376 | S7175 | PRI 10498937 Reilly Millville | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 109,156 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | $ | 107,589 |
| 376 | T0787 | GO 11491240 Woodlawn Meadows | CEP | 201703 | 2017 | 201803 | additions | N | $ | 97,135 |
| 376 | MX2014221 | GAS_MAIN_EXT MAPLEWOOD DR | CEP | 201711 | 2017 | 201905 | additions | N | $ | 96,462 |
| 303 | SG358SGGL | SG 358 - DEE MDM Scale - SGG Licens | CEP | 201703 | 2017 | 201709 | additions | N | $ | 92,243 |
| 376 | S9801 | STI 10798005 RED BNK EXPR MEDPACE | CEP | 201702 | 2017 | not_unitized | Replacement | N | $ | 89,486 |
| 376 | T1217 | STI 11397668 Westwood Northern CSO | CEP | 201703 | 2017 | 201908 | Replacement | N | $ | 78,381 |
| 376 | T8739 | GO 21038284 St Peters | CEP | 201709 | 2017 | not_unitized | additions | N | $ | 57,549 |
| 380 | CMRS10 | 2" or less steel C-M Replace | CEP | 201701 | 2017 | not_unitized | Replacement | Y | $ | 50,039 |
| 376 | T0735 | GO 10652365 223 Kemp Alley | CEP | 201704 | 2017 | 201804 | additions | N | $ | 49,903 |
| 376 | T4318 | GO 11822737 Amaryllis Ridge | CEP | 201707 | 2017 | not_unitized | additions | N | $ | 46,922 |
| 376 | P6138 | But-Oxford State Rd | CEP | 201607 | 2017 | not_unitized | Replacement | N | $ | 46,911 |
| 376 | T1895 | GO 11608626 6416 Manchester Rd | CEP | 201703 | 2017 | not_unitized | additions | N | $ | 46,032 |
| 376 | T4329 | GO 5627256 7447 Gungadin Dr | CEP | 201705 | 2017 | 201804 | additions | N | $ | 42,057 |
| 376 | T0238 | GO 11326499 3402 Kleeman | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 40,281 |
| 376 | T1176 | GO 11577487 Private Dr 50x STANLEY | CEP | 201705 | 2017 | 201804 | additions | N | $ | 38,084 |
| 376 | T8260 | GO 21145279 Bardean Dr | CEP | 201708 | 2017 | not_unitized | additions | N | $ | 35,222 |
| 378 | S9495 | STA 11091239 Reg 405 Inlet | CEP | 201701 | 2017 | not_unitized | Replacement | N | $ | 33,604 |
| 376 | S9283 | JT 10908562 Whitewater Trails S 1 | CEP | 201703 | 2017 | 201804 | additions | N | $ | 33,179 |
| 376 | T8463 | GO 21022361 Beech Ave | CEP | 201708 | 2017 | not_unitized | additions | N | $ | 31,573 |
| 376 | T2625 | GO 20681592 High St Millville | CEP | 201706 | 2017 | not_unitized | additions | N | $ | 27,006 |
| 378 | T0791 | STA 11667783 Sta 853 Vista Verde | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 26,921 |
| 376 | T1875 | GO 11726496 954 Phillips Rd | CEP | 201703 | 2017 | 201904 | additions | N | $ | 23,191 |
| 376 | S9797 | GO 11077690 CRESCENT ST MT ORAB | CEP | 201612 | 2017 | 201904 | additions | N | $ | 21,523 |
| 376 | S9734 | GO 10998163 Anthony Lane | CEP | 201612 | 2017 | 201904 | additions | N | $ | 21,309 |
| 376 | T0737 | GO 10719385 11142 Wood Ave | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 20,425 |
| 376 | T1877 | GO 20381631 700 Reisling Knoll | CEP | 201703 | 2017 | not_unitized | additions | N | $ | 16,839 |
| 387 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | $ | 15,291 |
| 376 | T6069 | GO 20024030 6815 Station Rd | CEP | 201704 | 2017 | not_unitized | additions | N | $ | 11,553 |
| 380 | LMCSP10 | ASRP Greater than 2" M-C Replace | CEP | 201704 | 2017 | not_unitized | Replacement | Y | $ | 11,456 |
| 376 | G9541 | MOD 656 | CEP | 201412 | 2017 | not_unitized | Replacement | N | $ | 10,976 |
| 380 | 6MCR10 | Replace M-C 6" - Ohio | CEP | 201703 | 2017 | 200812 | Replacement | Y | $ | (11,213) |
| 376 | P6168 | Pippin Rd C R 90 Improvements | CEP | 201610 | 2017 | not_unitized | Replacement | N | $ | (19,045) |
| 376 | Q1852 | CARSON RD REHABILITIAION PROJECT | CEP | 201506 | 2017 | not_unitized | Replacement | N | $ | (22,108) |
| 376 | P6306 | Brent Spence Bridge Gas Main AM-01 | CEP | 201506 | 2017 | 201905 | Replacement | N | $ | (26,491) |
| 380 | 4CMNEW10 | Install New C-M 4" | CEP | 201701 | 2017 | 201911 | Replacement | Y | $ | (51,167) |

For each Project ID (work order) listed above, please provide the following information:

a. A detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).

b. Work Order justification and approval at the highest approval level available based on the nature of the work order.

c. Estimated in-service date and actual in-service date.

d. 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 10%.

e. 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, materials and supplies, transportation, and employee expenses.

f. 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:

- 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 Mark Dady or Ralph Smith directly at (734) 522-3420 or msdady@gmail.com and rsmithla@aol.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

LA-DR-01-69. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment and the table below, which reflects 2018 CEP projects.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| **378** | **G8160** | **STA 120 Dicks Creek Reg Sta Replace** | **CEP** | **201809** | **2018** | **not_unitized** | **Replacement** | **N** | **$** | **12,487,188** |
| **380** | **MCNEWP10** | **New M-C Plastic 2 inch and Under OH** | **CEP** | **201801** | **2018** | **201911** | **Replacement** | **Y** | **$** | **8,838,841** |
| **397** | **SG000584G** | **SG DEO AMI BC - Tech Transition** | **CEP** | **201809** | **2018** | **not_unitized** | **Replacement** | **Y** | **$** | **7,456,253** |
| 380 | MCRP10 | Replace (non-AMRP) M-C Plastic 2 in | CEP | 200912 | 2018 | 200812 | Replacement | Y | $ | 6,259,813 |
| 376 | R0984 | WP27 Engineering for "D000b" replac | CEP | 201712 | 2018 | 201911 | Replacement | N | $ | 4,817,171 |
| 376 | S9548 | Line A000b, Seg 5020 Replacement | CEP | 201809 | 2018 | not_unitized | Replacement | N | $ | 3,201,481 |
| 380 | CMNEWP10 | Greater than 2" C-M Plastic | CEP | 201801 | 2018 | 201910 | Replacement | Y | $ | 2,841,034 |
| 380 | CMRP10 | Replace C-M Plastic 2 inch and Unde | CEP | 201801 | 2018 | 200812 | Replacement | Y | $ | 2,708,104 |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | $ | 2,634,724 |
| 376 | V0745 | Line C338 & C340 ILI Scheduled Digs | CEP | 201810 | 2018 | not_unitized | Replacement | N | $ | 2,575,316 |
| 376 | T0164 | STI 11449800 Lick Run VCS | CEP | 201809 | 2018 | not_unitized | Replacement | N | $ | 2,258,810 |
| 376 | MEAPJT10 | Joint Trench plasitc main extension | CEP | 201602 | 2018 | 201909 | additions | Y | $ | 2,175,022 |
| 376 | T0179 | STI 11463877 Shepherd Lane | CEP | 201711 | 2018 | 201910 | Replacement | N | $ | 1,993,438 |
| 378 | R1489 | Dicks Creek SCADA | CEP | 201811 | 2018 | not_unitized | additions | N | $ | 1,905,809 |
| 376 | T8067 | STI 21251312 Mason-Montgomery Rd | CEP | 201711 | 2018 | not_unitized | Replacement | N | $ | 1,817,872 |
| 376 | MX2570764 | INSTALL REPLACEMENT PROJECT | CEP | 201811 | 2018 | not_unitized | Replacement | N | $ | 1,434,405 |
| 394 | U1138 | Purchase Gas Tools Blanket | CEP | 201809 | 2018 | 201809 | Replacement | Y | $ | 933,916 |
| 376 | S9991 | Struble Rd Extension (Montauk) | CEP | 201707 | 2018 | not_unitized | additions | N | $ | 772,408 |
| 376 | T0069 | RPL 8947472 East Works "E" | CEP | 201710 | 2018 | 201908 | Replacement | N | $ | 747,890 |
| 376 | T8672 | STI 9052925 Princeton Rd | CEP | 201806 | 2018 | not_unitized | Replacement | N | $ | 740,131 |
| 376 | T1880 | INT 11695818 Carlisle Normac Rep | CEP | 201710 | 2018 | not_unitized | Replacement | N | $ | 619,547 |
| 380 | LMCNEWP10 | Greater than 2" M-C Plastic | CEP | 201801 | 2018 | not_unitized | additions | Y | $ | 500,646 |
| 376 | T1945 | STI 10366150 Kugler Mill Rd | CEP | 201705 | 2018 | not_unitized | Replacement | N | $ | 387,667 |
| 376 | S7064 | STI 10222541 Clvrt PID87226 | CEP | 201708 | 2018 | 201912 | Replacement | N | $ | 289,472 |
| 378 | T8023 | STA 41 Venice M&R Station | CEP | 201806 | 2018 | not_unitized | additions | N | $ | 275,477 |
| 378 | T1653 | STA 817 Salem & Sutton - Outlet | CEP | 201805 | 2018 | not_unitized | Replacement | N | $ | 247,995 |
| 376 | T1127 | STI 9225864 BUT-CR19-2 34, CIN-DAY | CEP | 201805 | 2018 | not_unitized | Replacement | N | $ | 237,094 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | $ | 170,063 |
| 376 | MX2243582 | MEA; 2160 FT PL-IP; CLOUGH PK; JARO | CEP | 201806 | 2018 | 201901 | additions | N | $ | 164,734 |
| 376 | T7755 | STI 7549754 Springbo | CEP | 201707 | 2018 | not_unitized | Replacement | N | $ | 124,033 |
| 376 | MX2209811 | 4" PL-IP main extension to feed 3 n | CEP | 201802 | 2018 | not_unitized | additions | N | $ | 121,513 |
| 380 | LCMSP10 | ASRP Greater than 2" C-M Install | CEP | 201803 | 2018 | not_unitized | additions | Y | $ | 93,180 |
| 376 | T1576 | STI 7992077 HAM-CR 73-0 00 | CEP | 201708 | 2018 | not_unitized | Replacement | N | $ | 89,557 |
| 376 | MX1373361 | Erkenbrecher Ave | CEP | 201803 | 2018 | not_unitized | Replacement | N | $ | 84,513 |
| 376 | MX2130953 | INSTALL GAS MAIN, 7301 DALEVIEW RD, | CEP | 201801 | 2018 | 201901 | additions | N | $ | 68,012 |
| 376 | MX0740807 | 1115' 4" PLASTIC MEA - ROAD IMPROVE | CEP | 201801 | 2018 | not_unitized | additions | N | $ | 63,773 |
| 376 | MX2488132 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201805 | 2018 | not_unitized | additions | N | $ | 55,651 |
| 303 | MOBS | Enable Mobility Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ | 46,674 |
| 376 | T8215 | GO 21003182 Cross Creek | CEP | 201709 | 2018 | not_unitized | additions | N | $ | 45,701 |
| 376 | T8085 | GO 21085124 Candy Ln | CEP | 201706 | 2018 | not_unitized | additions | N | $ | 25,677 |
| 303 | EXPDS | Enable Expert Designer Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ | 23,200 |
| 376 | MX8117481 | MEA PROJECT; 7731 DONES AVE ; MADEI | CEP | 201807 | 2018 | 201904 | additions | N | $ | 22,822 |
| 380 | LMCRS10 | Greater than 2" M-C REPL Steel | CEP | 201802 | 2018 | not_unitized | Replacement | Y | $ | 14,073 |
| 376 | H1001 | MOD 665 | CEP | 201411 | 2018 | not_unitized | Replacement | N | $ | 13,764 |
| 380 | CMSTRCAR | Curb to Meter for Streetcar Project | CEP | 201405 | 2018 | not_unitized | Replacement | N | $ | 11,849 |
| 376 | MX7773849 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201810 | 2018 | not_unitized | additions | N | $ | 11,580 |
| 376 | T8655 | GO 20668365 Socialville Foster Rd | CEP | 201710 | 2018 | not_unitized | additions | N | $ | 9,583 |
| 381 | SG000584G | SG DEO AMI BC - Tech Transition | CEP | 201810 | 2018 | not_unitized | Replacement | Y | $ | 7,478 |
| 376 | MX2102443 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201712 | 2018 | not_unitized | additions | N | $ | 6,867 |
| 376 | R8520 | RPL 9593802 Cinti Dayton Rd | CEP | 201606 | 2018 | not_unitized | Replacement | N | $ | 5,876 |
| 375 | T1666 | EGOC New Eastern Gas Ops Center | CEP | 201612 | 2018 | 201803 | additions | N | $ | (36,230) |
| 376 | H1389 | STA 812 - Inlet Piping | CEP | 201410 | 2018 | not_unitized | Replacement | N | $ | (43,104) |
| 376 | T4677 | STI 20989528 Pippin Rd | CEP | 201705 | 2018 | not_unitized | Replacement | N | $ | (46,585) |
| 376 | R9466 | STI 8353391Turtlecreek Twp | CEP | 201609 | 2018 | not_unitized | Replacement | N | $ | (50,263) |
| 376 | Q9755 | Maple Ave F/L "L000" | CEP | 201511 | 2018 | not_unitized | Replacement | N | $ | (85,028) |
| 380 | S8740 | STI 100004863 Quebec Rd Sewer Sep | CEP | 201611 | 2018 | not_unitized | Replacement | N | $ | (85,694) |
| 376 | S8740 | STI 100004863 Quebec Rd Sewer Sep | CEP | 201611 | 2018 | not_unitized | Replacement | N | $ | (85,694) |
| 376 | T2811 | GO 9023613 Winton Rd | CEP | 201712 | 2018 | not_unitized | Replacement | N | $ | (125,531) |
| 380 | MCSTRCAR | Main to Curb for Street Car Project | CEP | 201405 | 2018 | not_unitized | Replacement | N | $ | (135,282) |
| 376 | T2862 | RPL 20880718 Westside Ave Repl | CEP | 201705 | 2018 | not_unitized | Replacement | N | $ | (156,291) |
| 376 | R9469 | STI 10049085 Monroe Turrtlecreek | CEP | 201609 | 2018 | not_unitized | Replacement | N | $ | (190,377) |
| 376 | Q9754 | Maple Ave | CEP | 201512 | 2018 | not_unitized | Replacement | N | $ | (197,196) |
| 376 | R0979 | WP21 "C314" Pressure Test Pig Launc | CEP | 201610 | 2018 | not_unitized | Replacement | N | $ | (503,290) |
| 376 | R9779 | STI 8363343 Yankee Rd | CEP | 201609 | 2018 | not_unitized | Replacement | N | $ | (1,198,761) |
| 376 | P6306 | Brent Spence Bridge Gas Main AM-01 | CEP | 201506 | 2018 | 201905 | Replacement | N | $ | (5,510,964) |

For each Project ID (work order) listed above, please provide the following information:

a. A detailed description, scope, and objective of the work, including service area location and any other identifiers (budget mapping).

b. Work Order justification and approval at the highest approval level available based on the nature of the work order.

c. Estimated in-service date and actual in-service date.

d. 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 10%.

e. 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, materials and supplies, transportation, and employee expenses.

f. 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:

- Please send a sample of the detail that will be provided to make sure it is what we need. **Specifically, in order to ensure that the Company is providing what we need, please expedite compiling the detail for the first three Project ID's listed above (in bold) and provide by January 17, 2020.**
- If you have any questions, please contact Mark Dady or Ralph Smith directly at (734) 522-3420 or msdady@gmail.com and rsmithla@aol.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed.

**<u>Set 7 - Submitted on January 15, 2020</u>**

LA-DR-01-70. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically, the LARKIN-DR-01-035 Attachment. For each year 2012 (Apr-Dec) through 2018, please explain fully and in detail why many of the transactions listed by Project ID number listed are not unitized (per column G of the attachment).

LA-DR-01-71. Work Orders. Refer to the response to LARKIN-DR-01-035 and specifically to the LARKIN-DR-01-035 Attachment. For each year 2013 through 2018, the attachment includes Project ID number

MCRP10 which has the description "Replace (non-AMRP) M-C Plastic 2 in."

a. For each year 2013 through 2018, the attachment includes Project ID number MCRP10 which has the description "Replace (non-AMRP) M-C Plastic 2 in." Please provide a detailed explanation of what this project relates to.

b. How did the Company determine that Project ID number MCRP10 was not related to the AMRP and should be included in CEP expenditures? Explain fully.

c. For 2014, the attachment includes Project ID number G9677 which has the description "MOD 518 Addition - Non-AMRP." Please provide a detailed explanation of what this project relates to, including how DEO determined that this project was non-AMRP.

d. For 2015, the attachment includes Project ID number G9687 which has the description "MOD 677 Addition - Non-AMRP." Please provide a detailed explanation of what this project relates to, including how DEO determined that this project was non-AMRP.

e. For 2016, the attachment includes Project ID numbers G9687 and G9790 which have the descriptions "MOD 485 Addition (Non-AMRP) and "MOD 533 Addition Non-AMRP." Please provide a detailed explanation of what these projects relates to, including how DEO determined that these projects were non-AMRP.

LA-DR-01-72. Work Orders. Refer to the response to LARKIN-DR-01-035, specifically the LARKIN-DR-01-035 Attachment and the table below.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| | | **2013 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201212 | 2013 | 200412 | Replacement | Y | $ 308,408 46 |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201312 | 2013 | 200412 | Replacement | Y | $ 22,400 06 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201303 | 2013 | not_unitized | Replacement | Y | $ 890 46 |
| | | **2014 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201312 | 2014 | 200412 | Replacement | Y | $ 151,791 21 |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201412 | 2014 | 200412 | Replacement | Y | $ 5,032 13 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201401 | 2014 | not_unitized | Replacement | Y | $ 879 77 |
| | | **2015 Projects** | | | | | | | |
| 381 | 20062 | METERS - PURCHASE NEW GAS METERS | CEP | 201412 | 2015 | 200412 | Replacement | Y | $ 172,989 03 |
| 381 | AMIMODCHG | AMI MODULE INSTALL/REMOVE | CEP | 201504 | 2015 | not_unitized | Replacement | Y | $ 31 27 |
| | | **2016 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 1,388,723.09 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201601 | 2016 | 201708 | Replacement | Y | $ 277,589.94 |
| 376 | R1488 | AMRP 2015 Small Segments | CEP | 201511 | 2016 | not_unitized | Replacement | N | $ 257,321.63 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 243,820.16 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201601 | 2016 | 201910 | Replacement | Y | $ 232,515.98 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201601 | 2016 | not_unitized | Replacement | Y | $ 73,363.15 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201610 | 2016 | 201910 | Replacement | Y | $ 65.60 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201610 | 2016 | 201708 | Replacement | Y | $ 19.78 |
| 387 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201610 | 2016 | 201708 | Replacement | Y | $ 15.12 |
| 376 | P7607 | AMRP 2015 Small Segments Jan-Jul | CEP | 201507 | 2016 | not_unitized | Replacement | N | $ (103,377.99) |
| | | **2017 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 2,573,139.31 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 193,803.64 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201701 | 2017 | not_unitized | Replacement | Y | 141,246.87 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | 107,589.12 |
| 394 | SGOGPGMTR | Smart Grid Ohio Gap Gas Meter | CEP | 201501 | 2017 | 201512 | additions | Y | 90,161.20 |
| 380 | CMAP10 | Replace AMRP C-M Plastic | CEP | 201705 | 2017 | 201910 | Replacement | Y | 29,873.10 |
| 387 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201701 | 2017 | 201708 | Replacement | Y | 15,291.31 |
| 380 | MCAP10 | Replace AMRP M-C Plastic | CEP | 201708 | 2017 | 201708 | Replacement | Y | 14,851.59 |
| | | **2018 Projects** | | | | | | | |
| 381 | SETMETER | Set or Remove Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 2,634,723 83 |
| 381 | CHGMTRSM | Change Small Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 170,062 70 |
| 381 | CHGMTRLG | Change Large Meter Ohio | CEP | 201801 | 2018 | not_unitized | Replacement | Y | 144,539 25 |
| 380 | CMSTRCAR | Curb to Meter for Streetcar Project | CEP | 201405 | 2018 | not_unitized | Replacement | N | 11,849 45 |

As shown in the table above, for each year 2013 through 2018, the attachment includes projects which appear to relate to AMRP related expenditures and projects related to meters.

a. For the projects listed above that relate to AMRP, why were they included in CEP expenditures and not the AMRP Rider? Explain fully.

b. For the projects listed above that relate to meters, why were they included in CEP expenditures and not Rider AU? Explain fully.

LA-DR-01-73. Work Orders. Refer to the response to LARKIN-DR-01-035, specifically the LARKIN-DR-01-035 Attachment. For 2013, the attachment includes Project ID number 20064 which has the description "TO INCLUDE ALL LABOR MATERIALS AND" in the amounts of $93,874 and $46,937.

a. Please provide a detailed explanation of what this project relates to, including how it was designated as CEP.

LA-DR-01-74. Work Orders. Refer to the Direct Testimony of Company witness Jay P. Brown and response to LARKIN-DR-01-035, specifically the LARKIN-DR-01-035 Attachment. On pages 3 and 4 of his testimony, Mr. Brown, referencing the Commission's Order in Case No. 13-2417-GA-UNC, et al, states that the Company's CEP deferral includes the following components under R.C. 4929.111:

- Any infrastructure expansion, infrastructure improvement, or infrastructure replacement programs.
- 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.

For each year 2014, 2016, 2017 and 2018, the attachment to LARKIN-DR-01-035 includes Project ID number DUKEOHG (DUKOHG18 for 2018) which has the description "Fleet Off-Road Vehicles - Gas - OH" in the amounts of $336,430, $115,732, $162,821, and $4,695, respectively.

a. Please provide a detailed explanation of what this project relates to, including how it was designated as CEP.

b. Pursuant to part "a", under which component of R.C. 4929.111 does the Company believe this project relates to? Explain fully.

LA-DR-01-75. CEP Plant-in-Service. Refer to Exhibit J - Additional Schedules Supporting the Application and the response to LARKIN-DR-01-035 (specifically the LARKIN-DR-01-035 Attachment) and the table below.

| Description | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total | Reference |
|---|---|---|---|---|---|---|---|---|
| Total CEP In-Service Activity - Net Assets | $ 17,677,711 | $ 22,792,911 | $ 37,470,981 | $ 49,913,859 | $ 79,568,151 | $ 90,051,676 | $ 297,475,290 | Exhibit J - Sch. 4 - Monthly CEP Investments |
| Add Back Retirements | $ 4,199,618 | $ 3,515,619 | $ 5,346,597 | $ 18,552,658 | $ 7,655,424 | $ 5,085,027 | $ 44,354,944 | Exhibit J - Sch. 4 - Monthly CEP Investments |
| Total CEP In-Service Activity - Gross Assets | $ 21,877,330 | $ 26,308,530 | $ 42,817,578 | $ 68,466,517 | $ 87,223,575 | $ 95,136,703 | $ 341,830,234 | |
| 2013-2018 Work Order Total for CEP | $ 21,836,708 | $ 26,323,191 | $ 42,285,969 | $ 68,466,517 | $ 77,798,257 | $ 95,136,703 | $ 331,847,345 | LARKIN-DR-01-035 Attachment |
| Difference | $ 40,622 | $ (14,661) | $ 531,609 | $ - | $ 9,425,319 | $ (0) | $ 9,982,889 | |

For each year 2013 through 2018, the Company's filing reflects total gross CEP plant in-service (after adding back retirements) by the amounts shown on lines 1-3 in the table above. However, comparing the CEP related projects in the work order detail that was provided in LARKIN-DR-01-035 results in the variances shown on line 5.

a. Please explain and reconcile these discrepancies. Identify, quantify and explain each reconciling item.

LA-DR-01-76. Incentive Compensation. Refer to the electronic version of Exhibit J - Additional Schedules Supporting the Application and the response to LARKIN-DR-01-029.

a. Referring to the LARKIN-DR-01-029 Attachment, for each year 2013 through 2018, are the amounts of incentive compensation (shown by the resource types listed) embedded in the CEP investment detail that is reflected on the tab titled "WP4.1 - Assets by FERC"? If not, explain fully why not.

b. If the answer to part "a" is "yes", for each year 2013 through 2018, please identify by the FERC accounts listed on the "WP4.1 - Assets by FERC" tab, where the amounts of incentive compensation are reflected in the Company's filing.

**<u>Set 8 - Submitted on January 20, 2020</u>**

LA-DR-01-77. Work Orders. Refer to the response to LARKIN-DR-01-061, project SG000584G SG DEO AMI BC - Tech Transition for $7,456,253, funding project No. SG000584F with the following project description: "SG DEO AMI BC - Tech Transition - Gas. Communication nodes will be removed. OpenWay AMI meters will be installed."

a. Why has the Company included this project in CEP costs?

b. Identify and explain what equipment is being removed.

c. For the equipment that is being removed, identify (1) the dates it was installed, (2) the cost by account, (3) the amount of recorded depreciation through the date of removal, and (4) the cost of removal.

d. What was the anticipated useful life of the equipment that is being removed in this project?

e. How does this project relate to Duke's deployment plans for the installation of an automated gas meter reading system?

f. Were any of the costs of the equipment that is being replaced included by Duke in Rider AU? If so, how much? And which specific equipment and cost was included in Rider AU?

LA-DR-01-78. Work Orders. How does Duke distinguish between (1) costs that are includible in Rider AU, and (2) costs that it has included in the CEP? Explain fully and provide specific examples.

**<u>Set 9 - Submitted on January 21, 2020</u>**

LA-DR-01-79. AROs. Please confirm that no costs for Asset Retirement Obligations (AROs) are included in CEP investment.

a. If this is not confirmed, identify the amounts and specific AROs for each year 2012 through 2018 that are included in CEP investment.

b. Please breakout any 2012 ARO amounts identified in response to part "a" into (1) 1/1/2012 through 3/31/2012 and (2) 4/1/2012 through 12/31/2012.

LA-DR-01-80. BU 75027 work orders. Please confirm that no costs identified to work orders designated as Business Unit 75027 (DEO Gas Special) are included in CEP investment.

a. If this is not confirmed, identify the amounts and specific costs from each work order with at Business Unit 75027 designation for each year 2012 through 2018 that are included in CEP investment.

b. Please breakout any 2012 amounts identified in response to part "a" into (1) 1/1/2012 through 3/31/2012 and (2) 4/1/2012 through 12/31/2012.

LA-DR-01-81. BU 75080 work orders. Please confirm that no costs identified to work orders designated as Business Unit 75080 (DEO Common) are included in CEP investment.

a. If this is not confirmed, identify the amounts and specific costs from each work order with at Business Unit 75080 (Common) designation for each year 2013 through 2018 that are included in CEP investment.

b. Please breakout any 2012 amounts identified in response to part "a" into (1) 1/1/2012 through 3/31/2012 and (2) 4/1/2012 through 12/31/2012.

LA-DR-01-82. AMRP versus CEP inclusion. Refer to the response to LARKIN-DR-01-001, Attachment H.

a. What criteria did DEO use to identify amounts in the AMRP for the period 3/1/2012 through 12/31/2012 and for each year 2013 through 2015?

b. For each year, 2016 through 2018, what work orders and costs have been included in the CEP that prior to 12/31/2015 would have been included in AMRP? Explain and identify the related work orders and costs.

c. What caused DEO to cease treating work orders and costs as belonging in the AMRP starting 1/1/2016?

d. Is there any difference in the carrying charges or return that is applied to amounts in the AMRP and the CEP for any of the years 2013 through 2015? If so, please indentify, quantify and explain the difference in carrying charge rates for each year for AMRP and CEP.

LA-DR-01-83. Retirement Work in Progress (RWIP). Please confirm that no costs identified to work orders designated as Retirement Work in Progress are included in CEP investment.

a. If this is not confirmed, identify the amounts and specific costs from each work order for RWIP for each year 2013 through 2018 that are included in CEP investment.

b. Please breakout any 2012 amounts identified in response to part "a" into (1) 1/1/2012 through 3/31/2012 and (2) 4/1/2012 through 12/31/2012.

LA-DR-01-84. Rider AU versus CEP inclusion. Refer to the response to LARKIN-DR-01-001, Attachment H.

a. What criteria did DEO use to identify amounts in the Rider AU for the period 3/1/2012 through 12/31/2012 and for each year 2013 through 2014?

b. For each year, 2015 through 2018, what work orders and costs have been included in the CEP that prior to 12/31/2014 would have been included in Rider AU? Explain and identify the related work orders and costs.

c. What caused DEO to cease treating work orders and costs as belonging in the Rider AU starting 1/1/2015?

d. Is there any difference in the carrying charges or return that is applied to amounts in the Rider AU and the CEP for any of the years 2013 through 2015? If so, please indentify, quantify and explain the difference in carrying charge rates for each year for Rider AU and CEP.

LA-DR-01-85. 2018 On-Top Retirement. Refer to the responses to LARKIN-DR-01-001, Attachment H and LARKIN-DR-01-040.

a. Identify and provide the journal entry that resulted in the $13,558,319?

b. Identify exactly what was retired that resulted in the $13,558,319 On-Top entry.

c. Reconcile the $13,558,319 show in the response to LARKIN-DR-01-001, Attachment H, with the $13,871,438shown in the response to LARKIN-DR-01-040. Identify, quantify and explain each reconciling difference.

d. How much of the $13,558,319 On-Top retirement was included in the $90,051,676 CEP investment for 2018?

e. Was the $13,558,319 On-Top entry reversed or modified subsequent to 12/31/2018? If not, explain fully why not. If so, identify and provide the reversing or modifying journal entries.

f. Has the $13,558,319 On-Top entry been reconciled into PowerPlan? If so, show in detail how and when that was done. If not, explain fully why not.

LA-DR-01-86. Refer to the Depreciation Reserve records that were provided in LARKIN-DR-01-002 and Exhibit I, WPB-3.3 from the Company's filing. Referring to WPB-3.3k, for Company Account 1030 in year 2015, there is the amount of $11,664 under the column heading "Transfers/Reclassifications", but this amount is not reflected in the historical depreciation reserve records provided in LARKIN-DR-01-002. Please explain and reconcile this discrepancy and provide the support for the $11,664 amount.

LA-DR-01-87. Capitalization Policy during 2012 through 2018. Refer to the response to LARKIN-DR-01-010, Capitalization Guidelines, which were provided for 2010, 2014, 2016, 2017 and 2018.

a. Please identify and explain any significant changes in capitalization policy during the period 2012 through 2018.

b. Please identify and explain any significant changes in capitalization policy during the period 2012 through 2018 that affected accounting for the Duke Energy Ohio Gas utility and/or CEP investment amounts in any year.

LA-DR-01-88. $23,065,474 reconciling item in 2015. Refer to the responses to LARKIN-DR-01-001, Attachment H and the response to LARKIN-DR-01-024(b) concerning the $23,065,474.

a. Is any of the $23,065,474 reconciling item for 2015 on LARKIN-DR-01-001, Attachment H included in the $37,470,981 CEP for 2015? If so, how much and why?

b. Is any of the $23,065,474 allocated common plant? If so, how much? Also explain fully and show in detail how that common cost is allocated among DEO Gas and other entities or business units.

c. The response to LARKIN-DR-01-024 indicates that the $23,065,474 is a journal entry related to the retirement of smart grid meters. Provide a copy of the journal entry for the $23,065,474 retirement.

d. Identify how many smart meters were retired, the original cost of the retired smart meters, identify and explain when those smart meters were purchased and installed (quantity and cost by year) and explain the reason for the retirement.

e. What useful life and depreciation rate were being applied to the \$23,065,474 of smart meters prior to their retirement in 2015?

f. Identify and provide the work orders and cost accounting detail for the \$23,065,474 of smart meters as they were originally placed into public utility service.

g. Was any portion of the cost of the \$23,065,474 of smart meters that were retired in 2015 previously included in any rider, such as in Rider AU? If "yes" identify how much was included in each Rider and when (i.e., the time periods) it was included in each Rider.

LA-DR-01-89. For portions of DEO's Ohio service territory that include provision of both electric utility service and gas distribution service, is any cost related to the electric utility AMI or smart meter program or related investment in communications equipment being charged or allocated to DEO Gas utility operations in any year, 2012 through 2018.

a. If "yes" identify the total costs in each year, by account, and by business unit, and show in detail how the allocation is made to the DEO Gas distribution utility.

LA-DR-01-90. Please provide Duke Energy Ohio’s FERC Form 2s for the following years: 2013, 2014, 2016 and 2017.

## <u>Set 10 - Submitted on January 22, 2020</u>

LA-DR-01-91. Meters. As of each year-end, 12/31/2012 through 12/31/2018, identify and provide the following information concerning Meters in the Company's Ohio gas distribution system:

a. Number of gas meters by type.

b. Cost of gas meters by type.

c. Average unit cost of gas meters by type.

d. Number of new gas meters installed by type during each year, 2013 through 2018.

e. Number of gas meters retired by type during each year, 2013 through 2018.

f. Number of gas meters replaced by type during each year, 2013 through 2018.

g. Cost of gas meters purchased in each year (2013 through 2018) in total and by type of meter.

h. Number of gas meters purchased in each year (2013 through 2018) in total and by type of meter.

LA-DR-01-92. Gas AMI business plan/business case. Does the Company have any business plan or business case relating to its Ohio gas distribution system AMI systems? If not, explain fully why not. If so, please identify and provide the original Ohio AMI business plan/business case as well as revisions made to it affecting the period 2013 through 2018.

LA-DR-01-93. Gas AMI system.

a. Please provide a description of the AMI systems that the Company has installed for its Ohio gas distribution utility. Include a description of changes to that AMI equipment, including retirements and replacements that have occurred during each year in the period 2013 through 2018.

b. Is the same type of Gas AMI system that the Company installed for its Ohio gas distribution utility been installed at any other Duke Energy gas distribution utilities? If not, explain fully why not. If so, which ones?

LA-DR-01-94. AMI communications equipment/AMI equipment other than meters. As of each year-end, 12/31/2012 through 12/31/2018, identify and provide the following information concerning Gas Advanced Meter Infrastructure communications equipment:

a. Description of Gas AMI communications equipment installed by type.

b. Cost of Gas AMI communications equipment installed by type.

c. Gas AMI equipment (other than meters) retired by type during each year, 2013 through 2018, and the reasons for the retirements.

d. Gas AMI equipment (other than meters) purchased in each year (2013 through 2018) in total and by type of equipment.

e. A description of warranty terms for Gas AMI communications equipment.

LA-DR-01-95. Distribution system pipe. As of each year-end, 12/31/2012 through 12/31/2018, identify and provide the following information concerning the Company's Ohio gas distribution system pipe:

a. Quantity (approximate number of miles) of distribution system pipe by type and diameter classified as distribution mains.

b. Quantity (approximate number of miles) of distribution system pipe by type and diameter classified as distribution services.

c. Total cost of distribution system mains.

d. Cost of distribution system mains by type of pipe.

e. Total cost of distribution system services.

f. Cost of distribution system services by type of pipe.

LA-DR-01-96. Provide a copy of the Company's Distribution Integrity Management Plan (DIMP) for 2012 and each revision and DIMP plan re-write through 2018.

LA-DR-01-97. For each year, 2012 through 2018, identify and explain how the Company has evaluated the risks associated with gas distribution system pipe and prioritized pipe replacement.

LA-DR-01-98. Excavation damage and cost recovery.

a. For each year 2013 through 2018, identify the dollar amount of recoveries from insurance for excavation damage. For each year also show those insurance recovery amounts by account.

b. For each year 2013 through 2018, identify the dollar amount of recoveries from third parties for excavation damage. For each year also show those insurance recovery amounts by account.

c. For each year 2013 through 2018, how much cost for repairing excavation damage has the Company included in its CEP costs for each year?

d. Are the amounts for each year that were identified in response to part c, net of recoveries from insurance and third parties? If not, explain fully why not. If so, identify and show in detail the amounts of excavation damage recoveries from insurance and third parties, by account, for each year. Also explain whether any why (or why not) those excavation damage recovery amounts for each year were netted against the excavation damage repair costs for the Company's CEP.

LA-DR-01-99. Leak reports. Does the Company have any hazardous leak reports for its Ohio gas distribution system for years 2013 through 2018 which have not already been provided in the Company's response to LA-DR-48? If "yes" please identify and provide those hazardous leak reports.

## Set 11 - Submitted on January 24, 2020

LA-DR-01-100. Please provide Excel files for the Duke AMRP schedules filed since 2012.

LA-DR-01-101. Refer to the response to LARKIN-DR-01-49. Please provide as-built documentation for Line D.

LA-DR-01-102. Refer to the response to LARKIN-DR-01-49. Please provide as-built documentation for Line A000b.

LA-DR-01-103. Refer to the response to LARKIN-DR-01-49. Please provide as-built documentation for the Dicks Creek Project.

a. Were there any change orders issued with respect to the Dicks Creek project? If "yes" please identify and provide a copy of each change order.

LA-DR-01-104. Refer to the response to LARKIN-DR-01-49. Please provide as-built documentation for the Mason Station Project.

LA-DR-01-105. Enable project. Refer to the response to LARKIN-DR-01-49.

a. Identify the original budgeted cost of the Enable project, and identify and provide the related contracts. If the contracts are voluminous, please highlight the price terms and the delivery dates and completion dates for each work component.
b. Identify and provide a complete copy of each change order for the Enable project.
c. What was the final cost of the Enable project? Provide the cost in total and broken out by component.
d. Please identify the persons who are most knowledgeable about the Enable project, including managing the project, the related change order requests, and causes of project cost increases and delays.
e. Were costs for the Enable project included in the budget amounts shown for any year in the response to LARKIN-DR-01-49? If not, explain fully why not. If so, identify the amounts included in the budgeted costs for each year.
f. How much Enable project costs were included in the actual amounts shown for each year in the response to LARKIN-DR-01-49?

LA-DR-01-106. Central Corridor Project. Refer to the response to LARKIN-DR-01-49.

a. Please confirm that there are no costs related to the Central Corridor project included in the CEP deferrals. If this cannot be confirmed, please identify by amount and account, all costs related to the Central Corridor project that are included in the CEP.
b. Please confirm that the Central Corridor project is for a new pipeline that has not yet been built or placed into service. If this cannot be confirmed, please explain and identify assets related to the Central Corridor project that were placed into service by December 31, 2018.

c. Please identify the amounts of cost incurred related to the Central Corridor project and confirm that all such costs have been recorded in Construction Work in Progress through December 31, 2018 and through December 31, 2019 and that no related costs have been recorded in Plant in Service accounts through those dates. If this cannot be confirmed, please explain fully and identify the amounts recorded as Plant in Service through each of those dates.

d. Please provide the fact sheet for the Central Corridor project.

LA-DR-01-107. Please explain the criteria that the Company uses to distinguish between distribution and transmission pipelines for purposes of federal PHMSA regulations and Transmission Integrity Management.

LA-DR-01-108. Please provide site diagrams and addresses for the following facilities:

a. New Eastern Gas Ops Center building.

b. Mason Station project.

LA-DR-01-109. RFP process for blanket work orders.

a. Identify and provide each RFP that was issued during years 2012 through 2018 for blanket work order projects.

b. Identify and provide the responses that were received to each RFP identified in response to part "a".

c. Identify and provide the Company's evaluation of the responses that were identified in the response to part "b".

d. Identify and provide the price terms for each vendor/contractor that was selected by the Company to perform work on blanket work orders during the period 2012 through 2018.

LA-DR-01-110. RFP process for Major Projects.

a. Identify and provide each RFP that was issued during years 2012 through 2018 for Major Projects.

b. Identify and provided the responses that were received to each RFP identified in response to part "a".

c. Identify and provide the Company's evaluation of the responses that were identified in the response to part "b".

d. Identify and provide the price terms for each vendor/contractor that was selected by the Company to perform work on Major Projects during the period 2012 through 2018.

LA-DR-01-111. Major Projects group.

a. Explain the staffing and responsibilities of the Major Projects group.

b. Explain the criteria used for projects that are to be bid out, contracted by and supervised by the Major Projects group.

LA-DR-01-112. Distribution Projects Specialists.

a. Explain the staffing and responsibilities of the Distribution Projects Specialists group.

b. Explain the criteria used for projects that are to be bid out, contracted by and supervised by the DPS group.

LA-DR-01-113. Technical Field Operations (TFO).

a. Explain the staffing and responsibilities of the TFO group.

b. Explain the criteria used for projects that are to be bid out, contracted by and supervised by the TFO group.

## <u>Set 12 - Submitted on January 31, 2020</u>

LA-DR-01-114. Procedures used to identify excludable amounts of incentive compensation recorded in utility plant accounts. Please identify and provide the desktop procedure referred to by Jay Brown in the January 31, 2020 interviews that was used by the Company in the Annual Rider DCI Audit (Case No. 19-1287-EL-RDR) and in the Company's response to LA-DR-22 in the current Duke Energy Gas CEP audit for identifying capitalized amounts of incentive compensation that have been included in utility plant accounts under GAAP accounting but which should be excluded for Ohio utility ratemaking purposes.

LA-DR-01-115. Enable project cost allocation details.

a. Please show in detail the calculations of the allocation of the Enable project cost among the various entities/business units, including Duke Energy Ohio - Gas utility operations, which was described during the January 31, 2020 interviews as being based on customer counts. Include related documentation showing the customer counts used for each entity/business unit and related allocation details.

b. Identify as of which date, the customer counts used in the customer count-based allocation, were taken (e.g., customer counts for each entity/business unit as of *January 2, 2017* - or whatever the date was - were used).

c. Was the allocation of Enable project cost impacted by Duke's acquisition of Piedmont Gas? If not, explain fully why not. If so, explain how and show in detail how the cost allocation was made or updated to incorporate Piedmont Gas customer counts.

LA-DR-01-116. 2018 ROCR report.

a. As discussed during the January 31, 2020 afternoon interview, provide the 2018 ROCR report showing the budgeted and actual capital spending for 2018, along with the variances and variance explanations.

b. Please identify where, within the 2018 ROCR report, the 2018 capital spending actual amount of approximately $100 million and the related budgeted amount of $112 million that were mentioned for Duke Energy Ohio or Duke Energy Ohio Gas are shown.

LA-DR-01-117. Incentive compensation capitalized in Retirement Work in Progress (RWIP).

a. In each year, 2013 through 2018, how much incentive compensation did Duke Energy Ohio Gas record in RWIP. Identify the amounts and explain and show in detail how they were calculated.

b. How much of the capitalized incentive compensation amounts for each year identified in part a relate to earnings-based incentives? Explain and show calculations.

c. Explain in detail whether RWIP, and the incentive compensation amounts capitalized into RWIP in each year, 2013 through 2018, had any impact on the CEP deferral amounts being requested by the Company.

## <u>Set 13 - Submitted on February 3, 2020</u>

LA-DR-01-118. Invoicing for excavation damage repair cost. Refer to the response to LARKIN-DR-48(3) Attachment.

a. Explain and provide the guidance followed by the Company for recording amounts invoiced for reimbursement of excavation damage repair cost into each of the following accounts:

1) account 107000
2) account 416330
3) account 894000
4) account 874000
5) account 879000
6) account 887000
7) account 495031

b. Please confirm that the Company's CEP application reflects only the excavation reimbursement damage invoicing and collections that were recorded in account 107.

LA-DR-01-119. Amounts collected for excavation damage repair cost. Refer to the response to LARKIN-DR-48(3) Attachment. For 2018 there are payment amounts totaling $237,810 (i.e., amounts collected for invoices to DEO contractors and third parties for excavation damage repair costs) that are not identified to an account. Explain and show in what account the payments comprising the $237,810 were recorded. Specifically indicate how much of the $237,810 was recorded in account 107 or should have been recorded in account 107.

LA-DR-01-120. "Natural Forces" Leaks by Material and Cause. Refer to Larkin-DR-01-048(2) Attachment which shows 2013-2018 Leaks by Material and Cause and has a column entitled "Natural Forces." For 2016 through 2018 provide explanations of the "natural forces" related leaks including facility, material and other details (e.g., such as whether it was related to coupling failures, equipment failure, etc.) that is contained in the Company's investigations into each of the leaks that were attributable to "natural forces."

LA-DR-01-121. DIMP - reports. Refer to Sections 9.2 and 9.3 of the DIMP (provided in response to LARKIN-DR-96). For years 2013 through 2018 please provide the following reports for Duke Energy Ohio Gas.

a. Annual report to PHMSA.

b. Material Fittings Failures reports.

LA-DR-01-122. Subject Matter Expert (SME) Meetings. Refer to Section 10 of the DIMP (provided in response to LARKIN-DR-96).

Please provide the ICAM SME meeting documentation for 2013 through 2018 (to the extent it exists) related to the following:

a. non-leak based threats meetings.

b. meetings under DIMP.

LA-DR-01-123. Excavation Damages. Refer to the LARKIN-DR-48(2) Attachment. During the telephone interview with Jim Collins on February 3, 2020, it was stated that the three primary causes of leaks from excavation related damages included: (1) not using the 811 program, (2) using mechanized equipment when not necessary (i.e., 18-24 inch pipe), and (3) failure to protect pipe once it is exposed through the excavation process.

Referring to the number of excavation damages listed on the LARKIN-DR-48(2) Attachment:

a. For the period 2013 through September 2017 (i.e., when excavation damage investigations were conducted in house), please provide any root-cause analysis reports that were prepared pursuant to the three primary causes listed above.

b. For the period October 2017 through December 2018 (i.e., when excavation damage investigations were conducted by PRG), please provide any root-cause analysis reports that were prepared pursuant to the three primary causes listed above.

**<u>Set 14 - Submitted on February 4, 2020</u>**

LA-DR-01-124. Payroll taxes and fringe benefits allocated costs that follow payroll dollars. Refer to the responses to LARKIN-DR-62 and LARKIN-DR-22.

a. Referring to "Resource Type" 1825X, Payroll Tax Loader, from the response to LARKIN-DR-62, identify the payroll tax rates applicable for each year, 2013 through 2018, that were used, or which can be used to estimate the payroll taxes allocated to the Duke Energy Ohio Gas utility for cost allocations of payroll taxes to Duke Energy Ohio Gas that follow the payroll dollars allocation.

b. Referring to "Resource Type" 1835X, Fringes Benefits Loader, from the response to LARKIN-DR-62, identify the Fringe Benefit rates applicable for each year, 2013 through 2018, that were used, or which can be used to estimate the Fringe Benefit allocations to the Duke Energy Ohio Gas utility for cost allocations of Fringe Benefits to Duke Energy Ohio Gas that follow the payroll dollars allocation.

c. Referring to the response to LARKIN-DR-62, please confirm that overheads and indirect cost of the "Resource Type" 1825X, Payroll Tax Loader, for the years 2013 through 2018 are allocated to Duke Energy Ohio Gas based on payroll dollars (which include Labor [Resource Type 18000], Unproductive Labor [1800X] and Incentives [4840X, 4E002, 1E200 and 1E202]. Explain as needed if your response is more than a simple confirmation.

d. Referring to the response to LARKIN-DR-62, please confirm that overheads and indirect cost of the "Resource Type" 1835X, Fringes Benefits Loader, for the years 2013 through 2018 are allocated to Duke Energy Ohio Gas based on payroll dollars (which include Labor [Resource Type 18000], Unproductive Labor [1800X] and Incentives [4840X, 4E002, 1E200 and 1E202]. Explain as needed if your response is more than a simple confirmation.

e. Referring to the response to LARKIN-DR-62, please confirm that none of the costs of the Resource Types (1) 49500 Service

Company Overhead-Loader, (2) 78000 Affiliate Loader, or (3) 78000 Non-Labor Overhead Allocator for the years 2013 through 2018 are allocated to Duke Energy Ohio Gas based on payroll dollars for Incentives [resource types 4840X, 4E002, 1E200 and 1E202]. If this is not confirmed, identify the amounts of resource type costs for 49500 Service Company Overhead, 78000 Affiliate Loader, and 78000 Non-Labor Overhead Allocator that are allocated to Duke Energy Ohio Gas based on payroll dollars for Incentives [resource types 4840X, 4E002, 1E200 and 1E202], for each year, 2013 through 2018, and relate those cost allocations to the amounts for incentive compensation that were provided for each year in the response to LARKIN-DR-22.

## Set 15 - Submitted on February 5, 2020

LA-DR-01-125. 2012 Depreciation Offset. Refer to Exhibit J - Additional Schedules Supporting the Application at Schedule No. 11.

a. Please explain fully and in detail the rationale for reflecting this rate base offset in the Company's filing.

b. For each year 2013 through 2018, please provide documentation (beyond the FERC Form 2's) which supports the amounts shown on lines 1-4 of Schedule 11.

LA-DR-01-126. Amortization of Regulatory Asset. Refer to Exhibit J - Additional Schedules Supporting the Application at Schedule No. 1. As shown on line 22 of Schedule 1, the Company used the composite depreciation rate of 2.54% to calculate the amortization of the regulatory assets totaling $44.982 million.

a. Please confirm that the 2.54% composite depreciation rate is not used for any other calculations that are reflected on the schedules and/or workpapers in Exhibit J.

b. If part "a" is not confirmed, quantify and explain in detail any other calculations in the Exhibit J schedules and/or workpapers where the 2.54% composite depreciation rate was used.

c. Was the 2.54% composite depreciation rate in any other exhibits and/or schedules in the Company's SFR filing? If so, please indicate, by exhibit and schedule, where the 2.54% composite depreciation rate was used.

## Set 16 - Submitted on February 10, 2020

LA-DR-01-127. Retirements. Refer to Exhibit J - Additional Schedules Supporting the Application at the tab titled "WP4.2 - Retirements by FERC."

a. For each year 2013 through 2018, for each retirement listed on the referenced workpaper, was the accounting entry to credit plant-in-service and to debit accumulated depreciation?

b. If accumulated depreciation was not the debit entry for any of the retirements listed on WP4.2 - Retirements by FERC, identify what account(s) the debits were recorded in, and the related amounts. Explain fully.

## Set 17 - Submitted on February 25, 2020

LA-DR-01-128. Excavation damage. Refer to the response to LARKIN-DR-01-048.

a. Identify and provide the contract with the third party.

b. Identify and provide the detail reports from the third party contractor for September 2017 through December 2018 of excavation damage.

c. Identify and provide the invoices for excavation damage cost recovery for September 2017 through December 2018.

d. Why did Duke Energy change to using a third party contractor for excavation damage tracking and invoicing?

LA-DR-01-129. AMI. Refer to the response to LARKIN-DR-01-49(2) Supplemental, LARKIN-DR-01-093 and LARKIN-DR-01-094.

a. Explain why the AMI technology on the gas meters was changed.

b. Identify the cost in total by year for the current communication nodes.

c. Identify the anticipated useful life when the communication nodes were installed.

d. Identify the cost in total and by year for the communication nodes that were removed.

e. Explain in detail what the removed communication nodes were replaced with and why they were replaced.

LA-DR-01-130. AMI. Refer to the response to LARKIN-DR-01-94.

a. Is the currently installed Duke Energy Ohio Gas AMI system compatible with wireless 5G technology?

b. What is the current estimated useful life of the Duke Energy Ohio Gas AMI system? Explain fully. If different by component, state the expected useful life by component. If different, by plant account, state the expected useful life by plant account for each plant account that is associated with the Duke Energy Ohio Gas AMI system.

c. What components of the Duke Energy Ohio Gas AMI system are shared with the Duke Energy Ohio electric AMI system?

d. How are the costs of each of the shared components (identified in response to part c) allocated between Duke Energy Ohio electric and gas? Explain fully and show applicable allocations in detail.

e. Will components, such as communications systems, being used by the currently installed Duke Energy Ohio Gas AMI system need to be replaced to be compatible with wireless 5G technology? If not, explain fully why not. If so, identify when such replacements are expected to occur.

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o. How much, and at what cost, of the equipment purchased for the original smart grid (SG) deployment for Duke Energy Ohio gas was in service as of each year-end, 12/31/2012 through 12/31/2018? Show amounts by account for each type of original SG deployment plant.

p. How much of the equipment purchased for the original smart grid (SG) deployment for Duke Energy Ohio gas was retired and/or removed from service as of each year-end, 12/31/2012 through 12/31/2018? Explain and show the retirement entries, by year, related to such retirements of plant from the original smart grid deployment for Duke Energy Ohio.

LA-DR-01-131. Enable system. Refer to the supplemental response to LARKIN-DR-01-049 and the response to LARKIN-DR-01-52.

a. What functions or modules of the Enable system are used by Duke Energy Ohio gas?

b. Show in detail how the 5.43% allocation mentioned in the supplemental response to LARKIN-DR-01-49(3) was derived.

c. What is the anticipated useful life of the Enable system and how was that determined?

d. Is a ten year life being used for the Enable system, as indicated in the response to LARKIN-DR-01-52(d): "a depreciation rate of 10% for Miscellaneous Intangible Plant - Enable"? If not, what depreciation rate is being used for the Enable system?

e. When was the Enable system first placed into service for Duke Energy Ohio Gas?

LA-DR-01-132. Depreciation for intangible plant. Refer to the response to LARKIN-DR-01-52(d). Please identify the amounts of Intangible Plant as of each year-end, 12/31/2012 through 12/31/2018 to which each of these depreciation rates is being applied:

a. 10%

a. 20%

b. 33.33%

c. other (explain)

LA-DR-01-133. Information Technology. Refer to the response to LARKIN-DR-01-53.

a. For each year, 2013 through 2018 show the total amounts of Information Technology costs and show in detail how those costs were allocated to Duke Energy Ohio gas.

b. Do the allocations to Duke Energy Ohio gas for any components of Information Technology costs vary from year to year? If not, explain fully why not. If so, explain why the allocation to Duke Energy Ohio gas for Information Technology cost has changed from year to year.

LA-DR-01-134. TCJA impact. Refer to the response to LARKIN-DR-01-53. Was the excess accumulated deferred income tax amount returned to Duke Energy Oho gas customers? If not, explain fully why not. If so, how and when was it returned?

LA-DR-01-135. Gas meters. Refer to the response to LARKIN-DR-01-73.

a. Why were gas analog meters being installed in 2013?

b. How many gas analog meters were installed in 2013 and what was the total cost and per-meter cost?

c. Were gas analog meters installed in any other years, 2014 through 2018?

d. If the answer to part c is "yes" identify the number of gas analog meters that were installed in each year, 2014 through 2018 and identify the total cost and per-meter cost for each year.

e. As of 12/31/2018 how many gas analog meters were in service for the Duke Energy Ohio gas utility?

f. Identify the number of gas analog meters that were retired in each year, 2013 through 2018.

g. Identify the original cost of the gas analog meters that were retired in each year, 2013 through 2018.

h. For the gas analog meters that were retired in each year, 2013 through 2018, was the original cost credited to plant in service and debited to accumulated depreciation for those retirements? If not, explain fully why not, and identify the accounting in each year that was used for those retirements.

i. For the gas analog meters that were retired in each year, 2013 through 2018, were any of those replaced with AMI meters? If not, explain fully why not. If so, identify the number of gas analog meters that were replaced with AMI meters in each year.

LA-DR-01-136. Incorrect filtering affecting CEP plant in service balances. Refer to the response to LARKIN-DR-01-75. What corrections in each year, 2013 through 2018, are necessary to correct for the activity that was incorrectly included in the CEP balances? Identify, quantify and explain the corrections for each year.

LA-DR-01-137. Cloud computing cost capitalization. Refer to the response to LARKIN-DR-01-87.

a. Identify the amounts of cost for Cloud Computing that were capitalized, by plant account, for each year 2016, 2017 and 2018.

b. Identify the amounts of capitalized Cloud Computing costs that are included in the CEP, by plant account, for each year.

c. What depreciation/amortization has been applied for the amounts of capitalized Cloud Computing costs in each year? Explain fully and show amounts for each year.

LA-DR-01-138. $23 million "Unretirement". Refer to the response to LARKIN-DR-01-88.

a. Did the $23 million "Unretirement" have any impact on the Company's requested CEP costs in any year? If not, explain fully why not. If so, identify the impact on requested CEP costs in each year.

b. How many meters, and what type of meters, were accounted for in the $23 million "unretirement"?

c. How many of the meters identified in response to part b were in-service as of 12/31/2018?

d. How many of the meters identified in response to part b had been retired or removed from service as of 12/31/2018?

LA-DR-01-139. Meter types and quantities. Refer to the responses to LARKIN-DR-01-73 and LARKIN-DR-01-88.

a. How does the Company distinguish between (1) gas analog meters, (2) "smart" meters, (3) Smart Grid meters, (4) AMI meters, (5) "normal" meters, and (6) any other types of meters on the Duke Energy Ohio gas utility system? Explain fully.

b. As of each calendar year-end, 12/31/2012 through 12/31/2018, identify the quantity, total cost and unit cost of each type of meter for the Duke Energy Ohio gas utility system.

LA-DR-01-140. Excel-based risk model and GIS segmented risk model. Refer to the response to LARKIN-DR-01-97.

a. Please provide the Excel-based risk model used in each year 2012 through 2018 to rank and prioritize projects.

b. Please provide the documentation from the GIS segmented risk model used in 2018 to scope the riskiest areas and prioritize pipeline replacement work.

LA-DR-01-141. Mason Station Project. Refer to the response to LARKIN-DR-01-104.

a. Has any cost for the Mason Station project been included in the Company's requested CEP costs?

b. If the answer to part a is "yes" please identify the cost by year by plant account.

LA-DR-01-142. Transmission pipelines. Refer to the response to LARKIN-DR-01-104.

a. Does Duke Energy Ohio have any pipe in its Ohio gas system that operates over 20% SMYS?

b. If the answer to part a is "yes" please identify the approximate locations and cost of such pipe.

c. Does Duke Energy Ohio have any pipe in its Ohio gas system that runs to a large volume customer's location?

d. If the answer to part c is "yes" please identify the approximate locations and cost of such pipe.

e. Please identify in what plant accounts the Company has recorded the costs identified in response to parts b and d, above.

LA-DR-01-143. Recovery of excavation damage cost. Refer to the responses to LARKIN-DR-01-118 and LARKIN-DR-01-119.

a. Referring to the response to LARKIN-DR-01-119, how did the Company determine which amounts should be credited to account 107000 in years 2015 and 2016?

b. Referring to the response to LARKIN -DR-01-119, how did the Company determine which amounts should be credited to account 0894000 in years 2013 through 2018?

c. Referring to the response to LARKIN -DR-01-119, how did the Company determine which amounts should be credited to account 0887000 in years 2017 through 2018?

LA-DR-01-144. Leaks miscoded to "natural forces" and DIMP group meetings. Refer to the response to LARKIN-DR-01-120, which states in part that: "Based on this approach, the DIMP group has performed multiple meetings to provide clarity to field personnel of the proper definition of natural forces. The DIMP group believes that the majority of natural force leaks are mis coded and are more appropriately categorized as equipment failure."

a. Are there minutes or notes of the DIMP group meetings?

b. If the answer to part a is "yes" please identify and provide them for 2013 through 2018.

c. Identify by job title and work location the members of the DIMP group.

LA-DR-01-145. Depreciation offset. Refer to Exhibit J, Additional Schedules Supporting the Application at Schedule no. 11 and the response to LARKIN-DR-01-125. Referring to the FERC Form 2 information for each year:

a. For each year 2013 through 2018, how much cost of removal/negative net salvage was charged/debited to the accumulated depreciation account(s)? Explain and show amounts for each year.

b. For each year 2013 through 2018, how much cost for plant retirements was credited to utility plant in service accounts and charged/debited to the accumulated depreciation account(s)? Explain and show amounts for each year.

c. For each year, 2013 through 2018, what amounts for depreciation accruals were credited to the accumulated depreciation account(s)? Explain and show amounts for each year.

d. For each year, 2013 through 2018 were any amounts for Retirement Work in Progress charged against the accumulated depreciation account(s)? If "yes" please explain and show amounts for each year.

LA-DR-01-146. Dick's Creek Change Orders. Refer to the confidential attachment to the response to LARKIN-DR-01-103.

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**[END CONFIDENTIAL]**

**Set 18 - Submitted on February 27, 2020**

LA-DR-01-147. Property Taxes. Refer to Exhibit J - Additional Schedule Supporting the Application and the confidential response to STAFF-DR-05-001 from Case No. 17-2318-GA-RDR, which states:

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a. Did the discovery of the inaccurate asset balances noted in the passage above impact the deferred CEP plant balances, or the amounts of CEP-includable deferred property tax on Exhibit J, Schedule 7, including (1) the deferred property tax regulatory asset, and (2) the annualized property tax expense? If not, explain fully why not.

b. If the answer to part a is "yes", for each year 2013 through 2018, please identify and quantify (by amount and account), the impacts that the Company's amended property tax filing (i.e., updated asset balances) had on the deferred CEP plant balances and the amounts of deferred property taxes that the Company included in the CEP.

**Set 19 - Submitted on February 28, 2020**

LA-DR-01-148. Incentive Compensation. Refer to the responses to LARKIN-DR-01-022(b) and LARKIN-DR-01-29. With regard to resource types 18400 - Incentives Allocated and 18401 - Incentives Allocated-Union, the

Company indicated that the portion related to DEO's stock price, dividends or financial goals is "30% related to earnings prior to 2018." (emphasis added)

a. What percentage of resource type 18400 - Incentives Allocated related to DEO's stock price, dividends or financial goals during 2018?

b. What percentage of resource type 18401 - Incentives Allocated-Union related to DEO's stock price, dividends or financial goals during 2018?

c. Referring to the response to LARKIN-DR-01-29(c), please confirm that the Short-Term Incentive Plan (STIP) relates to resource types 18400 - Incentives Allocated and 18401 - Incentives Allocated - Union. If not confirmed, please describe the incentive compensation plan(s) to which resource types 18400 and 18401 relate.

LA-DR-01-149. Incentive Compensation. Refer to the supplemental response to LARKIN-DR-01-22 and Exhibit J - Additional Schedules Supporting the Application, Schedule No. 1.

a. Referring to the supplemental attachment to LARKIN-DR-01-22, as it relates to the gross plant incentives which cumulatively totals $574,626 (for the period 2013-2018), please identify by line item where this amount should be reflected on Schedule No. 1 from the Company's filing?

b. Referring to the supplemental attachment to LARKIN-DR-01-22, as it relates to the payroll tax impact which cumulatively totals $41,521 (for the period 2013-2018), please identify by line item where this amount should be reflected on Schedule No. 1 from the Company's filing.

c. Referring to the supplemental attachment to LARKIN-DR-01-22, as it relates to the fringe benefit impact which cumulatively totals $181,870 (for the period 2013-2018) please identify by line item where this amount should be reflected on Schedule No. 1 from the Company's filing.

d. Based on the information shown on the supplemental attachment to LARKIN-DR-01-22, please identify and quantify any other amounts that relate to incentive compensation that should be reflected on Schedule No. 1 from the Company's filing. Show detailed calculations.

**Set 20 - Submitted on March 6, 2020**

LA-DR-01-150. Cloud Computing. Refer to the responses to LARKIN-DR-01-87 and LARKIN-DR-01-137.

a. Were any amounts capitalized for Cloud Computing for affiliates of Duke Energy Ohio - Gas in 2016, 2017 or 2018?

b. If the answer to part a is "yes", were any of those amounts charged or allocated to Duke Energy Ohio - Gas?

c. If the answer to part b is "yes", please identify the amounts that were charged or allocated to Duke Energy Ohio - Gas for each year 2016, 2017 and 2018, in total and by account.

LA-DR-01-151. Work Order Detail. Refer to the response to LARKIN-DR-01-64 and the table below, which reflects 2013 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 380 | 3MCNEW10 | Install New M-C 3" | CEP | 201301 | 2013 | 201611 | additions | Y | $ 162,593 |
| 376 | G8149 | STA 820 Inlet Piping | CEP | 201305 | 2013 | not_unitized | additions | N | $ 33,944 |
| 376 | G8034 | GM emax 2941138 262 Main W | CEP | 201305 | 2013 | 201609 | additions | N | $ 33,881 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201301 | 2013 | 201611 | additions | Y | $ 31,352 |
| 376 | G8152 | STA 821 Inlet Piping | CEP | 201308 | 2013 | not_unitized | additions | N | $ 30,684 |
| 376 | G8150 | STA 820 Outlet Piping | CEP | 201305 | 2013 | not_unitized | additions | N | $ 22,614 |
| 376 | H0664 | Liberty-Fairfield Rd Main Extension | CEP | 201310 | 2013 | 201609 | additions | N | $ 11,540 |
| 380 | 6MCNEW10 | Install New M-C 6" | CEP | 201301 | 2013 | 201611 | additions | Y | $ 11,324 |
| 376 | G9997 | MEA 6020 Kyles Station | CEP | 201309 | 2013 | 201406 | additions | N | $ 9,280 |
| 376 | G9489 | 1 Letitia Amelia OH MEA | CEP | 201304 | 2013 | 201609 | additions | N | $ 8,443 |
| 376 | H0512 | Install Main on Red Oak Ct | CEP | 201309 | 2013 | 201609 | additions | N | $ 7,789 |
| 376 | H0617 | 6480 Hayes Rd Main Extension | CEP | 201310 | 2013 | 201609 | additions | N | $ 7,469 |
| 376 | G9078 | JT emax 3692484 Villages of Daybrk | CEP | 201303 | 2013 | 201609 | additions | N | $ 6,420 |
| 376 | G9945 | JT 4025980 Carriage Hill Sec 6C | CEP | 201311 | 2013 | 201609 | additions | N | $ 6,354 |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

LA-DR-01-152. Work Order Detail. Refer to the response to LARKIN-DR-01-65 and the table below, which reflects 2014 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 380 | 6MCNEW10 | Install New M-C 6" | CEP | 201403 | 2014 | 201611 | additions | Y | $ 70,106 |
| 376 | H0949 | JT emax 4298153 Carriage Hill Sec 7 | CEP | 201406 | 2014 | 201609 | additions | N | $ 57,826 |
| 376 | G9250 | eMax 3550087 10100 Progress Way | CEP | 201303 | 2014 | 201609 | additions | N | $ 54,450 |
| 376 | H1564 | JT 4341043 Oakley Commercial | CEP | 201412 | 2014 | not_unitized | additions | N | $ 51,647 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201401 | 2014 | 201611 | additions | Y | $ 45,815 |
| 376 | H0424 | Al Neyer LLC Install 6" PL | CEP | 201403 | 2014 | 201609 | additions | N | $ 41,684 |
| 380 | H1416 | 501 Race C-M | CEP | 201312 | 2014 | 201804 | additions | N | $ 30,527 |
| 376 | O7105 | Given Rd, Indian Hill MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 27,527 |
| 376 | G6985 | EMAX 3020988 Shaker Run 4B | CEP | 201408 | 2014 | 201502 | additions | N | $ 16,958 |
| 376 | H1510 | Ludlow Place Main Extension | CEP | 201404 | 2014 | not_unitized | additions | N | $ 16,805 |
| 376 | P6520 | Newtown Rd MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 15,010 |
| 376 | H0948 | JT emax 4298153 Carriage Hill Sec 5 | CEP | 201404 | 2014 | 201410 | additions | N | $ 14,549 |
| 376 | H4113 | JT 4767393 Sycamore Place Subd | CEP | 201405 | 2014 | 201609 | additions | N | $ 12,838 |
| 376 | H1006 | GM 4519899 Parks of Whitewater 2A | CEP | 201403 | 2014 | 201501 | additions | N | $ 12,195 |
| 376 | P6302 | Lynn St MEA | CEP | 201411 | 2014 | 201609 | additions | N | $ 11,927 |
| 376 | M2114 | JT 4857601 Windsor Estates Sec 3 | CEP | 201412 | 2014 | 201609 | additions | N | $ 11,436 |
| 376 | H0693 | JT emax 4420066 White Pillars Sec 3 | CEP | 201404 | 2014 | 201609 | additions | N | $ 11,212 |
| 376 | H1123 | Hunt Rd Main Extension | CEP | 201404 | 2014 | 201412 | additions | N | $ 11,195 |
| 376 | G9371 | JT emax 3814873 East Fork Crossing | CEP | 201312 | 2014 | 201609 | additions | N | $ 10,524 |
| 376 | H0231 | JT emax 4095788 Forest Glen Ph 2 | CEP | 201401 | 2014 | 201609 | additions | N | $ 10,393 |
| 376 | H0519 | JT emax 4323503 Woodbury Glen Subd | CEP | 201402 | 2014 | 201609 | additions | N | $ 8,255 |
| 376 | H1394 | JT 4620265 TRAILS OF SHAKER RUN ph4 | CEP | 201405 | 2014 | 201609 | additions | N | $ 7,991 |
| 376 | H0226 | JT emax 4172881 Knolls of Liberty | CEP | 201402 | 2014 | 201609 | additions | N | $ 7,182 |
| 376 | P6304 | Glen Willow Ln MEA | CEP | 201409 | 2014 | 201609 | additions | N | $ 6,893 |
| 380 | 6CMNEW10 | Install New C-M 6" | CEP | 201404 | 2014 | not_unitized | additions | Y | $ (13,088) |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

LA-DR-01-153. Work Order Detail. Refer to the response to LARKIN-DR-01-66 and the table below, which reflects 2015 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 376 | P8043 | Greenshire Ph 1 Subdivison MEA | CEP | 201507 | 2015 | not_unitized | additions | N | $ | 221,512 |
| 376 | G9075 | MOD 506 Addition | CEP | 201409 | 2015 | not_unitized | additions | N | $ | 134,014 |
| 376 | Q1124 | Rumpke Main Extension | CEP | 201507 | 2015 | 201609 | additions | N | $ | 82,939 |
| 376 | P7730 | West Tech Blvd MEA | CEP | 201505 | 2015 | 201609 | additions | N | $ | 58,678 |
| 376 | P3103 | Elizabeth Dr, Batavia MEA | CEP | 201410 | 2015 | 201803 | additions | N | $ | 54,320 |
| 376 | K5111 | Liberty Towne Center | CEP | 201505 | 2015 | not_unitized | additions | N | $ | 53,103 |
| 376 | P7637 | Aston Rd MEA | CEP | 201504 | 2015 | 201609 | additions | N | $ | 51,234 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201501 | 2015 | 201611 | additions | Y | $ | 43,944 |
| 376 | H0632 | Reg 404 - Inlet & Outlet | CEP | 201502 | 2015 | not_unitized | additions | N | $ | 43,597 |
| 376 | R2896 | Compton Rd MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ | 38,160 |
| 376 | O0130 | 800 W 5th St MEA | CEP | 201410 | 2015 | not_unitized | additions | N | $ | 32,505 |
| 376 | R2897 | Potomac Ct MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ | 27,954 |
| 376 | Q9760 | JT 7575703 Parks of Whitewater | CEP | 201509 | 2015 | not_unitized | additions | N | $ | 19,732 |
| 376 | R0093 | Hoskins Ln MEA | CEP | 201510 | 2015 | 201609 | additions | N | $ | 19,498 |
| 376 | R0069 | JT 7611771 Birdhaven Subdivision | CEP | 201510 | 2015 | 201609 | additions | N | $ | 19,304 |
| 376 | P7636 | Clermont Ln MEA | CEP | 201504 | 2015 | 201609 | additions | N | $ | 12,628 |
| 376 | P6757 | T/L CG04 - Install Corrosion Monito | CEP | 201411 | 2015 | not_unitized | additions | N | $ | 12,136 |
| 376 | P6495 | JT 6359913 Willows Bend Sect 3 | CEP | 201503 | 2015 | 201609 | additions | N | $ | 11,046 |
| 376 | H0869 | JT emax 4347751 Falling Brook Ph 2 | CEP | 201401 | 2015 | not_unitized | additions | N | $ | 8,048 |
| 376 | J7111 | JT 5039426 Skr Run PH 5A | CEP | 201503 | 2015 | 201609 | additions | N | $ | 5,535 |
| 376 | P6848 | JT 6089412 Parks of Whitewater | CEP | 201504 | 2015 | 201609 | additions | N | $ | 5,367 |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

LA-DR-01-154. Work Order Detail. Refer to the response to LARKIN-DR-01-67 and the table below, which reflects 2016 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | Charges |
|---|---|---|---|---|---|---|---|---|---|
| 376 | R8276 | GO 10000389 Cargill Main Ext | CEP | 201608 | 2016 | not_unitized | additions | N | $ 1,224,185 |
| 376 | R2759 | Sta 833 Outlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 152,586 |
| 376 | R2675 | STA 834 INLET PIPING | CEP | 201511 | 2016 | not_unitized | additions | N | $ 87,612 |
| 376 | R7262 | GO 9879292 5658 Colonial Dr | CEP | 42522 | 2016 | 201803 | additions | N | $ 79,442 |
| 376 | R2677 | STA 834 OUTLET PIPING | CEP | 201511 | 2016 | not_unitized | additions | N | $ 78,664 |
| 380 | CMNEWS10 | 2" or less Steel new C-M | CEP | 201603 | 2016 | not_unitized | additions | Y | $ 57,514 |
| 376 | S1460 | GO 10048200 8665 Koszo Dr | CEP | 201607 | 2016 | 201803 | additions | N | $ 54,883 |
| 376 | R3318 | Station 831 Inlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 38,911 |
| 376 | S9579 | GO 10953504 Abington | CEP | 201611 | 2016 | 201803 | additions | N | $ 38,154 |
| 376 | S9915 | GO 11380408 Creemer St | CEP | 201611 | 2016 | 201804 | additions | N | $ 33,187 |
| 380 | LMCNEWS10 | Greater than 2" M-C Steel | CEP | 201603 | 2016 | not_unitized | additions | Y | $ 27,659 |
| 376 | R0622 | JT 7971704 Terrace Ridge | CEP | 201601 | 2016 | 201609 | additions | N | $ 23,600 |
| 376 | R3319 | Station 831 Outlet Piping | CEP | 201512 | 2016 | not_unitized | additions | N | $ 22,200 |
| 376 | J7114 | JT 5039499 Shaker Run PH 4E | CEP | 201510 | 2016 | 201609 | additions | N | $ 8,186 |
| 376 | R1478 | JT 8127946 Gilmar Meadows | CEP | 201511 | 2016 | 201609 | additions | N | $ 7,226 |
| 376 | S9605 | GO 11220811 1008 Paxton Guinea | CEP | 201609 | 2016 | not_unitized | additions | N | $ 5,633 |
| 380 | 3CMNEW10 | Install New C-M 3" | CEP | 201601 | 2016 | 201611 | additions | Y | $ (27,819) |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

LA-DR-01-155. Work Order Detail. Refer to the response to LARKIN-DR-01-68 and the table below, which reflects 2017 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 376 | T1665 | GO 11853643 3888 Stillwell Beckett | CEP | 201704 | 2017 | not_unitized | additions | N | $ | 117,905 |
| 376 | S7175 | PRI 10498937 Reilly Millville | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 109,156 |
| 376 | T0787 | GO 11491240 Woodlawn Meadows | CEP | 201703 | 2017 | 201803 | additions | N | $ | 97,135 |
| 376 | MX2014221 | GAS_MAIN_EXT MAPLEWOOD DR | CEP | 201711 | 2017 | 201905 | additions | N | $ | 96,462 |
| 376 | T8739 | GO 21038284 St Peters | CEP | 201709 | 2017 | not_unitized | additions | N | $ | 57,549 |
| 376 | T0735 | GO 10652365 223 Kemp Alley | CEP | 201704 | 2017 | 201804 | additions | N | $ | 49,903 |
| 376 | T4318 | GO 11822737 Amaryllis Ridge | CEP | 201707 | 2017 | not_unitized | additions | N | $ | 46,922 |
| 376 | T1895 | GO 11608626 6416 Manchester Rd | CEP | 201703 | 2017 | not_unitized | additions | N | $ | 46,032 |
| 376 | T4329 | GO 5627256 7447 Gungadin Dr | CEP | 201705 | 2017 | 201804 | additions | N | $ | 42,057 |
| 376 | T0238 | GO 11326499 3402 Kleeman | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 40,281 |
| 376 | T1176 | GO 11577487 Private Dr 50x STANLEY | CEP | 201705 | 2017 | 201804 | additions | N | $ | 38,084 |
| 376 | T8260 | GO 21145279 Bardean Dr | CEP | 201708 | 2017 | not_unitized | additions | N | $ | 35,222 |
| 376 | S9283 | JT 10908562 Whitewater Trails S 1 | CEP | 201703 | 2017 | 201804 | additions | N | $ | 33,179 |
| 376 | T8463 | GO 21022361 Beech Ave | CEP | 201708 | 2017 | not_unitized | additions | N | $ | 31,573 |
| 376 | T2625 | GO 20681592 High St Millville | CEP | 201706 | 2017 | not_unitized | additions | N | $ | 27,006 |
| 376 | T1875 | GO 11726496 954 Phillips Rd | CEP | 201703 | 2017 | 201904 | additions | N | $ | 23,191 |
| 376 | S9797 | GO 11077690 CRESCENT ST MT ORAB | CEP | 201612 | 2017 | 201904 | additions | N | $ | 21,523 |
| 376 | S9734 | GO 10998163 Anthony Lane | CEP | 201612 | 2017 | 201904 | additions | N | $ | 21,309 |
| 376 | T0737 | GO 10719385 11142 Wood Ave | CEP | 201701 | 2017 | not_unitized | additions | N | $ | 20,425 |
| 376 | T1877 | GO 20381631 700 Reisling Knoll | CEP | 201703 | 2017 | not_unitized | additions | N | $ | 16,839 |
| 376 | T6069 | GO 20024030 6815 Station Rd | CEP | 201704 | 2017 | not_unitized | additions | N | $ | 11,553 |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

LA-DR-01-156. Work Order Detail. Refer to the response to LARKIN-DR-01-69 and the table below, which reflects 2018 CEP projects selected for sampling from the referenced response and that are designated as "Additions" under the work type column.

| FERC acct | Project ID number | Project Description | Rider | WO Completion Date (YYYYMM) | In-Service Date | Unitization Date (YYYYMM) | work type | Blanket Project? | | Charges |
|---|---|---|---|---|---|---|---|---|---|---|
| 376 | MEAPJT10 | Joint Trench plasitc main extension | CEP | 201602 | 2018 | 201909 | additions | Y | $ | 2,175,022 |
| 376 | S9991 | Struble Rd Extension (Montauk) | CEP | 201707 | 2018 | not_unitized | additions | N | $ | 772,408 |
| 380 | LMCNEWP10 | Greater than 2" M-C Plastic | CEP | 201801 | 2018 | not_unitized | additions | Y | $ | 500,646 |
| 376 | MX2243582 | MEA; 2160 FT PL-IP; CLOUGH PK; JARO | CEP | 201806 | 2018 | 201901 | additions | N | $ | 164,734 |
| 376 | MX2209811 | 4" PL-IP main extension to feed 3 n | CEP | 201802 | 2018 | not_unitized | additions | N | $ | 121,513 |
| 380 | LCMSP10 | ASRP Greater than 2" C-M Install | CEP | 201803 | 2018 | not_unitized | additions | Y | $ | 93,180 |
| 376 | MX2130953 | INSTALL GAS MAIN, 7301 DALEVIEW RD, | CEP | 201801 | 2018 | 201901 | additions | N | $ | 68,012 |
| 376 | MX0740807 | 1115' 4" PLASTIC MEA - ROAD IMPROVE | CEP | 201801 | 2018 | not_unitized | additions | N | $ | 63,773 |
| 376 | MX2488132 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201805 | 2018 | not_unitized | additions | N | $ | 55,651 |
| 376 | T8215 | GO 21003182 Cross Creek | CEP | 201709 | 2018 | not_unitized | additions | N | $ | 45,701 |
| 376 | T8085 | GO 21085124 Candy Ln | CEP | 201706 | 2018 | not_unitized | additions | N | $ | 25,677 |
| 376 | MX8117481 | MEA PROJECT; 7731 DONES AVE ; MADEI | CEP | 201807 | 2018 | 201904 | additions | N | $ | 22,822 |
| 376 | MX7773849 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201810 | 2018 | not_unitized | additions | N | $ | 11,580 |
| 376 | T8655 | GO 20668365 Socialville Foster Rd | CEP | 201710 | 2018 | not_unitized | additions | N | $ | 9,583 |
| 376 | MX2102443 | INSTALL GAS ONLY APPROACH MAIN - NE | CEP | 201712 | 2018 | not_unitized | additions | N | $ | 6,867 |

a. Are any of the CEP projects listed above related to the Company adding new customers? If not, explain fully why not.

b. If the answer to part a is "yes", for each CEP project, please specify the number of new customers that are being served as a result of the addition of each such CEP project.

c. Are any of the projects listed above related to the Company expanding its gas operations? If not, explain fully why not

d. If the answer to part c is "yes", for each CEP project, please explain fully and in detail the reason(s) for expanding the Company's gas operations by adding each such project.

e. Are the CEP projects listed in the table above revenue generating? If so, explain fully.

**<u>Set 21 - Submitted on March 11, 2020</u>**

LA-DR-01-157. Enable system cost charged to Duke Energy Ohio Gas utility.

a. Please confirm that the Cost Allocation Manual (CAM) based allocation factors for Duke Energy Ohio Gas (Business Unit 75026) for each year are as follows and provide the related pages from each year's CAM:

   1) 2014 CAM: 5.43%
   2) 2015 CAM: 5.41%
   3) 2016 CAM: 5.34%
   4) 2017 CAM: 5.30%

b. Please identify the Enable system cost for each year, 2014 through 2018.

c. Please show in detail how the Enable system cost for each year, 2014 through 2018, were allocated to DEO Gas.

d. Please show in detail how the Enable system cost for each year, 2014 through 2018, would have been allocated to DEO Gas in each year if the CAM allocation percent used had been updated for each year.

e. Please identify how much Enable system cost is being requested in the CEP for each year, 2013 through 2018.

f. Please identify how much Enable system cost would be included in the CEP for each year, 2013 through 2018, if the CAM percentage allocation to DEO Gas was updated each year. Include supporting calculations.

g. Please identify the Enable projects/applications and the related cost for each year, 2014 through 2018, that were determined to benefit the six Duke electric distribution utilities and two gas distribution utilities.

h. Was the 2014 CAM-based allocation to Duke Energy Ohio Gas of 5.43% used in each year for the costs for the Enable projects/applications identified in response to part g? If not, what allocation percentage was used for each project/application.

i. Please identify the Enable projects/applications and the related cost for each year, 2014 through 2018, that were determined to benefit the wider range of Duke business units including five electric transmission, seven electric distribution utilities and two gas distribution utilities.

j. Please identify the CAM allocation percentage for each year for the electric transmission business units for the 2014 through 2018 CAMs.

k. Please show in detail how the cost of the Enable projects/applications for each year, 2014 through 2018, that were determined to benefit the wider range of Duke business units (including electric transmission, electric distribution utilities and gas distribution utilities, etc.) were allocated to Duke Energy Ohio Gas. Include supporting calculations.

l. Please show in detail how the cost of the Enable projects/applications for each year, 2014 through 2018, that were determined to benefit the wider range of Duke business units (including electric transmission, electric distribution utilities and gas distribution utilities, etc.) would have been allocated to Duke Energy Ohio Gas in each year if the transmission allocation was updated each year per the annual CAM updates and the Duke Energy Ohio Gas CAM-based allocation was updated each year per the annual CAM updates. Include supporting calculations.

## Set 22 - Submitted on March 16, 2020

LA-DR-01-158. Dicks Creek Change Orders. Refer to the responses to LARKIN-DR-01-103 and LARKIN-DR-01-146 and the table below.

| Description | DEO Comments/Reasons for Change Order | Change Order Amount |
|---|---|---|
| PO 5138604 | 12-inch Direct Bury - SOD 205 units at $300 05 per unit - This item not on original bid | $ 61,510 23 |
| Equipment and Labor Sheet L32781 | T-M for breaking rock & overtime for Friday (7-14-2017) & Saturday (7-15-2017) | $ 18,164 67 |
| Equipment and Labor Sheet L32783 | Installing parking area outside fence, digging around old odorant tank; breaking rock | $ 9,402 94 |
| Equipment and Labor Sheet L33322 | Breaking rock Friday (8-11-2017) and Saturday (8-12-2017); Overtime at cut rate | $ 7,442 46 |
| Equipment and Labor Sheet L33323 | T&M includes premium time; breaking rock; cleaning up & pipe supports; moving valves & piping next to monitor skid and reinstalling | $ 11,985 02 |
| Equipment and Labor Sheet L32781 | T-M for breaking rock & overtime for Friday (7-14-2017) & Saturday (7-15-2017) | $ 18,164 67 |
| Equipment and Labor Sheet L35097 | Breaking rock - premium items (Friday & Saturday) | $ 10,753 64 |
| Equipment and Labor Sheet L35449 | Breaking rock: Spurlino ($468 91); Pac Van ($362 70); Gas for job trailer ($156 09); Rumpke ($728 53) | $ 7,950 95 |
| Equipment and Labor Sheet L35451 | Install additional flanges not on print | $ 50,028 32 |
| Equipment and Labor Sheet L35452 | Offsets not on print | $ 41,824 80 |
| | Total | $ 237,227 70 |

Source: LARKIN-DR-01-103 and LARKIN-DR-01-146

a. With regard to PO 5138604, please explain fully and in detail why these items, which totaled $61,510, were not on the original bid for the Dicks Creek project.

b. For each of the Equipment and Labor Sheet items listed in the table above, please explain fully and in detail (beyond the Company's comments/reasons listed) the reason for each change order and provide supporting documentation for the amounts shown (beyond what was provided in response to LARKIN-DR-01-103).

## Set 23 - Submitted on March 19, 2020

LA-DR-01-159. Correction of Errors. Refer to Exhibit J - Additional Schedules Supporting the Application and the responses to LARKIN-DR-01-75 and LARKIN-DR-01-136. The response to LARKIN-DR-01-136 indicates that, due to certain incorrectly being included in CEP, the CEP balances in Exhibit J, Schedule 4 - Monthly Investments should be reduced by $40,622 for 2013, increased by $14,661 for 2014 and reduced by $531,609 for 2015.

a. Please confirm that the adjustments noted above should be reflected in Exhibit J, Schedule 4 - Monthly CEP Investments on the Net Assets line which totals $297,475,290. If not confirmed, explain fully why not and show where these adjustments should be reflected on Exhibit J, Schedule 4.

b. For the 2013 amount of $40,622, please quantify any amounts related to accumulated depreciation and ADIT and identify where they should be reflected on Exhibit J as a result of this adjustment. Show detailed calculations.

c. For the 2014 amount of $14,661, please quantify any amounts related to accumulated depreciation and ADIT and identify where they should be reflected on Exhibit J as a result of this adjustment. Show detailed calculations.

d. For the 2015 amount of $531,609, please quantify any amounts related to accumulated depreciation and ADIT and identify where they should be reflected on Exhibit J as a result of this adjustment. Show detailed calculations.

e. Please confirm whether each of the adjustment amounts noted above, or the net adjustment of $557,570, should be multiplied by 5.32% in order to quantify the impact of these adjustments on the Post In-Service Carrying Cost (PISCC) related regulatory asset. If not confirmed, explain fully why not and quantify the impact(s) of these adjustments to the PISCC regulatory asset of $29,592,179.

LA-DR-01-160. Incentive Compensation. Refer to Exhibit J on the tab titled "WP4.1 - Assets by FERC" and the responses to LARKIN-DR-01-76 and LARKIN-DR-01-149. The response to LARKIN-DR-01-149, part d states: "See Schedule 13 in LARKIN-DR-01-149 Attachment, which includes all additional amounts and calculations that should be reflected in the final offset in Schedule No. 1, including the calculations for book depreciation, accumulated deferred income taxes, and various assumptions that would need to be made, such as composite book and tax life of the underlying assets." In addition, the response to LARKIN-DR-01-76, part a states that the amounts of incentive compensation are embedded in the CEP investment detail on "WP4.1 - Assets by FERC."

a. Based on the foregoing statement from the response to LARKIN-DR-01-149(d), please confirm that the line items on Schedule No. 1 for depreciation and ADIT should not also be adjusted for the removal of the earnings based capitalized incentives. If not confirmed, explain fully why not.

b. Since the amounts of incentive compensation are embedded in WP4.1 - Assets by FERC, should not the Post In-Service Carrying Costs (PISCC) amount of $29,592,179 also be adjusted to reflect the removal of the earnings based capitalized incentives? If not, explain fully why not.

c. If the answer to part b is "yes", please quantify the impact of removing the earnings based capitalized incentives in the context of the PISCC. Show detailed calculations.

## <u>Set 24 - Submitted on April 6, 2020</u>

LA-DR-01-161. Meters. Refer to Exhibit J, Schedule 4 - Monthly CEP Investments, the responses to LARKIN-DR-01-91 and LARKIN-DR-01-135, and the table below.

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

| Line | Description | Sum of 2012 | Sum of 2013 | Sum of 2014 | Sum of 2015 | Sum of 2016 | Sum of 2017 | Sum of 2018 |
|---|---|---|---|---|---|---|---|---|
| 1 | Total Meters in service per LA-DR-91(a) | 452,966 | 452,292 | 453,127 | 454,695 | 457,084 | 459,524 | 461,370 |
| 2 | Net Installs, Retirements, Replacements per LA-DR-91(d) | | (674) | 835 | 1,568 | 2,389 | 2,440 | 1,846 |
| | | | | | | | | |
| 3 | Number of meters purchased per year per LA-DR-91(h) | | 6,790 | 4,227 | 4,430 | 8,276 | 4,926 | 5,070 |

a. Based on the Company's response to LARKIN-DR-01-135(a), please confirm that all of the meters reflected in the table above are gas diaphragm meters. If not confirmed, explain fully why not and identify the type(s) of meters.

b. Referring to LARKIN-DR-01-135 (parts a & c), please explain fully and in detail the purpose of the new meters in each year 2013-2018 (e.g, to serve new customers, to replace old meters that had reached the end of their anticipated useful life, to replace defective meters, etc.).

c. Referring to lines 1 and 2 in the table above, are the costs associated with the total meters the costs that were provided in the response to LARKIN-DR-01-135 (part b for 2013 and part d for 2014-2018)? If not, explain fully why not.

d. If the answer to part c is "no", please quantify the costs of the total DEO gas utility meters on line 1 in the table above for each year 2012 through 2018.

e. Referring to line 2 in the table above, please provide a breakout showing the (1) installs, (2) retirements, and (3) replacements.

f. Please provide a breakout of the costs associated with the net installs, retirements and replacements.

g. Referring to the table above, for each year 2013 through 2018, are the costs associated with the total meters on line 1 (which includes the amounts on line 2) embedded in Exhibit J, Schedule 4 - Monthly CEP Investments? Explain fully.

h. Referring to the table above, are the amounts shown on line 3 for meters purchased actually in service (since they do not appear to be included in the total meters in service on line 1)? If not, explain fully why not. If so, explain fully.

i. Please quantify the costs of the purchased meters on line 3 in the table above for each year 2013 through 2018.

j. For 2013 through 2018, are the costs of the purchased meters on line 3 in the table above included in Exhibit J, Schedule 4 - Monthly CEP Investments? Explain fully.

k. Referring to the LARKIN-DR-01-135(d) and the related Attachment, for each year 2013-2018, please provide the per meter cost for each year as originally requested.

l. Referring to the LARKIN-DR-01-135 Attachment, for each year 2013-2018, please explain fully and in detail why the gas diaphragm meters listed in part f were retired (e.g., the meters had reached the end of their useful life, the meters were defective and failed and thus had to be replaced before the anticipated end of their useful life, the meter technology was determined by DEO to be obsolete and thus required the replacement of the meters, etc.).

m. Referring to the LARKIN-DR-01-135 Attachment, for each year 2013-2018, please confirm that the original cost of the gas diaphragm meters listed in part g relates to the retired gas diaphragm meters listed in part f. In addition, please state whether the original costs of the retired gas diaphragm meters listed in part g are embedded in Exhibit J, Schedule 4 - Monthly CEP Investments (and WP4.2 - Retirements by FERC). If not, explain fully why not.

LA-DR-01-162. Meters. Refer to Exhibit J, Schedule 4 - Monthly CEP Investments and the responses to LARKIN-DR-01-35, LARKIN-DR-01-77, LARKIN-DR-01-129 and LARKIN-DR-01-130.

a. Referring to the LARKIN-DR-01-35 Attachment (2013-2018 project work orders) and the LARKIN-DR-01-129 Attachment for Additions, please confirm that (1) the 2017 amount of $90,161 for Project SGOGPGMTR, and (2) the three 2018 amounts totaling $7,489,610 for Project SG000584G are the only costs included in the CEP filing (i.e., Exhibit J, Schedule 4 - Monthly CEP Investment) that relates to the Company changing the Badger AMI gas modules from the Echelon/Badger/Ambient AMI solution to the Itron Openway. If not confirmed, explain fully, and identify the amounts included in the CEP.

b. The response to LARKIN-DR-01-77 states that the Company's project to replace the communication modules did not start until 2017. Based on the foregoing, why were communication nodes removed in 2015 and 2016 (per the LARKIN-DR-01-129 Attachment for Retirements)? Explain fully.

c. Referring to the LARKIN-DR-01-129 Attachment for Retirements, for 2015 and 2016, please reconcile the retirements shown by project ID number to the type(s) of communication nodes that were removed.

d. Referring to the LARKIN-DR-01-129 Attachment for Retirements, why are the 2016 retirement amounts of $16,322,006 and

$5,610,769 (for a total of $21,932,775) for work order SGGASMTR positive amounts? Was the $21,932,775 credited to plant and debited to accumulated depreciation? Explain fully.

e. Referring to the LARKIN-DR-01-129 Attachment for Retirements, how are the retirements listed for 2015 and 2016 reflected on Exhibit J, Schedule 4 - Monthly CEP Investments (and WP4.2 - Retirements by FERC)? Explain fully.

f. Referring to LARKIN-DR-01-130, part d, show in detail how the depreciation expense related to the common assets is allocated between DEO electric and gas and state whether any portion allocated to electric is included in the CEP.

g. Referring to LARKIN-DR-01-130(e), please clarify whether the Itron OpenWay is 5G compatible. In the event Itron OpenWay is not 5G compatible, how does the Company plan to address this issue when the current 3G technology sunsets in 2022? Explain fully.

**<u>Set 25 - Submitted on April 9, 2020</u>**

LA-DR-01-163. Line A preexisting pipe risk analysis. Please identify and provide the risk rankings prepared by the Integrity Management Group which ranked the risk associated with approximately 2,000 feet of 18 inch pipe that were involved with the Line A pipe replacement project, showing in detail how the risk of that pipe was determined, and how that risk was compared and evaluated in comparison to the risks associated with other pipeline segments on Duke Energy Ohio's natural gas distribution system. Please include a copy of the related documents with your response.

LA-DR-01-164. Eastern Gas Ops Center, employee fitness center.

a. How much of the $16.844 million cost of the New Eastern Gas Ops Center, Project T1666 (from the response to LARKIN-DR-01-68) is for the employee fitness center at that location?

b. What is the actual or approximate square footage of the employee fitness center at that location?

c. What equipment and furniture is located in the employee fitness center?

d. What is the cost of that fitness center equipment and furniture? Please explain and identify the related cost amounts by account.

e. What is the approximate square footage of the finished office and conference room space at the New Eastern Gas Ops Center?

# Case No. 19-0791-GA-ALT
# Plant in Service and Capital Spending Prudence Audit
# Of Duke Energy Ohio, Inc. (Natural Gas)

## Set 26 - Submitted on April 21, 2020

LA-DR-01-165. Enable Project. Refer to the responses to LARKIN-DR-01-35, LARKIN-DR-01-75, LARKIN-DR-01-157 and the table below. The response to LARKIN-DR-01-157(e) states that the Enable Project costs being requested for recovery in the CEP is $9,425,319 for 2017 and $204,390 in 2018 for an overall total of $9,629,709. However, as shown in the table below, which is from the response to LARKIN-DR-01-35, Enable Project costs totaling $12,816,118, or a difference of $3,186,409, is included in CEP for 2017 and 2018.

| Line No. | FERC Account | Project ID Number | Project Description | Rider | Work Order Completion | In-Service Date | Unitization Date | Work Type | Blanket Project | Charges | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2017 Enable Project Costs** | | | | | | | | | | |
| 1 | 303 | ARCGS | Enable ArcGIS/ESRI Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 650,376.25 | |
| 2 | 303 | ARMS | Enable ARM Scheduler Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 609,300.60 | |
| 3 | 303 | ECOMS | Enable ECOM Data Hub Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 362,820.70 | |
| 4 | 303 | EGISS | Enable EGIS Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 2,080,857.24 | |
| 5 | 303 | EXPDS | Enable Expert Designer Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 466,125.75 | |
| 6 | 303 | MAXS | Enable Maximo Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 4,188,787.27 | |
| 7 | 303 | PPS | Enable PowerPlan Software | Non Rider Related | 201708 | 2017 | 201904 | additions | N | $ 181,330.28 | |
| 8 | 303 | SDDTS | Enable Subdiv Design Tool Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 351,799.73 | |
| 9 | 303 | WRTS | Enable WRT & WMSP Software | Non Rider Related | 201708 | 2017 | not_unitized | additions | N | $ 533 920.84 | |
| 10 | | | | | | | | **per LA-DR-157(e)** | | **$ 9,425,318.66** | Note A |
| 11 | 303 | MOBS | Enable Mobility Software | CEP | 201708 | 2017 | not_unitized | additions | N | $ 2,621,598.97 | |
| 12 | 391 | ARCGH | Enable ArcGIS/ESRI Hardware | CEP | 201708 | 2017 | 201904 | additions | N | $ 1,043.68 | |
| 13 | 391 | ARMH | Enable ARM Scheduler Hardware | CEP | 201708 | 2017 | 201907 | additions | N | $ 118.31 | |
| 14 | 391 | ECOMH | Enable ECOM Data Hub | CEP | 201708 | 2017 | 201907 | additions | N | $ 2,265.74 | |
| 15 | 391 | EGISH | Enable EGIS Hardware | CEP | 201708 | 2017 | 201904 | additions | N | $ 3,316.96 | |
| 16 | 391 | EXPDH | Enable Expert Designer Hardware | CEP | 201708 | 2017 | 201904 | additions | N | $ 279.74 | |
| 17 | 391 | MAXH | Enable Maximo Hardware | CEP | 201708 | 2017 | 201907 | additions | N | $ 24,066.28 | |
| 18 | 391 | MOBH | Enable Mobility Hardware | CEP | 201708 | 2017 | not_unitized | additions | N | $ 486,915.99 | |
| 19 | 391 | SDDTH | Enable Subdiv Design Tool Hardware | CEP | 201708 | 2017 | not_unitized | additions | N | $ 53.04 | |
| 20 | 391 | WRTH | Enable WRT & WMSP Hardware | CEP | 201708 | 2017 | not_unitized | additions | N | $ 76.21 | |
| 21 | | | | | | | | **Total 2017 per LA-DR-35** | | $ 12,565,053.58 | Total 2017 per LA-DR-35 |
| | **2018 Enable Project Costs** | | | | | | | | | | |
| 22 | 303 | ARCGS | Enable ArcGIS/ESRI Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 11,531 | |
| 23 | 303 | ARMS | Enable ARM Scheduler Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 15,294 | |
| 24 | 303 | ECOMS | Enable ECOM Data Hub Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 7,084 | |
| 25 | 303 | EGISS | Enable EGIS Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 36,068 | |
| 26 | 303 | EXPDS | Enable Expert Designer Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 23,200 | |
| 27 | 303 | MAXS | Enable Maximo Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 87,058 | |
| 28 | 303 | SDDTS | Enable Subdiv Design Tool Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 11,501 | |
| 29 | 303 | WRTS | Enable WRT & WMSP Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 12,654 | |
| 30 | | | | | | | | **per LA-DR-157(e)** | | **$ 204,390** | |
| 31 | 303 | MOBS | Enable Mobility Software | CEP | 201708 | 2018 | not_unitized | additions | N | $ 46,674 | |
| 32 | | | | | | | | **Total 2018 per LA-DR-35** | | $ 251 064 | |
| 33 | | | | | | | | **Total 2017-2018 per LA-DR-35** | | $ 12,816,117.66 | L12 + L23 |
| 34 | | | | | | | | **2017 Enable Costs in CEP per LA-DR-157(e)** | | $ 9,425,318.66 | Line 10 |
| 35 | | | | | | | | **2018 Enable Costs in CEP per LA-DR-157(e)** | | $ 204,390 | Line 30 |
| 36 | | | | | | | | **Total in CEP per LA-DR-157(e)** | | $ 9 629 709.11 | |
| 37 | | | | | | | | **Difference also included in CEP per LA-DR-35** | | $ 3,186,408.55 | L33 - L36 |

Notes

Note A The response to LA-DR-75 indicates that the projects totaling $9,425,319 were incorrectly labeled in the response to LA-DR-35 and should be in CEP

a. Please clarify whether the additional Enable Project costs that total $3,186,409 are also included in CEP (in addition to the $9,629,709 per LARKIN-DR-01-157).

b. If the answer to part a is "yes", why did the response to LARKIN-DR-01-157(e) state that only the $9,425,319 (2017) and $204,390 (2018) were included in CEP? Explain fully.