Docket No. 17-2009-EL-RDR

Compliance Audit of the 2017 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

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Prepared by
Blue Ridge Consulting Services, Inc.
114 Knightsridge Road
Travelers Rest, SC 29690
(864) 836-4497

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DISCLAIMER

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

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ORGANIZATION OF BLUE RIDGE'S REPORT

This report is organized according to the following major sections:

- *Executive Summary*: This section provides a summary of Blue Ridge's observations, findings, conclusions, and recommendations that are presented in more detail in the body of the report.
- *Summary of Blue Ridge Recommendations*: This section contains a listing of recommendations resulting from the 2016 Rider DCR audit.
- *Overview of Investigation*: This section includes discussion of these topics: background; project purpose; project scope; audit standard; information reviewed; description of the Rider DCR Compliance Filings reviewed; and a brief summary of the variance analyses, transactional testing, and other analyses.
- *Prior Compliance Audits Recommendations Status*: This section presents the current status of the Companies implementation of recommendations from prior DCR Rider audits.
- *Findings and Recommendations*: This section documents Blue Ridge's analysis that led to our observations, findings, and recommendations regarding the components that comprise Rider DCR. In several instances, Blue Ridge used information obtained from the prior audits of the 2011, 2012, 2013, 2014, 2015, and 2016 Riders DCR in this report. The information used is labeled to show that it was obtained during the prior audits and is provided with the workpapers supporting this report.

The report also contains appendices.

Blue Ridge prefaced each scope area with the objective of the tasks planned to accomplish that area's review. The scope of the audit includes an overview of the processes' and controls' policies and procedures that affect the categories that feed into the Rider DCR calculations. A set of variance analyses reviews significant changes in net plant and reserve by individual FERC account.

The scope also includes review of each component of Rider DCR. The Rider DCR specific exclusions are addressed in the subsection labeled Riders LEX, EDR, AMI, and General Exclusions, followed by analyses of jobbing, contracting, and mutual aid activities; gross plant in service; accumulated reserve for depreciation; accumulated deferred income taxes; depreciation expense; property tax expense; allocated Service Company; Commercial Activity Tax (CAT) and income taxes; and the return component. The report concludes with a review of the calculation of revenue requirements, followed by a review of the projections for the first quarter 2018.

EXECUTIVE SUMMARY

The FirstEnergy Service Company, on behalf of the three Ohio-regulated operating companies—The Cleveland Electric Illuminating Company (CE, CEI, or CECO), Ohio Edison Company (OE or OECO), and The Toledo Edison Company (TE or TECO), collectively referred to as "FirstEnergy" or "Companies"—prepared and submitted Compliance Filings regarding the Commission-approved Delivery Capital Recovery (DCR) Rider for actual plant in service through November 30, 2017, and estimated plant in service through February 28, 2018. Blue Ridge Consulting Services, Inc. ("Blue Ridge") was retained to perform a compliance audit of the filings.

BACKGROUND

Ohio's electric law, Senate Bill 221, requires electric utilities to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO), Section 4928.142 Revised Code, or an electric security plan (ESP), Section 4928.143 Revised Code. The Companies filed an application for approval of an ESP in Case No. 10-388-EL-SSO ("ESP II Case"). A majority of the parties in the case entered into an original stipulation and two supplemental stipulations (collectively, "Combined Stipulation"), and after a hearing, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order approving the Combined Stipulation in its entirety on August 25, 2010.

As part of its Opinion and Order, the Commission approved the establishment of the Rider DCR, effective January 1, 2012, to be updated and reconciled quarterly. The Opinion and Order allowed the Companies the opportunity to recover property taxes, Commercial Activity Tax, and associated income taxes, and to earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company, which was not included in the rate base determined in the Opinion and Order of January 21, 2009, in Case No. 07-551-EL-AIR (last rate case). On April 13, 2012, FirstEnergy filed an application for its next ESP, which was largely an extension of the Combined Stipulation, which the Commission approved with modifications on July 18, 2012, in Case No. 12-1230-EL-SSO ("ESP III Case"). The Rider DCR was extended with modifications by Order dated 31, 2016, and reaffirmed on October 12, 2016, in Case No. 14-1297-EL-SSO ("ESP IV Case").

The Commission ordered an annual audit review of its Rider DCR for the purpose of determining whether the amounts for which recovery is sought are not unreasonable in light of the facts and circumstances known to the Companies at the time such expenditures were committed. The agreement also stipulated that, at the Commission's discretion, either an independent third party auditor or the Commission's Staff would conduct the annual audit review.

The Commission's Request for Proposal (RFP) sought proposals to audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR since the Companies' last Rider DCR Compliance Audit. Blue Ridge submitted a proposal and was selected to perform the 2017 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, 2015, and 2016 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2016).

PURPOSE OF PROJECT

As defined in the RFP, the purpose of the project included the following:

- Audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR with regard to the return earned on plant-in-service since the Companies' last Rider DCR Compliance Audit.
- Identify capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions to ensure they are excluded from Rider DCR.
- Identify, quantify, and explain any significant net plant increase within individual accounts.
- Assess the substantive implementation of the provisions contained within the Joint Stipulation and Recommendations filed in Case No. 14-1929-EL-RDR.

PROJECT SCOPE

The audit as defined in the RFP will address the following project scope:

> Determine if FirstEnergy has implemented its Commission-approved DCR Rider and is in compliance with the Combined Stipulation agreement set forth in Case No. 10-388-EL-SSO, as extended with modifications in Case No. 14-1297-EL-SSO.

As required by the RFP, Blue Ridge reviewed appropriate information associated with the stipulation and prior cases associated with the implementation of Rider DCR. During the course of the audit, Blue Ridge reviewed the compliance filings, developed transactional testing using statistically valid sampling techniques, and performed other analyses to allow Blue Ridge to determine whether the costs included in the Rider DCR were not unreasonable.

FINDINGS AND RECOMMENDATIONS

Determine if the Companies implemented their Commission-approved Rider DCR and if the Companies are in compliance with the Combined Stipulation agreement set forth in the Opinion and Order issued in Case No. 10-388-EL-SSO and continued in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO.

OVERALL IMPACT OF FINDINGS ON RIDER DCR REVENUE REQUIREMENTS

Blue Ridge's review found several items that have an impact on Rider DCR Revenue Requirements, including adjustments for plant recovered through other riders that were not excluded, non-utility plant, vegetation management expenditures that should not be charged to plant, inconsistent formulas to calculated depreciation expenses, and failure to record a regulatory liability to reflect a refund of the excess deferred taxes owed to ratepayers because the Companies historically collected federal tax expense at 35% but will later pay the deferred portion to the federal government at 21%. The flow-through of these adjustments has the following impact on the DCR.

Table 1: Impact of Blue Ridge's Findings on Rider DCR Revenue Requirement

Adj #	Description	CEI	OE	TE	Total
	As Filed	**$ 140,265,193**	**$ 147,036,276**	**$ 36,860,287**	**$ 324,161,756**
1	Intercompany Transfer Error	-	702	-	702
2	Rider EDR(g) Wrong Amounts	(137)	-	-	(137)
3, 4	Dropped	-	-	-	-
5	Non-Utility Property	-	-	(153,555)	(153,555)
6, 7, 8	Vegetation Mgmt-Expense	(1,637,487)	(1,590,203)	(451,052)	(3,678,742)
9	ATSI Not Excluded	-	(3,458)	-	(3,458)
10	Delayed Retirement	-	-	-	-
11	AFUDC Overstated	(6,208)	-	-	(6,208)
12	Inconsistent Depreciation	(97,846)	(22,701)	-	(120,547)
13	Regulatory Liability	(20,099,373)	(24,379,378)	(6,447,244)	(50,925,996)
14	Delayed Retirement	-	-	-	-
15	Delayed Retirement	-	-	-	-
16	Delayed Retirement	-	-	-	-
17	Delayed Retirement	-	-	-	-
	Impact of All Adjustments	**(21,841,052)**	**(25,995,039)**	**(7,051,850)**	(54,887,940)
	Recommended Adjusted Rider DCR Revenue Requirements	**$ 118,424,142**	**$ 121,041,237**	**$ 29,808,437**	**$ 269,273,815**

Processes and Controls

Blue Ridge was able to obtain an understanding of the Companies' processes and controls that affect each of the categories within Rider DCR. Furthermore, we were satisfied with actions taken with regard to internal audits and the process and control of the prior Rider DCR recommendations. Based on information reviewed, Blue Ridge concluded that the Companies' controls were adequate and not unreasonable. However, the Companies' internal audit that addressed three prior Rider DCR recommendations suggested additional recommendations that Blue Ridge determined were not unreasonable. Blue Ridge recommends reviewing in next year's DCR audit whether those recommendations were implemented.

Blue Ridge does recommend implementation of the improvement opportunity identified in the Fleet Services audit: all FirstEnergy companies, not just the utility companies, should be allocated the costs of Fleet Services costs since it is a shared services organization. Additionally, internal auditors recommended, on the basis of the FirstEnergy Utilities Major Storm Back Office Review Process audit, that the Company design and implement an invoice review process for less significant major storms. Since the cost of storms, and their capital or expense designation, relates to the DCR process, Blue Ridge recommends that once an invoice review process has been implemented, it be reviewed as part of the DCR audit process.

Variance Analysis

Examining the differences of account balances associated with Rider DCR calculations helps determine the trustworthiness of the DCR development.

In the current audit of the DCR year 2017, Blue Ridge evaluated several changes and variances in account balances:

- 2017 Plant Additions, Retirements, Transfers, and Adjustments
- Year-to-Year DCR Filing Plant-In-Service Balances
- Year-to-Year DCR Filing Reserve Balances

- Year-to-Year DCR Filing ADIT Balances
- Year-to-Year DCR Filing Service Company Balances
- End-of-year 2016 DCR Filing to 2016 FERC Form 1 Plant-in-Service Balances
- 2017 Work Order Population totals to 2017 DCR Filing Year-to-Year Plant-In-Service Activity

In the review of *2017 Plant Additions, Retirements, Transfers, and Adjustments*, Blue Ridge examined data associated with 22 accounts. As a result of our analysis, Blue Ridge was satisfied with the changes in plant additions, retirements, adjustments, and transfers. However, Blue Ridge noted that four of the explanations for adjustments were in regard to originally unitizing to the wrong utility account. Although there are thousands of work orders unitized, the bulk are single units of property and auto-closed through WMS. The frequency with which this error has occurred among manually addressed work orders leads Blue Ridge to recommend that the Company review its unitization process for work orders to determine whether additional control can be implemented to ensure more accurate recording.

In the review of *Year-to-Year DCR Filing Plant-In-Service Balances*, Blue Ridge compared Plant-in-Service account balances (FERC 300-series accounts) from DCR year-end November 30, 2016 with the year-end November 30, 2017 filing.

The following table is a summary schedule of the net plant changes by classification of plant (i.e., Transmission, Distribution, General, and Intangible Plant). As this table shows, FirstEnergy's operating companies increased gross plant (including allocation of Service Company Plant) by $117.0 million, $122.8 million, and $30.4 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 4.0%, 3.7%, and 2.6% for CE, OE, and TE, respectively.

Table 2: Adjusted Plant Change from 11/30/2016 to 11/30/2017

Line No.	Account Title	Adjusted Balance 11/30/16	Adjusted Balance 11/30/17	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 431,628,975	$ 435,758,661	$ 4,129,686	1.0%
3	Distribution	2,217,333,891	2,310,562,922	93,229,031	4.2%
4	General	156,348,800	162,226,119	5,877,319	3.8%
5	Other	56,089,957	62,828,422	6,738,465	12.0%
6	Service Company Allocated	93,710,646	100,737,744	7,027,098	7.5%
7	**Total Cleveland Electric Illuminating Company**	**$ 2,955,112,269**	**$ 3,072,113,868**	**$ 117,001,599**	**4.0%**
8	**Ohio Edison Company**				
9	Transmission	$ 213,163,308	$ 214,517,354	$ 1,354,046	0.6%
10	Distribution	2,764,255,371	2,856,769,311	92,513,940	3.3%
11	General	178,984,926	189,827,704	10,842,778	6.1%
12	Other	81,134,820	90,743,432	9,608,612	11.8%
13	Service Company Allocated	113,560,685	122,076,281	8,515,596	7.5%
14	**Total Ohio Edison Company**	**$ 3,351,099,110**	**$ 3,473,934,082**	**$ 122,834,972**	**3.7%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,474,270	$ 22,815,338	$ 341,068	1.5%
17	Distribution	986,294,036	1,010,056,944	23,762,908	2.4%
18	General	74,463,450	74,842,863	379,413	0.5%
19	Other	26,720,165	28,912,125	2,191,960	8.2%
20	Service Company Allocated	49,987,804	53,736,249	3,748,445	7.5%
21	**Total Toledo Edison Company**	**$ 1,159,939,725**	**$ 1,190,363,519**	**$ 30,423,794**	**2.6%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,466,151,104**	**$ 7,736,411,469**	**$ 270,260,365**	**3.6%**

In the review of *Year-to-Year DCR Filing Reserve Balances*, Blue Ridge examined in detail seven specific reserve account variances of concern. The Companies provided information satisfying our concerns in six of the seven accounts. One of the accounts—OE's Account 389 Land & Land Rights—was a concern because it carried a negative balance. The Companies responded that in this instance, an intercompany transfer had been incorrectly recorded as a retirement. Blue Ridge recommends an adjustment to correct this error.

In the review of *Year-to-Year DCR Filing ADIT Balances*, Blue Ridge found no significant variances.

In the review of *Year-to-Year DCR Filing Service Company Balances*, Blue Ridge examined the changes through the evaluation of additions, retirements, transfers, and adjustments and through our work-order-testing activity discussed in the associated subsection of this report.

In the review of *End-of-year 2016 DCR Filing to 2016 FERC Form 1 Plant-in-Service Balances*, Blue Ridge was able to reconcile the balances from the 2016 end-of-year DCR filings to the balances of the 2016 FERC Forms 1, giving additional confidence that the 2017 beginning year DCR balances could be relied upon.

In the review of *Work Order Population totals to DCR Filing Year-to-Year Plant-In-Service Activity*, Blue Ridge compared the difference between the DCR November 30, 2017, gross plant balances and the November 30, 2016, gross plant balances for all Companies with the Work Order totals for the same period. The Companies provided information regarding some work orders related to the Companies' Experimental Company Owned LED Lighting Program that were included in the DCR

November 30, 2016, gross plant balances that should not have been. The Companies began removing this activity with the April 3, 2017, Rider DCR filings, and the amounts are not in the November 30, 2017, gross plant balance. After taking into account the work orders identified by the Companies' as excluded from the DCR population, Blue Ridge found that the balances matched.[1]

Therefore, FirstEnergy's responses regarding the variances in plant account balances were largely as a result of normal work order activity and are not uncommon among utilities. The changes in total plant balances for each of the Companies were not unreasonable.

Rider LEX, EDR, AMI, and General Exclusions

The Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL- SSO) requires that capital additions recovered through Commission-approved Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance.

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include line extension work that should have been included in the Rider LEX. Blue Ridge did not identify any Rider LEX charges within Rider DCR.

Regarding Rider EDR(g), during discovery, the Companies identified that $58,187 was incorrectly included in FERC account 366 instead of FERC account 367. The Companies also identified that the EDR(g) reserve balances had been calculated incorrectly due to a formula error. With these corrections, there is no change to gross plant and the reserve balance should be reduced by $350. The Companies stated (and Blue Ridge recommends) it will include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the activity been appropriate included in FERC account 367.[2] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations.

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include work for the Cleveland Clinic Foundation. No work for the Cleveland Clinic Foundation was identified within the sample. However, we did find Cleveland Clinic work orders in the work order population. The Companies indicated that these work orders were in the work order population and in the November 30, 2017, plant balances, but they were removed in the January 12, 2018, Rider DCR Filing (Exclusions Page). As the incremental increase in the Rider EDR(g) exclusion exceeded the amount identified in the population, Blue Ridge concluded that the costs were appropriately excluded from the Rider DCR.

Regarding Rider AMI, Blue Ridge compared the Companies' AMI Report in Support of Staff's 2017 Annual Review in Case 16-2166-EL-RDR with the AMI balances excluded from the DCR to ascertain whether the amount excluded was not unreasonable. We also reviewed the incremental change in AMI plant in 2017 to the incremental change in Rider AMI costs excluded through the Rider DCR. While there is a timing difference between the reporting period for the Rider AMI and the Rider DCR (the DCR reports from December to November and Rider AMI is calendar year), the difference is larger than can be explained through timing. Blue Ridge recommends that the Companies provide a reconciliation to document that there is no double recovery of AMI.

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[1] WP BRC Set 1-INT-002 and 1-INT-006 Comparison -Companies Response – Confidential and FirstEnergy's response to Data Request BRC Set 1-INT-006 – Confidential.
[2] FirstEnergy's response to Data Request BRC Set 1-INT-030.

The work order sample testing included specific criteria to review project descriptions to ensure the work orders did not include AMI work. No work associated with AMI was identified within the sample. However, several AMI work orders were identified in the population of work orders for the DCR since they were in the November 30, 2017, plant balances. The Companies indicated that those work orders were excluded from Rider DCR through Rider AMI included in the January 12, 2018, Rider DCR filing. Based upon Blue Ridge's comparison of the amount of plant reported recovered through the Rider AMI and the amount of AMI plant excluded in the Rider DCR, Blue Ridge was unable to confirm that there is not double recovery of AMI spending.

In addition to Riders LEX, EDR, and AMI, Blue Ridge reviewed other riders to ensure that capital additions recovered through those other riders were appropriately excluded from the DCR. Blue Ridge found that while no activity has occurred regarding the Government Directive Recovery Rider (Rider GDR), it has the potential to impact the Rider DCR in the future. During work order testing, costs associated with the Experimental Company Owned LED Lighting Program tariff were identified in the Rider DCR that should have been excluded. The Companies identified work order activity that should have been excluded from the December 2015–November 2016 OECO FERC account 373 Street Lighting and TECO FERC account 373 Street Lighting. FirstEnergy stated that it began to remove this activity with the April 3, 2017, Rider DCR Filing. Furthermore, FirstEnergy stated (and Blue Ridge recommends) that it will include a reconciliation in the Rider DCR revenue requirement in the next filing that incorporates the effect on revenues had the activity been appropriately excluded in the April 1, 2016, July 1, 2016, September 30, 2016, and December 30, 2016, Rider DCR Compliance filings.

Other than the costs associated with the Rider GDR and the Experimental Company Owned LED Lighting Program, Blue Ridge's review found there was no indication that non-Rider-DCR tariffs would contain distribution plant. Blue Ridge recommends that future Rider DCR filings specifically review any distribution-plant-related costs recovered through the Government Directives Recovery Rider and the Experimental Company Owned LED Lighting Program to ensure that these costs are excluded from the Rider DCR.

In addition, work order testing identified ATSI costs that should have been excluded from the DCR. Blue Ridge recommends an adjustment to remove these costs.

Jobbing, Contracting, and Mutual Aid Activities

Blue Ridge reviewed the controls in place for jobbing, contracting, and mutual aid activities and concluded that adequate controls exist within SAP and PowerPlant to ensure these activities are not included in the DCR. In addition, the accounts used to account for costs and revenue are not CWIP or Utility Plant in Service, which could be part of the DCR. The accounting used by the Companies is not unusual in the utility industry.

Gross Plant In Service

The Rider DCR Compliance Filings include the following gross plant-in-service incremental change for each company from the time of the prior audit.

Table 3: Incremental Change in Gross Plant from 11/30/16 to 11/30/17[3]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	2,955,112,270	3,072,113,869	117,001,599
Ohio Edison Company	3,351,099,110	3,473,934,081	122,834,971
The Toledo Edison Company	1,159,939,724	1,190,363,521	30,423,797
Total	7,466,151,104	7,736,411,471	270,260,367

Blue Ridge's review of gross plant through transactional testing and field inspection of selected work orders contained in the sample had findings that affect the gross plant included in the Rider DCR. The impact of each of these findings is discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements section of this report.

Validation Testing from Sampled Work Orders

The Companies provided a list of work orders that support gross plant in service for December 2016 through November 2017. Blue Ridge selected 64 work orders representing 157 FERC cost line items for detailed transactional testing. Blue Ridge had the following observations and findings related to the transactional testing performed on the work order sample:

1. Blue Ridge found that some work included in Rider DCR should not have been. During preparation of data responses, the Companies identified TECO work order activity for the Toledo Edison Plaza Tenant Improvement project that should have been excluded. The Companies stated (and Blue Ridge recommends) that a reconciliation calculation be included in a future Rider DCR filing to reflect the cumulative revenue requirement impact of removing the associated costs.

   Blue Ridge's sample included three work orders related to Vegetation Management (Tree Trimming). The Companies' policy number 1.3 discusses tree or limb removal outside corridors where no future maintenance is required. The wording gives the Companies broad leeway to remove any tree or limb outside a corridor for any reason and assign it as capital cost. However, the work described appears to Blue Ridge to be in conflict with the FERC definition of maintenance of overhead lines. Blue Ridge recommends that the statement be better defined. Furthermore, Blue Ridge recommends that the three vegetation management work orders be excluded from Rider DCR since they do not meet the FERC definition of capital expenditures.
2. Regarding exclusions for Rider AMI, Blue Ridge found that the work order sample did not contain any AMI or SmartGrid work orders.
3. Regarding exclusions for Rider LEX, Blue Ridge found that the work order sample did not contain any LEX work orders.
4. Regarding exclusions for Rider EDR, Blue Ridge found that the work order sample did not contain any EDR(g) work orders.
5. Regarding exclusions for generation work, Blue Ridge found that the work order sample did not contain any generation work orders.

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[3] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

6. Blue Ridge found that the Companies have adequate procedures in place to approve work orders. The procedures have not changed since our prior year review and, if followed, will yield the proper project approvals. Blue Ridge found no instance in which the Companies did not follow their stated policies.
7. Blue Ridge reviewed the justification for all projects in the sample, exclusive of blanket, multi-year projects, transfers, and adjustments, and found all project work orders included justifications that were not unreasonable.
8. In reviewing whether project costs were within the approved budget, Blue Ridge found four emergent projects and 10 other (accounting and storm) work orders without budgets. Of the remaining 50 work orders, 22 were under budget, 12 were over budget by less than 15%, and 16 were over budget by more than 15%.

   The Companies' reasoning for each project's actual costs exceeding the budget was specific and unique to that project and not unreasonable. However, approximately 28% of the projects that had budgets were over budget by greater than 15%. The large percentage of projects over budget and that two projects to implement the new mobile radio system were $12.8 million over budget raises a question about the Companies' planning process. Blue Ridge had similar concerns in the 2016 audit and included recommendation number 6 in its 2016 report that the Companies review the planning process. The Companies completed an internal audit with an objective to confirm that project management methodology and process design allows for projects to be fully scoped prior to project execution. The report issued on April 17, 2017, included several recommendations that are expected to be complete by June 2018.

9. Blue Ridge determined that the costs in PowerPlant support the work order charge and the categories of cost are not unreasonable.
10. Except for the five work orders discussed in comment 11 below, Blue Ridge found that, for replacement work orders, assets were retired, and cost of removal was charged.
11. Blue Ridge found that all the replacement work orders in the sample, with the exception of five, had asset retirement dates, cost of removal dates, and in-service dates of new assets that were all in alignment. All five of the exceptions had no retirement charged, and two of the five had not cost of removal charged. Adjustments to the current DCR revenue requirement calculations are being made for the five exceptions.
12. Blue Ridge found that, based on the description of the work performed, all work orders in the sample were closed to the proper FERC accounts.
13. Blue Ridge found that 25 work orders, or 39% of the 64 work orders sampled, had estimated in-service dates. Of those 25, approximately 40% had in-service dates that were over 90 days delayed from the estimates. The Companies provided explanations for why projects' actual in-service dates were over 90 days from the estimated in-service dates. While those explanations were not unreasonable, some of the work orders had significant delays. Blue Ridge understands that in some instances delays cannot be avoided. But over 40% of the work orders that had in-service dates were not completed by the estimated due dates. Blue Ridge recommended in the 2016 audit that the Companies place additional emphasis on completing projects timely when they have direct control of the projects and can mitigate

delays. That recommendation has been addressed in an internal audit completed on April 17, 2018.

14. Regarding closing project work orders to EPIS within a reasonable time frame from project completion, the following findings were noted:
    a. Four work orders were some form of an accounting adjustment and did not accrue AFUDC.
    b. One work order was not a DCR work order and was not tested. It was related to the Toledo Edison Plaza Tenant Improvements that the Companies stated should have been excluded from the DCR.
    c. Thirty work orders were project/blankets and did not accrue AFUDC.
    d. Eleven work orders could potentially over-accrue AFUDC because of project delays. The explanations for the project delays were not unreasonable. The impact on the DCR, if the over-accrual occurred, is minimal.
    e. Eleven projects had AFUDC accrued, but the charges were relatively minor, and the timing of closings would not impact the DCR.
    f. Seven work orders did not accrue AFUDC.

Field Inspections

Blue Ridge selected four projects for field verification from the work order sample. The four projects selected for field verification confirmed that the assets were installed and used and useful.

Work Order Backlog

Blue Ridge found that the Companies have made progress to reduce the unitization backlog. The December 31, 2017 is less than the 2016 levels, but the backlogs are still well above the backlogs from the 2015 audit.

While most of the work orders are Distribution and individually would not be material to the accumulated reserve for depreciation, on an aggregate basis, the total cost of work orders in the backlog is significant (although 37% below the 2016 total). There could be a potential impact on the accumulated reserve for depreciation.

In addition, the backlog could create problems with recording the replacement of assets that are still in the backlog and had not been unitized. This situation may become a particular problem when lines, poles, and transformers are replaced en masse as a result of storm restoration work. If an asset that is being replaced is not unitized, it holds up the storm unitization process. Blue Ridge recommends that the Companies continue to make a concerted effort to reduce the volume of backlog work orders both in quantity and dollar value.

Insurance Recoveries

Insurance recoveries can reduce gross plant and should be taken into consideration in the calculation of the DCR. FirstEnergy stated that there were no insurance recoveries charged to capital for the Companies from December 1, 2016, through December 31, 2017.

As noted in this report's subsection regarding status of prior audit recommendations (i.e., Prior Compliance Audits Recommendations Status), the Companies agree that for any insurance recoveries received for plant in service recognized in Rider DCR, the Companies will reduce plant in service for the recovery amounts.

Accumulated Reserve for Depreciation

The Rider DCR Compliance Filings include the following accumulated reserve for depreciation ("reserve") incremental change from the prior audit for each company.

Table 4: Incremental Change in Reserve for Depreciation from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	(1,269,202,085)	(1,329,820,008)	(60,617,923)
Ohio Edison Company	(1,317,426,765)	(1,380,011,274)	(62,584,509)
The Toledo Edison Company	(591,085,970)	(604,078,268)	(12,992,298)
Total	(3,177,714,820)	(3,313,909,549)	(136,194,729)

As discussed in the Gross Plant in Service subsection above, Blue Ridge found adjustments that should be made to the reserve balances to ensure that net plant is appropriately reflected in the DCR. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

Accumulated Deferred Income Taxes

The Rider DCR Compliance Filings include the following accumulated deferred income taxes (ADIT) incremental change from the prior audits for each company.

Table 5: Incremental Change in ADIT from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	(466,717,532)	(502,293,445)	(35,575,913)
Ohio Edison Company	(569,578,802)	(609,321,744)	(39,742,942)
The Toledo Edison Company	(151,388,071)	(162,103,480)	(10,715,409)
Total	(1,187,684,405)	(1,273,718,669)	(86,034,264)

The Companies stated that the treatment of ADIT in the Rider DCR was intended to be the same methodology approved in the last distribution rate case. However, the Companies' were unable to provide sufficient information to compare what is currently included in Rider DCR's ADIT to what was approved in Case No. 07-551-EL-AIR. The Companies provided the ADIT support included in Case No. 07-551-EL-AIR, which reflected high level descriptions. While CECO and TECO included many of the categories reflected in the Rider DCR, they did not include the level of detail provided in the DCR. The OECO ADIT included a single description "282 ELECTRIC" and a total. Blue Ridge was unable to confirm that ADIT reflected in the DCR was consistent with what was reflected in the Companies' last distribution rate case. Additional analysis was done on what was reflected in the DCR, and Blue Ridge ultimately found that the ADIT balances were related to plant in service and are not unreasonable. The revaluation of the estimated 2/28/18 ADIT balances to reflect the change in the tax rates is discussed in the Tax Cuts and Jobs Act Effects subsection of this report.

Depreciation Expense

The Rider DCR Compliance Filings include incremental depreciation expense for each company from the prior audit as shown in the following table.

Table 6: Incremental Change in Depreciation Expense from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	95,176,216	99,292,700	4,116,484
Ohio Edison Company	100,891,710	104,903,818	4,012,109
The Toledo Edison Company	38,032,714	38,953,731	921,017
Total	234,100,640	243,150,250	9,049,609

Blue Ridge found that the calculation of depreciation expense was consistent with the methodology used in the last distribution rate case with the exception of FERC account 390.3. The Rider DCR uses gross plant-in-service balances to develop the depreciation expense component of the revenue requirements. Any revisions to gross plant should be flowed through the Rider DCR model to ensure that the appropriate amount of depreciation expense is included within the DCR.

The depreciation accrual rates used in the Rider DCR are based upon the most recently approved Commission approved depreciation study.

PROPERTY TAX EXPENSE

The Rider DCR Compliance Filings include the following incremental property tax expense for each company from the prior audit.

Table 7: Incremental Change in Property Tax Expense from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	102,669,541	108,220,402	5,550,861
Ohio Edison Company	88,980,613	92,264,221	3,283,608
The Toledo Edison Company	30,026,201	30,860,390	834,189
Total	221,676,355	231,345,013	9,668,658

Blue Ridge found that the calculation of property tax is not unreasonable. As the Rider DCR uses plant-in-service balances to develop the property tax component of the revenue requirements, any revisions to gross plant should be flowed through the Rider DCR model to ensure the appropriate amount of property tax is included within the DCR.

SERVICE COMPANY

Blue Ridge found nothing that would indicate that Service Company costs included within Rider DCR are unreasonable.

COMMERCIAL ACTIVITY TAX AND INCOME TAXES

The Rider DCR Compliance Filings include the following incremental commercial activity tax (CAT) and income tax expense for each company.

Table 8: Incremental Change in CAT and Income Tax Expense from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	282,303	313,900	31,597
Ohio Edison Company	299,283	324,396	25,114
The Toledo Edison Company	70,871	77,431	6,561
Total	652,456	715,728	63,272

Blue Ridge found that the commercial activity tax and income tax expense were calculated consistent with prior filings. The effect of the recent federal tax rate change in discussed in the next subsection. In addition, any adjustments discussed in other subsections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

TAX CUTS AND JOBS ACT EFFECT

On December 22, 2017, the Tax Cuts and Jobs Act (TCJA) was signed into law by President Trump. The TCJA affects the accounting of regulated public utilities in notable ways. On January 12, 2018, the Companies filed replacement Rider DCR Compliance Filings with the Commission to incorporate the impacts of the TCJA, which reduced the federal corporate income tax rate from 35% to 21%. The Companies confirmed that the replacement filing did not include any other changes than the impact of the TCJA. The change reflects the restatement of the income tax expenses and revenue conversion factor to reflect the new statutory rate of 21%, which *reduced* the total revenue requirements and modifications of the ADIT, which *increased* the total revenue requirement. The replacement filings resulted in an annual *increase* of $39,314,722 to the total revenue requirement as follows.

Table 9: Revenue Requirement Change: Original (01/01/18) vs. Replacement (01/12/18) Filings

Company	Original	Replacement	Change
The Cleveland Electric Illuminating Company	125,085,002	140,265,193	15,180,191
Ohio Edison Company	128,757,802	147,036,276	18,278,474
The Toledo Edison Company	31,004,230	36,860,287	5,856,057
Total	284,847,034	324,161,756	39,314,722

While many utilities across the country have submitted new tariffs reducing customer rates, the Companies are an exception in that the DCR revenue requirements resulted in a 42% increase in from $93,221,892 in the original to $132,526,614 in the replacement filing. The 42% increase is primarily attributable to the revalued ADIT balances which decreased the rate base reduction, resulting in higher investment return requirements under the ratemaking formula. The Companies simplistic approach to calculate the tax-change effect on Estimated ADIT is theoretically reasonable, barring any company-specific nuances. The larger issue is lack of clarity surrounding treatment of the excess deferred income tax: (1) whether the Companies intend to set up a regulatory liability, (2) if that regulatory liability will be reflected as an offset in rate base, and (3) the timing and rate at which the excess deferred income taxes will be flowed back to customers.

A significant portion of a regulated public utility's ADIT reflects plant-related items. Since the Rider DCR was established to allow the Companies to recover, among other things, a return associated with changes in plant-related rate base, any change that affects plant-related ADIT balances should be reflected through the DCR. Blue Ridge recommends that the Companies include a regulatory liability on its ADIT worksheet in the Rider DCR to reflect a refund of the excess deferred taxes to ratepayers because the tax future obligation to the federal government decreased by 40%. In the replacement filing, the corresponding regulatory liability is not reflected in rate base, which would have resulted in no change to rate base. If the regulatory liability was appropriately established, the DCR would reflect a refund to the ratepayers based on the effect on the tax expense component. As an alternative to recording the regulatory liability with the Rider DCR ADIT balances, the Companies should demonstrate that it has reflected the customer savings in another filing that would offset the annual *increase* of $39,314,722 in the Rider DCR revenue requirements due to the ADIT revaluation.

RETURN

The Rider DCR Compliance Filings include the following calculated return on rate base at 8.48% for each company.

Table 10: Incremental Change in Return on Rate Base from 11/30/16 to 11/30/17

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	26,418,706	28,183,288	1,764,582
Ohio Edison Company	33,089,719	34,828,839	1,739,120
The Toledo Edison Company	2,805,374	3,374,926	569,551
Total	62,313,799	66,387,052	4,073,253

Although the adjustments discussed in other sections of this report will affect the final return included within the DCR, Blue Ridge found that the calculation of the return component of the DCR is not unreasonable.

RIDER DCR CALCULATION

The Compliance Filing Summary Schedules pull together the various components allowed within Rider DCR and calculate the revenue requirements based upon the actual November 30, 2017, and estimated February 28, 2018, balances. Although Blue Ridge found that the balances used in the Rider DCR calculations should be adjusted, Blue Ridge found that the Rider DCR calculation is not unreasonable.

The Annual Rider DCR Revenue through November 30, 2017, is under both the aggregate annual cap and the allocated annual cap by company.

PROJECTIONS

The Compliance Filings include projections for the first two months in 2018. To develop the first quarter 2018 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2018, the most recent (December 2017) forecast from PowerPlant. The estimated February 28, 2018, plant and reserve balances were then adjusted to reflect current assumptions (including project additions and delays), to incorporate recommendations from prior Rider DCR Audit Reports, and to remove the pre-2007 impact of a change in pension accounting.

Blue Ridge found that the projected amounts included through February 2018 are not unreasonable. In addition, the projected amounts will be reconciled to the actual amounts, and the Rider DCR revenue requirement will be adjusted to actual in the next quarter's Rider DCR Compliance Filings.

SUMMARY OF BLUE RIDGE RECOMMENDATIONS

For the 2017 Rider DCR assessment, Blue Ridge summarizes its recommendations as follows:

Rec-01. To address Blue Ridge's concerns regarding the adequacy of the Companies' planning process in the 2016 audit, the Companies completed an internal audit with an objective to confirm that project management methodology and process design allows for projects to be fully scoped prior to project execution. The report issued on April 17, 2017, included several recommendations that are expected to be complete by June 2018. Blue Ridge recommends that, during next year's DCR audit, the auditor reviews whether the recommendations presented in the Audit of the Distribution Portfolio and Planning Process (April 17, 2018) were implemented. (2017 DCR Report, p.42)

Rec-02. Blue Ridge recommends implementation of the improvement opportunity identified in the Fleet Services audit: all FirstEnergy companies that benefit from fleet services, not just the utility companies, should be allocated the costs of Fleet Services costs since it is a shared services organization. (2017 DCR Report, p. 42)

Rec-03. In the internal audit FirstEnergy Utilities Major Storm Back Office Review Process, auditors recommended the Companies design and implement an invoice review process for less significant storms. Since the cost of storms, and their capital or expense designation, relates to the DCR process, Blue Ridge recommends that once an invoice review process has been implemented, it should be reviewed as part of the DCR audit process. (2017 DCR Report, p. 42)

Rec-04. During Blue Ridge's evaluation of variances in regard to plant additions, retirements, adjustments, and transfers, the Companies' explanations for several adjustments were in regard to originally unitizing to the wrong utility account. The frequency with which this error occurred among semi-manually or manually addressed work orders leads Blue Ridge to recommend that the Companies' review its unitization process for work orders to determine whether additional control can be implemented to ensure more accurate recording. (2017 DCR Report, p. 46)

Rec-05. During discovery regarding Rider EDR(g) exclusions, the Companies identified an error where $58,187 was included in FERC account 366 instead of FERC account 367. The Companies stated, and Blue Ridge recommends, it will include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the activity been appropriately included in FERC account 367. (2017 DCR Report, p. 51)

Rec-06. In its review of the incremental change in AMI plant in 2017 to the incremental change in Rider AMI costs excluded through the Rider DCR through November 30, 2017, Blue Ridge noted a significant difference. While there is a timing difference between the reporting periods, the difference is larger than can be explained through timing. Blue Ridge recommends that the Companies provide a reconciliation to document that there is no double recovery of AMI. (2017 DCR Report, p. 53)

Rec-07. During work order testing, costs associated with the Experimental Company Owned LED Lighting Program were discovered to be included in the Rider DCR that should have been excluded. These costs are recovered through the Experimental Company Owned LED Lighting Program rider. The Companies stated that the FirstEnergy-identified work order activity began to be removed with the April 3, 2017, Rider DCR filing. Costs incurred prior to that date had not been removed. FirstEnergy stated, and Blue Ridge recommends, that it will include a reconciliation in the Rider DCR revenue requirement in the next filing that incorporates the effect on revenues had the activity been appropriately excluded in the 2016 quarterly Rider DCR Compliance filings. (2017 DCR Report, p. 55)

Rec-08. Blue Ridge identified two riders other than LEX, EDR, and AMI that have the potential to include distribution plant. Blue Ridge recommends that future Rider DCR filings specifically review any distribution-plant-related costs recovered through the Government Directives Recovery Rider and the Experimental Company Owned LED Lighting Program to ensure that these two riders are excluded from the Rider DCR. (2017 DCR Report, p. 55)

Rec-09. During the preparation of data responses during this audit, the Companies identified TECO work orders of $1,192,607 for the Toledo Edison Plaza Tenant Improvement project that should have been excluded from the Rider DCR. The Companies stated, and Blue Ridge recommends, that a reconciliation calculation be included in a future Rider DCR filing to reflect the cumulative revenue requirement impact of removing these costs. (2017 DCR Report, p. 61)

Rec-10. Blue Ridge believes that the Companies' policy Accounting for the Clearing of Transmission and Distribution Corridors, section 1.3, is in conflict with the FERC Uniform System of Accounts definition for FERC 365 and FERC 593 regarding what vegetation management costs should be capitalized and what costs should be recorded as a maintenance expense. First, the wording of the Companies' policy gives it broad leeway to remove any tree or limb outside a corridor for any reason and assign it as capital cost; thus, Blue Ridge recommends that the Companies' policy statement be better defined. Second, Blue Ridge recommends that the Companies revise its vegetation management policy in this area to be consistent with FERC definitions. Third, and as a result, Blue Ridge recommends that the three vegetation management work orders discovered in Blue Ridge's work order sample be excluded from the Rider DCR. (2017 DCR Report, pp. 61–63)

Rec-11. An emergent work order related to ATSI expenditures was found to have not been timely reimbursed, resulting in ATSI costs being recovered through the DCR. The Companies stated, and Blue Ridge recommends, that all necessary adjustments to the Companies' Rider DCR revenue requirements associated with this issue will be reflected in the reconciliation included in the next Rider DCR filing. (2017 DCR Report, p. 65—66)

Rec-12. During Blue Ridge's review of replacement work orders with associated asset retirement dates, two work orders had cost of removal recorded but had no retirements. The retirements had been passed to PowerPlant from CREWS, and the auto retirements processing failed. The errors were fixed in March 2018. The Companies stated, and Blue Ridge recommends, it will include a reconciliation in a future DCR filing to reflect the cumulative revenue requirement impact had the retirements not been delayed. (2017 DCR Report, pp. 71–72)

Rec-13. In regard to Blue Ridge's review of alignment of actual in-service dates with estimates, one project was found to have been delayed, and as a result, AFUDC was over accrued. Blue Ridge recommends adjustments to remove the excess AFUDC costs through a reconciliation in the Rider DCR revenue requirement in a future filing for this overstatement. (2017 DCR Report, p. 76)

Rec-14. In regard to depreciation expense, it was found that most of the FERC accounts used gross plant (as opposed to net plant—gross plant less reserve for depreciation) in calculating depreciation expense, which it was determined was consistent with the methodology used in the last distribution base rate case. FERC account 390.3 Leasehold Improvements used net plant. Blue Ridge recommends that a reconciliation be included in the next DCR filing that incorporates the effect on Rider DCR revenue requirements had the depreciation expense for FERC account 390.3 been calculated based on net plant in service. (2017 DCR Report, p. 87)

Rec-15. Although the Companies have made progress reducing unitization backlog, totals remain above 2015 levels. Blue Ridge recommends that the Companies continue to make a concerted effort to reduce the volume of backlog work orders both in quantity and dollar value. (2017 DCR Report, p. 78)

Rec-16. The Companies' estimated ADIT will need to be adjusted to reflect that bonus depreciation is no longer available to regulated public utilities. The Companies stated, and Blue Ridge recommends, that any impacts associated with bonus depreciation resulting from the federal income tax reform will be reconciled in the Companies' next Rider DCR filing. (2017 DCR Report, p. 96)

Rec-17. Regarding the Tax Cuts and Jobs Act, Blue Ridge recommends (1) that the amount by which the ADIT balance is revalued is also the amount by which the Companies' must set up a regulatory liability to refund the excess deferred taxes to ratepayers because the tax future obligation to the federal government decreased by 40%, and (2) that the Companies apply the average rate assumption method (ARAM) consistent with normalization requirements to update the regulatory liability to address the timing differences for the property reversal. Additionally, the Companies reported in Case No. 18-0047-AU-COI that they filed updated Riders DMR and DCR to incorporate the impacts of the TJCA that resulted in annual customer savings equating to nearly $40 million. This statement does not comport with the $39,314,722 *increase* in customer rates in the Rider DCR, Blue Ridge recommends reconciliation of the Companies' reported annual Tax Act savings reflected in all riders. As an alternative to recording the regulatory liability with the Rider DCR ADIT balances, the Company should demonstrate that it reflected the regulatory liability in another filing. (2017 DCR Report, pp. 94–98)

OVERVIEW OF INVESTIGATION

The FirstEnergy Service Company, on behalf of the three Ohio-regulated operating companies—The Cleveland Electric Illuminating Company (CE, CEI, or CECO), Ohio Edison Company (OE or OECO), and The Toledo Edison Company (TE or TECO), collectively referred to as "FirstEnergy" or "Companies"—prepared and submitted Compliance Filings regarding the Commission-approved Delivery Capital Recovery (DCR) Rider for actual plant in service through November 30, 2017, and estimated plant in service through February 28, 2018. Blue Ridge Consulting Services, Inc. (Blue Ridge) was retained to perform a compliance audit of the filings.

BACKGROUND

Ohio's electric law, Senate Bill 221, requires electric utilities to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO), Section 4928.142 Revised Code, or an electric security plan (ESP), Section 4928.143 Revised Code. The Companies filed an application for approval of an ESP in Case No. 10-388-EL-SSO ("ESP II Case"). A majority of the parties in the case entered into an original stipulation and two supplemental stipulations (collectively, "Combined Stipulation"), and after a hearing, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order approving the Combined Stipulation in its entirety on August 25, 2010.

As part of its Opinion and Order, the Commission approved the establishment of the Rider DCR, effective January 1, 2012, to be updated and reconciled quarterly. The Opinion and Order allowed the Companies the opportunity to recover property taxes, Commercial Activity Tax, and associated income taxes, and to earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company, which was not included in the rate base determined in the Opinion and Order of January 21, 2009, in Case No. 07-551-EL-AIR (last rate case). On April 13, 2012, FirstEnergy filed an application for its next ESP, which was largely an extension of the Combined Stipulation, which the Commission approved with modifications on July 18, 2012, in Case No. 12-1230-EL-SSO ("ESP III Case"). The Rider DCR was extended with modifications by Order dated March 31, 2016, and reaffirmed on October 12, 2016, in Case No. 14-1297-EL-SSO ("ESP IV Case").

The Commission ordered an annual audit review of its Rider DCR for the purpose of determining whether the amounts for which recovery is sought are not unreasonable in light of the facts and circumstances known to the Companies at the time such expenditures were committed. The agreement also stipulated that, at the Commission's discretion, either an independent third party auditor or the Commission's Staff would conduct the annual audit review.

The Commission's Request for Proposal (RFP) sought proposals to audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR since the Companies' last Rider DCR Compliance Audit. Blue Ridge submitted a proposal and was selected to perform the 2017 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, 2015, and 2016 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2016).

Excerpts of the Rider DCR provisions within the Opinion and Orders and Combined Stipulation are included within Appendix A. Appendix B contains a list of abbreviations and acronyms used within this report.

PURPOSE OF PROJECT

As defined in the RFP, the purpose of the project included the following:

- Audit and attest to the accuracy and reasonableness of FirstEnergy's compliance with its Commission-approved Rider DCR with regard to the return earned on plant-in-service since the Companies' last Rider DCR Compliance Audit.
- Identify capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions to ensure they are excluded from Rider DCR.
- Identify, quantify, and explain any significant net plant increase within individual accounts.
- Assess the substantive implementation of the provisions contained within the Joint Stipulation and Recommendations filed in Case No. 14-1929-EL-RDR.

PROJECT SCOPE

The audit as defined in the RFP will address the following project scope:

> Determine if FirstEnergy has implemented its Commission-approved DCR Rider and is in compliance with the Combined Stipulation agreement set forth in Case No. 10-388-EL-SSO, as extended with modifications in Case No. 14-1297-EL-SSO.

AUDIT STANDARD

Blue Ridge used the following standard during the course of the audit: "The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable. The determination of whether the amounts for which recovery is sought are not unreasonable shall be determined in light of the facts and circumstances known to the Companies at the time such expenditures were committed."[4]

INFORMATION REVIEWED

Blue Ridge reviewed the following information outlined in the RFP:

- Case Nos. 10-388-EL-SSO, 12-1230-EL-SSO, and 14-1297-EL-SSO and related stipulation agreements
- Case Nos. 11-5428-EL-RDR, 12-2855-EL-RDR, 13-2100-EL-RDR, 14-1929-EL-RDR, 15-1739-EL-RDR, and the Compliance Audit of the DCR Rider filed in Case No. 16-2041-EL-RDR
- Applicable testimony and workpapers
- All additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred from December 1, 2016, through November 30, 2017. The information was included in the January 2, 2018, and subsequently updated January 12, 2018, quarterly filings.
- All appropriate documentation relating to the issues identified in the Auditor's Report in Case Nos. 15-1739-EL-RDR and 16-2041-EL-RDR to determine if the issues raised have been addressed pursuant to the Auditor's recommendation, and if not, the impact of the Companies not addressing the identified concerns.

[4] Case No. 10-0388-EL-SSO Second Supplemental Stipulation, July 22, 2010, page 4.

During the audit process, Blue Ridge requested and was provided additional information. A list of the data requested is included as Appendix C. Electronic copies of the information obtained was provided on a compact disc to Staff.

Rider DCR Compliance Filings Reviewed

On January 2, 2018, the Companies submitted various schedules, bill impacts, and tariff pages that provide the detailed calculations related to plant in service, accumulated depreciation reserve, income taxes, commercial activity taxes, property taxes, rate base, depreciation expense, and the resulting revenue requirement related to the Rider DCR (Compliance Filings) as contemplated by the Orders in the Companies' Case Nos. 10-388-EL-SSO, 12-1230-EL-SSO, and 14-1297-EL-SSO Electric Security Plan proceedings. These schedules included actual amounts through November 30, 2016, and projected balances for the three months ended February 28, 2017. The filings were subsequently replaced on January 12, 2018. Blue Ridge used these Rider DCR Compliance Filings to perform its review.

The following summarizes Rider DCR Revenue Requirements requested by each of the FirstEnergy operating companies.

Table 11: Rider DCR Revenue Requirements Actual 11/30/17 and Projected 2/28/18[5]

	Revenue Requirements		
Operating Company	**Actual 11/30/17**	**Projected 2/28/18**	**Total**
The Cleveland Electric Illuminating Company	$ 120,730,714	$ 19,534,479	$ 140,265,193
Ohio Edison Company	$ 124,767,834	$ 22,268,442	$ 147,036,276
The Toledo Edison Company	$ 29,781,328	$ 7,078,958	$ 36,860,287
Total	$ 275,279,876	$ 48,881,880	$ 324,161,756

Variance Analyses, Transactional Testing, and Other Analyses

To identify, quantify, and explain any significant net plant increases within the individual accounts, Blue Ridge performed account variance analyses. The Companies were asked to explain any significant changes. The results of the analyses are included under the subsection labeled Variance Analysis.

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

Blue Ridge also performed various analyses, including mathematical verifications and source data validation, of the multitude of schedules that support the Rider DCR Compliance Filings. The report addresses each component of the Rider DCR, and the results of these analyses are included within each component's subsection.

A list of Blue Ridge's workpapers is included in Appendix D. Electronic copies were provided to the Staff of the Public Utilities Commission of Ohio and the Companies.

[5] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential-R2.

PRIOR COMPLIANCE AUDITS RECOMMENDATIONS STATUS

Blue Ridge performed the Rider DCR compliance audit that covered capital additions from December 1, 2015, through November 30, 2016. Blue Ridge's report included several findings and recommendations and was filed in Case No. 16-2041-EL-RDR. The following list includes those recommendations. Following each recommendation is FirstEnergy's response regarding the recommendation's status[6] and Blue Ridge's associated comments based upon observations from this compliance audit.

a) Recommendation 01, 2016 DCR Report, p. 44: Blue Ridge recommends the Companies include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the correct Rider EDR(g) balances been incorporated in prior Rider DCR filings, beginning with actual September 30, 2012, and ending with actual August 31, 2016, gross plant and reserve balances.

   FirstEnergy Response: The Companies' June 30, 2017 Rider DCR filing included an adjustment to incorporate the effect on revenue of the corrected EDR(g) balances. See response to BRC Set 1-INT-008 Attachment 2 – Confidential for support.

   Blue Ridge's Comments: No additional work is necessary.

b) Recommendation 02, 2016 DCR Report, pp. 44 and 50: Blue Ridge recommends the amount of the AMI work order included in the 2016 Rider DCR be included in the reconciliation calculation in a future Rider DCR filing.

   FirstEnergy Response: Starting with the June 30, 2017 Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the AMI-related work orders. The Companies' June 30, 2017 Rider DCR filing also included an adjustment for the cumulative revenue requirement impact associated with the correction. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

   Blue Ridge's Comments: No additional work is necessary.

c) Recommendation 03, 2016 DCR Report, p. 47: Blue Ridge recommends a reconciliation be included in the Rider DCR revenue requirements in a future filing that incorporates the effect on revenues had the correct, updated ATSI balances been incorporated beginning with the actual February 29, 2016, plant balances.

   FirstEnergy Response: The Companies' June 30, 2017 Rider DCR filing included an adjustment to incorporate the effect on revenue for the corrected ATSI balances. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

   Blue Ridge's Comments: No additional work is necessary.

d) Recommendation 04, 2016 DCR Report, p. 52: Because of the lack of detail associated with a single line adjustment of approximately $669,638 related to the retirements of unspecified assets that took place in November 2016, Blue Ridge recommends the Companies determine the impact of the retirements on the depreciation reserve, and specifically on the over

[6] All FirstEnergy status remarks are obtained from FirstEnergy's responses to Data Requests BRC Set 1-INT-11 and 12.

accrual of depreciation, relative to the CECO work order HE123, and adjust the subsequent DCR filling accordingly.

FirstEnergy Response: The Unspecified Location Assets were retired in November 2016 as part of an overall review of assets not assigned to a specific location. These assets were placed in service in 1997–1998. After extensive research, the Companies were not able to identify the specific assets, so they were retired. These assets were retired well before the end of their book lives. Accordingly, there was no over accrual of depreciation and no adjustment to depreciation expense is needed for purposes of Rider DCR. This treatment is no different than assets that retire prematurely due to early failures before their average fulfillment life.

Blue Ridge Comments: No additional work is necessary.

e) Recommendation 05, 2016 DCR Report, p. 52: Because Blue Ridge was unable to determine whether certain assets retired were related to replacement projects and whether those retirements were recorded timely, Blue Ridge recommends the Companies determine the impact of the retirements on the depreciation reserve, and specifically the over accrual of depreciation, relative to the TECO work order JC607, and adjust the subsequent DCR filing accordingly.

FirstEnergy Response: See response above to REC-04.

Blue Ridge Comments: No additional work is necessary.

f) Recommendation 06, 2016 DCR Report, pp. 52–53: Due to the large number of emergent projects identified in Blue Ridge's sample testing, Blue Ridge recommends the Companies consider how they review the conditions of infrastructure during the budget cycle to ensure, wherever possible, those type projects are budgeted and, therefore, part of the approved capital budget.

FirstEnergy Response: The Companies conducted an internal audit focused on the design and effectiveness of the Companies' distribution portfolio planning process to confirm that the project management methodology and process design allows for projects to be fully scoped prior to execution. To address Blue Ridge's 2016 recommendations number 6, 7, and 10, the Companies provided the results of the audit in a confidential report dated April 17, 2018. The audit found no major deficiencies but did included several recommendations to enhance or formalize the processes in place:[7]

- Develop a process and document the procedure to perform periodic reconciliation analysis between RPA (request project approval) and UI Planner budgeting system. Execution of the process will be triggered during the budget reforecasting process. Implementation will be completed by June 30, 2018.

- For major capital projects above an established threshold, a change control process will be established at CEI and OE, similar to the funding approval process utilized at TE. This is expected to be completed by June 2018.

[7] FirstEnergy's supplemental response to Data Request BRC Set 1-INT-011, Attachment 1 Confidential.

- IT will include a field in RPA to document lessons learned. Companies will be informed to populate lessons learned results upon project close-out.. This is expected to be completed by June 2018.

Blue Ridge Comments: The results of the audit and associated recommendations are not unreasonable. Blue Ridge recommends reviewing that the audit recommendations were implemented in next year's DCR audit.

g) Recommendation 07, 2016 DCR Report, p. 57: Due to the significant number of projects that were over budget greater than 15 percent, Blue Ridge recommends the Companies review their project planning process to ensure that the methodology allows for projects to be fully scoped prior to execution. This recommendation is similar to one made in the 2015 DCR Audit Report. In response to the recommendation in that report, the Companies stated that they intend to conduct an internal audit of the non-IT-related budget process to be initiated once a Stipulation and Recommendation has been filed in Case No. 15-1739-EL-RDR. Therefore, along with Recommendation 7 of the current report, Blue Ridge recommends that the Companies initiate that internal audit specified in their response to the 2015 report.

FirstEnergy Response: Please see the response to recommendation f above.

Blue Ridge Comments: The results of the audit associated recommendations are not unreasonable. Blue Ridge recommends reviewing that the audit recommendations were implemented in next year's DCR audit.

h) Recommendation 08, 2016 DCR Report, p. 59: Blue Ridge recommends the Companies include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the overstatement of AFUDC on Service Company work order SC-000002-1 not occurred.

FirstEnergy Response: Starting with the June 30, 2017 Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the overstatement of AFUDC. The Companies' June 30, 2017 Rider DCR filing also included an adjustment for the cumulative revenue requirement impact associated with the correction. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

Blue Ridge Comments: No additional work is necessary.

i) Recommendation 09, 2016 DCR Report, pp. 59–60: Blue Ridge recommends the Companies include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the overstatement of AFUDC on OECO work order OE-700402 not occurred.

FirstEnergy Response: Starting with the June 30, 2017 Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the overstatement of AFUDC. The Companies' June 30, 2017 Rider DCR filing also included an adjustment for the cumulative revenue requirement impact associated with the correction. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

Blue Ridge Comments: No additional work is necessary.

j) Recommendation 10, 2016 DCR Report, p. 61: Due to the significant number of projects that were placed in service greater than 90 days after the planned in-service date, Blue Ridge recommends the Companies place additional emphasis on completing projects timely when they have direct control of the projects and can mitigate delays.

FirstEnergy Response: Please see the response to recommendation f above.

Blue Ridge Comments: The results of the audit and associated recommendations are not unreasonable. Blue Ridge recommends reviewing that the audit recommendations were implemented in next year's DCR audit.

k) Recommendation 11, 2016 DCR Report, p. 64: Due to the significant growth in the number of backlog work orders, Blue Ridge recommends the Companies make a concerted effort to reduce the volume of backlog work orders both in quantity and dollar value.

FirstEnergy Response: The Companies have made reductions in the volume of backlog work orders, both in quantity and dollar value. The Companies continue to make efforts to further reduce the backlog. Please refer to BRC Set 1-INT-031 and BRC Set 1-INT-032.

Blue Ridge Comments: The Companies have reduced the volume of backlog work orders both in quantity and dollar value in 2017. Further discussion of the backlog is contained in other areas of this report.

l) Recommendation 12, 2016 DCR Report, p. 64: Blue Ridge recommends any insurance recovery reduce plant in service and be recognized in a future Rider DCR.

FirstEnergy Response: For any insurance recovery that the Companies receive for plant in-service recognized in Rider DCR, the Companies will reduce plant in-service for insurance recovery. From December 2016 – November 2017, there were no such insurance recoveries.

Blue Ridge Comments: Blue Ridge is satisfied with FirstEnergy's response. No additional work is necessary.

m) Recommendation 13, 2016 DCR Report, p. 69: Blue Ridge recommends to include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had depreciation expense not been calculated on the FAS109 land assets since the July 1, 2016 Rider DCR filing.

FirstEnergy Response: The Companies' June 30, 2017 Rider DCR filing included an adjustment to incorporate the effect on revenue for the correction to depreciation expense of the FAS109 land assets. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

Blue Ridge Comments: No additional work is necessary.

n) Recommendation 14, 2016 DCR Report, p. 70: Blue Ridge recommends a reconciliation be included in a future filing of the Rider DCR that will incorporate the effect on revenues had the correct OE personal property tax rate been used in the September 30, 2016, and December 30, 2016, Rider DCR Compliance filings.

FirstEnergy Response: The Companies' June 30, 2017 Rider DCR filing included an adjustment to incorporate the effect on revenue for the correction to OE personal property tax rate. See response to BRC Set 1-INT-008 Attachment 1 – Confidential for support.

Blue Ridge Comments: No additional work is necessary.

o) Recommendation 15, 2016 DCR Report, p. 71: Blue Ridge recommends reviewing the TECO real property tax rate in next year's audit to verify a decline based on TECO no longer paying property taxes on assets removed from plant in service.

FirstEnergy Response: See response to BRC Set 1-INT-12.

DR BRC Set 1-INT-12: PUCO's Initial Comments in Case No. 16-2041-EL-RDR recommended that Toledo Edison review the real property tax rate and verify the rate's decline. Staff also requested that FirstEnergy provide its review, including supporting documentation, to Staff no later than December 31, 2017. Please provide a copy of the review and supporting documentation.

FirstEnergy Response to BRC Set 1-INT-12: Please see BRC Set 1-INT-12 Attachment 1 for Toledo Edison's real property tax rates included in the December 31, 2015, December 30, 2016 and January 12, 2018 Rider DCR Filings. As anticipated by Blue Ridge in last year's Rider DCR audit report (p. 71), the real property tax rate for TE decreased due to the removal of plant associated with Toledo Edison Plaza and no longer paying taxes on those assets.

Blue Ridge Comments: Blue Ridge found that the TECO property tax rate in 2017 declined as TE should no longer pay property taxes on the assets that were removed from plant in service. However, the rate did not return to the 2015 property tax level. The Companies explained, "The 2017 TE property tax rate is higher than the 2015 due to normal fluctuations in real property tax rates, property assessment, and one-time charges/assessments. TE owns over 200 real properties, and each county, township, and school district combination has its own tax rate."[8] Blue Ridge found the Companies' explanation not unreasonable. No additional work is necessary.

p) Recommendation 16, 2016 DCR Report, p. 74: Blue Ridge recommends the Companies include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the correct effective income tax rate been used in the TECO calculation.

FirstEnergy Response: The correction of TECO effective income tax for the calculation of the estimated February 28, 2017 revenue requirement in the 12/31/2017 Rider DCR filing was incorporated in the quarterly reconciliation for actual February 28, 2017 revenue requirement calculation included in the April 3, 2017 Rider DCR filing.

Blue Ridge Comments: No additional work is necessary.

[8] FirstEnergy's response to Data Request BRC Set 11-INT-005.

FINDINGS AND RECOMMENDATIONS

Determine if the Companies implemented their Commission-approved DCR Rider and if the Companies are in compliance with the Combined Stipulation agreement set forth in the Opinion and Order issued in Case No. 10-388-EL-SSO

The purpose of the audit is to determine whether the Companies implemented their Commission-approved Rider DCR and whether the Companies are in compliance with the Combined Stipulation agreement set forth in the Opinion and Order issued in Case No. 10-388-EL-SSO and as extended with modifications in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO. This section includes an overview of the process and control policies and procedures that affect the plant balances and expense categories that feed into the Rider DCR calculations. Various variance analyses review any significant changes in net plant by individual FERC account.

Each component of Rider DCR is investigated separately. The specific exclusions are addressed in Riders LEX, EDR, AMI, and General Exclusions and are followed by our analysis of gross plant in service; accumulated reserve for depreciation; accumulated deferred income taxes; depreciation expense; property tax expense; allocated Service Company; Commercial Activity Tax (CAT) and income taxes; and the return component. The report concludes with a review of the calculation of revenue requirements, followed by a review of the projections for the first quarter 2018.

Authority to Recover Components of Rider DCR

Blue Ridge reviewed the Commission Opinion and Order in Case No. 10-388-EL-SSO, dated August 25, 2010, the Combined Stipulation, and the Rider DCR relevant testimony and hearing transcripts. The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (as modified and reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO[9]) provide the authority for what should be included within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following items are to be included:

> Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant including allocated general plant from FirstEnergy Service Company that supports the Companies, which was not included in the rate base determined in the Opinion and Order of January 21, 2009 in Case No. 07-551-EL-AIR et al. ("last distribution rate case").[10]
>
> The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case.[11]

[9] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[10] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[11] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.

> The filing shall show the Plant in Service account balances and accumulated depreciation reserve balances compared to that approved in the last distribution rate case. The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case. Net capital additions for Plant in Service for General Plant shall be included in the DCR so long as there are no net job losses at the Companies as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. For each account title the Companies shall provide the plant in service and accumulated depreciation reserve for the period prior to the adjustment period as well as during the adjustment period. The filing shall also include a detailed calculation of the depreciation expense and accumulated depreciation impact as a result of the capital additions. The Companies will provide the information on an individual Company basis.[12]

PROCESSES AND CONTROLS

A. Review and update the processes and controls identified during the last audit that affect the costs in Rider DCR to validate that FirstEnergy exhibits reasonable management practices associated with the investment funded by Rider DCR
B. Determine if the Companies' cost controls related to the items under review are adequate and reasonable.

Blue Ridge did not perform a management audit but did review FirstEnergy's processes and controls to ensure that they were sufficient so as not to adversely affect the costs in Rider DCR. Beginning from a basis of last year's review of the 2016 FirstEnergy Rider DCR processes and controls, Blue Ridge reviewed documents relied upon for that audit, supplemented with changes to those processes and controls that the Companies have made since that audit. Based on the documents reviewed, Blue Ridge was able to update its understanding of the Companies' processes and controls that affect each of the plant balances and expense categories within Rider DCR. Blue Ridge concluded that FirstEnergy exhibits reasonable management practices associated with the investment funded by Rider DCR. Furthermore, by reviewing internal audit reports conducted on various areas of the Companies' operations, Blue Ridge found that the Companies' have processes in place to evaluate whether cost controls were adequate and that no significant internal control deficiencies were noted in the internal audits.

The following is a summary of the areas Blue Ridge reviewed.

Policies and Procedures

Blue Ridge reacquainted itself with the policies, procedures, and process flow diagrams associated with the various processes that affect the categories that feed into the Rider DCR calculations. Furthermore, we reviewed post-2016 modifications to those policies, procedures, and/or process flow diagrams to determine whether any concerns were raised in connection to the

[12] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 15.

impact of those changes on the Rider DCR calculations. The policies, procedures, and process flow diagrams reviewed related to the following areas:

1. Plant Account
    a. Capitalization
    b. Preparation and approval of work orders
    c. Recording of CWIP including the systems that feed the CWIP trial balance
    d. Application of AFUDC
    e. Recording and closing of additions, retirements, cost of removal, and salvage in plant
    f. Unitization process based on the retirement unit catalog
    g. Application of depreciation
    h. Contributions in Aid of Construction (CIAC)
2. Purchasing/Procurement
3. Accounts Payable/Disbursements
4. Accounting/Journal Entries
5. Payroll (direct charged and allocated to plant)
6. Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)
7. Insurance Recovery
8. Property Taxes
9. Service Company Allocations
10. Budgeting/Projections
11. IT Projects

As a result of our review, Blue Ridge notes the following regarding processes that affect the Rider DCR.

Capitalization (1.a above); Plant Assets, including CWIP, Unitization, and Depreciation (1.c, 1.e, 1.f, 1.g); Accounting Entries, including Accounts Payable and Payroll (3, 4, 5)[13]

The Companies regard Capitalization as the procedure by which the total value of a capital asset of specified qualifications is assigned to its Balance Sheet classification of "Property, Plant and Equipment." This value is expensed to the Income Statement over its expected life by means of depreciation expense. Specifically, the Capitalization policy states, "Costs which result in additions or improvements of a permanent character which add value to the property shall be capitalized if a) the useful life is greater than one year and b) costs are greater than $1,000 (excluding computer software). Computer software shall be capitalized for costs greater than $5,000. . . . All other costs shall be expensed."[14]

The Capitalization Policy also holds the relevant policies for plant additions, retirements, removal cost, and salvage applicable to Rider DCR. The policy provides the qualifications for capital additions, which include extensions, enlargements, expansions, or replacements made to an existing asset. Once an asset is capitalized, the Companies track it using the Continuing Property Records

[13] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy – Confidential.
[14] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy – Confidential.

(CPR). This CPR is a PowerPlant[15] ledger that contains a full audit trail for all plant transactions (additions, retirements, adjustments, inter and intra company transfers, etc.). Retirements (classified as such according to specific criteria) are accounted for by crediting their original cost to its plant account. The Retirement Unit Catalog is a listing within PowerPlant of all retirement units. Based on a specific set of criteria, these units are identified as retirement units to differentiate between replacements or additions chargeable to plant accounts (capital) and those chargeable to maintenance accounts (expense).

Construction work in process (CWIP) is the account to which capitalized costs are charged during the construction phase. Following construction, when the asset is ready to be placed into service, the cost is transferred to the completed construction not classified account (CCNC). Finally, after unitization, the asset is transferred to electric plant in service (EPIS).

FirstEnergy had no significant procedural or policy changes in regard to the capitalization policy in 2017.[16]

FirstEnergy did make accounting revisions in the area of Accounts Payable/Disbursements regarding reimbursement costs in two areas: (1) charitable contributions or donations are now allowed to be paid by employees and submitted for reimbursement if approved by the President and Chief Executive Officer, and (2) professional dues and memberships are now allowed if considered necessary and consistent with the performance of job responsibilities (instead of only if pre-approved in writing by the appropriate Vice President).[17] These dues and contributions are defined under Employee Expense Accounts and, therefore, would not affect the DCR capital accounts or any feeder system that results in CWIP and that would close to the plant in service becoming part of this DCR.[18]

Preparation and Approval of Work Orders[19]

Blue Ridge had reviewed both the Work Management Process flow diagram as well as the CREWS (Customer Request Work Scheduling System) Work Request Type Narratives. Elements such as project size and contractor involvement affect the process for managing the work. According to the CR (Customer Request) in the CREWS name, the system would seemingly include only work specifically initiated by request of customers. However, the system does include routine preventive and corrective maintenance as well.

The CREWS Work Request Type Narratives categorize work based on area (e.g., Distribution, Forestry, Meter, Substation) and then by more specific activity within those categories.

FirstEnergy did not significantly modify this process for the Companies in 2017.[20]

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[15] "PowerPlant" is a commercially available computer software application used in plant accounting.
[16] FirstEnergy's response to Data Request BRC Set 1-INT-014 and 015 – Confidential.
[17] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential, c, including confidential Attachments 1 and 2.
[18] Confirmed in FirstEnergy's response to Data Request BRC Set 9-INT-019 – Confidential.
[19] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, b, Attachment 1, Work Management Process – Confidential and WP FE response to 2011 audit Data Request BRC Set 1-INT-003, b, Attachment 2, CREWS Work Request Narratives – Confidential.
[20] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.

Contributions in Aid of Construction (CIAC)[21]

Regarding Contributions in Aid of Construction, Blue Ridge had examined the Companies' Invoicing Process Flow Chart that follows work initiation, authorization, scheduling, and completion in accordance with funding—invoicing, payment, and recording.

FirstEnergy did not significantly modify this process for the Companies in 2017.[22]

Application of AFUDC[23]

FirstEnergy has a policy in place to account for capitalized financing costs during construction. Three conditions must be met: (1) expenditures for the asset must have been made; (2) activities necessary to prepare the asset for its intended use must be in progress; and (3) interest cost must be incurring. Interest capitalization ceases when any of these conditions ceases or, of course, when construction is complete.

FirstEnergy did not significantly modify this process for the Companies in 2017.[24]

Purchasing/Procurement[25]

Blue Ridge had reviewed FirstEnergy's procedure by which the Companies' Supply Chain prepares, reviews, approves, and processes procurement documents for all materials, equipment, and services. The procedure applies to all business units and operating companies within FirstEnergy. The procedure identifies minimum requirements, exceptions, responsibilities, and actual process steps. Process steps include justifications, requisitions, approvals, buyer activity, sourcing strategy, bidding process, award, execution, and order maintenance.

FirstEnergy did not significantly modify this process for the Companies in 2017.[26]

Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)[27]

In its Accounting for Income Taxes procedure, the Companies stated that tax reporting and disclosing of both current and future income taxes in their financial statements is in accordance with generally accepted accounting principles.

FirstEnergy did not significantly modify this process for the Companies in 2017.[28]

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[21] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, e, Attachment 1, Invoicing Process Flow Chart – Confidential.
[22] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[23] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, d, Attachment 1, Accounting For Capitalized Financing Costs During Construction – Confidential.
[24] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[25] WP FE response to 2016 audit Data Request BRC Set 1-INT-013, b, including Attachment 3, Procedure for Enterprise Sourcing of Materials and Services – Confidential.
[26] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[27] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, m, Attachment 1, Income Tax Policy and Procedure – Confidential.
[28] FirstEnergy's response to Data Request BRC 1-INT-014 – Confidential.

Insurance Recovery[29]

According to the Companies, Insurance Risk Management (IRM) coordinates all large property and non-subrogation insurance recoveries. IRM oversees the process from notification to them by field personnel when an event occurs, through evaluation, claim, gathering of costs and expenses, and settlement, and finally culminating in ensuring proper accounting of recoveries.

FirstEnergy did not modify this process for the Companies in 2017.[30]

Property Taxes[31]

Blue Ridge examined the FirstEnergy desktop procedure for Ohio Property Tax returns. The procedure addresses steps taken in producing property tax schedules.

FirstEnergy did not modify this process for the Companies in 2017.[32]

Service Company Allocations[33]

According to the Stipulation in Case 10-388-EL-SSO and continued in Case No. 12-1230-EL-SSO and Case No. 14-1297-EL-SSO, expenditures reflected in the quarterly filing will be "broken down by the Plant in Service Accounts Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case."[34] The most recent base distribution rate case is Case No. 07-0551-EL-AIR. There were no changes to these allocation factors for the Companies in 2017.

Budgeting/Projections[35]

The Rider DCR Compliance Filings include three months of projected data through the end of February 2018. The estimate is based on the 2017 forecast adjusted to reflect current assumptions, to incorporate recommendations from the March 2013, April 2014, April 2015, and April 2016 Rider DCR Audit Reports, and to remove the cumulative pre-2007 impact of a change in pension accounting.[36] Blue Ridge had reviewed the Companies' capital budget process to understand whether that process was sound and results in reasonable projections of expected capital expenditures that would be included in the Rider DCR. Blue Ridge had sought to understand the Companies' processes and practices for justifying and approving the capital funds that would be expended on FirstEnergy's transmission, distribution, general, and intangible gross plant. The policies, procedures, and process

[29] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, a - Confidential.
[30] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[31] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, n, Attachment 1, Ohio Property Tax Returns – Confidential.
[32] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[33] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[34] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 15.
[35] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Confidential; WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure – Confidential; and WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 3, Energy Delivery Capital Allocation Process – Confidential.
[36] DCR Filings: CE 12-30-16 DCR Filing.pdf, OE 12-30-16 DCR Filing.pdf, and TE 12-30-16 DCR Filing.pdf.

flow diagrams showing key controls related to, among other things, capital budgeting and projections had been reviewed. Blue Ridge also had reviewed whether the cost controls were adequate and reasonable.

The budgeting activity of the Companies, with regard to its impact on Rider DCR, rests within a well-documented process flow. Capital Portfolio development and capital management highlight the process steps from business unit initiation, through decision points, and to the final consolidation and approvals necessary to complete the process. The Capital Planning cycle is aligned with the Integrated Business Planning calendar. The Capital Management Group guides the process, including entering the business units' settled capital target into the capital planning database, allowing the business units to structure their portfolios accordingly.

FirstEnergy's capital budgeting is known internally as "Multi-Year Enterprise Capital Portfolio."[37] Individual business unit programs drive the approval of the capital budgets at the business unit level.[38] In addition, the procedure for creating and acquiring approval for the capital portfolio states, "Business Units will utilize internal review and approval processes to analyze and create a prioritized Capital Portfolio."[39]

In 2014, FirstEnergy implemented a new system to facilitate budget entry. This system, however, had no impact from a procedural or policy standpoint on developing budgets and projects.[40] Additionally, FirstEnergy made no significant procedural or policy change in 2017.[41]

Information Technology

FirstEnergy manages Information Technology (IT) projects through a formalized process. The process includes standardized templates to describe and manage the three basic management categories for IT projects: charter (establishment), scorecard (status, health, issues, and risks), and changes (through change requests). IT's Project Management Office meets biweekly to review IT projects. During these biweekly reviews, the scorecard is used to help track the actual spend on the projects relative to the original budget.

IT project cost definition begins with project estimates for labor and other-than-labor costs. These estimates become the initial budget for the project. The project manager controls the project's refinement as the project scope is finalized. The project manager manages this refinement through a change control process in which justification for changes (resource hours, cost, and schedule) must be provided and approvals for the changes must be received from senior IT management. While a requested change may be for a specific project, the review and approval process also takes into consideration any impacts on the overall portfolio for IT projects. If changes to an individual project

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[37] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Confidential.
[38] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure – Confidential.
[39] WP FE response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Section C.2 – Confidential.
[40] WP FE response to 2014 audit Data Request BRC Set 1-INT-015 – Confidential.
[41] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.

are approved, FirstEnergy manages the project according to the new forecast (both cost and schedule).[42]

FirstEnergy did not modify this process for the Companies in 2017.[43]

Development of Rider DCR Compliance Filings

The Rider DCR schedules are compiled and calculated using Microsoft Excel® spreadsheets by a Rates Analyst within the FirstEnergy Service Company's Rates and Regulatory Affairs Department. The Analyst coordinates the gathering of the data and performs the calculations and relies on the provider of the information for accuracy. The Rider DCR Compliance filings are comprised of a number of schedules. The schedules and information sources are summarized as follows:[44]

- Revenue Requirements Summary – calculated by the Rates Department
- DCR Revenue Requirement Calculation – gross plant, reserve, ADIT, depreciation, and property tax expense roll up from detailed schedules; commercial activity tax (CAT) and income tax rates are provided by the Tax Department; and revenue requirements are calculated by the Rates Department
- Plant in Service – Plant Accounting
- Reserve for Depreciation – Plant Accounting
- Accumulated Deferred Income Taxes (ADIT) Balances – Tax Department
- Depreciation Accrual Rates – Plant Accounting provides the gross plant balances; accrual rates are based upon the rates established in Case No. 07-551-EL-AIR, et al.
- Property Tax Calculations – Tax Department
- Summary of Exclusions – primarily from Plant Accounting
- Service Company Allocation Summary – gross plant, reserve, ADIT, depreciation and property tax expense roll up from detailed schedules; allocations are based upon last distribution rate case, Case No. 07-551-EL-AIR, et al.
- Service Company Depreciation Accrual Rates – rates are based upon the weighted average of the approved depreciation rates for the three Ohio Operating Companies
- Service Company Property Tax Rate – rates are based upon the weighted average of the property tax rates for the three Ohio Operating Companies; True Value Percentages & Capitalized Interest Workpaper – Tax Department
- Intangible Depreciation Expense – intangible plant balances provided by Plant Accounting; accrual rates are based on the last distribution rate case, Case No. 07-551-EL-AIR, et al.
- Rider DCR/Rate Design – the Case No. 10-388-EL-SSO Combined Stipulation provides the rate design for Rider DCR
- Billing Units – Forecasting group in the Rates Department (The most recent forecast was used)

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[42] WP FE response to 2013 audit Data Request BRC Set 1-INT-032 – Confidential.
[43] FirstEnergy's response to Data Request BRC Set 1-INT-014 – Confidential.
[44] Summary of the process repeats process as recorded in previous Rider DCR Compliance Audit Reports. See Compliance Audit of the 2011, 2012, 2013, 2014, and 2015 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

- Typical Bill Comparisons – prepared by the Rates Department to reflect the updated rates for Rider DCR
- Rider DCR Tariff – prepared by the Rates Department to reflect the updated rates for Rider DCR

After the Analyst prepares the Rider DCR schedules, they undergo a three-tiered review process. A peer Analyst completes the initial review. The Manager of Revenue Requirements (who is also trained to prepare the Rider DCR filings) and the Director of OH Rates and Regulatory Affairs complete reviews two and three prior to submission to the Commission. The Vice President of Rates and Regulatory Affairs reviews the filing as needed.

The description of this process largely parallels the process from previous years; however, FirstEnergy continues its ongoing effort to incorporate and track specific recommendations that come out of the previous years' Rider DCR audits.[45]

Internal Audit and SOX Compliance

Blue Ridge reviewed the list of 18 internal audits performed in 2017 regarding controls that would affect Rider DCR.[46] In particular, we examined and were satisfied with the findings and recommendations associated with the following 14 audits.[47]

1. Sarbanes-Oxley 404 Assessment of Internal Controls over Financial Reporting
2. 2016 SOX Annual Progress Report: 2016 SOx Program
3. Audit of Accounts Payable for the Year Ended December 31, 2016
4. 2017 First Quarter Sarbanes-Oxley Assessment of Internal Controls over Financial Reporting
5. PowerPlan Upgrade- Go No Go Decisions Support
6. 2016 Governance Risk & Compliance Segregation of Duties Access Risk Analysis Risk Assessment
7. FirstEnergy Utilities Mutual Assistance Billing and Invoice Process
8. PowerPlan Pre-Implementation Audit
9. 2017 Second Quarter Sarbanes-Oxley Assessment of internal Controls over Financial Reporting
10. Contractor Information Management System Audit
11. 2017 Third Quarter Sarbanes-Oxley Assessment of Internal Controls over Financial Reporting
12. Revenew's Payment Recovery Audit for Accounts Payable
13. Audit of Capital and Operation & Maintenance Expenses
14. Consulting Services on North American Reliability Corporation Risk-Based Internal Controls Program and Governance Structure – Phase 1.[48]

Regarding four of the 18 audits, Blue Ridge notes the following issues:

- Audit of the Distribution Portfolio Planning Process

[45] FirstEnergy's response to Data Request BRC Set 1-INT-013 - Confidential.
[46] FirstEnergy's response to Data Request BRC Set 4-INT-002, Attachment 1 – Confidential.
[47] FirstEnergy's response to Data Request BRC Set 4-INT-002, Attachment 1 – Confidential.
[48] FirstEnergy's response to Data Request BRC Set 4-INT-002, Attachment 1 – Confidential.

The Audit of the Distribution Portfolio and Planning Process was completed April 17, 2018. The findings and recommendations address recommendations 6, 7, and 10 from our 2016 Rider DCR audit (as noted in the Prior Compliance Audits Recommendations Status subsection above). Blue Ridge recommends that, during next year's DCR audit, the auditor reviews whether the recommendations presented in the internal audit were implemented.

- Fleet Services and Investment Strategy Review

  The Fleet Services and Investment Strategy Review identified 11 opportunities for improvement. The scope of the audit centered on the processes for acquiring and disposing of vehicles and equipment. The audit recommendations did not indicate that internal controls were not in place but rather that improvement opportunities could be made. Blue Ridge examined the identified improvement opportunities and found one to be of potential impact to the DCR process. Fleet Services is a shared services function; however, associated costs are currently charged to only the FirstEnergy utility companies. The audit recommended that costs be assessed to all FirstEnergy companies since all take advantage of Fleet Services. Because costs are currently allocated to only utility companies (and among them, the Ohio companies), the Ohio companies are receiving a greater share of the costs than they should. Since a percentage of the allocated costs are subsequently capitalized, there is a potential effect on the DCR. However, in adjusting the current allocation, the subsequent decrease in the amount of the capitalized percentage would be minor.[49] However, Blue Ridge recommends that FirstEnergy implement the audit recommendation that all companies that benefit from Fleet services be assessed Corporate Fleet Service charges and that General Accounting make changes to the assessments to promote accurate shared services' cost allocations.

- 2016 GRC ARA Ruleset Review Amended Memo

  The 2016 GRC ARA Ruleset Review Amended Memo audit had recommendations related to custom transactions. We do not believe any of these recommendations will impact the DCR in any material way (or possibly at all).

- FirstEnergy Utilities Major Storm Back Office Review Process

  FirstEnergy Utilities Major Storm Back Office Review Process audit concluded that the overall internal control environment was adequately designed and operating effectively to provide reasonable assurance the invoice review process ensures storm charges are valid, accurate, and properly supported. The audit also recommended, among other things, that the Companies design and implement an invoice review process for less significant major storms.[50]

  The cost of storms is part of the DCR. Therefore, the initial invoice review process is important to ensure that activity is correctly charged to the appropriate work order. A second step in the review process is the allocation of the storm costs between capital and expense. We recommend that the allocation process, and subsequent percentage split between capital vs. expense, be reviewed as part of the next DCR audit.

[49] FirstEnergy's response to Data Request BRC Set 11-INT-002 – Confidential.
[50] FirstEnergy's response to Data Request BRC Set 4-INT-002, Attachment 1- Confidential.

Additionally, Blue Ridge requested information regarding control deficiencies resulting from two audits related to quarterly Sarbanes-Oxley assessments (Property Accounting: All Control IDs and FEU Accounting policy and services: All Control IDs). None had significant deficiencies. .[51]

Conclusion

Blue Ridge was able to obtain an understanding of the Companies' processes and controls that affect each of the categories within Rider DCR. Furthermore, we were satisfied with actions taken with regard to internal audits and the process and control of the prior Rider DCR recommendations. Based on information reviewed, Blue Ridge concluded that the Companies' controls were adequate and not unreasonable. However, the Companies' internal audit that addressed three prior Rider DCR recommendations suggested additional recommendations that Blue Ridge determined were not unreasonable. Blue Ridge recommends reviewing in next year's DCR audit whether those recommends were implemented.

Blue Ridge does recommend implementation of the improvement opportunity identified in the Fleet Services audit: all FirstEnergy companies that benefit from Fleet Services, not just the utility companies, should be allocated the costs of Fleet Services costs since it is a shared services organization. Additionally, internal auditors recommended, on the basis of the FirstEnergy Utilities Major Storm Back Office Review Process audit, that the Companies design and implement an invoice review process for less significant major storms. Since the cost of storms, and their capital or expense designation, relates to the DCR process, Blue Ridge recommends that once an invoice review process has been implemented, it be reviewed as part of the DCR audit process.

VARIANCE ANALYSIS

C. Perform a variance analysis to determine the reasonableness of any changes in plant in service balances including additions, retirements, transfers, and adjustments

Examining the differences of account balances associated with Rider DCR calculations helps determine the trustworthiness of the DCR development.

In the current audit of the DCR year 2017, Blue Ridge evaluated several changes and variances in account balances:

- 2017 Plant Additions, Retirements, Transfers, and Adjustments
- Year-to-Year DCR Filing Plant-In-Service Balances
- Year-to-Year DCR Filing Reserve Balances
- Year-to-Year DCR Filing ADIT Balances
- Year-to-Year DCR Filing Service Company Balances
- End-of-year 2016 DCR Filing to 2016 FERC Form 1 Plant-in-Service Balances
- 2017 Work Order Population totals to 2017 DCR Filing Year-to-Year Plant-In-Service Activity

[51] FirstEnergy's response to Data Request BRC Set 4-INT-001 - Confidential.

2017 Plant Additions, Retirements, Transfers, and Adjustments

Blue Ridge began its account variance analyses by examining the plant additions, retirements, transfers, and adjustments in order to understand changes to the unadjusted plant balances. In its investigation, Blue Ridge asked a multi-part data request regarding certain account changes of concern. FirstEnergy responded with account detail and explanations as called for, resulting in the following conclusions for the accounts in question:[52]

1. CEI Account 364 Poles, towers, and fixtures—Adjustments of $360,482

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

2. CEI Account 365 Overhead conductors, devices—Transfers/Adjustments of $299,953

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

3. CEI Account 367 Underground conductors, devices—Adjustments of $426,079.

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

4. CEI Account 368 Line transformers—Adjustments of $174,677

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

5. CEI Account 370 Meters—Adjustments of $1,315,955

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

6. CEI Account 394 Tools, shop, garage equipment—Adjustments of $1,517,147

   Analysis: The adjustment represents the effect of transfers for work orders originally unitized to the wrong utility account. Blue Ridge was satisfied with the transaction detail.

7. CEI Account 397 Communication equipment—Additions of 8,861,041

   Analysis: The account increased by about 34% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

8. CEI Account 303 Misc intangible plant—Additions of $6,608,631

   Analysis: The account increased by about 11.5% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

9. OE Account 362 Station equipment—Adjustments of $359,534

   Analysis: Spares were transferred from ATSI to Plant. The Companies noted that when a spare is used in construction, it is transferred from the spare location to the asset location on which installation occurs.[53] Blue Ridge was satisfied with the transaction detail.

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[52] FirstEnergy's response to Data Request BRC Set 2-INT-001, with Attachments 1 through 22 – Confidential.
[53] FirstEnergy's response to Data Request BRC Set 7-INT-006 – Confidential.

10. OE Account 368 Line transformers—Negative Adjustments of $522,445

    Analysis: Blue Ridge was satisfied with the transaction detail.

11. OE Account 390 Structures and improvements—Negative Additions of $647,060 and Negative Adjustments of $2,163,697

    Analysis: The negative adjustments had an offsetting adjustment in account 364. Additionally, a portion of the adjustment was the net effect of transfers from OE to FECO. Blue Ridge was satisfied with its examination of the transaction details.

12. OE Account 392 Transportation equipment—Additions of $607,234

    Analysis: The account increased by about 26% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

13. OE Account 397 Communication equipment—Additions of $13,625,363

    Analysis: The account increased by about 42.5% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

14. OE Account 303 Misc intangible plant—Additions of $9,690,408

    Analysis: The account increased by about 12% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

15. TE Account 392 Transportation equipment—Additions of $183,616

    Analysis: The account increased by about 15.5% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

16. TE Account 397 Communication equipment—Additions of $1,084,281

    Analysis: The account increased by about 7% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

17. TE Account 303 Misc intangible plant—Additions of $2,191,966

    Analysis: The account increased by about 8% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

18. FESC Account 390 Structures and improvements—Additions of $2,679,747 (with no retirements) and Adjustments of $2,157,227

    Analysis: The account increased by about 8% from last year's balance. The adjustment was the net effect of transfers from OE to FECO. Blue Ridge was satisfied with its examination of the transaction details for both the additions and the adjustment.

19. FESC Account 391 Office furniture, equipment—Additions of $19,618,396 and Retirements of $16,268,728

    Analysis: The account increased by about 2% from last year's balance. Blue Ridge was satisfied with the additions and retirements based on an examination of the account and transaction details.

20. FESC Account 392 Transportation equipment—Additions of $425,502

Analysis: The account increased by about 93% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

21. FESC Account 397 Communication equipment—Additions of $10,070,553

    Analysis: The account increased by about 8% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

22. FESC Account 303 Misc intangible plant—Additions of $32,370,033

    Analysis: The account increased by about 10% from last year's balance. Blue Ridge was satisfied with the additions based on an examination of the account and transaction details.

As a result of our analysis, Blue Ridge was satisfied with the changes in plant additions, retirements, adjustments, and transfers. However, Blue Ridge noted that four of the explanations for adjustments were in regard to originally unitizing to the wrong utility account (see #s 1, 2, 3, and 6 of the above list). Although there are thousands of work orders unitized, the bulk are single units of property and auto-closed through WMS. The frequency with which this error has occurred among semi-manually or manually addressed work orders leads Blue Ridge to recommend that the Companies review its unitization process for work orders to determine whether additional control can be implemented to ensure more accurate recording.

Year-to-Year DCR Filing Plant-In-Service Balances

To support identifying, quantifying, and explaining any significant net plant increases within individual accounts, Blue Ridge compared Plant-in-Service account balances (FERC 300-series accounts) from DCR year-end November 30, 2016 with the year-end November 30, 2017 filing.

The following table is a summary schedule of the net plant changes by classification of plant (i.e., Transmission, Distribution, General, and Intangible Plant). As this table shows, FirstEnergy's operating companies increased gross plant (including allocation of Service Company Plant) by $117.0 million, $122.8 million, and $30.4 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 4.0%, 3.7%, and 2.6% for CE, OE, and TE, respectively.

Table 12: Adjusted Plant Change from 11/30/2016 to 11/30/2017[54]

Line No.	Account Title	Adjusted Balance 11/30/16	Adjusted Balance 11/30/17	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 431,628,975	$ 435,758,661	$ 4,129,686	1.0%
3	Distribution	2,217,333,891	2,310,562,922	93,229,031	4.2%
4	General	156,348,800	162,226,119	5,877,319	3.8%
5	Other	56,089,957	62,828,422	6,738,465	12.0%
6	Service Company Allocated	93,710,646	100,737,744	7,027,098	7.5%
7	**Total Cleveland Electric Illuminating Company**	**$ 2,955,112,269**	**$ 3,072,113,868**	**$ 117,001,599**	**4.0%**
8	**Ohio Edison Company**				
9	Transmission	$ 213,163,308	$ 214,517,354	$ 1,354,046	0.6%
10	Distribution	2,764,255,371	2,856,769,311	92,513,940	3.3%
11	General	178,984,926	189,827,704	10,842,778	6.1%
12	Other	81,134,820	90,743,432	9,608,612	11.8%
13	Service Company Allocated	113,560,685	122,076,281	8,515,596	7.5%
14	**Total Ohio Edison Company**	**$ 3,351,099,110**	**$ 3,473,934,082**	**$ 122,834,972**	**3.7%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,474,270	$ 22,815,338	$ 341,068	1.5%
17	Distribution	986,294,036	1,010,056,944	23,762,908	2.4%
18	General	74,463,450	74,842,863	379,413	0.5%
19	Other	26,720,165	28,912,125	2,191,960	8.2%
20	Service Company Allocated	49,987,804	53,736,249	3,748,445	7.5%
21	**Total Toledo Edison Company**	**$ 1,159,939,725**	**$ 1,190,363,519**	**$ 30,423,794**	**2.6%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,466,151,104**	**$ 7,736,411,469**	**$ 270,260,365**	**3.6%**

In our analysis of specific account variances from November 30, 2016, through November 30, 2017, Blue Ridge identified accounts with significant change that would warrant further investigation. However, these same accounts were identified in Blue Ridge's analysis of 2017 Plant Additions, Retirements, Transfers, and Adjustments, and therefore, discussion of these changes is provided under that heading.

Year-to-Year DCR Filing Reserve Balances

In our analysis of specific reserve account variances from November 30, 2016, through November 30, 2017, Blue Ridge submitted questions and received responses from FirstEnergy regarding seven variances of concern among the three FirstEnergy operating companies,[55] resulting in the following determinations:

1. Reserve OE Account 360 Land & Land Rights: November 30, 2017, balance = $9,193; Reserve balance for land

[54] BRCS WP FE DCR CF Variance 2017– Confidential.xlsx, tab—PIS Summary.
[55] FirstEnergy's response to Data Request BRC Set 2-INT-002 – Confidential.

Analysis: FirstEnergy explained that the reserve balance is associated with salvage, and when the transaction is closed, the balance will be removed from the reserve. Blue Ridge requested additional information regarding why there was salvage charged to a reserve account since land is not depreciated (which would normally preclude having a reserve). FirstEnergy responded that the salvage amount of $9,193 was from a portion of the sale of two properties, and those amounts are automatically processed to the reserve to they can be recorded appropriately with the retirement and cost of removal.[56] To better understand the transaction, Blue Ridge issued another data request asking more detailed information regarding why the sale of land would have a cost of removal. The Companies' response provided the necessary accounting detail that satisfied Blue Ridge's concern.[57]

2. OE Account 389 Land & Land Rights: November 30, 2016, balance = $(74,752); Reserve balance for land

   Analysis: FirstEnergy explained that the reserve balance was associated with a retirement recorded to the reserve. When asked for additional information, the Companies responded that in this instance, an intercompany transfer had been incorrectly recorded as a retirement. While net plant in service was correct, the transfer was recorded as a reduction to depreciation reserve instead of being recorded as an addition to gross plant in service. It resulted in an understatement of Rider DCR's property tax expense, since gross plant in service was understated by $74,752. The Companies will make an adjustment to the DCR revenue requirement had gross plant been correct over the audit period. The error will be reversed on OE's books.[58] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #1**].

3. OE Account 369 Services: November 30, 2016, balance = $85,520,231 and November 30, 2017, balance = $84,320,090; difference = $1,200,141; Reduction in balance

   Analysis: FirstEnergy explained that the reduction included an increase in the provision for depreciation of $4,136,932, offset by $(4,829,831) in cost of removal charges and $(504,118) in retirements less reserve activity of $(3,124) for an asset included in GL account 185—Temporary facilities that is not included in Rider DCR. Blue Ridge is satisfied with the transaction.

4. OE Account 370 Meters: November 30, 2016, balance = $36,964,606 and November 30, 2017, balance = $32,776,294; difference = $4,188,312; Reduction in balance

   Analysis: FirstEnergy explained that the reduction included an increase in the provision for depreciation of $5,014,016, offset by $(6,278,554) in cost of removal charges and $(2,923,773) in retirements. Blue Ridge is satisfied with the transaction.

5. OE Account 373 Street Lighting and Signal Systems: November 30, 2016, balance = $36,885,734 and November 30, 2017, balance = $35,552,559; difference = $(1,333,175); Reduction in balance

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[56] FirstEnergy's response to Data Request BRC Set 7-INT-002 – Confidential.
[57] FirstEnergy's response to Data Request BRC Set 11-INT-001 – Confidential.
[58] FirstEnergy's response to Data Request BRC Set 7-INT-003 – Confidential.

Analysis: FirstEnergy explained that the reduction included an increase in the provision for depreciation of $799,307, offset by $(469,704) in cost of removal charges, $27 in salvage and other credits, $(1,662,663) in retirements, and an adjustment of $(141) for reserve related to LED Streetlighting that was incorrectly included in the 11/30/2016 balances. Blue Ridge is satisfied with the transaction.

6. TE Account 370 Meters: November 30, 2016, balance = $19,433,375 and November 30, 2017, balance = $18,934,908; difference = $498,467; Reduction in balance

   Analysis: FirstEnergy explained that the reduction included an increase in the provision for depreciation of $1,574,884, offset by $(1,513,479) in cost of removal charges and $(559,871) in retirements. Blue Ridge is satisfied with the transaction.

7. TE Account 390 Structures and Improvements: November 30, 2016, balance = $10,809,446 and November 30, 2017, balance = $9,717,390; difference = $1,092,056; Reduction in balance

   Analysis: FirstEnergy explained that the reduction included an increase in the provision for depreciation of $749,753, offset by $(200,099) in cost of removal charges, $364,467 in impairments, and $(2,006,176) in retirements. Blue Ridge questioned how the accounting for an impaired asset could affect the reserve for depreciation. The Companies responded that it was not actually not an impairment. A building was demolished and retired with a loss on disposal, which had been inadvertently classified as an impairment.[59] Blue Ridge is satisfied with the transaction.

Year-to-Year DCR Filing ADIT Balances

Blue Ridge found no significant variances regarding year-to-year ADIT balances.

Year-to-Year DCR Filing Service Company Balances

Blue Ridge evaluated the change in Service Company balances through the evaluation of additions, retirements, transfers, and adjustments and through our work-order-testing activity discussed in the associated chapter of this report.

End-of-year 2016 DCR Filing to 2016 FERC Form 1 Plant-in-Service Balances

Blue Ridge received from FirstEnergy, during the 2016 DCR audit, a reconciliation between the 2016 plant-in-service account balances in the Companies' DCR Compliance Filings to their 2016 FERC Forms 1. Blue Ridge requested this reconciliation to ensure the DCR balances, with the appropriate adjustments, correctly correlated to what was reported on the FERC Forms 1. FirstEnergy provided a chart comparing the balances and offering the explanations for the differences. After examination, Blue Ridge found the explanations not unreasonable and, with those explanations, found that the balances from the 2016 end-of-year DCR filings matched the balances of the 2016 FERC Forms 1, giving additional confidence that the beginning year DCR balances could be relied upon.[60]

Work Order Population totals to DCR Filing Year-to-Year Plant-In-Service Activity

Blue Ridge compared the difference between the DCR November 30, 2017, gross plant balances and the November 30, 2016, gross plant balances for all Companies with the Work Order totals for

[59] FirstEnergy's response to Data Request BRC Set 7-INT-004 – Confidential.
[60] WP FE response to 2016 audit Data Request BRC Set 1-INT-007 – Confidential with Attachment.

the same period. The Companies provided information regarding some work orders included in the DCR population that should not have been, particularly in regard to the Companies' Experimental Company Owned LED Lighting Program. After taking into account the work orders identified by the Companies' as excluded from the DCR population, Blue Ridge found that the balances matched.[61]

Conclusion

FirstEnergy's responses regarding the variances in plant account balances were largely as a result of normal work order activity and are not uncommon among utilities. The changes in total plant balances for each of the Companies were not unreasonable.

RIDER LEX, EDR, AMI, AND GENERAL EXCLUSIONS

D. Determine if capital additions recovered through Riders LEX, EDR, and AMI have been identified and excluded from Rider DCR

The Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO[62] and 14-1297-EL-SSO[63]) requires that capital additions recovered through Commission-approved Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance.[64]

The Schedule within the Rider DCR Compliance Filings labeled "Summary of Exclusions per Case No. 14-1297-EL-SSO" identifies the capital additions recovered through Riders LEX, EDR, and AMI, and other general adjustments that have been excluded from Rider DCR. The other general adjustments include exclusions for net plant related to land leased to ATSI, FirstEnergy's transmission subsidiary.

Line Extension Recovery Rider (Rider LEX)

Rider LEX includes deferred line extension costs during the period January 1, 2009, through December 31, 2011, including post-in-service carrying charges.[65]

The Companies' Rider DCR Compliance Filings state, "As implemented by the Companies, Rider LEX will recover deferred expenses associated with the lost up-front line extension payments from 2009–2011. These deferred expenses are recorded as a regulatory asset, not as plant in service on the Companies' books. Therefore, there is no adjustment to plant in service associated with Rider LEX."[66]

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[61] WP BRC Set 1-INT-002 and 1-INT-006 Comparison -Companies Response – Confidential and FirstEnergy's response to Data Request BRC Set 1-INT-006 – Confidential.
[62] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10–11.
[63] Case No. 14-1297-EL-SSO Commission Opinion and Order, March 31, 2016, page 119.
[64] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[65] Case No. 08-0935-EL-SSO Stipulation and Recommendation, Section B.3, page 16.
[66] CEI, OE, and TE Rider DCR Compliance Filings dated 1/12/18, page 19 and 44.

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include line extension work that should have been included in the Rider LEX. Blue Ridge did not identify any Rider LEX charges within Rider DCR.[67]

Economic Development Rider (Rider EDR(g))

Rider EDR(g) includes the cost of the electric utility plant, facilities, and equipment installed to reliably support the Cleveland Clinic Foundation's major expansion plans at its Main Campus located at 9500 Euclid Avenue in Cleveland, Ohio. Also included within the rider are the depreciation and taxes over a five-year period on a service-rendered basis, starting June 1, 2011.[68] FirstEnergy further stated that the capital additions associated with the Cleveland Clinic project recovered through Rider EDR(g) are excluded from Rider DCR pursuant to the ESP 2 Order in Case No. 10-388-SSO and continued in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO.

The Companies' Rider DCR Compliance Filings stated that the exclusions related to Rider EDR(g) are determined by the WBS CE-000303.[69] The Rider EDR(g) gross plant and reserve balances are shown separately in the Companies' workpapers to demonstrate that they are appropriately excluded from the balances that are recovered under Rider DCR. The incremental change from 2016 to 2017 in the amount of Rider EDR(g) excluded from Rider DCR is shown in the following table.[70]

Table 13: Incremental Change in Rider EDR(g) Exclusions from 2016 to 2017

	Actual 11/30/16		Actual 11/30/17		Change	
Company	**Gross**	**Reserve**	**Gross**	**Reserve**	**Gross**	**Reserve**
CEI	$ (6,894)	$ 3,705	$ 247,748	$ 3,175	$ 254,642	$ (530)

During discovery, the Companies identified that $58,187 was incorrectly included in FERC account 366 instead of FERC account 367. The error occurred beginning with the Companies April 3, 2017, Rider DCR Filing. The Companies also identified that the EDR(g) reserve balances had been calculated incorrectly due to a formula error. With these corrections, there is no change to gross plant, the actual reserve balance should be reduced by $350, and the estimated reserve balance should be increased by $217. The Companies stated (and Blue Ridge recommends) it will include a reconciliation in the Rider DCR revenue requirement in a future filing that incorporates the effect on revenues had the activity been appropriately included in FERC account 367.[71] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #2**].

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include work for the Cleveland Clinic Foundation. No work for the Cleveland Clinic Foundation was identified within the sample.[72] However, we did find Cleveland Clinic work orders in the work order population totaling $142,108.23. The Companies indicated that these work orders were in the work order population and in the November 30, 2017, plant balances.

[67] FirstEnergy's response to Data Request BRC Set 11-INT-013 - Confidential.
[68] Case No. 10-0388-EL-SSO Stipulation and Recommendation, Section F.2, pages 27-28.
[69] CEI, OE, and TE Rider DCR Compliance Filings dated 1/12/18, pages 19 and 44.
[70] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[71] FirstEnergy's response to Data Request BRC Set 1-INT-030 - Confidential.
[72] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1c.

They were removed in the January 12, 2018, Rider DCR Filing (Exclusions Page).[73] As the incremental increase in the Rider EDR(g) exclusion exceeded the amount identified in the population, Blue Ridge concluded that the costs were appropriately excluded from the Rider DCR.

Advanced Metering Infrastructure Rider (Rider AMI)

Rider AMI includes FirstEnergy's Smart Grid Modernization Initiative. Key components include distribution automation; voltage control; substation relay-based protection; alternate pricing programs; communications and data infrastructure; and data collection, analysis, and reporting.[74]

The Companies' Rider DCR Compliance Filings state that only CEI has an AMI project, so this exclusion does not affect OE or TE. Specific depreciation groups in PowerPlant and WBS CE-004000 determine exclusions related to Rider AMI. The Rider AMI gross plant and reserve balances are shown separately in the Companies' workpapers to demonstrate that they are appropriately excluded from the balances that are recovered under Rider DCR.

The Summary of Exclusions in the Compliance filings lists the following amounts associated with Rider AMI that were excluded from Rider DCR.

Table 14: Rider AMI Gross Plant and Reserve Reported in the Summary of Exclusion as Excluded from Rider DCR

FERC Account	CEI	
	Gross	Reserve
303	$ (1,159,454)	$ (174,266)
362	5,384,748	1,718,763
364	169,310	55,885
365	1,839,568	971,861
367	11,080	3,255
368	185,568	99,728
370	17,090,137	6,968,857
397	4,766,987	1,816,481
Grand Total	$28,287,943	$11,460,564

Blue Ridge reviewed the Companies' AMI Report in Support of Staff's 2017 Annual Review in Case 16-2166-EL-RDR filed on February 28, 2018. Through December 31, 2017, Rider AMI plant-in-service cumulative spend was $33,866,780 and accumulated depreciations was $16,641,158. These amounts were compared to the AMI balances that the Companies reflected on the Summary of Exclusions as exclusions to the DCR to ascertain whether the amount excluded in the DCR for Rider-AMI-recovered plant was not unreasonable. As shown in the following table, the amount included in Rider AMI is significantly higher than the amount that is included in the Summary of Exclusions for AMI activity.

[73] FirstEnergy's response to Data Request BRC Set 11-INT-014 - Confidential.
[74] Case No. 09-1820-EL-ATA, et. al., Application pages 5–7.

Table 15: Comparison of Cumulative AMI Reported in Rider AMI Vs. Rider AMI Reported on Summary of Exclusions as AMI Excluded in Rider DCR

	Plant in Service	Accumulated Depreciation
AMI Accumulated Spend through 12/31/17	$ 33,866,780	$ 16,641,158
Excluded from Rider DCR as of 11/30/17	28,287,943	11,460,564
Difference AMI Rider through 12/31/2017 vs. Exclusion through DCR through 11/30/17	$ (5,578,837)	$ (5,180,595)

The Companies explained that, as a result of the 2013 DCR audit, it made adjustments within the DCR revenue requirements model to plant balances to remove work order activity identified as AMI.[75] After reviewing the 2013 adjustments, Blue Ridge identified approximately $2.161 million in AMI work orders that are manually removed through the DCR model plant balances and not included in the Summary of Exclusions. The Company's manual process to reflect the 2013 AMI adjustments within the model and not include those exclusions in the Summary of Exclusions support makes it difficult to reconcile recovery between the AMI Rider and the DCR rider to ensure there is no double recovery.

We also reviewed the incremental change in AMI plant in 2017 to the incremental change in Rider AMI costs excluded through the Rider DCR through November 30, 2017. The incremental change from the 2016 audit to 2017 audit in the amount of Rider AMI excluded from Rider DCR is shown in the following table.[76]

Table 16: Incremental Change in Rider AMI Exclusions from 2016 to 2017

	Actual 11/30/16		Actual 11/30/17		Change	
Company	**Gross**	**Reserve**	**Gross**	**Reserve**	**Gross**	**Reserve**
CEI	$28,230,395	$ 8,983,556	$28,287,943	$11,460,564	$ 57,548	$2,477,008

The following table compares the incremental 2017 AMI plant obtained from the Companies' AMI Report in Support of Staff's 2017 Annual Review in Case 16-2166-EL-RDR, filed on February 28, 2018, to the amount excluded in the Rider DCR through November 30, 2017. There is $589,887 more plant in service being recovered through Rider AMI than has been excluded in the Rider DCR.

[75] FirstEnergy's response to Data Request BRC Set 11-INT-015.
[76] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

Table 17: Comparison of Incremental 2017 AMI Vs. Rider AMI Excluded from DCR through 11/30/17

	Plant in Service	Accumulated Depreciation
Prior Year Accumulated Spend	$ 33,219,345	$ 13,280,080
Accumulated Spend - 12/31/17	33,866,780	16,641,158
Rider AMI 2017 Spend	$ 647,435	$ 3,361,079
Incremental Rider AMI Costs Excluded in DCR	57,548	2,477,008
Difference 2017 Rider AMI vs. Amount Excluded in DCR through 11/31/2017	$ (589,887)	$ (884,071)

While there is a timing difference between the reporting period for the Rider AMI and the Rider DCR (the DCR reports from December to November and Rider AMI is calendar year), the difference is larger than can be explained through timing. Blue Ridge recommends that the Companies provide a reconciliation to document that there is no double recovery of AMI.

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include AMI work. No work associated with AMI was identified within the sample.[77] However, several AMI work orders were identified in the population of work orders for the DCR since they were in the November 30, 2017, plant balances. The Companies indicated that those work orders were excluded from Rider DCR through Rider AMI included in the January 12, 2018 Rider DCR filing.[78] Based upon Blue Ridge's comparison of the amount of plant reported recovered through the Rider AMI and the amount of AMI plant excluded in the Rider DCR, Blue Ridge was unable to confirm that there is not double recovery of AMI spending.

Other Riders

In addition to Riders LEX, EDR, and AMI, the Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO[79] and 14-1297-EL-SSO[80]) requires that capital additions recovered through any other subsequent rider authorized by the Commission to recover delivery-related capital additions be identified and excluded from Rider DCR and the annual cap allowance.[81] In addition to the Riders DCR, LEX, EDR, and AMI, the Companies' tariffs include the following riders:

[77] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1a.
[78] FirstEnergy's response to Data Request BRC Set 11-INT-015 - Confidential.
[79] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[80] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[81] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.

1	Residential Distribution Credit	21	Non-Distribution Uncollectible
2	Transmission and Ancillary Service Rider	22	Experimental Real Time Pricing
3	Alternative Energy Resource	23	Experimental Critical Peak Pricing
4	School Distribution Credit	24	CEI Delta Revenue Recovery – CE
5	Business Distribution Credit	25	Experimental Company Owned LED Lighting Program
6	Hospital Net Energy Metering	26	Generation Service
7	Peak Time Rebate Program – CE	27	Demand Side Management and Energy Efficiency
8	Universal Service	28	Deferred Generation Cost Recovery
9	State kWh Tax	29	Deferred Fuel Cost Recovery
10	Net Energy Metering	30	Non-Market-Based Services
11	Grandfathered Contract – CE	31	Residential Deferred Distribution Cost Recovery
12	Delta Revenue Recovery	32	Non-Residential Deferred Distribution Cost Recovery
13	Demand Side Management	33	Residential Electric Heating Recovery
14	Reasonable Arrangement	34	Residential Generation Credit
15	Distribution Uncollectible	35	Phase-In Recovery
16	Economic Load Response Program	36	Distribution Modernization
17	Generation Cost Reconciliation	37	Government Directives Recovery Rider
18	Fuel	38	Ohio Renewable Resources Rider
19	Delivery Service Improvement	39	Commercial High Load Factor Experimental Time-of Use Rider
20	PIPP Uncollectible	40	Residential Critical Peak Pricing Rider

The Companies confirmed that the above riders should not include distribution capital additions or Service Company capital additions that are allocated to Rider DCR.[82] Blue Ridge reviewed the tariff for the above riders and found that three of the new riders required further review to understand the charges that were being recovered through the tariff. The Distribution Modernization Rider, Ohio Renewables Resources Rider, and the Government Directives Recovery Rider nomenclature implied that plant could be a component of the riders' revenue requirement calculation. Further review found that only the Government Directive Recovery Rider (Rider GDR) has the potential to impact the Rider DCR in the future. Rider GDR recovers costs associated with federal or state government mandates enacted after August 4, 2014. No activity has occurred on Rider GDR to date.[83] The Companies stated that to the extent the Rider GCR is populated in the future any costs included for recovery would exclude capital additions or other components that are currently being recovered through Rider DCR.[84]

During the reconciliation of the *Work Order Population totals to DCR Filing Year-to-Year Plant-In-Service Activity*, Blue Ridge compared the difference between the DCR November 30, 2017, gross plant balances and the November 30, 2016, gross plant balances for all Companies with the Work Order totals for the same period. The Companies provided information regarding some work orders related to the Companies' Experimental Company Owned LED Lighting Program that were included in the DCR November 30, 2016, gross plant balances that should not have been. The Companies began removing this activity with the April 3, 2017, Rider DCR filings, and the amounts are not in the November 30, 2017, gross plant balance.

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[82] FirstEnergy's response to Data Request BRC Set 1-INT-036 - Confidential.
[83] FirstEnergy's response to Data Request BRC Set 11-INT-003 - Confidential.
[84] WP FE response to 2016 audit Data Request BRC Set 10-INT-001 - Confidential.

The Experimental Company Owned LED Lighting Program costs are recovered through the Tariff program, originally approved in Case No. 14-1027-EL-ATA on November 20, 2014, and continued by Commission Order in Case 16-470-EL-ATA on October 12, 2016.[85] The Companies identified work order activity that should have been excluded from the December 2015—November 2016 OE FERC account 373 Street Lighting ($6,640, in-service January 2016) and TE FERC account 373 Street Lighting ($31,957, in-service February–May 2016). FirstEnergy stated that it began to remove this activity with the April 3, 2017, Rider DCR filing. Furthermore, FirstEnergy stated (and Blue Ridge recommends) that it will include a reconciliation in the Rider DCR revenue requirement in the next filing that incorporates the effect on revenues had the activity been appropriately excluded in the April 1, 2016, July 1, 2016, September 30, 2016, and December 30, 2016, Rider DCR Compliance filings.[86] The balances were excluded from the November 30, 2017, plant balances.

Other than the costs associated with the Government Directives Recovery Rider and the Experimental Company Owned LED Lighting Program, Blue Ridge's review found there was no indication that these non-Rider-DCR tariffs would contain distribution plant. Blue Ridge recommends that future Rider DCR filings specifically review any distribution-plant-related costs recovered through the Government Directives Recovery Rider and the Experimental Company Owned LED Lighting Program to ensure that these two riders are excluded from the Rider DCR.

General Adjustments

Consistent with Case No. 07-551-EL-AIR, the Companies removed land leased to ATSI, FirstEnergy's transmission subsidiary, from Rider DCR. The amounts are not jurisdictional to distribution-related plant in service and were excluded accordingly from each operating company.

Table 18: ATSI Land Lease (FERC Account 350) Excluded from Rider DCR[87]

	Actual 11/30/17		Estimated 2/28/18	
Company	**Gross**	**Reserve**	**Gross**	**Reserve**
CEI	$ 56,405,971	$ -	$ 56,405,971	$ -
OE	86,977,415	-	86,977,415	-
TE	15,628,438	-	15,628,438	-
Total	$159,011,823	$ -	$159,011,823	$ -

The ATSI Land Lease exclusion value was changed by the amount of incremental activity (net of additions, retirements, transfers, and adjustments) in FERC Account 350. The ATSI Land Lease exclusions for each year following the approval of Rider DCR are shown in the following table.

[85] FirstEnergy's response to Data Request BRC Set 11-INT-004 - Confidential.
[86] FirstEnergy's response to Data Request BRC Set 1-INT-006 - Confidential.
[87] CEI, OE, and TE Rider DCR Compliance Filings dated 1/12/18, page 19 and page 44.

Table 19: ATSI Land Lease-Change in Amounts from Case No. 07-551-EL-AIR and Prior Audits[88]

Description	CEI	OE	TE	Total
Case No. 07-551-EL-AIR				
Staff Report	$ 64,744,646	$ 93,234,013	$ 17,061,251	
Exhibit TJF-1	$ (7,478,215)	$ (7,943,389)	$ (1,432,451)	
Staff Agrees	$ 57,266,431	$ 85,290,624	$ 15,628,800	$158,185,855
12/31/2011 Rider DCR Amounts	$ 57,266,431	$ 85,290,624	$ 15,628,800	$158,185,855
12/31/2012 Rider DCR Amounts	$ 57,227,343	$ 85,471,094	$ 15,628,438	$158,326,875
12/31/2013 Rider DCR Amounts	$ 59,306,092	$ 86,963,323	$ 16,373,799	$162,643,214
11/30/2014 Rider DCR Amounts	$ 57,224,624	$ 85,567,532	$ 15,628,438	$158,420,594
11/30/2015 Rider DCR Amounts-Corrected	$ 56,418,950	$ 86,956,515	$ 15,628,438	$159,003,903
11/30/2016 Rider DCR Amounts-Corrected	$ 56,405,971	$ 86,982,409	$ 15,628,512	$159,016,892
11/30/2017 Rider DCR Amounts	$ 56,405,971	$ 86,977,415	$ 15,628,438	$159,011,823
Change from 2016 to 2017 (Incremental Activity)	$ 0	$ 4,994	$ 74	$ 5,069
Difference 2017 vs Case 07-551-EL-AIR	$ (860,460)	$ 1,686,791	$ (362)	$ 825,968

As discussed in the work order testing section, work order OECO 15037327 was identified as including costs associated with ATSI that should have been excluded from the DCR. Blue Ridge recommends an adjustment to reflects its removal [**ADJUSTMENT #9**].

Generation

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include generation amounts. Blue Ridge found no generation amounts included within the sample work orders that should have been removed.

Conclusion

Blue Ridge was unable to verify that the plant associated with the Rider AMI was fully excluded in the Rider DCR. While there is a timing difference between the reporting period for the Rider AMI and the Rider DCR (the DCR reports from December to November and Rider AMI is calendar year), the difference is much larger than can be explained through timing. Blue Ridge recommends that the Companies provide a reconciliation to document that there is no double recovery of AMI.

There were adjustments required for exclusions associated with Rider EDR(g), Experimental Company Owned LED Lighting Program, and ATIS work orders.

JOBBING, CONTRACTING, AND MUTUAL AID ACTIVITIES

Jobbing and Contracting Activities

The terms *jobbing* and *contracting* apply to those activities initiated by a customer for whom work is performed by the Companies and paid for by that initiating customer alone. The process includes the following steps:

[88] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

- The customer contacts the Company regarding need for a specific project.
- The Company establishes a work order specific to that customer project.
- All costs for the work are charged to the specific work order.
- During month-end closing, all costs are moved from each jobbing and contracting work order to balance sheet FERC account 186—Miscellaneous Deferred Debits.
- When the job is closed and in-service, the costs and corresponding revenue are recorded in the income statement FERC accounts 415—Revenues from Merchandising, Jobbing, and Contract Work and 416—Cost and Expenses of Merchandising, Jobbing, and Contract Work.

The Companies have controls in place both in SAP and PowerPlant (Settlement Rules) to keep the revenues and expenses from being included in Rider DCR or any other retail recovery mechanism.[89] Blue Ridge confirmed that no jobbing or contracting work orders were in the population of work orders for the DCR.[90]

Mutual Aid Activities

The term *mutual aid* refers to activities performed by the Companies at the request of another utility outside FirstEnergy's territory. Most mutual aid assistance is provided under an agreement as to what costs are to be billed based on what was requested and what was provided. Mutual aid is normally associated with storms or other natural disasters for which the host utility needs help restoring power to its service area. The process includes the following steps:

- SAP creates a specific work order used to accumulate costs. A work order is created for each operating company asked to provide assistance. or as determined by FirstEnergy when requested to provide assistance.
- The requesting utility is invoiced for the mutual aid activities.
- After all costs have been invoiced the work order will net to zero.
- Reimbursements from the host utility are journal-entered to FERC account 415—Revenues from Merchandising, Jobbing, and Contract Work. Expenses are moved to FERC account 416—Cost and Expenses of Merchandising, Jobbing, and Contract Work.[91]

The same controls in place for Jobbing and Contracting apply to Mutual Aid.

Blue Ridge concluded that adequate controls exist within SAP and PowerPlant to ensure that activities related to Jobbing, Contracting, and Mutual Aid are not included in the DCR. In addition, the accounts used to account for costs and revenue are not CWIP or Utility Plant in Service, which could be part of the DCR. The accounting used by the Companies is not unusual in the utility industry.

[89] FirstEnergy's response to Data Request BRC Set 5-INT-009 - Confidential.
[90] FirstEnergy's response to Data Request BRC Set 5-INT-011 - Confidential.
[91] FirstEnergy's response to Data Request BRC Set 5-INT-012 - Confidential.

GROSS PLANT IN SERVICE

E. Determine if the Companies' recovery of the incremental change in Gross Plant are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following gross plant-in-service incremental change for each company from the time of the prior audit.

Table 20: Incremental Change in Gross Plant from 11/30/16 to 11/30/17[92]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	2,955,112,270	3,072,113,869	117,001,599
Ohio Edison Company	3,351,099,110	3,473,934,081	122,834,971
The Toledo Edison Company	1,159,939,724	1,190,363,521	30,423,797
Total	7,466,151,104	7,736,411,471	270,260,367

Actual and Estimated Schedules B-2.1 support the incremental change in gross plant in service for transmission, distribution, and general plant. Other plant includes intangibles that are supported on separate schedules within the filings. The plant balances developed on these schedules are used throughout the Rider DCR revenue requirement calculations.

The Companies did not have any large construction and/or replacement programs in 2017. Each company had normal, recurring replacement programs, including Pole Replacements, Underground Cable Replacement, Feeder Repair/Replacement, Worst Performing Circuit/CEMI Program, and Downtown Network Upgrades.[93]

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included in the actual and estimated schedules that support gross plant and also verified that gross plant balances rolled forward to the revenue requirement calculation correctly. We did not identify anything in the mathematical computations as unreasonable.[94]

Source Data Validation

Blue Ridge traced the values used for actual November 30, 2017, and estimated February 28, 2018, gross plant-in-service balances to source documentation. The actual and estimated balances reconciled to the supporting documents. The supporting workpapers for the February 28, 2018, estimate recognize a true up of forecast to actual November 30, 2017, balances and adjustments from prior audits.[95]

[92] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[93] FirstEnergy's response to Data Request BRC Set 1-INT-021 - Confidential.
[94] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[95] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachments 3, 4, 5, 6, and 7 – Confidential.

Change in Pension Accounting

Schedule B-2.1 includes a note that plant in service is adjusted to remove the cumulative pre-2007 impact of a change in pension accounting. In the prior audit, FirstEnergy explained the adjustment as follows:

> Effective in the fourth quarter of 2011, FirstEnergy Corp. (FE) elected to change its method of recognizing actuarial gains and losses for its defined benefit pension plans and other postretirement plans (OPEB). Previously, FE recognized actuarial gains and losses as a component of Accumulated Other Comprehensive Income (AOCI) within the Consolidated Balance Sheets on an annual basis. Actuarial gains and losses that were outside a specific corridor were subsequently amortized from AOCI into earnings over the remaining service life of affected employees within the related plans. Under the new methodology, which is preferable under GAAP, FE has elected to immediately recognize net actuarial gains and losses in earnings, subject to capital labor rates, in the fourth quarter of each reporting year as gains and losses occur and whenever a plan is determined to qualify for a re-measurement during a reporting year. The cumulative impact of this change in accounting methodology was reflected in FE's 2011 year-end financial results. Net plant in service was impacted by the appropriate capitalized portion of actuarial gains and losses recognized as a result of this accounting methodology change.[96]

Blue Ridge found FirstEnergy's explanation to be not unreasonable. In addition, Blue Ridge compared the Change in Pension Accounting amounts from year to year and found that the amounts were the same.[97]

Additional Validation Testing from Sampled Work Orders

The Companies provided a list of work orders that support gross plant in service for December 2016 through November 2017.[98] Blue Ridge validated that the work order amounts reconciled to the Companies' DCR filing gross plant balances.[99] Blue Ridge reviewed the population of work orders for work order numbers that represent plant that is specifically excluded from Rider DCR. Blue Ridge's findings are discussed in the Rider LEX, EDR, AMI, and General Exclusions section. In addition, Blue Ridge sorted the cost line items and grouped them by work order number to eliminate pulling duplicate sample work orders and ensuring that all cost line items for selected work orders were reviewed; scanned the population for unusual transactions and included them as judgment samples if not selected in the statistical sample; and identified other work orders for FERC accounts not selected during the sample draw.

In addition to global evaluations of the population, Blue Ridge selected work orders for additional detail testing. Using probability-proportional-to-size (PPS) sampling techniques[100] and

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[96] WP FE response to 2011 Audit Data Request BRC Set 14-INT-001.
[97] WP FEOH 2017 Pre-Date Certain Pension Impact Analysis 2012-2017 - CONFIDENTIAL.
[98] FirstEnergy's response to Data Request BRC Set 1-INT-002, Attachment 1 – Confidential.
[99] WP BRC Set 1-INT-002 and 1-INT-006 Comparison WP BRC Set 1-INT-002 and 1-INT-006 Comparison - Companies Response - Confidential, FirstEnergy's response to Data Request BRC Set 1-INT-002, Attachment 1 – Confidential and FirstEnergy's response to Data Request BRC Set 1-INT-006.
[100] WP FEOH 2017 Sample Size Calculation Work Orders through 11-30-17 - CONFIDENTIAL.

professional judgment, Blue Ridge selected 64 work orders representing 157 FERC cost line items for detailed transactional testing. The following table provides the number of work orders and FERC cost line items in the population and the number in Blue Ridge's sample.

Table 21: Work Orders and FERC Cost Line Items in Population and Sample by Company[101]

	Population		Sample	
	Work Orders	**FERC Cost Line Items**	**Work Orders**	**FERC Cost Line Items**
Cleveland Electric	29,957	43,271	18	74
Ohio Edison	41,365	63,942	19	36
Toledo Edison	16,611	23,270	16	37
Service Company	173	201	11	11
Total	**88,103**	**130,684**	**64**	**157**

The testing of work orders included review of project justifications, project actual vs. budgeted cost, variance explanations, reasonableness of the in-service dates in comparison to the estimated in-service dates, proper charge of the actual detailed cost to the proper FERC account, AFUDC charge on the work order (and if so, that it was appropriate), timeliness of recording of asset retirements for replacement work orders, and appropriate charge of cost of removal. The results of the detailed transaction testing performed on the work order sample are included in the workpapers.[102] Specific observations and findings about the testing are listed below.

Description of Projects

The Companies provided a description of the projects included in the work order sample. In general, the projects may be categorized according to the following types of additions, replacements, adjustments, and transfers:

1. Installation of underground and overhead conduit, conductors, and devices, including installation on customer premises
2. Meters
3. Station equipment
4. Street lighting
5. Structures
6. Office furniture and equipment
7. Transportation and power-operated equipment
8. Poles, towers, and fixtures
9. Services
10. Structures and Improvements
11. Miscellaneous intangible plant (software)
12. Communication equipment
13. Adjustments, transfers, and plant unitization cleanup

[101] FirstEnergy's response to Data Request BRC Set 1-INT-002 and WP FEOH 2017 Sample Size Calculation Work Orders through 11-30-17-Confidential.xlsx
[102] WP FEOH 2017 Sample Work Order Testing Matrix-Confidential.

Project Testing

The sampled work orders were evaluated based on objective criteria identified as T1 through T10.[103] Blue Ridge's observations and findings against the criteria are summarized below.

T1: The work is appropriately includable in Rider DCR. Rider DCR includes plant in service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies.

During the Companies' preparation of data responses, the Companies identified work order activity of $1,192,607 in TECO work orders (Structures and Improvements) that should have been excluded because the work was for the Toledo Edison Plaza Tenant Improvement project.[104]

Table 22: Toledo Edison Plaza Tenant Improvement Project Work Orders

Work Order	Description	Total Activity
14864861	Edison Plaza Fifth Floor Renovations	$(7,583.97)
14869255	Edison Plaza Water Damage	$(21,707.76)
TW-001199-F	Edison Plaza - Tenant Improvements-2014	$1,013.96
TW-001254-F	Edison Plaza 1st Floor	**$974,716.14**
TW-001254-F-3	Edison Plaza 15th Floor	$246,168.17
Total		**$1,192,606.54**

Work Order TW-001254-F was identified in the work order sample. The Companies stated (and Blue Ridge recommends) that a reconciliation calculation be included in a future Rider DCR filing to reflect the cumulative revenue requirement impact of removing the abovementioned costs.[105] Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(153,555) [**ADJUSTMENT #5**].

Tree Trimming and Clearing and Grading of Land

Blue Ridge's sample included three work orders related to Vegetation Management (Tree Trimming). To fully understand how the Companies classify vegetation management between capital and maintenance activity, Blue Ridge requested the Companies' vegetation management capitalization policies and procedures.

The Companies stated that FirstEnergy management, in conjunction with their external auditors, developed and approved the policy Accounting for the Clearing of Transmission and Distribution Corridors. This policy establishes means by which to differentiate between capital

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[103] WP FEOH 2017 Sample Work Order Testing Matrix-Confidential.
[104] FirstEnergy's response to Data Request BRC Set 3-INT-001 - Confidential.
[105] FirstEnergy's response to Data Request BRC Set 1-INT-003 - Confidential.

and O&M activity. The Companies' approved policy for capitalizing or expensing of activities associated with clearing of transmission and distribution corridors includes these guidelines:

1. CAPITALIZATION
   - 1.1. All expenditures associated with the initial clearing of transmission and distribution corridors shall be capitalized.
   - 1.2. Expenditures, such as removals, pruning, brush clearings, etc., associated with the initial widening of an existing corridor clearing zone shall be capitalized. Examples include:
     - 1.2.1. increasing initial distribution corridor clearing zones from 10 to 15 feet; and
     - 1.2.2. expanding the initial transmission clearing zone corridor.
   - 1.3. Expenditures associated with the subsequent removal of priority trees or other large tree limbs outside the corridor (where no future tree maintenance is required) shall be capitalized. The removal of tree limbs that overhang at a height 15 feet or more above conductors with voltages below 115 kv and which emanate from trees growing within the corridor shall be capitalized. If in the process of directionally pruning the overhang fifteen feet or higher, it becomes necessary to remove the entire tree, the tree removal cost shall be capitalized.
   - 1.4. Allowance for Funds Used During Construction shall not be applied to the subsequent removal of priority trees or large tree limbs.
2. EXPENSE
   - 2.1. Expenditures associated with the clearing or reclamation of an existing corridor clearing zone that are not capitalized in accordance with this policy shall be expensed. Such charges include:
     - 2.1.1. routine circuit maintenance,
     - 2.1.2. customer ticket work,
     - 2.1.3. clearing overgrown vegetation and overhang within the initial corridor clearing zone that are not capitalized under 1.2 above; and
     - 2.1.4. herbicide programs.[106]

The FERC Code of Federal Regulations (18 CFR), parts 101 to 142 defines capital in part as follows:

> **Capital:** FERC 365 (Overhead conductor and devices, part 9) The account shall include the cost of tree trimming initial cost, including the cost of permits.[107]

Blue Ridge interprets this FERC statement to cover the initial cost of clearing and trimming of what the Companies call a corridor. We also agree that it would cover initial expansion activity (although FERC does not specifically mention corridor expansion). Therefore, we do not disagree with Companies' policy numbers 1.1, 1.2, 1.2.1, and 1.2.2 above.

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[106] FirstEnergy's response to Data Request BRC Set 9-INT-004-Confidential.
[107] FERC Code of Federal Regulations (18 CFR), parts 101 to 142.

FERC defines expense in part as follows:

> **Maintenance:** FERC 593 (maintenance of overhead lines which deals with assets in FERC 365. Part k) This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services: trimming trees and clearing brush. (References operating expense instruction 2: Maintenance, part C, item 3: Work performed specifically for the purpose of preventing failure, restoring service ability, or maintaining life of plant.[108]

Blue Ridge interprets this FERC statement to cover preventive maintenance associated with existing corridors. Therefore, we do not disagree with Companies' policy numbers 2.1, 2.1.1, 2.1.2, 2.1.3, and 2.1.4, which appear to fall under FERC accounting guidelines.

Companies' policy number 1.3 discusses tree or limb removal outside the corridor where no future maintenance is required. Blue Ridge found that the wording in Companies' policy number 1.3 gives the Companies broad leeway to remove any tree or limb outside a corridor for any reason and assign it as capital cost. We recommend that this statement be better defined. Furthermore, Blue Ridge believes this type of activity appears to be maintenance since the work is not done in conjunction with the initial or expansion work for a corridor.

Companies' policy number 1.3 also states the "removal of tree limbs that overhang at a height of 15 feet or more above conductors with voltages below 115 kv and which emanate from trees growing within the corridor shall be capitalized. If, in the process of directionally pruning the overhang fifteen feet or higher, it becomes necessary to remove the entire tree, the tree removal cost shall be capitalized." Blue Ridge interprets this to mean that any tree limb or tree can be removed that is within the initial or expanded corridor or outside the corridor that are from trees within the corridor, after the initial capital work was done and capitalized. The voltage restriction below 115kv essentially covers all distribution and sub transmission and excludes voltage above 115kv, which would be Transmission. It would appear that this type of work is to prevent failure and would fall under the FERC definition of maintenance of overhead lines. However, Blue Ridge found that the Companies inappropriately interpret this type of work as capital and not within the FERC accounting guidelines for maintenance.

We recommend that the Companies revise their vegetation management polices to be consistent with FERC Uniform System of Accounts. We also recommend that the three vegetation management work orders be excluded from Rider DCR as they do not meet the FERC Uniform System of Accounts definition of capital expenditures.

- Work Order CE-900186-VMPL-DIST – Total Project - $8,070,533: This program covers vegetation management beyond the normal CEI tree trimming budget and will encompass the planned removal of overhanging branches and off-corridor trees, both of which may be capitalized. Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(1,637,487) [**ADJUSTMENT #6**].

[108] FERC Code of Federal Regulations (18 CFR), parts 101 to 142.

- Work Order: OE-900186-VMPL-DIST – Total Project - $9,989,590. Prevention of tree contact with overhead conductors. Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(1,590,203) [**ADJUSTMENT #7**].
- Work Order: TW-900186-VMPL-DISt – Total Project. $2,384,402, Prevention of tree contact with overhead conductors.[109] Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(451,052) [**ADJUSTMENT #8**].

T1a: Exclusions Rider AMI: Review project descriptions for Distribution projects (FERC 360 accounts) to ensure that those descriptions exclude any discussion of AMI or SmartGrid projects.

Blue Ridge found that the sample did not contain any AMI or SmartGrid work orders.[110]

T1b: Exclusions Rider LEX: Review descriptions for Distribution projects only (FERC account 360 - Distribution Plant – Land and Land Rights) to ensure that they do not include line extension work.

Blue Ridge reviewed the project scope for each work order that had FERC account 360 charged to confirm that LEX work orders were properly excluded from Rider DCR. Blue Ridge found that the sample did not include any LEX work orders.[111]

T1c: Exclusions Rider EDR: Review project descriptions for CECO and FE only to ensure that the projects do not include work for the Cleveland Clinic Foundation.

Blue Ridge found no work orders in the sample related to EDR(g).[112]

T1d: Exclusions GEN: Review project descriptions to ensure that the projects do not include generation work.

Blue Ridge found no work orders in the sample related to generation.[113]

T2: Work order packages contain the project approval documentation or work order was approved at the project level.

Blue Ridge found that the Companies have adequate procedures in place to approve work orders. The procedures have not changed since our prior year review and, if followed, will yield the proper project approvals. Blue Ridge found no instance in which the Companies did not follow their stated policies.[114]

T3: For specific work orders (i.e., not a blanket work order or multi-year project, such as pole and meter replacements), the work order packages contain project justification.

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[109] WP FEOH 2017 Sample Work Order Testing Matrix-Confidential and FirstEnergy's response to Data Request BRC Set 3-INT-001, attachment 1 – Confidential.
[110] FirstEnergy's response to Data Request BRC Set 1-INT-005, part b - Confidential.
[111] FirstEnergy's response to Data Request BRC Set 1-INT-005, part d - Confidential.
[112]WP FEOH 2017 work order testing matrix.
[113]WP FEOH 2017 work order testing matrix and First Energy's response to Data Request BRC Set-1-INT-005, part a - Confidential.
[114] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential, BRC Set 1-INT-026 and BRC Set 9-INT-001 - Confidential.

Blue Ridge reviewed the justification for all work orders in the sample, exclusive of blanket, multi-year projects, transfers, and adjustments, and found all project work orders included justifications that were not unreasonable. The Companies use Accounting Work Orders for asset-related activities that are not immediately driven from a construction project and do not require project justifications. The Companies explained the nature of the adjustment, and the explanation was not unreasonable.

T4: Project costs are within the approved budget. Explanations and approval for cost overruns were provided.

In summary, Blue Ridge found the following calculated results:

25%—16 projects over budget greater than 15%
19%—12 projects over budget by less than 15%
34%—22 projects were under budget
22%—14 projects did not have budgets (emergent work, accounting work orders, or storm work)

Included within these projects, four of the seven work orders booked to FERC 303 were over budget by more than 15%, and three were under budget.

Specifically, the following four work orders were considered emergent projects and were not in the original capital budget.[115]

- CECO 14434161 - CE - Implement New Mobile Radio System: $5,972,286
- OECO 14434236 - OE - Implement New Mobile Radio System: $6,834,326

  The Companies explained that they were required by the vendor to stop using radio communications. Management made the decision to move their communications to another vendor network rather than rebuild the prior system since the rebuild option would have added significant costs and a much longer timeline toward an ultimate solution. The project was not in the original capital budget.[116]

- OECO 15037327: $21,635
- This work order was used to capture costs associated with the Distribution under build component of an ATSI transmission project. This project was not in the original capital budget plan because the request for the support was from ATSI. The work was not identified until the OECO capital budget portfolio was approved.[117] ATSI typically reimburses the distribution company for the expenses within the month in which the expenses are incurred so that the distribution company realizes a net zero impact upon the processing for the month-end close activities. However, in this case, this particular work order was not flagged appropriately for the reimbursement accounting to be processed, so the reimbursement was not booked in a timely fashion. The issue was identified during a subsequent review of similar work, and the reimbursement was then booked in February 2018. The Companies stated that all necessary adjustments to the Companies' Rider DCR

[115] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachments 1 and 2 and BRC Set 7-INT-001, Attachment 1 - Confidential.
[116] FirstEnergy's response to Data Request BRC Set 10 -INT-002 and 003 - Confidential.
[117] FirstEnergy's response to Data Request BRC Set 10 -INT-10-004 - Confidential.

revenue requirements associated with this issue will be reflected in the reconciliation included in the next Rider DCR filing based on February 28, 2018, balances. Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(3,458) [**ADJUSTMENT #9**].

- OECO OE-005700-SPEC-D-2017 - 700MHz Block A Spectrum Purchase Dx 2017: $1,077,721

  This project was for the 700MHz Block A Spectrum Purchase Dx 2017 to aid reliability.[118]

Besides the four emergent projects that did not have budgets, Blue Ridge found another 10 of the 64 work orders / projects selected for testing that did not have budgets. These 10 included six accounting work orders and four storm work orders that are not budgeted.

Of the remaining 50 work orders, 22 work orders were under budget, 12 were over budget by less than 15%, and 16 were over budget by more than 15%. Companies provided explanations for the 16 projects that were over budget by more than 15%:

1. OECO 14777209 - MOD SUB
   a. Actual Capital Spend: $3,194,417.58
   b. Budget: $2,410,453.57
   c. Over budget by 32.5%: $783,964.01
   d. Description: Purchased substation site in 2010. In 2016 begin below grade work and in 2017 install a 138kV/12.47kV, 11/14 MVA, 2-750 MCM parallel Al urd exit mod-sub with scada in order to serve growing load along SR 29 and relieve substations. New sub to be served by the new 138KV transmission line completed in 2014.
   e. Reason for cost overrun: Higher than planned construction overheads was the primary driver of the unfavorable variance for this project. Direct charged expenses were less than a 10% variance and was mainly attributed to higher than planned contractor support for the project. The cost of the land for the substation was charged to Plant Held for future use and remains in that account through 12/13/17. This accounting is appropriate and not included in the DCR. The dollars will be transferred in 2018.[119]
2. CECO 15010905 - Equip Replacement - PT
   a. Actual: $179,466.38
   b. Budget: $62,035.22
   c. Over budget by 189.13%: $117,431.16
   d. Description: N/A
   e. Reason for cost overrun: Labor, materials, and construction overhead expense greater than planned.[120]
3. CECO 14671767 - (PID#10900)
   a. Actual: $6,317,333.23
   b. Budget: $5,197,161.52
   c. Over budget by: 21.6%: $1,120,171.71

[118] FirstEnergy's response to Data Request BRC Set 3 -INT-001, Attachment 1 - Confidential.
[119] FirstEnergy's response to Data Request BRC Set 10-INT-005 - Confidential.
[120] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 1 - Confidential.

   d. Description: Relocate affected overhead circuitry in coordination with Cuyahoga County widening 2.3 miles. Project affects 36 KV 13.2 KV circuits. Phase 1 Relocate 51 sub-transmission facilities & cross over secondary distribution facilities. Phase 2 Affects 36 sub-transmission facilities & cross over secondary & distribution facilities.
   e. Reason for cost overrun: The annual Pension Mark-to-Market adjustment allocated to this project was the main driver of the unfavorable variance. Upon further review, the Companies explained that the Pension Mark-to-Market adjustment impacted the overall project variance by $(1.357 million). Excluding the impact of the Mark-to-Market adjustment, the project would have been slightly favorable as compared to the original budget. The total capitalized amount of the 2016 Pension Mark-to-Market entry for CECO was spread across all eligible work orders that had capital activity in 2016. Based on this allocation process, this particular project was allocated approximately $1.3 million of the total.[121] We reviewed the Pension Mark-to Market allocation process and associated accounting and found it to be not unreasonable.[122]
4. OECO 14948792 - INTERCHANGE PROJECT
   a. Actual: $3,687,795.88
   b. Budget: $2,093,027.24
   c. Over budget by 76.2%: $1,594,768.64
   d. Description: Reconstruct and modify access points and geometry west of the interchanges.
   e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to additional requirements identified by the City of Akron to complete the broader work. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
5. OECO PA88740150 - PO FW: 389N-25 1638
   a. Actual: $12,656,510.09
   b. Budget: $2,829,473.04
   c. Over budget by 347.3%: $9,827,037.05
   d. Description: OE - Blanket - Forced Failures
   e. Reason for cost overrun: Variance is driven by a budget issue in 2017 where blanket expenditures were not appropriately allocated across normal work types. The issue was related to allocation by blanket work type subcategories rather than for the overall blanket work in the capital portfolio.[123] Although we are seeing large variances in individual blanket categories, in total, blanket spend was 5% less than budget for the year. None of the errors impacted other operating companies. Since the issue was related to an allocation by blanket work order type the variance would have been the same.[124]
6. OECO 14776434 - Commercial
   a. Actual: $2,762,614.11
   b. Budget: $1,643,271.76
   c. Over budget by 68.1%: $1,119,342.35

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[121] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 1 – Confidential and Set 15-INT-001 – Confidential.
[122] FirstEnergy's response to Data Request BRC Set 16-INT-001.
[123] FirstEnergy's response to Data Request BRC Set 9-INT-016, D - Confidential.
[124] FirstEnergy's response to Data Request BRC Set 9-INT-016, A - Confidential.

   d. Description: OE - Blanket - New Business - Commercial
   e. Reason for cost overrun: Variance is driven by a budget issue in 2017 where blanket expenditures were not appropriately allocated across normal work types. The issue was related to allocation by blanket work type subcategories rather than for the overall blanket work in the capital portfolio. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 5% less than budget for the year.
7. CECO 13857618 - CES-MOBILE SUB - 3 CEI (capital project
   a. Actual: $383,706.96
   b. Budget: $239,808.93
   c. Over budget by 60%: $143,898.03
   d. Description: Mobile #3 is a 7.5 MVA mobile with 36kv and 11kV high side taps and a 4.8kV low side tap. This project will replace the trailer, high side interrupting device, low side breaker, relaying and metering. It will refurbish the mobile to like new condition.
   e. Reason for cost overrun: Higher than budgeted materials expense was the main driver of the unfavorable variance for this project.
8. OECO 13847485 - Sub - SCADA C/I and Adaptive Re
   a. Actual: $532,659.21
   b. Budget: $176,879.95
   c. Over budget by 201.1%: $355,779.26
   d. Description: Install SCADA C/I and adaptive relaying on (2) distribution circuits and telemetering where not available. Scope may require change out of relays. Utilize adaptive relaying cabinets in inventory. Telemetering should include watts, vars, amps, and volts on distribution exit breakers. Install telemetering on low side of transformers where not available.
   e. Reason for cost overrun: This was a multi-year project that experienced scope increases due to technological advances in the equipment being installed causing higher material costs than originally assumed. Due to the scope increase, overall costs of this project exceeded the initial budget for this work.
9. CECO CE-700386 - IT GIS Upgrade
   a. Actual: $748,000
   b. Budget: $312,709
   c. Over budget by 139.2%: $435,291
   d. Description: Upgrade GIS to new Data Model and Geo-spatial Map
   e. Reason for cost overrun: The GIS Upgrade required additional application code development to resolve overall slow performance when deployed across all FE. There also were code defects/bugs which affected map functionality that were fixed by our vendor and within FE.
10. CECO CE-700418 - IT 2016 EMS Upgrade/Patch Project
    a. Capital Project Cost: $202,044
    b. Budget: $146,580
    c. Over budget by 37.8%: $55,464
    d. Description: EMS Upgrade/Patch Project - Includes contractor, software and hardware for improvements to upgrade to latest version of software
    e. Reason for cost overrun: While direct costs and AFUDC charges remained in line with the original budget, a large pension adjustment was made in December 2016

resulting in the overhead variance. We reviewed the Pension Mark-to Market allocation process and associated accounting and found it to be not unreasonable.[125]

11. FECO ITS-SC-000301-1 - Implement Prtl Strategy - Cap
    a. Capital Project Cost: $1,270,146
    b. Budget: $1,103,226
    c. Over budget by 15.1%: $166,920
    d. Description: This project will implement the strategy developed to move the content currently managed on the Portal (consumer), as well as upgrading the remaining portion of the Portal (producer) to support full mobile capability.
    e. Reason for cost overrun: The variance is largely due to the fact that Overheads and AFUDC were not included in the original budget.
12. FECO ITS-SC-000412-1 - 2016 Continuous Improve - CAP
    a. Capital Project Cost: $1,810,851
    b. Budget: $507,411
    c. Over budget by 256.9%: $1,303,440
    d. Description: This project maintains the environment and existing applications and allows for growth with setting standards and a new publisher. The business gains value in the new applications developed for use in gathering insights into data.
    e. Reason for cost overrun: During the project, a strategic decision was made to increase the footprint of customer base to include more users. This resulted in the acceleration of the purchase of 2000 additional licenses to take advantage of economies of scale resulting in additional internal and external labor hours to create reports as needed.
13. FECO ITS-SC-000442-1 - BAC Replacement - CAP
    a. Capital Project Cost: $200,862
    b. Budget: $106,605
    c. Over budget by 88.4%: $94,257
    d. Description: HP is replacing BAC with a new product running on a new Operating System. This project will replace the existing software, including hardware and Operating System.
    e. Reason for cost overrun: Project estimates resulted in additional labor hour requirements that were not included in the original budget.
14. FECO ITS-SC-000448-1 - FE Corp Responsive Design - CAP
    a. Capital Project Cost: $1,108,540
    b. Budget: $728,435
    c. Over budget by 52.2%: $380,105
    d. Description: Enhance the FECorp.com website to reduce complexity by combining codebase into a single model that will work for multiple screen sizes
    e. Reason for cost overrun: An extensive amount of retesting occurred due to a multitude of defects and changes discovered during user testing. This drove up labor costs which exceeded what was in the original budget.
15. OECO OE-710001 - IT ED Legacy Circuit Replacements
    a. Capital Project Cost: $7,192,316
    b. Budget: $4,161,837
    c. Over budget by 72.9%: $3,034,917

[125] FirstEnergy's response to Data Request BRC Set 16-INT-001.

   d. Description: Replacement of circuits used for Remote Terminal Unit (RTU) communication to the Energy Management System Front End Processors (FEPs). Where applicable, other voice and data circuits serving these substations will be replaced at the same time to optimize the communications infrastructure.
   e. Reason for Cost overrun: The difference in actual versus budgeted costs on this project is primarily attributable to timing differences. The Legacy Circuit Replacement project is a multi-year initiative. During 2017, Legacy Circuit Replacement was made a priority, and available IT funds were transferred to this project to accelerate work. Work was accelerated to cutover unreliable circuits at a faster rate to ensure system reliability. Over the life of the Legacy Circuit Replacement project, total project costs will be in line with expectations at the time of the original budget.

16. OECO OE-700386: IT GIS Upgrade
   a. Capital Project Cost: $1,440,497
   b. Budget: $507,756
   c. Over budget by 183.7%: $932,741
   d. Description: Upgrade GIS to new Data Model and Geo-spatial Map
   e. Reason for cost overrun: The GIS Upgrade required additional application code development to resolve overall slow performance when deployed across all FE. There also were code defects/bugs which affected map functionality that were fixed by our vendor and within FE.

For most of the projects, the Companies' reasoning for each project's actual costs exceeding the budget was specific and unique to that project and not unreasonable. However, approximately 28% of the projects that had budgets were over budget by greater than 15%. The large percentage of projects over budget and that two projects to implement the new mobile radio system were $12.8 million over budget raises a question about the Companies' planning process. Blue Ridge had similar concerns in the 2016 audit and included recommendation number 6 in its 2016 report that the Companies review the planning process. The Companies completed an internal audit with an objective to confirm that project management methodology and process design allows for projects to be fully scoped prior to project execution. The report issued on April 17, 2017 included several recommendations that are expected to be complete by June 2018.[126]

T5: Cost detail in Power Plant supports the work order charge and the categories of cost are reasonable.

Blue Ridge determined that the costs in PowerPlant support the work order charge and the categories of cost are not unreasonable.[127]

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[126] FirstEnergy's responses to Data Request BRC Set 4-INT-002, Attachment 1, a – Confidential and Data Request BRC Set 1-INT-011, Attachment 1 Confidential.

[127] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 3 and 4 - Confidential. Cost detail in BRC Set 2-INT-001, Attachment 3 less the retirements in BRC Set 2-INT-001, Attachment 4 = the work order selection for replacement work orders - Confidential

T6: Project detail indicates that assets were retired, and costs incurred for cost of removal and salvage.

Except for the five work orders discussed in testing step T6a below, Blue Ridge found that, for replacement work orders, assets were retired, and cost of removal was charged. Scrap sales are not recorded on an individual work order. Scrap from multiple operating companies is charged to a separate work order, and the proceeds are allocated to the various operating companies based on their estimated contribution to the total scrap sale. When equipment is sold for other than scrap, the proceeds are charged to the accumulated reserve for depreciation.[128]

The process for recording scrap and equipment sales is common in the utility industry, and the end result conforms to FERC accounting requirements. Additional comments related to retirements and costs of removal are included in T6a and T6b below.

T6a: Replacement work orders: The date assets were retired, cost of removal date, and replacement asset in-service dates are in line.

Except for the five work orders listed below, Blue Ridge found that all the replacement work orders in the sample had asset retirement dates, cost of removal dates, and in-service dates of new assets that were all in alignment.

- CECO Work Order 14017963 – Replace Voltage Regulator - $520,032. Cost of removal was charged but not retirements. This work order was unitized in December 2017, and $3,275 in retirements were recorded at that time.[129] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #10**].

- CECO Work Order 15348305 – Cable Replacement UD5098 - $56,324. Cost of removal was recorded but not retirements. The recording of retirements of $8,738 was delayed to March 2018.[130] This work order should have had retirements. While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #14**].

  The Companies stated that the retirements for these two work orders were passed to PowerPlant from CREWS. The processing of the retirements failed during the auto retirements processing with an error message of "insufficient quantities." The errors were fixed in March 2018 and the retirements processed. The Companies stated it will include a reconciliation in a future DCR filing to reflect the cumulative revenue requirement impact had the retirements not been delayed.[131] Blue Ridge recommends a reconciliation in a future DCR filing to reflect the cumulative revenue requirement impact for all five work orders, which includes the following three:

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[128] WP FE response to 2015 audit Data Request BRC Set 13-INT-004 and response to Data Request BRC Set 1-INT-014.a.v - Confidential.
[129] FirstEnergy's response to Data Request BRC Set 10-INT-007 - Confidential.
[130] FirstEnergy's response to Data Request BRC Set 15-INT-003 - Confidential
[131] FirstEnergy's response to Data Request BRC Set 10-INT-007 - Confidential.

- CECO Work order 15195180 – Equipment replacement – Transformer Oil - $79,563. No retirements or cost of removal was charged.[132] This work order should have had $55,190 in retirements and $10,104 in cost of removal recorded.[133] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #15**].

- CECO Work Order 15010905 – Equipment Replacement – PT - $59,535. No retirements or cost of removal was charged.[134] This work order should have had $302 in retirements and $5,856 in cost of removal recorded.[135] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #16**].
- TECO Work Order 14492230 – Replace Transformer and protector - $233,972. No retirements or cost of removal was charged.[136] This work order should have had $159,719 in retirements and $28,280 in cost of removal.[137] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #17**].

T6b: Replacement work orders: Cost of removal has been appropriately charged.

Blue Ridge found that the five work orders, that appeared to be replacement projects, did not have Cost of Removal charged.

Please see comments in testing step T6a above.

T7: Following completion of the work, the work order was closed out to the proper FERC 300 account(s).

Blue Ridge found that, based on the description of the work performed, all work orders in the sample were closed to the proper FERC accounts.[138] The types of work orders identified in test step T3 were, transfers, adjustments, and a PUCO audit finding and do not represent project work. All adjustments were made to a FERC 300 account, which is included in the DCR. Three of the four adjustments were credits to the DCR for the respective operating companies.

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[132] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 3 – Confidential and 10-INT-006 - Confidential.
[133] FirstEnergy's response to Data Request BRC Set 15-INT-004 - Confidential
[134] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 3 – Confidential and 10-INT-006 - Confidential.
[135] FirstEnergy's response to Data Request BRC Set 15-INT-004 - Confidential
[136] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 3 – Confidential and 10-INT-006 - Confidential.
[137] FirstEnergy's response to Data Request BRC Set 15-INT-004 - Confidential
[138] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 1 and 3 – Confidential.

T8: Actual in-service date is in line with the estimate (at or before).

Blue Ridge found that 25 work orders, or 39% of the 64 work orders sampled, had estimated in-service dates. Of those 25, approximately 40% had in-service dates that were over 90 days delayed from the estimates.[139]

Of the remaining 39 work orders in our sample, 38 were blankets or projects or other types of work orders, such as emergent projects, storms, and adjustments. Those work orders would not typically have estimated in-service dates.

One work order TW-001254-F was for the Toledo Edison Plaza Tenant Improvement that the Companies stated should have been excluded from the DCR. Its removal is reflected in ADJUSTMENT #5.

The following 10 work orders had in-service dates greater than 90 days beyond the planned in-service date.

1. CECO 14877367 - New OH Dist for Mod-Sub
    a. Capital Project Cost: $697,287.00
    b. In-Service Date: 9/20/17
    c. Need Date: 5/1/17
    d. In-Service days after estimated date: 142
    e. Description: Planning Criteria violations at 72-HK transformer and (7) 13kV area feeders in 2017 along with load growth from new business have necessitated the construction of a new 138-13kV Mod-Sub to provide capacity to Cleveland areas. This project provides load relief to the transformer and to the area feeders. Significant additional load from future development of the VA property should be considered. The Sub work includes install new 138kV breaker in the ring bus, install existing 11/14MVA 138-13.2kV xfmr (that was purchased but never used), install new 3-breaker mod-sub 13.2kV switchgear unit and design substation initially to accommodate a larger 16/22MVA xfmr that will need to be purchased in the future to replace the 11/14MVA xfmr when area load develops.
    f. Reason for greater than 90 day delay: N/A. Upon further review, the reason for the delay was due to prioritization of other line work and the determination that this would not cause any operational issues.[140] The Companies accrued only $6,641 of AFUDC. Therefore, it would appear that the delay did not result in an over accrual of AFUDC.
2. TECO 14492230 - Replace transformer and protector due to
    a. Capital Project Cost: $233,972.00
    b. In-Service Date: 3/20/17
    c. Need Date: 12/31/15
    d. In-Service days after estimated date: 445
    e. Description: Purchase and install 4 network protectors and 8 Relay Cabinets to replace the damaged units. Repair 2 damaged vault tops. Repair of 3 failed or damaged transformers(predicted).

[139] FirstEnergy's response to Data Request BRC Set 3-INT-001, Attachment 1 and Attachment 2 and BRC Set 7-INT-01, Attachment 1 - Confidential.
[140] FirstEnergy's response to Data Request BRC Set 9-INT-017 - Confidential.

   f. Reason for greater than 90 day delay: Long lead times for material purchases and prioritization of labor resources did not allow project to be completed by need date.
3. TECO 14921741 - Investigate and repair feeder trip (2353)
   a. Capital Project Cost: $6,945.00
   b. In-Service Date: 6/1/16
   c. Need Date: 12/31/15
   d. In-Service days after estimated date: 153
   e. Description: Purchase and install 4 network protectors and 8 Relay Cabinets to replace the damaged units. Repair 2 damaged vault tops. Repair of 3 failed or damaged transformers(predicted).
   f. Reason for greater than 90-day delay: Delay was caused by work order not being closed in a timely manner. Project work was completed on schedule. No AFUDC was accrued so the delay did not impact the DCR.
4. CECO 14017963 - Sub - Replace Voltage Regulation
   a. Capital Project Cost: $520,032.00
   b. In-Service Date: 4/7/17
   c. Need Date: 12/31/15
   d. In-Service days after estimated date: 463
   e. Description: Replace existing Voltage Control Scheme with new Controller
   f. Reason for greater than 90-day delay: Completion of this project was delayed by the time it took to develop, test, install and verify the new scheme for the relay.
5. CECO 14671767 - BAGLEY RD & PLEASANT VALLEY(PID#10900)
   a. Capital Project Cost: $3,166,073.00
   b. In-Service Date: 12/7/16
   c. Need Date: 7/1/16
   d. In-Service days after estimated date: 159
   e. Description: Relocate affected overhead circuitry in coordination with Cuyahoga County widening 2.3 miles. Project affects 36 KV 13.2 KV circuits. Phase 1 Relocate 51 sub-transmission facilities & cross over secondary distribution facilities. Phase 2 Affects 36 sub-transmission facilities & cross over secondary & distribution facilities
   f. Reason for greater than 90-day delay: Resource availability in Engineering and Lines caused the delay in completing this project. The project accrued approximately $7,349 of AFUDC in total. Therefore, it would appear that the AFUDC was stopped when the project was delayed.
6. OECO 14948792 - INTERCHANGE PROJECT
   a. Capital Project Cost: $10,377.00
   b. In-Service Date: 11/7/16
   c. Need Date: 5/30/16
   d. In-Service days after estimated date: 161
   e. Description: Reconstruct and modify access points and geometry west of the interchanges.
   f. Reason for greater than 90 day delay: This was a multi-year project that got delayed due to additional requirements by the customer.
7. CECO 13857618 - CES-MOBILE SUB - 3 CEI (capital project)
   a. Capital Project Cost: $383,707.00
   b. In-Service Date: 5/31/17
   c. Need Date: 3/31/16

   d. In-Service days after estimated date: 426
   e. Description: Mobile #3 is a 7.5 MVA mobile with 36kv and 11kV high side taps and a 4.8kV low side tap. This project will replace the trailer, high side interrupting device, low side breaker, relaying and metering. It will refurbish the mobile to like new condition.
   f. Reason for greater than 90 day delay: Delays in receipt from the manufacturer of trailer needed to construct the mobile sub
8. OECO 13259124 - SUB ADAPTIVE RELAY 2012
   a. Capital Project Cost: $836,741.00
   b. In-Service Date: 4/25/17
   c. Need Date: 12/31/13
   d. In-Service days after estimated date: 1,211
   e. Description: Install SCADA C/I on (5) distribution circuits and adaptive relaying on (4) distribution circuits and telemetering where not available. Scope may require change out of relays. Utilize adaptive relaying cabinets in inventory. An addition to the project scope 4-25-2013: Replace the existing HU transformer #1 and #2 overall differential relay due to repeated failures. Replace with a SEL 587 and install according to specification from OE protection engineer. Telemetering should include watts, vars, amps, and volts on distribution exit breakers. Install telemetering on low side of transformers where not available (watts, vars, amps, deg, tap...).
   f. Reason for greater than 90-day delay: Project was deferred due to reallocation of labor resources.
   g. The Companies accrued AFUDC totaling $138,842. The Company explained that even though the project was deferred certain labor continued along with materials to keep the project progressing.[141] Therefore, AFUDC continued. The explanation is not unreasonable.
9. OECO 13847485 - Sub - SCADA C/I and Adaptive Re
   a. Capital Project Cost: $515,853.00
   b. In-Service Date: 4/25/17
   c. Need Date: 12/15/14
   d. In-Service days after estimated date: 862
   e. Description: Install SCADA C/I and adaptive relaying on (2) distribution circuits and telemetering where not available. Scope may require change out of relays. Utilize adaptive relaying cabinets in inventory. Telemetering should include watts, vars, amps, and volts on distribution exit breakers. Install telemetering on low side of transformers where not available.
   f. Reason for greater than 90-day delay: Project was deferred due to reallocation of labor resources.
   g. The Companies continued to accrue AFUDC totaling $75,562 through the delay because work progressed, even though it was at a slower pace.[142] The explanation is not unreasonable
10. Work Order CE-700418 – IT EMS Upgrade/Patch Project
    a. Capital Project Costs: $202,044.

[141] FirstEnergy's response to Data Request BRC Set 15-INT-005 – Confidential.
[142] FirstEnergy's response to Data Request BRC Set 15-INT-006 – Confidential.

b. This project was completed 66 days after the estimated in-service date, and the Companies indicated that this project was on schedule. The project was within the 90-day window Blue Ridge uses to test for project delays. Blue Ridge asked the Companies to explain why they thought this project was completed on time. Upon further investigation, the Companies determined that the project was completed ahead of the need date and placed in-service. However, the action necessary to close out the work order was delayed five months, and as a result, AFUDC was over accrued by $26,433. The Companies indicated (and Blue Ridge recommends) that it will include a reconciliation in the Rider DCR revenue requirement in a future filing for this overstatement.[143] Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(6,208) [**ADJUSTMENT #11**].

The Companies provided explanations why projects' actual in-service dates were over 90 days from the estimated in-service dates. While those explanations were not unreasonable, some of the work orders had significant delays. Blue Ridge understands that in some instances delays cannot be avoided. But over 40% of the work orders that had in-service dates were not completed by the estimated due dates. Blue Ridge recommended in the 2016 audit that the Companies place additional emphasis on completing projects timely when they have direct control of the projects and can mitigate delays. That recommendation has been addressed in an internal audit completed on April 17, 2018, which is discussed in other sections of this report.[144]

T9: The work orders were placed in service and closed to EPIS within a reasonable timeframe from project completion. If not, AFUDC was stopped.

Blue Ridge made the following findings:

- Four work orders were some form of an accounting adjustment and did not accrue AFUDC.
- One work order was not a DCR work order and was not tested. Work order TW-001254-F and three other work orders, totaling $1,192,607, were related to the Toledo Edison Plaza Tenant Improvements that the Companies stated should have been excluded from the DCR. Its removal is reflected in ADJUSTMENT #5.
- Thirty work orders were project/blankets and did not accrue AFUDC.
- Eleven work orders could potentially over-accrue AFUDC because of project delays. The explanations for the project delays were not unreasonable. The impact on the DCR, if the over-accrual occurred, is minimal.
- Eleven projects had AFUDC accrued, but the charges were relatively minor, and the timing of closings would not impact the DCR.
- Seven work orders did not accrue AFUDC.

T10: For work performed in 2017, this project is a candidate for field verification to determine whether it is used and useful.

[143] FirstEnergy's response to Data Request BRC Set 9-INT-018 - Confidential.
[144] FirstEnergy's response to Data Request BRC Set 1-INT-011 – Attachment a, Confidential.

Blue Ridge identified four work orders within the sample as candidates for field visits. The field inspections are discussed in the next subsection.

Field Inspections

Blue Ridge selected four projects for field verification from the work order sample. The purpose of the field verification was to determine whether the assets have been installed per the work order scope and description and whether they are used and useful in rendering service to the customer. The work order/project selection criteria were assets that can be physically seen and were installed within the scope period of this review. Experienced staff from the Public Utilities Commission of Ohio, with assistance from FirstEnergy representatives, conducted the field verifications in March. Staff was provided with information for each work order / project and completed a standard questionnaire developed by Blue Ridge for each location. Where possible, Staff took pictures of the installed assets. The completed questionnaires and pictures are included as workpapers with this report.

The following projects were field inspected:

1. CECO - Work Order: 13857618 - CES-MOBILE SUB - 3 CEI (capital project)
    a. Description: Mobile #3 is a 7.5 MVA mobile with 36kv and 11kV high side taps and a 4.8kV low side tap. This project will replace the trailer, high side interrupting device, low side breaker, relaying and metering. It will refurbish the mobile to like new condition.
    b. In-Service Date: 5/31/2017
    c. Capital Project Costs: $309,150
    d. Final Project Cost: $383,707

2. CECO - Work Order: 14697805 - "HP" 138-13kV Mod Sub – Region
    a. Description: Planning Criteria violations at Sub 72-HK transformer and (7) 13kV area feeders in 2017 along with load growth from new business have necessitated the construction of a new 138-13kV Mod-Sub to provide capacity to Cleveland areas. This project provides load relief to the transformer and to the area feeders. Significant additional load from future development of the VA property should be considered. The Sub work includes install new 138kV breaker in the ring bus, install existing 11/14MVA 138-13.2kV xfmr (that was purchased but never used), install new 3-breaker mod-sub 13.2kV switchgear unit and design substation initially to accommodate a larger 16/22MVA xfmr that will need to be purchased in the future to replace the 11/14MVA xfmr when area load develops.
    b. In-Service Date: 5/17/2017
    c. Capital Project Costs: $1,920,000
    d. Final Project Cost: $3,365,887

3. CECO - Work Order: 14877367 - New OH Dist for New Mod-Sub
    a. Description: Planning Criteria violations at Sub 72-HK transformer and (7) 13kV area feeders in 2017 along with load growth from new business have necessitated the construction of a new 138-13kV Mod-Sub to provide capacity Cleveland areas. This project provides load relief to the transformer and to the area feeders. Significant additional load from future development of the VA property should be considered. The Sub work includes install new 138kV breaker in the ring bus, install existing 11/14MVA 138-13.2kV xfmr (that was purchased but never used), install new 3-

breaker mod-sub 13.2kV switchgear unit and design substation initially to accommodate a larger 16/22MVA xfmr that will need to be purchased in the future to replace the 11/14MVA xfmr when area load develops.
b. In-Service Date: 9/20/2017
c. Capital Project Costs: $1,920,000
d. Final Project Cost: $3,365,887

4. OECO - Work Order: 14777209 - Mod Sub
a. Description: Purchased substation site in 2010. In 2016 begin below grade work and in 2017 install a 138kV/12.47kV, 11/14 MVA, 2-750 MCM parallel Al urd exit mod-sub with scada in order to serve growing load. New sub to be served by the new 138KV transmission line completed in 2014.
b. In-Service Date: 8/23/2017
c. Capital Project Costs: $1,826,058
d. Final Project Cost: $3,194,417.58

The four projects selected for field verification confirmed that the assets were installed and used and useful.

Work Order Backlog

Blue Ridge found that the Companies have made progress to reduce the unitization backlog. The December 31, 2017, level is less than the 2016 level, but the backlog is still well above the backlog from the 2015 audit. Last year, FirstEnergy explained that the primary reason for the increase in the unitization backlog is internal resources being committed to other regulatory projects during 2016. The Companies further explained that they continue to focus on ensuring the accuracy of the work orders and that they do not expect the current backlog to have a material impact on the accumulated reserve for depreciation.[145]

Table 23: Backlog over 15 Months of Work Order Unitization[146]

Description	Unitization Backlog	Unitization Backlog $
as of 12/31/13	1,346	
as of 11/30/14	4,156	
as of 11/30/15	983	$3,959,518
as of 12/31/16	4,032	$62,191,009
as of 12/31/17	3,039	$39,928,597

While most of the work orders are Distribution (83%) and individually would not be material to the accumulated reserve for depreciation, on an aggregate basis, the work orders in the backlog total over $39 million, which is significant (although 37% below the 2016 total). There could be a potential impact on the accumulated reserve for depreciation.

In addition, the backlog could create problems with recording the replacement of assets that are still in the backlog and had not been unitized. This situation may become a particular problem when lines, poles, and transformers are replaced en masse as a result of storm restoration work. If an asset that is being replaced is not unitized, it holds up the storm unitization process. Blue Ridge

[145] WP FE response to 2016 audit Data Request BRC Set 2-INT-007 - Confidential.
[146] FirstEnergy's response to Data Request BRC Set-1-INT-031 and 032 - Confidential.

recommends that the Companies continue to make a concerted effort to reduce the volume of backlog work orders both in quantity and dollar value.

Insurance Recoveries

Insurance recoveries can reduce gross plant and should be taken into consideration in the calculation of the DCR. FirstEnergy stated that there were no insurance recoveries charged to capital for the Companies from December 1, 2016, through December 31, 2017.[147]

As noted in this report's subsection regarding status of prior audit recommendations (i.e., Prior Compliance Audits Recommendations Status), the Companies agree that for any insurance recoveries received for plant in service recognized in Rider DCR, the Companies will reduce plant in service for the recovery amounts.[148]

Conclusion

Blue Ridge's review of gross plant through transactional testing and field inspection of the work order sample had several findings that impact the gross plant included in the Rider DCR. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

Accumulated Reserve for Depreciation

F. Determine if the Companies' recovery of the incremental change in Accumulated Reserve for Depreciation are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following accumulated reserve for depreciation ("reserve") incremental change from the prior audit for each company.

Table 24: Incremental Change in Reserve for Depreciation from 11/30/16 to 11/30/17[149]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	(1,269,202,085)	(1,329,820,008)	(60,617,923)
Ohio Edison Company	(1,317,426,765)	(1,380,011,274)	(62,584,509)
The Toledo Edison Company	(591,085,970)	(604,078,268)	(12,992,298)
Total	(3,177,714,820)	(3,313,909,549)	(136,194,729)

The Actual and Estimated Schedules B-3 support the incremental change to the reserve, which provide the reserve for accumulated depreciation balances by FERC account for distribution, subtransmission, general, and intangible plant and for allocated Service Company general and intangible plant. A separate schedule supports the intangible gross plant balances.

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147 FirstEnergy's response to Data Request BRC Set 1-INT-022 - Confidential.
148 FirstEnergy's response to Data Request BRC Set 1-INT-011 - Confidential.
149 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential-R2.

Mathematical Verification

Blue Ridge performed mathematical checks on calculations included in the actual and estimated schedules that supported the reserve and checked whether the reserve rolled forward to the revenue requirement calculation correctly. While the calculations and roll forward were correct, there were several cells (not used in the calculation) that were not linked to the correct amount or had hard-coded numbers.[150]

Source Data Validation

Blue Ridge traced the values used for the actual November 30, 2017, and estimated February 28, 2018, reserve balances to the source documentation. The actual and estimated balances reconciled to the supporting documents.

Impact of Change in Pension Accounting

Similar to the Gross Plant schedules, the reserve balances were adjusted to remove the cumulative pre-2007 impact of a change in pension accounting.

Additional Validation Testing

In addition to reconciling the reserve to supporting documentation, Blue Ridge performed additional analysis to validate the reserve balances. Assets are placed in service primarily as (1) an addition of new assets (for example, a new residential sub-division) or (2) a replacement of existing assets. When assets are replaced, the existing assets are retired. Gross plant in service and the depreciation reserve is reduced to reflect that the assets are no longer in service on the books of the Companies. When assets are replaced, the Companies incur cost of removal and, in some cases, receives salvage for the old assets. Thus, the reserve has three components: (1) accumulated depreciation, (2) cost of removal, and (3) salvage. Cost of removal represents the cost of dismantling, demolishing, tearing down, or otherwise removing retired utility plant. Salvage represents the amount received for property retired.

The retirement of assets does not affect net plant in service since the original cost retired reduces gross plant in service and also reduces the reserve. However, the recording of cost of removal decreases the reserve and, therefore, increases net plant in service. Salvage increases the reserve and, therefore, decreases net plant in service.

Of the 64 sampled work orders Blue Ridge obtained as part of the validation testing, 29 work orders were for replacement work, including blanket and project work orders. The Companies provided the cost of the new assets, retirement data, cost of removal, and, if appropriate, salvage for each work order from the PowerPlant Asset Accounting system except for the five work orders discussed in testing step T6. Salvage is captured in most instances on an aggregate basis. Scrap is sold from a separate work order to avoid individual scrap transactions and additional paperwork. This procedure is normal for utilities.

Conclusion

As discussed in testing steps T1 through T10 above, Blue Ridge found adjustments that should be made to the reserve balances to ensure that net plant is appropriately reflected in the DCR. The

[150] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential, see Est CEI Sch b3, Est-OE Sch B3, Est-TE Sch B3.

specific adjustments are also discussed, as necessary, in the Variance, Exclusions, and Gross Plant in Service subsections. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements subsection of this report.

ACCUMULATED DEFERRED INCOME TAXES

G. Determine if the Companies' recovery of the incremental accumulated deferred income taxes (ADIT) are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following accumulated deferred income taxes (ADIT) incremental change from the prior audits for each company.

Table 25: Incremental Change in ADIT from 11/30/16 to 11/30/17[151]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	(466,717,532)	(502,293,445)	(35,575,913)
Ohio Edison Company	(569,578,802)	(609,321,744)	(39,742,942)
The Toledo Edison Company	(151,388,071)	(162,103,480)	(10,715,409)
Total	(1,187,684,405)	(1,273,718,669)	(86,034,264)

The incremental change is supported by the actual and estimated ADIT Schedules. The schedules include the FERC accounts 281 and 282 Property Accounts. The Companies' ADIT includes the allocation portion of the ADIT attributed to the Service Company.

Authority to Recover ADIT in Rider DCR

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO provide the authority for the inclusion of Accumulated Deferred Income Taxes (ADIT) within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and <u>accumulated deferred income taxes associated with plant in service</u> since the Companies' last distribution rate case.[152] [Emphasis added]

During the 2011 audit, Staff further clarified that the treatment of ADIT in the Rider DCR was intended to be the same methodology approved in the last distribution rate case.[153] The Companies' were asked to provide a list of the ADIT with descriptions and amounts approved in Case No. 07-551-EL-AIR. The Companies provided the ADIT support provided in Case No. 07-551-EL-AIR which reflected high level descriptions.[154] While CECO and TECO included many of the categories reflected in the Rider DCR, they did not include the level of detail included in the DCR. The OECO ADIT included a single description "282 ELECTRIC" and a total of $204,736,245. Blue Ridge was unable to confirm

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151 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential-R2.
152 Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
153 Blue Ridge's Compliance Audit of the 2011 Delivery Capital Recovery (DCR) Rider, submitted April 12, 2012, page 52.
154 FirstEnergy's response to Data Request BRC Set-9-INT-023 - Confidential.

that ADIT reflected in the DCR was consistent with what was reflected in the Companies' last distribution rate case. Our review of specific items included in the ADIT and their appropriateness for inclusion in the DCR is provided later in this section.

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included on the actual and estimated Companies' and Service Company's ADIT Schedules and verified that ADIT rolled forward to the revenue requirement calculation correctly. No exceptions were noted.[155]

Source Data Validation

The ADIT balances included with the Compliance filings reconciled to the supporting documentation.

Blue Ridge reviewed the change in ADIT balances from year to year as shown in the following table and chart.[156]

Table 26: Change in ADIT Balances 12/31/11–2/28/18

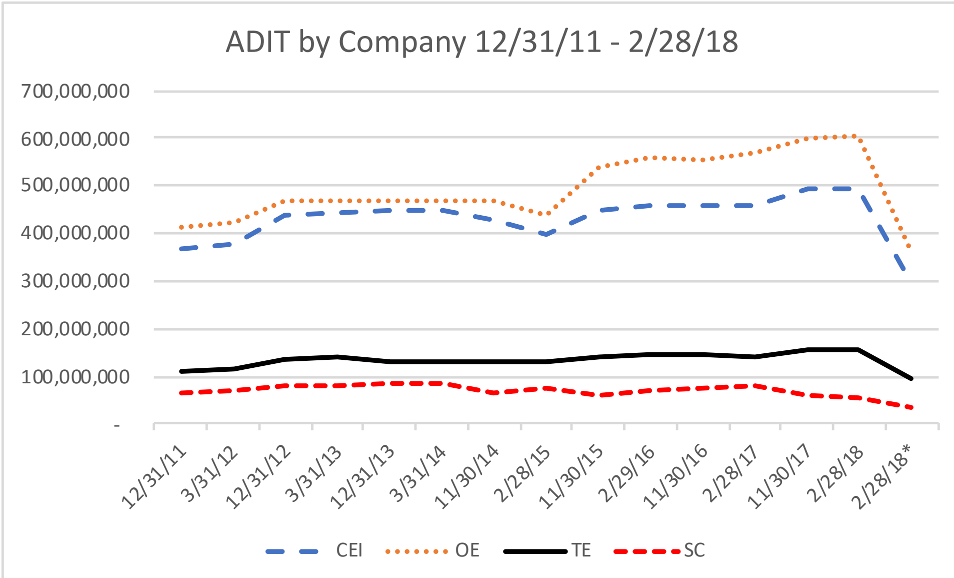
Ending Balance	Balances					Percent Change				
	CEI	OE	TE	SC	Total	CEI	OE	TE	SC	Total
12/31/11	366,534,879	412,466,559	110,175,136	66,632,539	955,809,113					
3/31/12	377,163,534	422,814,390	114,649,711	69,091,522	983,719,157	2.9%	2.5%	4.1%	3.7%	2.9%
12/31/12	439,391,664	467,058,500	134,130,888	79,995,501	1,120,576,553	16.5%	10.5%	17.0%	15.8%	13.9%
3/31/13	445,232,032	469,254,252	139,683,828	80,123,836	1,134,293,948	1.3%	0.5%	4.1%	0.2%	1.2%
12/31/13	447,001,488	468,366,272	128,867,664	86,935,066	1,131,170,490	0.4%	-0.2%	-7.7%	8.5%	-0.3%
3/31/14	447,045,104	466,374,818	128,540,440	85,069,763	1,127,030,125	0.0%	-0.4%	-0.3%	-2.1%	-0.4%
11/30/14	429,384,904	467,051,490	132,671,996	64,940,593	1,094,048,983	-4.0%	0.1%	3.2%	-23.7%	-2.9%
2/28/15	398,642,670	438,040,057	130,035,391	76,445,511	1,043,163,629	-7.2%	-6.2%	-2.0%	17.7%	-4.7%
11/30/15	449,120,379	537,026,491	141,834,185	62,059,622	1,190,040,677	12.7%	22.6%	9.1%	-18.8%	14.1%
2/29/16	460,573,406	561,203,344	145,504,633	69,142,814	1,236,424,197	2.6%	4.5%	2.6%	11.4%	3.9%
11/30/16	456,006,288	556,598,673	145,674,402	75,378,217	1,233,657,580	-1.0%	-0.8%	0.1%	9.0%	-0.2%
2/28/17	456,239,049	570,836,219	143,076,682	79,260,799	1,249,412,749	0.1%	2.6%	-1.8%	5.2%	1.3%
11/30/17	493,643,979	598,840,125	157,489,620	60,868,869	1,310,842,593	8.2%	4.9%	10.1%	-23.2%	4.9%
2/28/18	495,024,392	602,309,930	157,893,875	55,151,828	1,310,380,025	0.3%	0.6%	0.3%	-9.4%	0.0%
2/28/18*	297,014,635	361,385,958	94,736,325	33,091,097	786,228,015	-39.8%	-39.7%	-39.8%	-45.6%	-40.0%

*Reflects change in federal income tax rate.

The balances in the table above were plotted and are shown in the following figure.

155 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
156 WP ADIT Year to Year Comparison.

Figure 1: Change in ADIT from 12/31/11 - 2/28/18*



*Reflects the change in federal income tax rate.

The significant change in the February 28, 2018, balance reflects the Companies' revaluation of ADIT to reflect the Tax Cuts and Jobs Act (TCJA) signed into law by President Trump on December 22, 2017. The TCJA reduced the federal corporate income tax rate from 35% to 21%. As a result, the ADIT balances as of January 1, 2018, would need to be revalued at that lower rate, along with any additional deferred taxes arising in the future. The Companies revalued the 2018 ADIT balances to reflect the percent change in tax rate of -40% (21% / 35% - 1). The Companies estimated the new ADIT balance by multiplying the complement of the percent change times the original projected ADIT balances as of February 28, 2018 (CEI example $495,024,392 x [1 - 40%] = $297,014,635).[157] The revaluation is discussed further in the section labeled Tax Cuts and Jobs Act Effects.

The Companies stated that ADIT includes all property-related ADIT except for balances associated with CWIP, Pension Restatement as of 2006, Future Use and Non-Utility, ATSI Land Lease, Capital Leased Vehicles, and Smart Meters/Smart Grid, since the corresponding plant in service balances are not included in Rider DCR.[158]

The Companies provided a list of the items included in ADIT for each distribution company and the Service Company.[159] Blue Ridge found the majority of dollars included in ADIT are temporary differences associated with (1) the differences between book and tax depreciation, (2) Section 263A overheads and indirect costs that are required to be capitalized for book purposes and deducted as incurred for tax purposes, and (3) repairs that, for book purposes, are capitalized and depreciated over the life of the asset and, for tax purposes, are allowed to be deducted as a repair. The Companies

[157] FirstEnergy's response to Data Request BRC Set-1-INT-001, Attachment 8 - Confidential and WP ADIT Year to Year Comparison.
[158] FirstEnergy's response to Data Request BRC Set-8-INT-001 - Confidential.
[159] FirstEnergy's response to Data Request BRC Set-1-INT-001, Attachment 8 – Confidential.

excluded deferred taxes in CWIP. The Companies provided explanations for the items that were not clearly identified as being related to plant in services.[160] In the initial information provided, Blue Ridge found that most of the Companies' explanations regarding how each of the items was related to plant in service to be not unreasonable. However, several items required additional review.

OE ADIT totaling $473,287 and TE ADIT totaling $108,174 included descriptions that appeared to be related to another jurisdiction-PA. The Companies provided an explanation:

> Consistent with prior years, the ADIT balances included in Rider DCR are based on the effective tax rate for each Company, including any state and local income taxes. Use of the effective tax, including federal, state and local taxes, is consistent with the Companies' last distribution rate case and prior Rider DCR filings. In previous years, OE's and TE's effective income tax rate included a small apportionment to due to activities the Company had in PA. As a result, OE and TE have income tax obligations to PA associated with their total taxable income. The PA ADIT line items . . . represent Rider DCR related ADIT associated with that apportionment.[161]

The Companies provided additional explanation:

> In prior years, OE and TE had intercompany sale leaseback transactions with FirstEnergy Genco and FirstEnergy Nuclear Genco. Under these transactions, OE and TE had a share of property rent expense, and a small amount of payroll associated with the assets in Pennsylvania. When there was a 3-factor formula, which included sales, property and payroll, OE and TE had an apportionment to PA. The Pennsylvania related income taxes and ADIT balances on the books of OE and TE are appropriately included in Rider DCR because the Companies' taxable income related to the return on plant in service in Rider DCR would yield an obligation to Pennsylvania for income taxes (including ADIT) associated with this apportionment.[162]

While the explanation relates to generation related activity, it appears that the ADIT was included in the last distribution rate case. Blue Ridge found the Companies explanation on the inclusion of the PA-based ADIT to be not unreasonable.

There were also ADIT items included in the Service Company with descriptions that appeared to be related to other jurisdictions—DC, MD, NJ, PA, WV. The Companies explained that the Service Company has assets located in various jurisdictions. In order to recognize that portions of these assets are associated with other jurisdictions, Rider DCR includes only an allocation of the total Service Company assets to the Companies. Since the Rider DCR revenue requirement includes an allocated portion of Service Company plant in service, it also includes a corresponding allocated portion of total FirstEnergy Service Company ADIT.[163] Blue Ridge found the Companies' explanation not unreasonable.

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[160] FirstEnergy's response to Data Request BRC Set-8-INT-002 and BRC Set 13-INT-005 - Confidential.
[161] FirstEnergy's response to Data Request BRC Set-8-INT-003 - Confidential.
[162] FirstEnergy's response to Data Request BRC Set-13-INT-006 - Confidential.
[163] FirstEnergy's response to Data Request BRC Set-8-INT-004 - Confidential.

Conclusion

The Companies stated that the treatment of ADIT in the Rider DCR was intended to be the same methodology approved in the last distribution rate case. However, the Companies' were unable to provide sufficient information to compare what is currently included in Rider DCR's ADIT to what was approved in Case No. 07-551-EL-AIR. The Companies provided the ADIT support included in Case No. 07-551-EL-AIR, which reflected high level descriptions. While CECO and TECO included many of the categories reflected in the Rider DCR, they did not include the level of detail provided in the DCR. The OECO ADIT included a single line item, "282 ELECTRIC," and a total. Blue Ridge was unable to confirm that ADIT reflected in the DCR was consistent with what was reflected in the Companies' last distribution rate case. Additional analysis was done on what was reflected in the DCR, and Blue Ridge ultimately found that the ADIT balances were related to plant in service and are not unreasonable. The revaluation of the estimated 2/28/18 ADIT balances to reflect the change in the tax rates is discussed in the Tax Cuts and Jobs Act Effects subsection of this report.

DEPRECIATION EXPENSE

H. Determine if the Companies' recovery of the incremental depreciation expense are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include incremental depreciation expense for each company from the prior audit as shown in the following table.

Table 27: Incremental Change in Depreciation Expense from 11/30/16 to 11/30/17[164]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	95,176,216	99,292,700	4,116,484
Ohio Edison Company	100,891,710	104,903,818	4,012,109
The Toledo Edison Company	38,032,714	38,953,731	921,017
Total	234,100,640	243,150,250	9,049,609

Schedule B-3.2 for each operating company provides the calculated depreciation expense based on the plant investment. The depreciation (usually referred to as amortization) calculations associated with Other Plant FERC 303 accounts were performed on Schedule Intangible Depreciation Expense Calculation.

Mathematical Verification

Blue Ridge verified the mathematical accuracy of the depreciation expense calculations and found that the Distribution Companies' depreciation expense was calculated using gross plant balances. In several instances, the net plant was less than the depreciation expense recorded in the DCR; thus Blue Ridge was concerned that too much depreciation expense was being recorded in the Rider DCR as shown in the following table:

[164] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

Table 28: Depreciation Expense in Excess of Actual Net Plant at 11/30/17

		Plant Investment			Depreciation Expense		
Acc No.	**Account Title**	**Gross**	**Reserve**	**Net**	**Rate**	**Calculated**	**Excess**
354	Towers & Fixtures	327,942	1,577,023	(1,249,081)	1.77%	5,805	(5,805)
390.3	Leasehold Improvements	436,850	436,850	-	22.34%	97,592	(97,592)
391.1	Office Furniture & Equipment	3,629,867	3,457,073	172,793	7.60%	275,870	(103,077)
398	Miscellaneous Equipment	74,238	74,238	-	6.67%	4,952	(4,952)
CECO		**4,468,898**	**5,545,185**	**(1,076,287)**		**384,219**	**(211,426)**
354	Towers & Fixtures	276,919	302,866	(25,947)	1.82%	5,040	(5,040)
390.3	Leasehold Improvements	108,959	108,959	-	20.78%	22,642	(22,642)
OECO		**385,878**	**411,825**	**(25,947)**		**27,682**	**(27,682)**
352	Structures & Improvements	218,299	214,277	4,022	2.50%	5,457	(1,435)
354	Towers & Fixtures	34,264	40,543	(6,279)	1.85%	634	(634)
369	Services	67,779,435	68,678,936	(899,501)	3.17%	2,148,608	(2,148,608)
392	Transportation Equipment	1,362,150	1,271,922	90,229	6.92%	94,261	(4,032)
396	Power Operated Equipment	904,891	881,084	23,807	5.28%	47,778	(23,971)
TECO		**70,299,039**	**71,086,762**	**(787,722)**		**2,296,738**	**(2,178,681)**
Total Depreciation Expense in Excess of Net Plant							**(2,417,788)**

The Companies stated that depreciation expense was calculated based on gross plant, consistent with the last distribution rate case:[165]

> The methodology to calculate depreciation expense for OE, CEI, and TE was approved in Case No. 07-551-EL-AIR, and must continue to be used in Rider DCR in order to properly calculate incremental depreciation expense. For Service Company, the Companies did not have an approved methodology for calculating depreciation expense. The Companies created the Service Company depreciation expense schedules for Rider [DCR] based on net plant in service, which have consistently been used in all Rider DCR filings since inception.[166]

The Companies provided depreciation Schedule B-3.2 from Case No. 07-551-EL-AIR.[167] Blue Ridge reviewed the schedules and confirmed that depreciation expense was calculated based on gross plant. However, there was an irregularity in how depreciation expense was calculated in the FERC account 390.3 Leasehold Improvements. The last rate case calculated depreciation expense based on net plant while the DCR used gross plant. The Companies stated (and Blue Ridge recommends) that a reconciliation be included in the next DCR filing that incorporates the effect on Rider DCR revenue requirements had the depreciation expense for FERC account 390.3 been calculated based on net plant in service, as opposed to gross plant in service.[168] Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(120,547) [**ADJUSTMENT #12**].

The plant balances used to calculate the depreciation were linked to the plant schedules and no exceptions were noted. The calculated depreciation expense on Schedule B-3.2 and the Intangible Depreciation Schedule rolled forward to the revenue calculation correctly.[169]

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165 FirstEnergy's response to Data Request BRC Set 11-INT-008 - Confidential.
166 FirstEnergy's response to Data Request BRC Set 11-INT-012 - Confidential.
167 FirstEnergy's response to Data Request BRC Set 11-INT-007 - Confidential.
168 FirstEnergy's response to Data Request BRC Set 11-INT-010 - Confidential.
169 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

Source Data Validation

The depreciation accrual rates used were from the approved depreciation study as part of Case No. 07-551-EL-AIR. The PUCO Staff presented the results of its study in its Staff Report issued on December 4, 2007. The PUCO Order in Case No. 07-551-EL-AIR was issued on January 21, 2009, and directed the Companies to use the accrual rates proposed by the Staff.[170]

Blue Ridge compared the depreciation accrual rates used in the Rider DCR sub-transmission, distribution, and general plant depreciation calculations to the rates within Staff's Reports.[171] Two items were identified and resolved: (1) the Case No. 07-551-EL-AIR Staff Report did not have a balance for CE Account 359 Roads & Trails, so no depreciation accrual rate was provided (CE used the accrual rate from Case No. 89-1001-EL-AIR) and (2) the CE accrual rate for Account 371 Installation on Customer Premises did not agree with the Staff report. Further investigation determined that the Staff Report was corrected during the last distribution case. Both issues were resolved, and the accrual rates used by CE were not unreasonable.

Conclusion

Blue Ridge found that the calculation of depreciation expense was consistent with the methodology used in the last distribution rate case with the exception of FERC account 390.3. The Rider DCR uses gross plant-in-service balances consistent with the last distribution rate case to develop the depreciation expense component of the revenue requirements. Any revisions to gross plant should be flowed through the Rider DCR model to ensure that the appropriate amount of depreciation expense is included within the DCR.

The depreciation accrual rates used in the Rider DCR are based upon balances as of May 31, 2007. The Companies updated the depreciation study using plant as of December 31, 2013, and provided the updated study to the Commission Staff on June 1, 2015, fulfilling the Companies' obligation.[172]

PROPERTY TAX EXPENSE

I. Determine if the Companies' recovery of incremental property taxes are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following incremental property tax expense for each company from the prior audit.

[170] FirstEnergy's response to Data Request BRC Set 1-INT-024 - Confidential.
[171] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[172] WP FE response to 2015 Data Request BRC Set 1-INT-012 – Confidential.

Table 29: Incremental Change in Property Tax Expense from 11/30/16 to 11/30/17[173]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	102,669,541	108,220,402	5,550,861
Ohio Edison Company	88,980,613	92,264,221	3,283,608
The Toledo Edison Company	30,026,201	30,860,390	834,189
Total	221,676,355	231,345,013	9,668,658

The Actual and Estimated Schedules C-3.10 support the incremental calculation of personal and real property taxes based upon the gross plant for the three operating companies. A separate schedule supports the property tax associated with the Service Company plant in service.

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations and validated that the calculated property taxes rolled forward to the revenue requirement calculation performed correctly. No exceptions were noted.[174]

Source Data Validation

Blue Ridge found the workpapers were well organized and fully sourced.

Blue Ridge noted that the personal property tax rates that increased significantly for TE in 2016 filing and, as expected were reduced in 2017 as shown in the following table and chart.

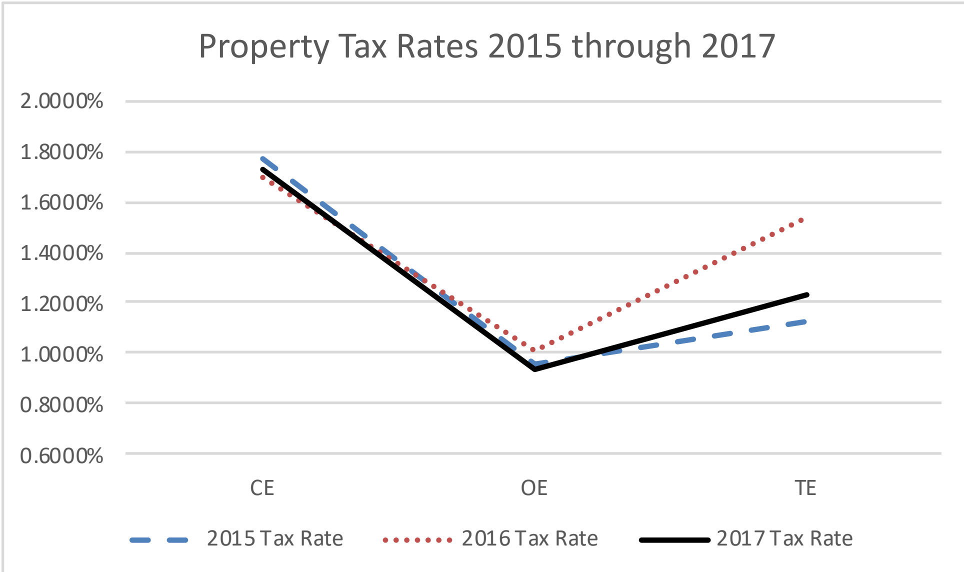
Table 30: Comparison of Personal Property Tax Rate 2015, 2016, and 2017[175]

Description	CE	OE	TE
2015 Tax Rate	1.7652%	0.9530%	1.1310%
2016 Tax Rate	1.6935%	1.0061%	1.5338%
2017 Tax Rate	1.7258%	0.9361%	1.2367%
Difference 2016-2015	-0.072%	0.053%	0.403%
% increase	-4.06%	5.57%	35.62%
Difference 2017-2016	0.032%	-0.070%	-0.297%
% increase	1.91%	-6.96%	-19.37%
Difference 2017-2015	-0.039%	-0.017%	0.106%
% increase	-2.23%	-1.77%	9.35%

The property tax rates in the above table are shown in the following figure.

173 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
174 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
175 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

Figure 2: Comparison of Property Tax Rates by Company for 2015, 2016, and 2017[176]



In 2016, the Companies explained the real property tax rate is calculated as real property taxes paid over real property capitalized cost. The increase in the TE real property tax rate was due primarily to the removal of plant associated with Toledo Edison Plaza (located in FERC Accounts 389 and 390) from Account 101 (Plant In-Service) to Account 102 (Electric Plant Purchased or Sold). The resulting decrease in the denominator (plant balance) between the December 31, 2015, Rider DCR filing and the December 30, 2016, Rider DCR filing, combined with an immaterial change to the numerator (real property taxes paid) between the two filings, resulted in a higher real property tax rate.[177] Blue Ridge found the Companies' explanation reasonable and as was expected the property tax rate in 2017 declined as TE should no longer pay property taxes on the assets that were removed from plant in service. However, the rate did not return to the 2015 property tax level. The Companies explained, "The 2017 TE property tax rate is higher than the 2015 due to normal fluctuations in real property tax rates, property assessment, and one-time charges/assessments. TE owns over 200 real properties, and each county, township, and school district combination has its own tax rate."[178] Blue Ridge found the Companies' explanation not unreasonable.

Conclusion

Blue Ridge found that the calculation of property tax is not unreasonable. As the Rider DCR uses plant-in-service balances to develop the property tax component of the revenue requirements, any revisions to gross plant should be flowed through the Rider DCR model to ensure the appropriate amount of property tax is included within the DCR.

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[176] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[177] WP FE response to 2016 Data Request BRC Set 9-INT-003 - Confidential.
[178] FirstEnergy's response to Data Request BRC Set 11-INT-005 - Confidential.

SERVICE COMPANY

J. Determine if the Companies' recovery of allocated Service Company plant in service, accumulated reserve, ADIT, depreciation expense, and property tax expense are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following Service Company incremental plant in service, accumulated reserve, ADIT, depreciation expense, and property tax expense for each company.

Table 31: Change in Service Company Rate Base and Expense from 11/30/16 to 11/30/17[179]

Description	CEI	OE	TE	Total
Actual 11/30/17				
Gross Plant	100,737,744	122,076,281	53,736,249	276,550,274
Reserve	52,490,968	63,609,744	28,000,108	144,100,820
ADIT	8,649,466	10,481,619	4,613,860	23,744,946
Rate Base	**39,597,310**	**47,984,918**	**21,122,281**	**108,704,509**
Depreciation Expense	4,600,244	5,574,680	2,453,895	12,628,819
Property Tax Expense	56,639	68,636	30,213	155,488
Total Expenses	**4,656,883**	**5,643,316**	**2,484,108**	**12,784,307**
Actual 11/30/16				
Gross Plant	93,710,646	113,560,685	49,987,804	257,259,136
Reserve	45,324,499	54,925,255	24,177,319	124,427,073
ADIT	10,711,245	12,980,129	5,713,669	29,405,043
Rate Base	**37,674,903**	**45,655,301**	**20,096,817**	**103,427,020**
Depreciation Expense	4,415,804	5,351,171	2,355,510	12,122,485
Property Tax Expense	54,260	65,754	28,944	148,958
Total Expenses	**4,470,064**	**5,416,925**	**2,384,454**	**12,271,442**
Incremental				
Gross Plant	7,027,098	8,515,596	3,748,445	19,291,139
Reserve	7,166,469	8,684,489	3,822,789	19,673,747
ADIT	(2,061,778)	(2,498,510)	(1,099,809)	(5,660,097)
Rate Base	**1,922,407**	**2,329,617**	**1,025,464**	**5,277,488**
Depreciation Expense	184,440	223,509	98,385	506,335
Property Tax Expense	2,379	2,883	1,269	6,530
Total Expenses	**186,819**	**226,391**	**99,654**	**512,865**

The Compliance Filings include actual November 30, 2017, and estimated February 28, 2018, schedules that accumulate Service Company general and intangible gross plant, reserve, ADIT, and

[179] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential-R2.

incremental depreciation and property tax expense that are then allocated to the Companies based upon the allocation factors agreed to within the Combined Stipulation.

Authority to Include Service Company Costs and Support for Allocation Factors

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (reaffirmed in Case Nos. 12-1230-EL-SSO[180] and 14-1297-EL-SSO[181]) provide the authority for the Service Company allocation factors used within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case.[182] (Emphasis added.)

The following allocation factors were used in Case No. 07-551-EL-AIR[183] and were appropriately used in accordance with the Combined Stipulation to allocate Service Company costs in Rider DCR:

Table 32: Service Company Allocation Factors

	CEI	OE	TE	Total
Allocation Factors	14.21%	17.22%	7.58%	39.01%

Mathematical Verification

Blue Ridge performed mathematical checks on the calculations included within the Service Company schedules and verified that allocated items rolled forward to the operating companies' schedules correctly as incremental changes from the values used in the last distribution rate case.[184]

Source Data Validation

The Actual November 30, 2017, and Estimated February 28, 2018, general and intangible gross plant balances, reserve, and ADIT were reconciled to their source documentation.[185] The Actual November 30, 2017, Intangibles included a description: "FECO 101/6-303 2018 Software." When asked why dollars for 2018 were included in the November 30, 2017, actual balance, the Companies explained that the project was originally budgeted to a 2018 software group as the estimated in-service date was 1/2/18. The project was completed and in service prior to 11/30/2017. During unitization in February of 2018, the depreciation group on the project was changed to 2017 software.[186]

The Service Company depreciation accrual rates and the property tax rates are based upon the weighted average of the Companies' rates using the authorized allocation factors. The approach is not unreasonable.

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180 Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
181 Case No. 14-1297-EL-SSO Commission Opinion and Order, March 31, 2016, page 119.
182 Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
183 WP FE response to 2011 Audit Data Request BRC-10-10 and 10-11.
184 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
185 WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
186 FirstEnergy's response to Data Request BRC Set 9-INT-020 - Confidential.

Additional Validation Testing

As discussed in the Gross Plant subsection of this report, Blue Ridge performed additional validation testing using selected sample work orders. Service Company work orders were included within the performed testing.

Conclusion

Blue Ridge found nothing that would indicate that Service Company costs included within Rider DCR are unreasonable.

COMMERCIAL ACTIVITY TAX AND INCOME TAXES

K. Determine if the Companies' recovery of Commercial Activity Tax (CAT) associated with the revenue requirement are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed
L. Determine if the Companies' recovery of associated income taxes associated with the revenue requirement are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following incremental commercial activity tax (CAT) for each company. The CAT is calculated based on the statutory 0.26 percent.

Table 33: Incremental Change in CAT from 11/30/16 to 11/30/17[187]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	282,303	313,900	31,597
Ohio Edison Company	299,283	324,396	25,114
The Toledo Edison Company	70,871	77,431	6,561
Total	652,456	715,728	63,272

The Rider DCR Compliance Filings include the following incremental income tax expense for each company. The Actual November 30, 2017, income tax rate is based on the Federal tax rate of 35 percent and the apportioned municipal and state tax rates.

Table 34: Incremental Change in Income Tax from 11/30/16 to 11/30/17[188]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	8,996,264	9,685,425	689,161
Ohio Edison Company	11,218,352	11,817,559	599,207
The Toledo Edison Company	944,791	1,136,850	192,059
Total	21,159,407	22,639,834	1,480,427

The Companies replaced its initial filing to reflect the change in the federal income tax rate. The Estimated February 28, 2018, income tax expense in the replaced filing reflects the recent change in the federal income tax rate from 35 percent to 21 percent and the apportioned municipal and state tax rates. The tax-change effect is discussed in the next section.

[187] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[188] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

Rider DCR Actual and Estimated Summary Schedules include the calculation for the commercial activity tax and income taxes.

Authority to Include Commercial Activity Tax and Income Tax in Rider DCR

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO (reaffirmed in Case Nos. 12-1230-EL-SSO[189] and 14-1297-EL-SSO[190]) provide the authority for the recovery of income taxes and commercial activity tax within Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

> Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes. . . .[191] (Emphasis added.)

Mathematical Verification

Blue Ridge performed mathematical checks on the calculation of the commercial activity tax and income tax expense included in the Summary Schedules of the Compliance Filings.[192] No exceptions were noted.

Source Data Validation

FirstEnergy substantiated the CAT rate and applied the rate of 0.26% to gross receipts calculated within the Compliance Filings. The following table shows the composite tax rates used by the Companies' filings. The effective tax rate appropriate reflects the 2017 and reduced 2018 federal income tax and the Ohio, and municipalities' tax rates.

Table 35: Effective Income Tax Rates Reflected in Companies' Filings for 2017 and 2018

Description	CEI	OE	TE
2017 Effective Income Tax Rates			
Local Effective Tax Rate	1.79%	1.33%	1.08%
Federal Income Tax Rate	35%	35%	35%
2017 Effective Income Tax Rate	36.16%	35.87%	35.70%
2018 Effective Income Tax Rates			
Local Effective Tax Rate	1.79%	1.33%	1.08%
Federal Income Tax Rate	21%	21%	21%
2018 Effective Income Tax Rate	22.41%	22.05%	21.85%

Conclusion

Blue Ridge found that the commercial activity tax and income tax expense were calculated consistent with prior filings. The effect of the recent federal tax rate change in discussed in the next

[189] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[190] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[191] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[192] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

subsection. In addition, any adjustments discussed in other subsections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

TAX CUTS AND JOBS ACT EFFECT

On December 22, 2017, the Tax Cuts and Jobs Act (TCJA) was signed into law by President Trump. The TCJA affects the accounting of regulated public utilities in notable ways. On January 12, 2018, the Companies filed replacement Rider DCR Compliance Filings with the Commission to incorporate the impacts of the TCJA, which reduced the federal corporate income tax rate from 35% to 21%. The Companies confirmed that the replacement filing did not include any other changes than the impact of the TCJA.[193] The change reflects the restatement of the income taxes expenses and revenue conversion factor to reflect the new statutory rate of 21% which *reduced* the total revenue requirements and modifications of the ADIT which *increased* the total revenue requirement. The replacement filings resulted in an annual *increase* of $39,314,722 to the total revenue requirement as follows.

Table 36: Revenue Requirement Change: Original (01/01/18) Vs. Replacement (01/12/18) Filings

Company	Original	Replacement	Change
The Cleveland Electric Illuminating Company	125,085,002	140,265,193	15,180,191
Ohio Edison Company	128,757,802	147,036,276	18,278,474
The Toledo Edison Company	31,004,230	36,860,287	5,856,057
Total	284,847,034	324,161,756	39,314,722

Blue Ridge performed mathematical checks on the Companies' calculations and validated that the calculated income taxes and revenue conversion factor reflected the new statutory rate of 21%. Blue Ridge also noted that the Companies revalued the reported ADIT balances at February 28, 2018, to reflect the change in the federal tax rate. The Companies explained that the increase in the revenue requirement was due to decreases in the accumulated deferred income taxes (ADIT). The decrease in ADIT resulted in an increase in rate base used in the calculation of the Rider DCR.[194] The change in law required the Companies to revalue their ADIT balances, which arise due to temporary differences between the balance sheet amounts for assets and liabilities reported on the financial statements and the tax basis amounts for those same assets and liabilities reported on the income tax returns. The capital-intensive nature of utilities, combined with accelerated depreciation of those investments under the tax code, normally results in a net deferred tax liability (DTL) position on the balance sheet. Within the ratemaking formula, DTLs are treated as interest-free loans from the government and are reflected as a rate base reduction, which *lowers* the revenue requirement.

Per GAAP principles, deferred tax balances are to be valued "using the enacted tax rate(s) expected to apply to taxable income in the periods in which the deferred tax liability or asset is expected to be settled or realized."[195] Thus, since the TCJA was passed in 2017, stipulating a reduced corporate tax rate effective beginning 2018, the balances as of January 1 would need to be revalued

[193] FirstEnergy's response to Data Request BRC Set 5-INT-001 - Confidential.
[194] FirstEnergy's response to Data Request BRC Set 5-INT-002 – Confidential.
[195] ASC 740-10-10-3.

at that lower rate, along with any additional deferred taxes arising in the future. The percent change in tax rate was -40% (21% / 35% - 1). The Companies estimated the new DTL balance of $(766,045,755) by multiplying the complement of the percent change times the original projected ADIT balances as of February 28, 2018 ($1,276,742,926 x [1 - 40%]).[196] The amount by which the balance is revalued, as shown below, is referred to as the "excess deferred income taxes."

Table 37: ADIT Estimated Balance Change: Original (01/02/18) Vs. Replacement (01/12/18) Filings

Company	Original	Replacement	Excess ADIT
The Cleveland Electric Illuminating Company	(502,861,467)	(301,716,880)	201,144,587
Ohio Edison Company	(611,807,075)	(367,084,245)	244,722,831
The Toledo Edison Company	(162,074,384)	(97,244,630)	64,829,754
Total	(1,276,742,926)	(766,045,755)	510,697,171

Blue Ridge found that the Companies' simplistic approach to revalue ADIT theoretically correct, barring any company-specific nuances with respect to its system for tracking timing differences and journalizing deferred tax activity.

The Companies gross estimate of the impact of the TCJA on ADIT will also need to be adjusted to reflect that bonus depreciation is no longer available to public utilities. The Companies estimated 2018 ADIT reflects the corporate budgeting system projection configured to estimate 40 percent bonus depreciation on estimated additions that qualify for bonus depreciation. The budget was prepared prior to the passage of the federal income tax reform. The Companies stated (and Blue Ridge recommends) that any impacts associated with bonus depreciation resulting from the federal income tax reform will be reconciled in the Companies' next Rider DCR filing.[197] Due to the lack of available information and that the estimated ADIT balances will be trued up to actual, Blue Ridge did not calculate the impact to the DCR.

Additional Data Requests

Due to the significant increase in customer rates that would result from the Companies' application of the tax-change effect on the Rider DCR, Blue Ridge sought additional information to understand the Companies' position on the ratemaking impacts of the TCJA, specifically regarding treatment of the excess deferred taxes that resulted from revaluation of the ADIT balances.

- **Request:** Does the replacement filing represent FE's position as to the proper accounting and ratemaking treatment for the FTJCA? If no, please explain what other adjustments should be made to reflect the full impact of the FTJCA on the DCR and/or on other components of the companies' rates/tariffs?

  Companies' Response: Yes, for purposes of Rider DCR. Otherwise, the request is outside the scope of the 2017 Rider DCR audit.[198]

- **Request:** The change in the law requires recalculation of deferred tax liabilities leading to excess deferred tax reserves after a federal income tax rate reduction. How will FE account

[196] FirstEnergy's response to Data Request BRC Set-1-INT-001, Attachment 8 - Confidential.
[197] FirstEnergy's response to Data Request BRC Set 1-INT-035 - Confidential.
[198] FirstEnergy's response to Data Request BRC Set 5-INT-003 - Confidential.

for excess deferred taxes from a taxation, financial reporting and from a ratemaking perspective?

Companies' Response: The request is outside the scope of the 2017 Rider DCR audit.[199]

- **Request:** Please explain FE reasoning for excluding the impact of excess deferred taxes reserve and any potential reduction in the revenue requirement in the replacement filing?

  Companies' Response: Rider DCR, as originally approved by the Commission in Case No. 10-0388-EL-SSO and continued in Case No. 12-1230-EL-SSO and Case 14-1297-EL-SSO, explicitly includes only plant in service, accumulated reserve for depreciation, and ADIT associated with plant in service.[200]

- **Request:** Does the replacement filing, which does not reflect a regulatory liability for excess deferred taxes in rate base, represent the position that it should be excluded?

  Companies' Response: Yes, for purposes of Rider DCR.[201]

In summary, the Companies did not provide an explanation that helped us understand their ADIT revaluation approach and whether there are any nuances that should be considered. The Companies asserted that the direction and magnitude of the change in revenue was reasonable because their calculation was "consistent with the approved calculation methodology for Rider DCR." With respect to transition issues related to excess deferred taxes, the Companies responded, "The request is outside the scope of the 2017 Rider DCR audit."

Blue Ridge disagrees with the Companies assessment. Blue Ridge recommends that the amount by which the ADIT balance is revalued is also the amount by which the Companies' must set up a regulatory liability to refund the excess deferred taxes to ratepayers because the tax future obligation to the federal government decreased by 40% to properly reflect the changes in plant-related rate base recovered through the DCR. In the replacement filing, the corresponding regulatory liability is not reflected in rate base, which would have resulted in no change to rate base. If the regulatory liability was appropriately established, the DCR would reflect a refund to the ratepayers based on the effect on the tax expense component. Blue Ridge also recommends that the Companies apply the average rate assumption method (ARAM)[202] consistent with normalization requirements to update the regulatory liability to address the timing differences for the property reversal. Blue Ridge recommends that a regulatory liability be included in the rate base component of the DCR to appropriately reflect the revalued ADIT balance. Blue Ridge has estimated the impact to the current DCR revenue requirement calculations to be $(50,925,996) [**ADJUSTMENT #13**].

Case No. 18-0047-AU-COI

On January 10, 2018, the Commission opened an investigation into the financial impacts of the TCJA on regulated Ohio utilities. On February 15, 2018, the Companies submitted comments stating that they filed updated Riders DMR and DCR to incorporate the impacts of the TJCA that resulted in annual customer savings equating to nearly $40 million. While Blue Ridge did not review the Companies' Rider DMR filings, this statement does not comport with the $39,314,722 *increase* in

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[199] FirstEnergy's response to Data Request BRC Set 5-INT-004 - Confidential.
[200] FirstEnergy's response to Data Request BRC Set 5-INT-005 - Confidential.
[201] FirstEnergy's response to Data Request BRC Set 5-INT-006 - Confidential.

revenue requirements per the Rider DCR filings. Therefore, Blue Ridge recommends reconciliation of the Companies' reported annual savings reflected in all riders.

Conclusion

While many utilities across the country have submitted new tariffs reducing customer rates, the Companies are an exception in that their approach results in a 42% increase in DCR revenue requirements from $93,221,892 in the original to $132,526,614 in the replacement filing. The 42% increase is primarily attributable to the revalued ADIT balances which decreased the rate base reduction, resulting in higher investment return requirements under the ratemaking formula. The Companies simplistic approach to calculate the tax-change effect on Estimated ADIT is theoretically reasonable, barring any company-specific nuances with respect to its system for tracking timing differences and journalizing deferred tax activity. The larger issue is lack of clarity surrounding treatment of the excess deferred income tax: (1) whether the Companies intend to set up a regulatory liability, (2) if that regulatory liability will be reflected as an offset in rate base, and (3) the timing and rate at which the excess deferred income taxes will be flowed back to customers.

Blue Ridge recommends that the Companies include a regulatory liability on its ADIT worksheet in the Rider DCR to reflect a refund of the excess deferred taxes owed to ratepayers because the Companies historically collected federal tax expense at 35% but will later pay the deferred portion to the federal government at 21%. In the replacement filing, the corresponding regulatory liability is not reflected in rate base, which would have resulted in no change to rate base and no change to the required investment return. If the regulatory liability was appropriately established, the DCR would reflect a reduction in tax expense of $11,611,873 ($23,515,535 - $11,933,853) relative to the original filing (prior to any other recommended adjustments) as shown on line 14 in the table below.

Table 38: Comparison of Original Filing, Replacement Filling, and Blue Ridge Adjusted Calculation

			Original Filing 1/2/18			Replacement Filing 1/12/18			BRC Adjusted for Regulatory Liability
1	Gross Plant		$ 7,819,319,217			$ 7,819,319,217			$ 7,819,319,217
2	Accumulated Reserve		(3,363,499,919)			(3,363,499,919)			(3,363,499,919)
3	Net Plant In Service		4,455,819,297			4,455,819,297			4,455,819,297
4	ADIT		(1,276,742,926)	510,697,171		(766,045,755)			(766,045,755)
5	Regulatory Liability		-			-	(510,697,171)		(510,697,171)
6	Rate Base		$ 3,179,076,371			$ 3,689,773,543			$ 3,179,076,371
7	Rate Base at May 31, 2007		$ 2,365,954,000			$ 2,365,954,000			$ 2,365,954,000
8	Incremental		$ 813,122,371			$ 1,323,819,543			$ 813,122,371
9	Return on Rate Base	8.48%	$ 68,956,030		8.48%	$ 112,265,193		8.48%	$ 68,956,030
10	Incremental Depreciation Expense		99,694,580			99,694,580			99,694,580
11	Incremental Property Tax Expense		91,940,563			91,940,563			91,940,563
12	Revenue Requirement		$ 260,591,172			$ 303,900,335			$ 260,591,172
13	Equity Return	5.15%	$ 41,835,146		5.15%	$ 68,110,515		5.15%	$ 41,835,146
14	Income Tax	35.98%	23,515,535		22.19%	19,429,140		22.19%	11,933,853
15	CAT	0.26%	740,603		0.26%	842,848		0.26%	710,412
16	Taxes		$ 24,256,138			$ 20,271,988			$ 12,644,265
17	**Revenue Requirement + Tax**		**$ 284,847,310**			**$ 324,172,322**			**$ 273,235,437**

As an alternative to recording the regulatory liability with the Rider DCR ADIT balances, the Company should demonstrate that it reflected the regulatory liability in another filing.

RETURN

M. Determine if the Companies return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including allocated general plant from FirstEnergy Service Company are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Rider DCR Compliance Filings include the following calculated return on rate base at 8.48% for each company.

Table 39: Incremental Change in Return on Rate Base from 11/30/16 to 11/30/17[203]

Company	11/30/16	11/30/2017	Incremental
The Cleveland Electric Illuminating Company	26,418,706	28,183,288	1,764,582
Ohio Edison Company	33,089,719	34,828,839	1,739,120
The Toledo Edison Company	2,805,374	3,374,926	569,551
Total	62,313,799	66,387,052	4,073,253

The Rider DCR Summary Schedule includes the calculation for the rate of return and the return on plant using the calculated rate base.

Authority to Collect a Return on Plant-in-Service in Rider DCR

The Combined Stipulation and Order in Case No. 10-0388-EL-SSO (and reaffirmed in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO[204]) provides the capital structure, cost of debt, and return on equity that is allowed in Rider DCR Revenue Requirements. Section B.2 states the following:

> The return earned on such plant will be based on the cost of debt of 6.54% and a return on equity of 10.5% determined in the last distribution rate case utilizing a 51% debt and 49% equity capital structure.[205]

Mathematical Verification

The rate of return and the return on plant is calculated correctly in accordance with the Combined Stipulation.[206]

Source Data Validation

The capital structure and rates used within Rider DCR agree with the stipulated amounts.

Conclusion

Although the adjustments discussed in other subsections of this report will affect the final return included within the DCR, Blue Ridge found that the calculation of the return component of the DCR is not unreasonable.

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[203] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential-R2.
[204] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11, and Case No. 14-1297-SSO Commission Opinion and Order, March 31, 2016.
[205] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[206] WP V&V FE DCR Compliance Filing 1.12.2018-Confidential.

RIDER DCR CALCULATION

N. Determine if the Companies' revenue requirement calculation for Rider DCR are not unreasonable based upon the facts and circumstances known to the Companies at the time such expenditures were committed

The Compliance Filing Summary Schedules pull together the various components allowed within Rider DCR and calculate the revenue requirements based upon the actual November 30, 2017, and estimated February 28, 2018, balances. The Annual Rider DCR Revenue is compared against the Commission-approved Revenue Cap in the Companies' filings.[207]

Mathematical Verification

The various actual November 30, 2017, and estimated February 28, 2018, components, including gross plant, reserve, ADIT, depreciation, and property tax expense, were discussed in other subsections of this report and roll forward into the revenue requirements. The calculations are correct.

Annual Cap

Recovery through the DCR is subject to annual caps. The annual cap has been modified several times since the inception of the Rider DCR. The cap for the filing under review is a composite from two stipulations approved by the Commission.

The Stipulation in Case No. 12-1230-EL-SSO modified the annual cap of the Rider DCR Revenue collected effective June 1, 2014, as follows:

> For the twelve-month period from June 1, 2014, through May 31, 2015, that Rider DCR is in effect, the revenue collected by the Companies shall be capped at $195 million, <u>for the following twelve-month period, the revenue collected under Rider DCR shall be capped at $210 million</u> [emphasis added].[208]

The Stipulation in Case No. 14-1297-EL-SSO modified the annual cap of the Rider DCR Revenue collected as follows:

> The revenue caps for the Delivery Capital Recovery Rider (Rider DCR) <u>will increase annually to $30 million for the period of June 1, 2016, through May 31, 2019</u>; $20 million for the period of June 1, 2019, through May 31, 2020; and $15 million for the period of June 1, 2022, through May 31, 2024.[209]

The Companies appropriately applied the annual caps in the stipulations in Case Nos. 12-1230-EL-SSO and 14-1297-EL-SSO that resulted in an annual cap for the 2017 DCR as follows:

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[207] CEI, OE, and TE Rider DCR Replacement Compliance Filings dated 1/12/18, page 57.
[208] Case No. 12-12-1230-EL-SSO Opinion and Order, July 18, 2012, page 10.
[209] Case No. 14-1297-EL-SSO Opinion and Order, March 31, 2016, page 25.

Table 40: Companies' Calculation of Annual Cap Prior to Under (Over) Recovery Adjustment[210]

12 months 6/1/15- 5/31/16	$ 210,000,000	
Prorated for seven months		$ 87,500,000
12 months 6/1/16-5/31/17	$ 240,000,000	
Prorated for seven months		$ 140,000,000
Annual Cap Calculated by Companies		$ 227,500,000
2017 Increase		$ 30,000,000
		$ 257,500,000

Over/Under Recovery

The Stipulations in Case Nos. 10-388-EL-SSO and 12-1230-EL-SSO contain similar language addressing over or under recoveries against the annual caps as follows:

> For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap.[211]

The January 12, 2018, Rider DCR Replacement Compliance Filing cover letters state, "The attached schedules demonstrate that the year-to-date revenue is below the permitted cap for 2017." Blue Ridge confirmed that the Companies has not exceeded the Commission-approved DCR Revenue Cap.

The annual cap analysis included in the January 12, 2018, filing included revenues through November 30, 2017. Using the actual annual revenue through December 31 for years 2015 and 2016, the Companies have a cumulative under recovery of $26,355,244 as shown in the following table.[212]

Table 41: Annual DCR Revenues Vs. Annual Cap through December 31, 2017

Period	Annual Cap	Annual Revenue	Under (Over)	Cum Under (Over)
2012	$ 150,000,000	$ 128,616,253	$ 21,383,747	$ 21,383,747
2013	$ 165,000,000	$ 185,631,927	$ (20,631,927)	$ 751,820
2014	$ 188,750,000	$ 191,709,557	$ (2,959,557)	$ (2,207,737)
2015	$ 203,750,000	$ 207,078,057	$ (3,328,057)	$ (5,535,794)
2016	$ 227,500,000	$ 216,681,105	$ 10,818,895	$ 5,283,100
2017	$ 257,500,000	$ 236,427,856	$ 21,072,144	$ 26,355,244

In addition to the total cap, the Companies have individual annual caps that limit recovery through the Rider DCR. The following table shows the Companies' revenue to the aggregate annual

[210] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[211] Case No. 10-0388-EL-SSO Opinion and Order, August 25, 2010, page 12 and Case No. 12-12-1230-EL-SSO Opinion and Order, July 18, 2012, page 10.
[212] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.

cap (adjusted for the cumulative under [over] recovery) and the allocated Companies' caps. Blue Ridge confirmed the Actual Revenue through November 30, 2017, included in the Companies' filing.[213] Each of the operating companies' DCR revenues through November 30, 2017, are below the annual cap.

Table 42: 2017 Annual DCR Revenue to Aggregate and Allocated Caps through November 30, 2017[214]

Period	Aggregate Annual Cap	CEI	OE	TE
% of Aggregate Annual Cap		70%	50%	30%
2017 Annual Cap	$ 257,500,000			
Cumulative Under (Over)-2016	$ 5,283,100			
Adjusted 2017 Annual Cap	$ 262,783,100	$ 183,948,170	$ 131,391,550	$ 78,834,930
Annual Revenue Through 11/30/2017	$ 236,427,856	$ 104,709,923	$ 105,631,023	$ 26,086,910
Under (Over) 2017 Revenue Cap	$ 26,355,244	$ 79,238,246	$ 25,760,526	$ 52,748,019

Conclusion

Although Blue Ridge found that the balances used in the Rider DCR calculations should be adjusted, Blue Ridge found that the Rider DCR revenue requirements calculation is not unreasonable.

The Annual Rider DCR Revenue through November 30, 2017, is under both the aggregate annual cap and the allocated annual cap by company.

PROJECTIONS

O. Develop an understanding of the projection methodology used by the Companies for plant-in-service, property taxes, Commercial Activity Tax, and Income Tax

The Compliance Filings include projections for the first two months in 2018. To develop the first quarter 2018 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2018, the most recent (December 2017) forecast from PowerPlant. The estimated February 28, 2018, plant and reserve balances were then adjusted to reflect current assumptions (including project additions and delays), to incorporate recommendations from prior Rider DCR Audit Reports, and to remove the pre-2007 impact of a change in pension accounting.[215]

Authority to use Projected Data

The Opinion and Order and Combined Stipulation from Case No. 10-388-EL-SSO and continued in Case Nos. 12-12-1230-EL-SSO and 14-1297-EL-SSO provide the authority to include estimated balances in Rider DCR. Section B.2 of the Combined Stipulation specifically states the following:

The quarterly filings will be based on estimated balances as of August 31, November 30, February 28, and May 31, respectively, with any reconciliation between actual and forecasted information being recognized in the following quarter.[216]

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[213] FirstEnergy's response to Data Request BRC Set 11-INT-006 - Confidential.
[214] WP V&V FE DCR Compliance Filing 01.12.2018 – Confidential.
[215] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachment 3 – Confidential.
[216] Case No. 12-1230-EL-SSO Stipulation and Recommendation April 13, 2012, page 22.

Mathematical Verification and Source Validation

The actual and estimated schedules in the Compliance Filings used the same format and calculations for each of the components and the revenue requirements calculations. Blue Ridge reviewed the estimated February 28, 2018, schedules while performing specific tasks in each of the previous subsections. Specific observations and findings are discussed in the appropriate subsections.

Conclusion

Blue Ridge found that the projected amounts included through February 2018 are not unreasonable. In addition, the projected amounts will be reconciled to the actual amounts, and the Rider DCR revenue requirement will be adjusted to actual in the next quarter's Rider DCR Compliance Filings.

OVERALL IMPACT OF FINDINGS ON RIDER DCR REVENUE REQUIREMENTS

P. Determine the impact of all findings to Rider DCR revenue requirements.

Blue Ridge's review found several items that have an impact on Rider DCR Revenue Requirements, including adjustments for plant recovered through other riders that were not excluded, non-utility plant, vegetation management expenditures that should not be charged to plant, inconsistent formulas to calculated depreciation expenses, and failure to record a regulatory liability to reflect a refund of the excess deferred taxes owed to ratepayers because the Companies historically collected federal tax expense at 35% but will later pay the deferred portion to the federal government at 21%. The flow through of these adjustments has the following impact on the DCR.

Table 43: Impact of Blue Ridge's Findings on Rider DCR Revenue Requirement[217]

Adj #	Description	CEI	OE	TE	Total
	As Filed	**$ 140,265,193**	**$ 147,036,276**	**$ 36,860,287**	**$ 324,161,756**
1	Intercompany Transfer Error	-	702	-	702
2	Rider EDR(g) Wrong Amounts	(137)	-	-	(137)
3, 4	Dropped	-	-	-	-
5	Non-Utility Property	-	-	(153,555)	(153,555)
6, 7, 8	Vegetation Mgmt-Expense	(1,637,487)	(1,590,203)	(451,052)	(3,678,742)
9	ATSI Not Excluded	-	(3,458)	-	(3,458)
10	Delayed Retirement	-	-	-	-
11	AFUDC Overstated	(6,208)	-	-	(6,208)
12	Inconsistent Depreciation	(97,846)	(22,701)	-	(120,547)
13	Regulatory Liability	(20,099,373)	(24,379,378)	(6,447,244)	(50,925,996)
14	Delayed Retirement	-	-	-	-
15	Delayed Retirement	-	-	-	-
16	Delayed Retirement	-	-	-	-
17	Delayed Retirement	-	-	-	-
	Impact of All Adjustments	**(21,841,052)**	**(25,995,039)**	**(7,051,850)**	(54,887,940)
	Recommended Adjusted Rider DCR Revenue Requirements	**$ 118,424,142**	**$ 121,041,237**	**$ 29,808,437**	**$ 269,273,815**

[217] WP FEOH 2017 Adjustments to Plant and Reserve-Confidential and WP Impact of Findings BRC Set 1-INT-001 Attachment 1 – FE DCR Compliance Filing 1.12.2018-Confidnetial.

APPENDICES

Appendix A: Rider DCR Excerpts within Stipulations and Order

Appendix B: Abbreviations and Acronyms

Appendix C: Data Requests and Information Provided

Appendix D: Workpapers

Appendix A: Rider DCR Excerpts within Order and Combined Stipulation

Excerpts from the Commission Opinion and Order and the Combined Stipulation specifically related to Rider DCR are provided below.

Case No. 10-388-EL-SSO Commission Opinion and Order

On August 25, 2010, the Commission issued its Opinion and Order regarding Case No. 10-388-EL-SSO. The Order approved the following Stipulation Agreements with modifications:

- Original Stipulation Agreement included with the Companies' Application dated March 23, 2010
- First Supplemental Stipulation Agreement dated May 13, 2010 which modified the terms of the original stipulation
- Second Supplemental Stipulation dated July 19, 2010

The original stipulation and two supplemental stipulations are collectively referred to as the Combined Stipulation, which addressed all the issues within the case. The Commission's Order included several references to the Deliver Capital Recover Rider (DCR), which is the subject of this report. Those excerpts are provided as follows:

Order, pages 11-12 B. Summary of the Combined Stipulation:

(13). Effective January 1, 2012, the Delivery Capital Recovery Rider (Rider DCR) will be established to provide the Companies with the opportunity to recovery property taxes, commercial activity tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in *In re FirstEnergy*, Case No. 07-551-EL-AIR, et al, Opinion and Order (January 21, 2009). The return earned on such plant will be based on the cost of debt of 6.54 percent and a return on equity of 10.5 percent determined in that proceeding utilizing a 51 percent debt and 49 percent equity capital structure (*id*. at 13-14).

For the first twelve months Rider DCR is in effect, the revenue collected by the Companies shall be capped at $150 million; for the following 12 months, the revenue collected under Rider DCR shall be capped at $165 million; and for the following five months, the revenues collected under Rider DCR shall be capped at $75 million. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be excluded from Rider DCR and the annual cap allowance. Net capital additions for plant in service for general plant shall be included in Rider DCR provided that there are no net job losses at the Companies as a result of involuntary attrition due to the merger between FirstEnergy Corp. and Allegheny Energy, Inc. (*id*. at 14-15).

Rider DCR will be adjusted quarterly, and the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of Section 4909.18, Revised Code. The first quarterly filing will be made on or about October 31, 2011, based upon an estimated balance as of December 31, 2011, with rates effective for bills rendered as of January 1, 2012. For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following

> cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap (*id*. at 15-17).

Order, page 25, 2. "Does the settlement, as a package, benefit ratepayers and the public interest?"
a. Summary of the Parties' Arguments.

> FirstEnergy further notes that the proposed ESP would replace its existing Rider DSI with the Rider DCR; FirstEnergy contends that Rider DCR will provide for important investments in the Companies' distribution infrastructure and that Rider DCR incorporates additional customer and regulatory improvements over Rider DSI (Staff Ex. 2 at 4). FirstEnergy notes that Staff and other Signatory Parties will have the opportunity to review quarterly updates to Rider DCR and to participate in an annual audit process (Co. Ex. 4 at 18; Tr, I at 225-227).

And on page 27.

> Moreover, Staff claims that Rider DCR will recover costs, subject to revenue requirement caps each year, associated with actual investments in the Companies' distribution system. All revenue associated with Rider DCR will be included as revenue in the return on equity calculation for purposes of the SEET test and will be eligible for refund.

Order, page 35, "Does the settlement, as a package, benefit ratepayers and the public interest?"
b. Commission Decision

> The Commission also believes that the Combined Stipulation should be modified with respect to the provision that net capital additions for plant in service for general plant shall be included in Rider DCR so long as there are no net job losses at "the Companies" as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. 0oint Ex. 1 at 15). According to testimony at the hearing, this provision does not cover employees of FirstEnergy Service Company (Tr. I at 85-86). However, many functions for the Companies are performed by employees of the FirstEnergy Service Company (Co. MRO Ex. 6 at 4-5). Therefore, the Commission will modify the Combined Stipulation to include employees of FirstEnergy Service Company who provide support for distribution services provided by OE, CEI, and TE and are located in Ohio within the meaning of "no net job losses" in the Combined Stipulation.
>
> Further, the Commission will clarify that the second paragraph on page 15 of the original stipulation will be replaced by the new language contained in the second supplemental stipulation joint Ex. 1 at 15; Joint Ex. 3 at 4).

And on page 36.

> As agreed to by the signatory parties, approval of Rider DCR, which will not be implemented until January 1, 2012, is in recognition of the Companies' commitments to freeze base distribution rates through May 31, 2014, and to forgo recovery of a minimum of $360 million of legacy RTEP charges (Co. Ex. 12 at 2, 4; Joint Ex. 3 at 6) as well as approximately $42 million in MISO exit fees and PJM integration charges (Staff Ex. 1 at 4).

Order, page 37, 3. "Does the settlement violate any important regulatory principle or practice?"

a. Summary of the Parties' Arguments.

> According to Staff, the proposed ESP improves the CBP used in the current ESP, and, in Rider DCR, provides for a mechanism to expedite funding for reliability enhancements.

And on page 38.

> OCEA also claims that provisions of the Combined Stipulation related to Rider DCR violate regulatory principles and practices. These provisions include the provision that states that updated filings shall not be considered to be "an application to increase rates" within the meaning of Section 4909.18, Revised Code (OCC Ex. 2 at 14). OCEA also cites to the provision of the Combined Stipulation which provides for participation in the audits for the DCR by Staff and other Signatory Parties but does not mention other interested parties (OCC Ex. 2 at 16).

Order, page 40, 3. "Does the settlement violate any important regulatory principle or practice?"
b. Commission Decision

> With respect to OCEA's claim that the provisions related to Rider DCR violate important regulatory principles and practices, the Commission expects that reasonable management will carry out the investments funded by Rider DCR in a manner to achieve significant improvements in distribution reliability and energy efficiency in order to facilitate Ohio's effectiveness in the global economy. Section 4928.02(N), Revised Code. Further, the Commission finds that the provision of the Combined Stipulation which clarifies that the quarterly updates to Rider DCR are not "applications for an increase in rates" subject to the requirements of Section 4909.18, Revised Code, was filed as part of an application submitted pursuant to Section 4928.143, Revised Code. The statutory authority to file an application under Section 4928.143, Revised Code is separate and independent from the statutory provisions of Section 4909.18, Revised Code. OCEA has cited to no previous decision by the Commission or the Ohio Supreme Court holding that adjustments to riders authorized under an ESP must be filed pursuant to Section 4909.18, Revised Code,
>
> OCEA also objects to the provision of the Combined Stipulation which provides for participation in the audits for Rider DCR by Staff and other Signatory Parties. The Commission finds that the Signatory Parties negotiated in good faith for the right to participate in the DCR audits. Nothing in the Combined Stipulation precludes FirstEnergy from including non-signatory parties hi the audit process, and OCEA is free to negotiate with FirstEnergy for the right to participate along with the Signatory Parties. Further, OCEA will have the opportunity to fully participate in any Commission proceeding resulting from the audit process, including ample rights for discovery.

And on page 41.

> Direct Energy states that there is no evidence in the record the Commission has examined the reliability of FirstEnergy's distribution system for the proposed ESP. The Commission finds that Direct Energy's reliance upon Section 4928,143 (B) (2) (h), Revised Code, is misplaced. The provisions of the Combined Stipulation related to Rider DCR were not filed under Section 4928.143(B)(2)(h), Revised Code; therefore, there is no requirement to conduct an examination of the reliability of FirstEnergy's distribution system.

The Commission also considered the question: "Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. On page 43, OCC witness Gonzalez net present value analysis of the proposed ESP compared to an MRO combined with a potential distribution rate case for the Companies based upon three alternative scenarios. The scenarios included assumptions regarding the DCR, based upon Company witness Ridmann's testimony. First Energy responds that Mr. Gonzalez's testimony is flawed. The Commission found that the assumptions underlying OCC witness Gonzalez's testimony were arbitrary and unrealistic.

Page 47 stated, it is, therefore, ordered that the Combined Stipulation, as modified by the Commission, be adopted and approved.

Combined Stipulation

The Combined Stipulation are comprised of the following documents:

- Original Stipulation Agreement included with the Companies' Application dated March 23, 2010
- First Supplemental Stipulation Agreement dated May 13, 2010 which modified the terms of the original stipulation
- Second Supplemental Stipulation dated July 19, 2010

The key sections related to the scope of this audit from the Combined Stipulation follow:

B. Distribution

Section 2 Effective January 1, 2012, a new rider, hereinafter referred to as Rider DCR ("Delivery Capital Recovery"), will be established to provide the Companies with the opportunity to recover property taxes, Commercial Activity Tax and associated income taxes and earn a return on and of plant in service associated with distribution, subtransmission, and general and intangible plants including allocated general plant from FirstEnergy Service Company that supports the Companies, which was not included in the rate base determined in the Opinion and Order of January 21, 2009 in Case No. 07-551-EL-AIR et al. ("last distribution rate case"). The return earned on such plant will be based on the cost of debt of 6.54% and a return on equity of 10.5% determined in the last distribution rate case utilizing a 51% debt and 49% equity capital structure. The net capital additions included for recognition under Rider DCR will reflect gross plant in service not approved in the Companies' last distribution rate case less growth in accumulated depreciation reserve and accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case. Rider DCR shall be adjusted quarterly to reflect in-service net capital additions and encourage investment in the delivery system. For the first 12 months Rider DCR is in effect, the revenue collected by the Companies under Rider DCR shall be capped at $150 million; for the following 12 months the revenue collected by the Companies under Rider DCR shall be capped at $165 million, and for the following five months the revenue collected by the Companies under Rider DCR shall be capped at $75 million. Consistent with the time periods for the revenue caps established above, each individual Company will have a cap of 50%, 70% and 30% for Ohio Edison, CEI and Toledo Edison, respectively, of the total aggregate caps as established above. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from Rider DCR and the annual cap allowance. Revenue requirements will be derived for each company separately, and on that basis the recovery of the revenue among the classes of each Company will be calculated using the same methodology as the existing DSI Rider. To effect the quarterly adjustments, the Companies will submit a filing that contains the adjustment requested, the resulting rate for each customer class and the bill impact on customers. The filing shall show the Plant in Service account balances and accumulated depreciation reserve balances compared to that approved in the last distribution rate case. The expenditures reflected in the filing shall be broken down by the Plant in Service Account Numbers associated with Account Titles for subtransmission, distribution, general and intangible plant, including allocated general plant from FirstEnergy Service Company that supports the Companies based on allocations used in the Companies' last distribution rate case. Net capital additions for plant in Service for General Plant shall be included in the DCR so long as there are no net job losses at the Companies as a result of involuntary attrition as a result of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. For each account title the Companies shall provide the plant in service and accumulated depreciation reserve for the period prior to the adjustment period as well as during the adjustment period. The filing shall also include a detailed calculation of the depreciation expense and accumulated depreciation impact as a result of the capital additions. The Companies will provide the information on an individual Company basis.

(Section 2 Second paragraph of original text replaced by Second Supplemental Stipulation) The Signatory Parties agree that the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of R.C. § 4909.18 and each Signatory Party further agrees it will not advocate a position to the contrary in any future proceeding. The first quarterly filing will be made on or about October 31, 2011, based on an estimated balance as of December 31, 2011 with rates effective on January 1, 2012 on a bills rendered basis. Thereafter, quarterly filings will be made on or about January 31, April 30, July 30, and October 31 with rates effective on a bills rendered basis effective April 1, July 1, October 1, and January 1, respectively. The quarterly filings will be based on estimated balances as of March 31, June 30 September 30, and December 31, respectively, with any reconciliations between actual and forecasted information being recognized in the following quarter. The Companies will bear the burden to demonstrate the accuracy of the quarterly filings. Upon the Companies meeting such burden, any party may challenge such expenditures with evidence. Upon a party presenting evidence that an expenditure is unreasonable, it shall be the obligation of the Companies to demonstrate that the expenditure was reasonable by a preponderance of the evidence. An annual audit shall be conducted by an independent auditor. The independent auditor shall be selected by Staff with the consent of the Companies, with such consent not being unreasonably withheld. The expense for the audit shall be paid by the Companies and be fully recoverable through Rider DCR. The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable and will be conducted following the Companies' January 31,2012, January 31,2013 and January 31, 2014 filings, and one final audit following the Companies' July 30, 2014 final reconciliation filing. For purposes of such audits and any subsequent proceedings referred to in this paragraph, the determination of whether the amounts for which recovery is sought are not unreasonable shall be determined in light of the facts and circumstances known to the Companies at the time such expenditures were committed. Staff and Signatory Parties shall file their recommendations and/or objections within 120 days after the filing of the application. If no objections are filed within 120 days after the filing of the application, the proposed DCR rate will remain in effect without adjustment, except through the normal quarterly update process or as may be ordered by the Commission as a result of objections filed in a subsequent audit process. If the Companies are unable to resolve any objections within 150 days of the filing of the application, an expedited hearing process will be established in order to allow the parties to present evidence to the Commission regarding the conformance of the application with this Stipulation, and whether the amounts for which recovery is sought are not unreasonable.

For any year that the Companies' spending would produce revenue in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenue collected under the Companies' Rider DCR is less than the annual cap allowance, as established above, then the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap. In no event will authorization exist to recover in the DCR any expenditures associated with net plant in service additions made after May 31, 2014.

Section 3: Any charges billed through Rider DSI prior to January 1, 2012 shall not be included as revenue in the return on equity calculation for the Companies for purposes of applying the Significantly Excessive Earnings Test ("SEET"), nor considered as an adjustment eligible for refund. Any charges billed through Rider DCR after January I, 2012 will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. For each year during the period of this ESP, adjustments will be made to exclude the impact: (i) of a reduction in equity resulting from any write-off of goodwill, (ii) of deferred carrying charges, and (iii) associated with any additional liability or write-off of regulatory assets due to implementing this ESP. The significantly excessive earnings test applicable to plans greater than three years and set forth in R.C. § 4928.143(E) is not applicable to this three-year ESP.

D. Continuance of Existing Tariff Riders and Deferrals, Section 3

The following new tariff riders are attached as part of Attachment B, with such new tariffs approved as part of this ESP:

Rider DCR Delivery Capital Recovery (Discussed in Section B.2 above)

H. Other Issues

Section 1: The Companies' corporate separation plan in Case No. 09-462-EL-UNC shall be approved as filed. However, within six months after the completion of the merger between FirstEnergy Corp. and Allegheny Energy, Inc. or within 18 months after this Stipulation is approved, whichever comes first, if the Companies' corporate or operational structure has changed, then the Companies shall file an updated corporate separation plan. In either case whether an updated corporate separation plan is filed or not, this plan may be audited by an independent auditor. The Commission shall select and solely direct the work of the auditor. The Companies shall directly contract for and bear the cost of the services of the auditor chosen by the Commission. Staff will review and approve payment invoices submitted by the consultant.

Section 5: With respect to the recent announcement of the combination of FirstEnergy Corp. and Allegheny Energy, Inc., the Signatory Parties agree that the Commission should not assert jurisdiction and review the merger, and further agree and recommend that the Commission should not in this instance initiate its own review of the merger in light of the facts that the merger is the result of an all stock transaction and there is no change in control of the Companies. Approval of the Stipulation by the Commission indicates acceptance of the Signatory Parties' recommendation.

Case No. 12-1230-EL-SSO Commission Opinion and Order

On April 13, 2012, FirstEnergy filed an application to provide for a standard service offer (SSO) for an electric security plan (ESP). The parties agreed to a Stipulation (ESP 3) that extended the Combined Stipulation for an additional two years. The Commission approved the Stipulation, with modifications, on July 18, 2012. In regards to the Delivery Capital Recovery Rider (Rider DCR), the Order stated.

Order, page 10-11, B. Summary of the Stipulation:

(13). The Delivery Capital Recovery Rider (Rider DCR) will continue to be in effect to provide the Companies with the opportunity to recover property taxes, commercial activity tax, and associated income taxes, and earn a return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in *In re FirstEnergy*, Case No. 07-551-EL-AIR, et al., Opinion and Order (January 21, 2009). The return earned on such plant will be based on the cost of debt of 6.54 percent and a return on equity of 10.5 percent determined in that proceeding utilizing a 51 percent debt and 49 percent equity capital structure. (*Id* at 19.)

For the twelve-month period from June 1, 2014, through May 31, 2015, that Rider DCR is in effect, the revenue collected by the Companies shall be capped at $195 million, for the following twelve-month period, the revenue collected under Rider DCR shall be capped at $210 million. Capital additions recovered through Riders LEX, EDR, and AMI, or any other subsequent rider authorized by the Commission to recover delivery-related capital additions, will be excluded from Rider DCR and the annual cap allowance. Net capital additions for plant-in-service for general plant shall be included in Rider DCR provided that there are no net job losses at the Companies as a result of involuntary attribution due to the merger between FirstEnergy Corp. and Allegheny Energy, Inc. (*Id*. At 20-21.)

Rider DCR will be updated quarterly, and the quarterly Rider DCR update filing will not be an application to increase rates within the meaning of Section 4909.18, Revised Code. The first quarterly filing will be made on or about April 20, 2014, based upon the actual plant-in-service balance as of May 31, 2014, with rates effective for bills rendered as of June 1, 2014. For any year that the Companies' spending would produce revenues in excess of that period's cap, the overage shall be recovered in the following cap period subject to such period's cap. For any year the revenues collected under the Companies' Rider DCR is less than the annual cap allowance, the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap. (*Id*. At 23).

(14). Any charges billed through Rider DCR will be included as revenue in the return on equity calculation for purposes of the SEET test and will be considered an adjustment eligible for refund (*Id* at 23).

Order, page 27, 2. "Does the settlement, as a package, benefit ratepayers and public interests?"
Page 28-29, a. General Arguments

Regarding distribution, FirstEnergy contends that the distribution provisions of the ESP 3 will provide additional certainty and stability to customer rates because the ESP 3 continues the distribution rate freeze instituted by the ESP 2 Case through May 31, 2016, except for certain emergency conditions provided for by Section 4909.16, Revised Code (Co. Ex. 3 at 12-13). FirstEnergy further notes that the ESP 3 would continue to provide for investments in the Companies' distribution infrastructure by continuing Rider DCR through the ESP 3 period, which would also be capped (Co. Ex. 1, Stip. at 18-20; Co. Ex. 3 at 14). Additionally, the Companies point out that Staff and other signatory parties would have the opportunity to review quarterly updates and participate in an annual audit process (Co. Ex. 1, Stip. at 21-23).

And on page 33-34, c. Distribution Rate Freeze and Rider DCR

OCC/CP argue that the continued use of Rider OCR is not in the public interest. Initially, OCC/CP admit that Ohio law provides an opportunity for an electric distribution utility (EDU) to request recovery for distribution expenditures as part of an ESP proposal under Section 4928.143(B)(2)(h), Revised Code. However, OCC/CP note that the statute also requires the Commission to review the reliability of the EDU's distribution system to ensure that customers' and the EDU's expectations are aligned and that the EDU is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system. Here, OCC/CP argue that the Companies have failed to provide the information necessary for the Commission to complete this review. OCC/CP contend that testimony presented by Staff witness Baker demonstrated that the reliability standards were achieved in 2011 but did not correlate the Companies' reliability performance in 2011 to the Rider DCR recovery sought in the proposed ESP 3. Further, OCC/ CP argue that the evidence submitted on customer expectations utilized reliability standards established in 2009 or 2010 compared to the Companies' actual performance in 2011 (Staff Ex. 2 at 5; Tr. II at 221-222). OCC/CP state that this information will be "stale" at the beginning of the term of the proposed ESP 3. Further, OCC/CP argue that the Companies' and customers' expectations are not aligned, that the resources the Companies have dedicated to enhance distribution service are excessive, and that there is no remedy to address excessive distribution-related spending in the annual Rider DCR audit cases.

Similarly, NOPEC/NOAC argue that the ESP 3 proposal does not benefit ratepayers and the public interest because residential and small commercial customers will be negatively affected by increases of approximately $405 million in the amount of distribution improvement costs proposed to be recovered through Rider DCR.

AEP Retail also argues that the "cap" on recovery under Rider DCR under the Stipulation may provide a benefit, or may not, depending on the amounts FirstEnergy invests in distribution over the ESP 3 period. However, AEP Retail claims that the Companies have failed to introduce evidence concerning their anticipated distribution investments or accumulated depreciation, making it impossible for the Commission to evaluate this claimed benefit.

OSC contends that Rider DCR recovery is only limited by certain revenue caps and could total $405 million during the period of the proposed ESP 3. OSC argues that, instead of Rider DCR, the Companies should be required to file a formal distribution rate increase case, as, in the past, the Commission has not awarded the Companies the full amount of the requested increase for distribution-related investments. Distribution Rate Case, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48.

The Companies respond that the reliability information utilized in this proceeding was not "stale," citing the fact that OCC witness Gonzales admitted that the Companies' reliability performance standards are not required to be updated (Tr. III at 117-118). Further, the Companies point out that they are also not required by statute to prove that additional investments in the system will impact reliability performance or demonstrate that the Companies' reliability performance and customers' expectations for a proposed ESP are aligned. The Companies also argue that OCC/CP and OSC's claims that the Companies have proposed to recover $405 million as increased distribution revenue recovery is wrong. The Companies proffer that the ESP 3 proposes that recoveries under Rider DCR be capped, and that the caps are proposed to increase by $15 million on an annual basis, identical to the annual increases in the ESP 2 Case (Co. Ex. 3 at 14). The Companies state that this increase in the amount of the caps represents a cumulative $45 million increase over the caps allowed in the ESP 2 Case. Further, the Companies note that, as stated in the Stipulation, they will be required to show what they spent and why it is appropriate to recover these investments through Rider DCR and that the recovery will also be subject to an annual audit.

The Commission finds that the Companies have demonstrated the appropriate statutory criteria to allow continuation of Rider DCR as proposed in the Stipulation. As discussed in Staff's testimony, Staff examined the reliability of the Companies' system and found that the Companies complied with the applicable standards (Staff Ex. 2 at 5-6). Further, the Stipulation provides for an annual audit of recovery under Rider DCR and requires the Companies to demonstrate what they spent and why the recovery sought is not unreasonable. Additionally, the Commission notes that the caps on Rider DCR do not establish certain amounts that the Companies will necessarily recover-thus, the Commission emphasizes that the $405 million figure discussed by NOPEC/NOAC and OSC is the maximum that could be collected under Rider DCR and is not a guaranteed amount. (Co. Ex. 1, Stip. at 20-23; Co. Ex. 3 at 14.)

And on pages 42-44, h. Commission Decision

Page 43: Further, with respect to Rider DCR, the Commission encourages the Companies to consult with Staff to select projects, among others, which will mitigate effects of the transmission constraint in the ATSI zone of PJM (Co. Ex. 1, Stip. at 19-

20). There is an ample record in this proceeding that the transmission constraint has resulted in a higher charge for capacity in the ATSI zone than PJM as a whole. Moreover, the record demonstrates that there are projects which can be undertaken by the Companies to mitigate, at the distribution level, the transmission constraint, in order to reduce capacity charges resulting from future base residual auctions (Tr. I at 335-336; Staff Ex. 1; Tr. II at 240-242). The Stipulation also adopts the terms and conditions of the Combined Stipulation regarding distribution rate design, as clarified by the Commission in the ESP 2 Case.

Page 43-44: The Commission also notes that the auditor for Rider DCR is to be selected by the Staff with the consent of the Companies (Co. Ex. 1, Stip. at 22). Although the Commission is confident that the Companies would not unreasonably withhold consent, the Commission uses independent, outside auditors for a number of functions, and the Commission generally does not obtain the consent of the utility. Although this case does include unique circumstances, the Commission does not find that such circumstances justify this departure from general Commission practice. Accordingly, we will eliminate the provisions of the Stipulation requiring the consent of the Companies in the selection of the auditor for Rider DCR.

The Commission notes that the Stipulation provides that the riders listed on Attachment B of the Stipulation shall be subject to ongoing Staff review and audit. According to the terms of the Combined Stipulation and past practice, separate dockets have been opened for the review of Riders DCR, AMI, and AER. The Commission clarifies that the Companies annually should file applications in separate dockets for the review and audit of Riders DCR, AMI, AER, NMB, and DSE. In addition, the Companies annually should file an application for the combined review of Riders PUR, DUN, NDU, EDR, GCR, and GEN. The Commission directs the Companies and Staff to develop a schedule for the filing of the annual reviews and audits. For all other riders on Attachment B, the Companies should continue to docket the adjusted tariff sheets; however, these tariff sheets should be filed in a separate docket rather than this proceeding, as has been the practice in the ESP 2 Case. Further, all filings adjusting riders listed on Attachment B should include the appropriate work papers.

With this clarification, the Commission finds that the Stipulation as modified benefits ratepayers and the public interest, in accordance with the second prong of our test for the consideration of stipulations.

Order Page 44: 3. Does the settlement package violate any important regulatory principle or practice?

Staff further claims that the Stipulation affirmatively supports the state policies enumerated in Section 4928.02, Revised Code. Staff contends that the Stipulation supports competition by avoiding standby charges and other limitations consistent with Ohio policy. Section 4928.02(8), (C), Revised Code. It supports reliability though the continuation of the DCR mechanism consistent with Ohio policy. Section 4928.02(A), Revised Code. Staff claims that the Stipulation supports energy efficiency efforts through the support of energy coordinators, Section 4928.02(M), Revised Code, and supports at risk populations, Section 4928.02(L), Revised Code. Finally, Staff contends that economic development measures support Ohio's effectiveness in the global economy consistent with state policy. Section 4928.02(N), Revised Code.

And on page 48, c. Deferred Carrying Charges

The Commission notes that, under the terms of the proposed Stipulation, charges billed though Rider DCR will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. However, the Stipulation specifically excludes deferred carrying charges from the SEET calculation (Co. Ex. 1, Stip. at 23). We find that the provision of the Stipulation that provides for the exclusion of deferred carrying charges from the SEET does not violate an important regulatory principle or practice. Although the AEP-Ohio SEET Case stands for the principle that deferrals, including deferred carrying charges, generally should not be excluded from the SEET, Section 4928.143(F), Revised Code, specifically requires that consideration "be given to the capital requirements of future committed investments in this state." Rider DCR will recover investments in distribution, subtransmission, and general and intangible plant. Therefore, the Commission finds that, in order to give full effect to this statutory requirement, we may exclude deferred carrying charges from the SEET where, as in the instant proceeding, such deferred carrying charges are related to capital investments in this state and where the Commission has determined that such deferrals benefit ratepayers and the public interest. Accordingly, we find that the Stipulation provision excluding deferred carrying charges from the SEET does not violate an important regulatory principle or practice.

Order page 48, 4. Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code?

a. Summary of Parties' Arguments

Page 49: FirstEnergy first contends that the quantitative benefits of the ESP 3 are more favorable than an MRO. FirstEnergy specifies that, in its ESP v. MRO analysis, it considered the following quantitative provisions of the ESP: (1) estimated Rider DCR revenues from June 1, 2014, through May 31, 2016; (2) estimated PIPP generation revenues for the period of the ESP 3, reflecting the six percent discount provided by the Companies; (3) economic development funds and fuel fund commitments that the Companies' shareholders will contribute; and (4) estimated RTEP costs that will not be recovered from customers (Co. Ex. 3 at 17-19). Further, FirstEnergy states that it considered the following quantitative provisions of the MRO: (1) estimated revenue from base distribution rate increases based on the proposed Rider DCR revenue caps; and (2) generation revenue from PIPP customers excluding the six percent discount provided by the Companies. After comparing these quantitative factors, the Companies calculate that the quantitative benefits of the ESP 3 exceed the quantitative benefits of an MRO by $200 million. (Co. Ex. 3 at 17-19.)

In its discussion of the quantitative benefits of the ESP 3, FirstEnergy acknowledges that Staff witness Fortney provided a different perspective of the ESP v. MRO analysis. In particular, the Companies note that Staff witness Fortney testified that the costs to customers of Rider DCR, which are included in FirstEnergy witness Ridmann's ESP analysis, and the costs of a distribution case, which are included in FirstEnergy witness Ridmann's MRO analysis, could be considered as a "wash" (Staff Ex. 3 at 4-5). Consequently, the Companies point out that Staff witness Fortney concluded that, even if foregoing RTEP cost recovery was eliminated as a benefit of the ESP 3, he would nevertheless consider the ESP 3 as benefiting customers relative to an MRO by over $21 million (Staff Ex. 3 at 5).

Page 50: As noted by the Companies, Staff also takes the position that an MRO is not preferable to the ESP 3 in this proceeding. In its ESP v. MRO analysis, Staff states that there are two ways to view the situation. Under the first view, Staff argues that one should remove the effect of the agreement to forego collection of RTEP costs from the analysis because this benefit was agreed to and provided in the ESP 2 and brings no new value to the ESP 3. Under this interpretation, Staff finds that the difference in cost between the ESP and MRO is less than $8 million. Staff contends that this is a sufficiently small difference in costs that the flexibility provided by the proposed ESP 3 makes it superior to an MRO. Further, Staff notes that the qualitative benefits of the ESP 3 further counterbalance the nominal difference in cost. Under the second view, Staff argues that the costs of Rider DCR under the ESP 3 and the effects of a rate case under an MRO are essentially a "wash," and that FirstEnergy witness Ridmann's analysis should be adjusted to remove the Rider DCR costs from the ESP 3 and the rate case expense from the MRO, respectively. Under this view, Staff argues that the ESP 3 is the more advantageous option by $21 million, even disregarding qualitative factors. (Staff Ex. 3 at 2-5.)

Page 50-51: In contrast, OCC/CP contend that the ESP 3 is not more favorable in the aggregate than an MRO under a quantitative or qualitative analysis. Regarding the Companies' quantitative analysis, OCC/CP contend that the alleged RTEP benefit was improperly double-counted by the Companies and should be excluded from the analysis. Specifically, OCC/CP argue that the RTEP cost recovery forgiveness amount would remain the Companies' obligation under the ESP 2 and is not contingent upon the Commission's approval of the ESP 3 (Joint NOPEC/NOAC Ex. 1 at 5). Next, OCC/CP argue that Rider DCR cannot be considered a "wash" with a distribution rate case outcome. More specifically, OCC/CP contend that Rider DCR is more costly to customers because, according to FirstEnergy witness Ridmann, $29 million net cost is attributed to Rider DCR due to lag in distribution cost recovery (Co. Ex. 3 at 18). OCC/CP next argue that the PES offer of a six percent discount to PIPP customers should not be considered a benefit of the ESP 3, because it would not be a prohibited arrangement in an MRO (OCC Ex. 11 at 30-31). Further, OCC/CP point out that the Companies did not solicit bids from other suppliers besides PES to determine if there was interest in serving the PIPP load at an even greater discount. Next, OCC/CP contend that the alleged public benefits of the fuel funds ignore the benefit derived by FirstEnergy. OCC/CP explain that the $9 million in fuel fund monies is used for the payment of electric bills and, consequently, argue that this represents a benefit to the Companies because it ensures revenues. Finally, OCC/CP argue that the costs associated with the economic development provisions of the Stipulation are merely "transfers" of payments and should not be considered a benefit of the ESP 3. OCC/CP specify that the economic development provisions contain dollar amounts and non-bypassable discounts given to certain entities, which are ultimately recovered from other customers (OCC Ex. 11 at 33).

Page 51-52: Similar to OCC/CP's arguments, NOPEC/NOAC contend that FirstEnergy has failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically,· NOPEC/NOAC argue that FirstEnergy's analysis wrongly seeks to double-count the RTEP cost recovery forgiveness benefits for purposes of the ESP v. MRO test, although that obligation was incurred as part of the ESP 2 (NOPEC/NOAC Joint Ex. 1 at 5). NOPEC/NOAC argue that, when this quantitative benefit is removed, the ESP 3 value becomes $7 million less favorable than an MRO (Id. at 6). Additionally, NOPEC/NOAC argue that FirstEnergy improperly included in its analysis an assumed Commission-approved distribution rate increase of $376 million under an MRO in order to offset the $405 million to be collected from Rider DCR under the ESP 3 (Co. Ex. 3, Att. WRR-1). NOPEC/NOAC contend that the $376 million assumption is unrealistic and speculative, given that FirstEnergy was only awarded a distribution rate increase of $137.6 million in 2007. NOPEC/NOAC argue that a more accurate estimate of a distribution rate increase would make the proposed ESP 3 less favorable than the MRO by several hundred million dollars.

Page 52: NOPEC/NOAC next contend that, if the Commission desires to adopt an ESP over an MRO, the Commission should also adopt NOPEC/NOAC's recommendations so that the ESP 3 proposal can satisfy the ESP v. MRO test. NOPEC/NOAC recommend that the Commission include the following modifications to the proposed ESP 3 (1) elimination of the continuation of Rider DCR after May 31,2014, and replacement with a separately filed distribution rate case; (2) elimination of FirstEnergy' s proposal to exclude income it receives from deferred charges from the SEET calculation; (3) requirement that the Companies bid all of their eligible demand response and energy efficiency resources into all future PJM capacity auctions; and (4) holding of the proposed energy auctions in October 2012 and January 2013 in accordance with the terms of the Combined Stipulation.

OSC similarly contends that, when the Companies' proposal is viewed in light of the evidence presented in this case, the Companies have failed to demonstrate that the ESP 3 is more favorable in the aggregate than the expected results of an MRO. Specifically, OSC claims that the evidence presented at hearing shows that, quantitatively, the ESP 3 proposal will cost consumers more than the expected results of an MRO because the ESP 3 proposal will allow FirstEnergy to continue Rider DCR after May 31, 2014, to recover up to $405 million in distribution improvement expenditures. (Tr. I at 129.)

AEP Retail also contends that the Companies' proposed ESP 3 fails the ESP v. MRO test quantitatively. Specifically, AEP Retail contends that the $293.7 million in RTEP costs should not be included in the analysis because this benefit was a result of the Commission's decision in the ESP 2 Case and would not be a benefit of the ESP 3 (Staff Ex. 3 at 2). AEP Retail also argues that the claimed qualitative benefits are suspect because the Companies were unable to secure any benefit by bidding demand response resources into the 2015-2016 base residual auction, because the benefits of a six percent PIPP discount are unknown and violate Section 4928.02, Revised Code, because the extension of the recovery period for REC costs is not a benefit, because the distribution "stay out" period and Rider DCR are an illusory benefit, and because any benefit of the three-year blending proposal is impossible to assess. (Tr. IV at 23; OCC Ex. 9 at 8-9; OCC Ex. 11 at 32; Tr. I at 250-257.)

Page 53: Regarding Rider DCR, the Companies reply to other parties' arguments that the recovery of any dollars in a rate case is speculative, especially when compared to the amounts that the Companies recovered in their last distribution rate case. The Companies contend that, if they are able to make a proper showing to obtain recovery of distribution infrastructure costs under Rider DCR, there is no reason to believe that they would be unable to make a similar showing to obtain recovery in a rate case. Further, the Companies argue, in response to OCC/CP, NOPEC/NOAC, and OSC's arguments that recovery could be up to $405 million, that the caps established in Rider DCR are just caps-and that there is no guarantee to what the Companies may recover under Rider DCR.

Page 53-54: Next, the Companies rebut OCC/CP and AEP Retail's arguments that the Companies' agreement not to seek a base distribution rate increase is not a benefit. The Companies point out that a rate case would involve the recovery of costs beyond those permitted to be recovered under Rider DCR. Further, the Companies point out that the Commission has already held that a base distribution rate freeze provides a benefit that makes an ESP more favorable in the aggregate than an MRO in the ESP 2 Case. Finally, the Companies note that they cannot recover any monies unless they can show that the plant is in service, and that Rider OCR is subject to quarterly reconciliations and an annual audit. ESP 2 Case, Opinion and Order (Aug. 25, 2010) at 44.

Page 54: In its reply, Staff reiterates that the Companies have met their criteria regarding Rider DCR. Staff contends that it examined the reliability of the Companies' system and found that the Companies were in compliance with the applicable standards (Staff Ex. 2 at 5-6). Staff states that compliance with the standards means that customers are getting the level of reliability that they want.

In their reply brief, OCC/CP respond that the Companies are unrealistic in assuming that, if they collected $405 million through Rider DCR, they would likely recover that same amount of costs through a distribution rate case. OCC/CP point out that, in the last distribution rate case, the Companies requested $340 million, but that the Commission reduced the amount to $137 million in annual rate increases. Distribution Rate Case, Case No. 07-551-EL-AIR, Opinion and Order (January 21, 2009) at 48. Further, OCC/CP contend that they are not advocating for a decrease in service quality, but do not want the Companies to" gold plate" their distribution systems.

Page 55, b. Commission Decision

Page 56: The Commission also notes that the proposed ESP 3 is consistent with policy guidelines in Ohio. Specifically, the proposed ESP 3 supports competition and aggregation by avoiding standby charges, supports reliable service through the continuation of the DCR mechanism, supports business owners' energy efficiency efforts, protects at-risk populations, and supports industry in order to support Ohio's effectiveness in the global economy (Co. Ex. 3 at 11-12).

Dissenting Opinion of Commissioner Cheryl L. Roberto

Page 4-5: D. Continuation of Rider DCR: utility and customer expectations are not aligned; without alignment utility gains additional revenues without produces additional customer value

Rider DCR is proposed pursuant to Section 4928.143(B)(2)(h), Revised Code, which authorizes an ESP to include:

> Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking . . . provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include ... any plan providing for the utility's recovery of costs ... a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

In order for Rider DCR to be included appropriately within the ESP 3, the Companies have the burden to demonstrate that the Companies' and customers' expectations are aligned and the Companies are dedicating sufficient resources to reliability. Additionally, this provision must be judged as part of the aggregate terms and conditions of an ESP; e.g. if a similar or better result is achievable through an MRO, then it calls into question whether the ESP is beneficial.

The Sierra Club notes that despite ample notice of the 2015/2016 RPM auction and the likely consequences for the Companies' customers, the Companies failed to take any steps to prepare for the RPM auction. These actions could have included bidding in energy efficiency and demand response. Accordingly, the Sierra Club argues that the Companies should be held accountable for the financial harm caused to its customers. I agree with the majority that this proceeding was not opened to investigate the Companies' bidding behavior. It is not a complaint case. The majority notes that "the record does not support a finding that the Companies' actions in preparation for bidding into the 2015/2016 base residual auction were unreasonable." If this were a complaint case, a standard of reasonableness would be appropriate. See Section 4905.26, Revised Code. In this instance, however, the burden is upon the Companies to demonstrate that its actions are aligned with both its own interests and those of its customers and that it is dedicating sufficient resources to reliability. The Companies may only avail themselves of the benefits of single-issue rate-making pursuant to Section 4928.143, Revised Code, after they have successfully made this demonstration. The information in our record is insufficient to find that the Companies dedicated sufficient resources to reliability, particularly in the form of participation in the base residual auctions whose very purpose is reliability. For this reason, I find that continuation of Rider DCR is not supported by this record.

Finally, the Companies have a remedy for cost recovery for prudent distribution system investments in form of a distribution rate case. If the Companies require additional resources, they may file requests under traditional ratemaking processes.

Case No. 14-1297-EL-SSO Commission Opinion and Order

Order, page 25, (11) Third Supplemental of the Stipulation:

> The revenue caps for the Delivery Capital Recovery Rider (Rider DCR)[218] will increase annually to $30 million for the period of June 1, 2016, through May 31, 2019; $20 million for the period of June 1, 2019, through May 31, 2022; and $15 million for the period of June 1, 2022, through May 31, 2024. Further, the audit schedule set forth in the Application shall be amended to provide audits for the entire term of the Stipulated ESP IV, and the amended language shall read: "The independent auditor shall be selected by Staff. The audit shall include a review to confirm that the amounts for which recovery is sought are not unreasonable and will be conducted following the Companies' December 31 filing during the term of the Companies' ESP IV, and one final audit following the Companies' final June 30 reconciliation filing." (Co. Ex. 154 at 13.)

Order, page 29, (32) Third Supplemental of the Stipulation:

> The Signatory Parties agree that the following termination and transition of the Stipulated ESP IV must occur under the fourth-year test required by RC 4928.143(E): (1) the Commission's test of the plan, including the impact of termination on the financial health of the utilities; and (2) a finding that the results of the test conclude that the remainder of the Stipulated ESP IV is no longer more favorable than an MRO and that the remainder of the ESP IV is likely to result in significantly excessive earnings for each utility. However, termination shall not affect continued cost recovery of Riders DCR and RRS. (Co. Ex. 154 at 18.)

Order, page 65-66, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (e) Delivery Capital Recovery Rider

> FirstEnergy also argues that Stipulated ESP IV benefits customers and the public interest by helping to ensure reasonably priced and reliable distribution service. Initially, FirstEnergy contends that continuing the distribution rate freeze will also benefit customers (Co. Ex. 155 at 3). In connection with the freeze, FirstEnergy states the continued recovery of lost distribution revenue will appropriately balance the interests of customers with the interests of the Companies' shareholders (Co. Ex. 7 at 8). Further, the Companies stress that they will be required to show total investment amounts and provide justification as to why it is appropriate to recover these investments through Rider DCR, which will then be subject to an annual audit. As Rider DCR provides the Companies with the opportunity to invest in infrastructure in a more proactive manner, FirstEnergy asserts that the Companies have consistently outperformed their system average interruption frequency index (SAIFI)[219] and customer average interruption duration index (CAIDI)[220] minimum reliability standards since Rider DCR has been in effect (Co. Ex. 50 at 9). Additionally, the Companies propose to increase the annual cap for revenue recovered under Rider

[218] Rider DCR allows the Companies to earn a return of and on plant-in-service associated with distribution, transmission, general, and intangible plant, which was not included in the rate base from the Companies' last distribution rate case.
[219] Represents the average number of interruptions per customers.
[220] Represents the average interruption duration.

DCR from $15 million per year to $30 million for the first three years, with a $20 million increase annually for the subsequent three years and $15 million annually for the final two years of the proposed eight-year term (Tr. Vol. XX at 3961-64). During the evidentiary hearing, FirstEnergy alleged that no intervening witnesses could contest that actual revenue requirements have increased $30 million annually on average (Tr. Vol. XXI at 4117-19; Tr. Vol. XXXVIII at 8231).

While OCC/NOAC initially contends that Rider DCR will not result in a financial "wash" under the MRO v. ESP test, as proffered by FirstEnergy witness Fanelli, OCC/NOAC, NOPEC, and RESA argue the alleged qualitative benefits arising from Rider DCR will not actually accrue to customers and, instead, will cause customers to pay more than they otherwise would be required to pay under a distribution rate case (Co. Ex. 50 at 7; OCC Ex. 18 at 17; OCC/NOPEC Ex. 8 at 30; OCC/NOPEC Ex. 11 at 22-23). OCC/NOAC, NOPEC, and RESA argue these revenue cap increases could ultimately result in customers paying an additional $240 to $330 million in revenues, for a total of $915 million in Rider DCR charges over the term of Stipulated ESP IV (OCC/NOPEC Ex. 11 at 23-24). Additionally, OMAEG and NOPEC maintain the Companies have provided no evidence showing the need for this increased cap, especially since no major distribution capital projects are currently planned (Co. Ex. 50 at 4; Staff Ex. 6 at 7-9; OCC Ex. 18 at 19). OCC/NOAC, Power4Schools, and OMAEG further assert that Rider DCR will function more efficiently or foster greater reliability when collecting these costs through a base distribution rate case (OCC/NOPEC Ex. 8 at 31). OMAEG, NOPEC, and Power4Schools assert it would not be reasonable or prudent for the Commission to allow the Companies to incrementally increase the distribution rate, absent a thorough Commission review of such rates in a distribution rate case, noting it has already been seven years since the Companies' last distribution rate case (OCC Ex. 22 at 3; Tr. Vol. XX at 3901). Moreover, OMAEG and NOPEC add that, in the event the Companies are earning returns that exceed their actual costs of capital, additional Rider DCR increases are both unnecessary and inappropriate (OCC Ex. 18 at 11). OCC/NOAC further asserts that allowing Rider DCR to continue to be charged to customers in the event the ESP is terminated pursuant to R.C. 4928.143(E) would be harmful, due to the fact, in their opinion. Rider DCR contributes to the failure of the MRO v. ESP test.

Order, page 66-67, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (f) Government Directives Recovery Rider

FirstEnergy believes that the Government Directives Recovery Rider (Rider GDR) proposed in its application will permit timely recovery of future costs related to implementing programs required by legislative or governmental directives over which the Companies would have no control (Tr. Vol. I at 180; Co. Ex. 16 at 4). Given the proposed eight-year term of Stipulated ESP IV, FirstEnergy argues that it is appropriate to establish a cost-recovery mechanism now for possible future charges incurred because of governmental actions or directives in order to ensure the recovery oi such costs is completed in a uniform and consistent manner subject to Commission review and approval. (Tr. Vol. XXIV at 4905; Co. Ex. 16 at 3). As a part of Stipulated ESP IV, the Companies are specifically requesting deferral authority and recovery of the costs associated with the supplier web portal and bill logos through

Rider GDR. Additionally, the Companies note that no costs related to proposed Rider GDR had been incurred at the time of the evidentiary hearing. (Co. Ex. 15 at 7-8; Tr. Vol. V. at 1030-33,1079-83,1101.)

Similar to its objections to Rider DCR, OCC/NOAC, Power4Schools, and NOPEC argue the alleged benefits resulting from Rider GDR are without merit, noting that this is again an attempt by the Companies to request approval of an asymmetric, single-issue ratemaking request when substantial excess earnings are already being recovered by the Companies. OCC/NOAC additionally contend that the proposed Rider GDR provides no incentive or requirement for Companies to file for rate reductions resulting from changes hi governmental regulations. (OCC/NOPEC Ex. 7 at 32.) OMAEG also adds that FirstEnergy witness Mikkelsen even testified that it is too early to ascertain the types of costs that will result from implementing these directives or to estimate the amount of costs to be recovered under the rider from customers (Co. Ex. 7 at 25).

Order, page 69-70, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (i) Grid Modernization Program

FirstEnergy alleges that the Stipulated ESP IV will also benefit customers through its grid modernization provision, as this provision contains several initiatives that would further promote customer choice in the Companies' service territories, including, but not limited to. Advanced Metering Infrastructure (AMI), DACR, Volt/VAR, engaging Staff to attempt to remove any barriers for distributed generation, consulting with Staff regarding net-metering tariffs, and full deployment of advanced smart meters (Co. Ex. 154 at 9-10). The Companies believe implementation of such initiatives will ultimately lead to customer savings and promote retail competition in the state of Ohio (Co. Ex. 154 at 3). Additionally, FirstEnergy states that the Companies will file a grid modernization plan with the Commission within 90 days of the filing of Stipulated ESP IV, in which all interested parties would have the opportunity to participate (Co. Ex. 154 at 9-10; Co. Ex. 155 at 4; Tr. Vol. XXXVI at 7584-85, 7624). The Companies state that costs associated with any approved grid modernization project would be recovered through Rider AMI, commencing within three months after Commission approval of the project and would be calculated based on a forward-looking formula rate (Co. Ex. 154 at 9-10). Further, FirstEnergy provides that the ROE would be initially set at 10.88 percent based on the currently approved ROE for ATSI plus a 50 basis point incentive mechanism to incentivize grid modernization investment over other potential types of investment (Co. Ex. 154 at 10; Tr. Vol. XXXVI at 7631-32; Tr. Vol. XXXVII at 7775).

Environmental Groups and OCC/NOAC allege that the Stipulated ESP IV may actually harm customers, noting the preclusion to terminate Rider RRS and Rider DCR before 2024 and arguing the Companies' commitment to file a grid modernization plan does not warrant the Commission approving an incentive ROE on grid modernization investments absent any evidence showing that it will not provide windfall profits to the Companies (ELPC Ex. 28 at 13-14). OCC/NOAC further asserts that the proposed ROE is unjust and unreasonable, as it is higher than the current ROE approved for FirstEnergy's SmartGrid pilot (Tr. Vol. XXXVII at 777^-7775). OCC/NOAC and OHA also contend that it would be unwise for the Commission to agree to an upfront fixed

ROE for facility deployment regarding DACR and Volt/VAR technologies before any details of the grid modernization plan are known.

Order, page 75, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (m) Low-Income Customer Assistance Programs and Initiatives

> As discussed earlier, FirstEnergy and Citizens Coalition maintain that Stipulated ESP IV will benefit customers and the public interest by supporting low-income customers. Apart from all customers enjoying reliable power at market-based prices, FirstEnergy has corrupted to provide funding for several programs geared toward assisting low-income customers, including the Community Corrections program, the Cleveland Housing Network, the Council for Economic Opportunities in Greater Cleveland, the Consumer Protection Association for a Fuel Fund Program, OPAE, and the Customer Advisory Agency. (Co. Ex. 7 at 30; Tr. Vol, I at 44, 65, 200-201, 205; Tr. Vol. II at 427; Co. Ex. 154 at 17; Co. Ex. 155 at 11.) Citizens Coalition also emphasizes the importance of and demonstrable need for maintaining these various low-income programs, adding that the funding provided as a part of Stipulated ESP IV will help promote involvement in these programs.
>
> OCC/NOAC state that, contrary to FirstEnergy's assertions, low-income customers will be significantly impacted by Stipulated ESP IV, as it is does not continue certain low-income assistance programs and will significantly increase costs charged to these customers through Rider RRS, Rider DCR, and Rider GDR. Moreover, OCC/NOAC believe that, due to the exorbitant costs to low-income customers, the amount of customers whose electric service is terminated for non-payment may increase as a result oi approving Stipulated ESP IV. Further, NOPEC points out that while many low-income groups will be receiving payouts funded by shareholders, the Stipulated ESP IV does little to benefit the Companies' ratepayers, who NOPEC asserts are captive and will be required to pay the eventual cost of Rider RRS. (OCC/NOPEC Ex. 9 at 7,12; OCC Ex. 27 at 7-9,13-14,16,19,22.)

Order, page 92-93, E Consideration of Stipulated ESP IV/ 2- Does the settlement, as a package, benefit ratepayers and the public interest?/ (m) Commission Decision/ (iv) Additional Benefits of Stipulation

> The key provisions in the Stipulations related to distribution rates is the continuation of rate base distribution rate freeze for eight years under ESP IV. The extension of the distribution rate freeze will promote stable rates, as base distribution rates will not rise during the term of ESP IV (Co. Ex. 155 at 3). The Commission notes that base distribution rates have not increased in the Companies' service territories since 2009. In re FirstEnergy, Case No. 07-551-EL-AIR et. al., Opinion and Order (Jan. 29, 2009). However, in light of the proposed distribution rate freeze, it is necessary and appropriate to continue the existing Rider DCR mechanism, which allows the Companies to recover reasonable investments in plant in service associated with distribution, subttansmission, and general and intangible plant, which was not included in the rate base oi the Companies' last distribution rate case. We note that Rider DCR was first approved by the Commission in FirstEnergy's ESP II and has been in effect since January 1, 2012. ESP II Case, Opinion and Order at 11. The Stipulations provide for continued annual audits of recovery under Rider DCR and requires the

> Companies to demonstrate what they spent and why the recovery sought is not unreasonable. These distribution investments are necessary to maintain distribution reliability at current levels. Likewise, the storm cost deferral mechanism facilitates the distribution rate freeze by allowing the Companies to defer unusually high storm damage expenses in the event such expenses are actually incurred.

Order, page 105-106, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (c) Other Provisions

> Regarding Rider DCR, OCC/NOAC and Power4Schools oppose its proposed continuation and the continuation of the base distribution rate freeze, arguing that this proposal avoids the scrutiny of a base distribution rate case in violation of prudent regulatory policy (Co. Ex. 154 at 13).

Order, page 107, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (c) Other Provisions

> Next, FirstEnergy responds to parties' arguments regarding the lawfulness of Riders DCR and GDR. FirstEnergy asserts that R.C. 4928.143(B)(2)(h) expressly permits single issue ratemaking as part oi an ESP. Additionally, FirstEnergy points out that the Commission previously approved Rider DCR as part of an ESP. ESP II Case; ESP III Case. FirstEnergy also addresses the Environmental Groups' argument that the Companies should not be permitted to receive lost-distribution revenue tied to the Customer Action Program under Commission precedent. FirstEnergy argues that this provision is an integral part of the Stipulated ESP IV that is supported by all signatory parties, and that tae Customer Action Program is an energy efficiency program authorized by R.C. 4928.662 and is contained in the Companies' Commission-approved EE/PDR Portfolio Plan. In re FirstEnergy, Case No. 12-2190-EL-POR, Finding and Order (Nov. 20, 2014) at 8-9. Next, FirstEnergy addresses parties' objections to the federal advocacy provision, arguing that this provision does not violate state policy and the Commission is well within its powers to accept the recommendation if it believes it is reasonable. Finally, FirstEnergy asserts that the proposed HLF/TOU pilot program is not unduly discriminatory and unjust as alleged by some parties, arguing that eligibility requirements in order to create a homogenous pool are necessary for such a pilot program (Tr. Vol. II at 290-291, 463-467; Co. Ex. 146 at 17).

Order, page 111, E Consideration of Stipulated ESP IV/ 4- ESP versus MRO Test

> With respect to Rider DCR, the Commission is not persuaded by claims by OCC/NOAC and others that costs under Rider DCR fail to receive proper scrutiny. As we have stated previously, Rider DCR is subjected to annual audits which require the Companies to demonstrate what they spent and why the recovery sought is unreasonable. ESP III Case, Opinion and Order at 34. The Commission has been conducting such audits annually since the inception of Rider DCR. Thus, OCC/NOAC and any other party have had, and will continue to have, a full and fair opportunity to raise any issues regarding distribution investments to be recovered under Rider DCR during the audit process.

Order, page 113-114, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (i) Appropriate Application of the MRO v. ESP Test

> NOPEC initially argues that the General Assembly intended, and the Ohio Supreme Court later confirmed, that the Commission is limited to only consider the quantitative factors listed in R.C. 4928.143(B) in its analysis of a proposed ESP, and thus, the language within R.C. 928.143(C)(1) must be construed consistent with that intent. R.C. 1.49; In re Columbus S. Power Co., et al, 128 Ohio St.3d 402, 2011-Ohio-958. Thus, NOPEC states that while a variety of qualitative benefits have been forwarded by the Companies in support of Stipulated ESP IV for purposes of prong two of the three-prong test, these qualitative benefits may not be considered for purposes of the ESP v. MRO test. Accordingly, NOPEC and OCC/NOAC provide that the Commission's determination of whether the proposed Stipulated ESP IV is more favorable in the aggregate than the MRO rests on a determination of whether the identifiable costs of the ESP are greater than the cost of an MRO. Additionally, as only the items listed in R.C. 4928.143(B) may be included for the Commission's consideration of an ESP, NOPEC also argues that the implementation of Rider GDR should be disallowed since no foreseeable costs to be recovered through this rider have been presented (OCC Ex. 18 at 23). NOPEC also disagrees with the Companies' decision to omit the costs associated with Rider DCR as part of the ESP v. MRO test, noting that OCC/NOPEC witness Kahal demonstrated that the revenues associated with Rider DCR were a quantifiable cost of the ESP and that they should be considered since the "expected results" of R.C. 4928.142 do not contemplate consideration of rate results of a distribution rate case. Power4Schools also contends that only quantitative benefits should be considered, and thus, the Commission should find the ESP to be less favorable than an MRO. P3/EPSA and RESA assert that the Companies have failed to meet their burden to show that the ESP would be more beneficial than an MRO, stating Stipulated ESP IV does not contain an explicit evaluation of this test, and instead, relies on conclusory arguments that this is the case. (Co. Ex. 154 at 18; Co. Ex. 155 at 10-14.)

Order, page 114-116, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (ii) Quantitative Benefits and Analysis

> FirstEnergy claims that the ESP is estimated to be more favorable than the expected results of the MRO by $612.1[221] on a normal basis, or $260 million on a NPV basis (Co. Ex. 155 at 12; Co. Ex. 156 at 4-6). More specifically, and as discussed above, the Companies assert that this quantitative benefit is a combination of the Economic Stability Program as well as economic development and low-income funding. The

[221] The Companies derive this number by adding their projected net benefit attributed to Rider RRS, $561 million, and the additional $51.1 million in quantitative benefits in the form of shareholder funding for economic development, low-income customers, and a customer advisory agency.

Companies elected to omit the costs of Rider DCR m this analysis, posited on the fact that the Companies would utilize a CBP to procure generation under either Stipulated ESP IV or an MRO; thus, there would be no quantifiable difference relating to this pricing between either the two scenarios. Additionally, FirstEnergy reiterates its earlier arguments regarding the quantitative benefits associated with Stipulated ESP IV.

OCC/NOAC argue that the Companies' proposed Stipulated ESP IV is quantitatively more costly to customers than an MRO over its eight-year term, noting that the combined analyses of OCC/NOPEC witnesses Wilson and Kahal demonstrated that the actual cost of the ESP over that of an MRO would range from $3.26 to $3.35 billion (OCC/NOPEC Ex. 11 at 16, 26-27; OCC/NOPEC Ex. 7 at 8). Exelon, RESA, NOPEC, and OMAEG also provide that the only number that should be considered for purposes of this test is the Companies' projected credit arising under Rider RRS, since there is no indication that rate other payments to be paid under Stipulated ESP IV could not otherwise be made under an MRO (Tr. Vol. XIII at 596). While OCC/NOAC initially contends that Rider DCR will not result in a financial "wash," as proffered by FirstEnergy witness Fanelli, OCC/NOAC, NOPEC, and RESA argue the alleged qualitative benefits arising from Rider DCR will not actually accrue to customers and, instead, will cause customers to pay more than they otherwise would be required to pay under a distribution rate case (Co. Ex. 50 at 7; OCC Ex. 18 at 17; OCC/NOPEC Ex. 8 at 30; OCC/NOPEC Ex. 11 at 22-23). Additionally, Exelon states the evidence in the record shows the speculative nature of this projection, while also noting that the Companies failed to conduct, or even consider, a CBP in order to ensure customers pay the least amount for the purported benefits under Rider RRS (Tr. Vol. XXXVl at 7736; Exelon Ex. 4 at 3; Exelon Ex. 1 at 20.) Environmental Groups also state that the Commission lacks any reassurances, such as a competitive procurement or some objective benchmark price, which would allow it to adequately evaluate whether the PPA is just and reasonable or more favorable in the aggregate than an MRO. Based on OCC/NOPEC witness Kahal's analysis, and further supported by Exelon's offer, NOPEC also contends that Rider RRS should be quantified as costing ratepayers $2.97 billion (OCC/NOPEC Ex. 11 at 18). OMAEG notes that while the Companies made changes to its claimed quantitative analysis to account for the shortened eight-year term of Rider RRS and updated ROE of 10.38 percent, they failed to update their energy, capacity, natural gas, and CO2 price forecasts, which were more than 17 months old (Tr. Vol. XXXVI at 7513). OMAEG argues this outdated information cannot be considered reasonable by rate Commission, especially when other parties in this proceeding have provided more recently updated forecasts that allude to an entirely different outlook for consumers (Tr. Vol. XXXVIII at 8118-19; OCC/NOPEC Ex. 9 at 12-13). Additionally, OMAEG asserts that the Companies failed to provide any costs associated with the riders and programs contained in the Third Supplemental Stipulation in their bill impact analyses, even though these provisions may result in significant additional costs to customers who are not eligible for such programs or do not receive the specific benefits (Co. Ex. 154 at 9-15).

Next, FirstEnergy responds to parties' arguments regarding whether Rider DCR should be included in calculation of the quantitative impact. FirstEnergy maintains that Rider DCR does not have a quantitative impact on the ESP v. MRO test, as Commission precedent considers recovery of distribution capital costs through Rider DCR to be equivalent to the recovery of similar costs through a distribution rate case. ESP III Case Order at 56. Further, FirstEnergy responds to parties' arguments that low-income funding commitments should not be counted as a quantitative benefit because similar commitments could be made by the Companies under an MRO. FirstEnergy urges the Commission to reject these arguments on the grounds that whether the Companies theoretically could make such funding commitments under an MRO is irrelevant, as FirstEnergy witness Mikkelsen explained these funding commitments are specifically being made as part of the proposed ESP and would not exist otherwise (Tr. Vol. XXXVI at 77^5-77^6). Additionally, FirstEnergy points out that there is no Commission precedent showing that any such commitments could be required as part of a distribution rate case.

Order, page 116-117, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (a) Summary of the Parties' Arguments / (iii) Qualitative Benefits and Analysis

The Companies further assert that Stipulated ESP IV includes a variety of qualitative benefits, which promote rate stability, economic development, retail competition, customer optionality, grid modernization, resource diversification, low-income customer assistance, continued investment in the delivery system, and system reliability. The Companies have concluded that these benefits would not be available under an MRO. (Co. Ex. 155 at 13, Co. Ex. Co. Ex. 8 at 11; Co. Ex. 50 at 8-9.) As discussed earlier, the Companies state that several provisions previously approved in the ESP III Case will continue to be utilized in Stipulated ESP IV, including the continuation of the base distribution rate freeze, the procurement of non-shopping load through a CBP, the continuation of Riders DCR, ELR, and EDR(h), and the continued support of economic development and low-income programs through various funding initiatives. Additionally, FirstEnergy reiterates its earlier arguments regarding the qualitative benefits evaluated above in the traditional three-prong test.

Though many parties have argued that qualitative benefits should not even be considered for purposes of the ESP v. MRO test, they also argue that in the event the Commission could or would consider them, they would be significantly outweighed by the quantifiable costs attributable to Stipulated ESP IV. P3/EPSA, Power4Schools, and RESA indicated taat there has been an overreliance on the qualitative benefits to shadow the fact that the quantitative benefits will likely not accrue to the Companies' customers (Tr. Vol. XXXVl 7736-37). NOPEC and Power4Schools also state that even if the Commission was statutorily authorized to consider qualitative factors during its evaluation of the MRO v. ESP test, it would be unlawful to consider qualitative factors that fall outside of the provisions oi R.C. 4928.143(B) and unreasonable for such qualitative benefits, such as benefits furthering the state policies codified in R.C 4928.02 or the benefits of proposed Riders DCR and GDR, to supersede the quantitative analysis required by R.C 4928.143(C)(1). Furthermore, OMAEG, OCC, NOAC, and Power4Schools assert tae Companies have failed to show that the qualitative benefits of Stipulated ESP IV are more favorable than an MRO, initially noting that the projected costs of Rider RRS during the eight-year term outweigh any claimed benefits, such as rate stability or reliable electric service (OCC/NOPEC Ex. 4 at 49-52; OCC/NOPEC Ex. 8 at 8). Specifically, OMAEG contends that the costs attributed to Rider RRS would greatly outweigh any incremental annual rate increase customers would experience otherwise, while adding that there would be no change in reliability if the Plants and OVEC entitlement units were to continue to operate as they do today but such a decision might have significant opportunity costs such as foregone new generation construction (OCC/NOPEC Ex. 9 at 12; Tr. Vol. XIII at 2797-99). In addition, OMAEG argues that the projected economic development benefits are flawed and the Companies' analysis fails to accurately reflect the impact of Rider RRS on the costs to customers and the resulting economic development in this region, noting that the Companies should not be able to claim these projected benefits if they cannot definitively state that the Plants and OVEC entitlement units are currently operating economically (Co. Ex. 141 at 6; OCC/NOPEC Ex. 11 at 20-21). OMAEG concludes by arguing that while the Companies assert the provisions contained in Stipulated ESP IV will provide additional qualitative benefits, these provisions will only benefit a handful of customers to the detriment of the majority. In addition, many parties reiterated their concerns regarding the various purported benefits in the second prong analysis of the traditional three-prong test.

Order, page 119, E Consideration of Stipulated ESP IV/ 3- Does the settlement package violate any important regulatory principle or practice? / (b) Commission Conclusion

With respect to whether Rider DCR should be included in the quantitative analysis, the Commission previously has determined that Rider DCR allows the Companies to earn a return on and of plant in service associated with distribution, subttansmission, and general and intangible plant which was not included in the rate base of the Companies' last distribution rate case. Pursuant to R.C 4909.15, the Commission is required to determine, in a distribution rate case, the valuation, as of the date certain, of property used and useful in rendering public utility service. Thus, we concluded that, to the extent that the Companies have made capital investments since the last distribution rate case, those investments will be recovered to an equal extent, through either Rider DCR or through distribution rates, provided that the property is used and useful in the provision of distribution service. Accordingly, over the long term, the Companies will recover the equivalent of the same costs, and, for purposes of the ESP v. MRO Test, the costs of Rider DCR and the costs of a potential distribution rate case should be considered substantially equal and removed from the ESP v. MRO analysis. ESP III Case, Opinion and Order (Jul. 18, 2013) at 55-56; Entry on Rehearing (Jan 30, 2013) at 22-23.

Appendix B: Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report.

ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used during Construction
AMI Rider	Advanced Metering Infrastructure (Smart Grid) Rider
ARO	Asset Retirement Obligation
ATSI	American Transmission Systems, Inc.
CAT	Commercial Activity Tax
CE, CEI, or CECO	Cleveland Electric Illuminating Company, The
CIAC	Contributions in Aid of Construction
CPR	Continuing Property Records
CREWS	Customer Request Work Scheduling System
CWIP	Construction Work in Progress
DCR	Delivery Capital Recovery Rider
DSI Rider	Delivery Service Improvement Rider
DTL	Deferred Tax Liability
EDR Rider	Economic Development Rider
ESP	Electric Security Plan
FE or FECO	FirstEnergy Service Company
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
IT	Information Technology
LEX Rider	Line Extension Recovery
LOSA	Level of Signature Authority
MRO	Market Rate Offer
OE or OECO	Ohio Edison Company
PUCO	Public Utilities Commission of Ohio
RFP	Request for Proposal
RWIP	Retirement Work in Progress
TE or TECO	Toledo Edison Company, The
TCJA	Tax Cuts and Jobs Act
SEET	Significantly Excessive Earnings Test
SSO	Standard Service Offer
WBS	Work Breakdown Structure

APPENDIX C: DATA REQUESTS AND INFORMATION PROVIDED

The following is a list of the data requests submitted by Blue Ridge to FirstEnergy. Responses were provided electronically and are available on a confidential CD.

Note: Due to size, some requests have been abridged. The full request is available in the electronic workpapers.

REQUEST #	REQUEST
FE-01.01	Priority Data Request - DCR Filings: For each company, please provide the workpapers and documents that support the information included within the December 31, 2017, Rider DCR Compliance Filing. Please provide the source data in its original electronic format.
FE-01.02	Priority Data Request - Workorders: For each company and the Service Company, please provide in a Microsoft Excel spreadsheet a list of work orders by FERC account for 12/1/16 through 11/30/17. Include the description, dollar amount, completion date, and whether the work was an addition or replacement.
FE-01.03	Priority Organization Charts: For each company and the Service Company, please provide a current organizational chart.
FE-01.04	Priority Organization Chart: Please confirm that the following individuals were in the same positions for 2017. Please identify any changes.
FE-01.05	Workorders: Please provide a list of work orders by FERC account used for the following types of work in December 2016 and January through November 2017: a. Generation b. AMI c. EDR d. LEX e. Annual blanket/program work orders (include any work that is a carryover from prior years) f. IT g. Storms h. Joint-owned facilities
FE-01.06	Workorder: Please provide a reconciliation of the list of workorders provided in Data Request 1.2 to the amounts included in the December 31, 2017, DCR filing.
FE-01.07	FERC Form 1 Reconciliations: Please provide a reconciliation of the Rider DCR balances to the balances in the 2017 FERC Form 1.
FE-01.08	DCR Filing: Please provide the workpaper that calculates the DCR revenue requirement impact from the 2016 audit.
FE-01.09	Budget: Please provide the 2017 budget supporting the 2017 Compliance Filings. Also, please include the assumptions supporting the budget/projected data.
FE-01.10	Budget: Please provide the total actual capital dollars spent and the approved budget by operating company, and by functional area (i.e., Transmission, Distribution, General, and Other Plant) for 2017.
FE-01.11	Status of 2016 Recommendations: Please provide a narrative on how the companies have addressed the recommendations listed on pages 19–20 in Blue Ridge's Compliance Audit of the 2016 DCR Riders dated May 1, 2017.
FE-01.12	Status of 2016 Recommendations: PUCO's Initial Comments in Case No. 16-2041-EL-RDR recommended that Toledo Edison review the real property tax rate and verify the rate's decline. Staff also requested that FirstEnergy provide its review, including supporting documentation, to Staff no later than December 31, 2017. Please provide a copy of the review and supporting documentation.
FE-01.13	DCR Filings: Please provide a narrative of any changes made to the development process of the 2017 Rider DCR Compliance Filings and schedules from the development process of the 2017 DCR Compliance Filing and schedules.

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FE-01.14	Policies and Procedures: For each company and the Service Company, please provide any changes for 2017 to the policies and procedures for the following activities. a. Plant Accounting i. Capitalization, including additions to retirement units of property. ii. Preparation and approval of work orders iii. Recording of CWIP including the systems that feed the CWIP trial balance iv. Application of AFUDC v. Recording and Closing of additions, retirements, cost of removal, and salvage in plant vi. Unitization process based on the retirements unit catalog vii. Application of depreciation viii. Contributions in Aid of Construction (CIAC) b. Purchasing/Procurement c. Accounts Payable/Disbursements d. Accounting/Journal Entries e. Payroll (direct charged and allocated to plant) f. Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax) g. Insurance Recovery h. Property Taxes i. Service Company Allocations j. Budgeting/Projections k. IT projects
FE-01.15	Policies and Procedures: Please specifically explain any changes that have been made in capitalization polices that would transfer costs from operating expenses to capital.
FE-01.16	Internal Audits: For each company and the Service Company, please provide a list of Internal Audits completed or in-progress for 2017. List the name of the audit, scope, objective, and when the work was performed.
FE-01.17	SOX Compliance Audits: For each company and the Service Company, please provide a list of SOX compliance work completed or in-progress during 2017. List the name of the audit, scope, objective, and when the work was performed.
FE-01.18	Variance Analysis: For each company, please provide in a Microsoft Excel spreadsheet in FERC Form 1 format the beginning and ending period balance by primary plant (300 account and sub account), additions, retirements, transfers, and adjustments for 12/1/16 through 11/30/17.
FE-01.19	Variance Analysis: For each company, please provide in a Microsoft Excel spreadsheet the beginning and ending period balance for jurisdictional accumulated reserve for depreciation balances by FERC 300 account for 12/1/16 through 11/30/17.
FE-01.20	Variance Analysis: For each company and the Service Company, please provide in a Microsoft Excel spreadsheet beginning and ending period balance of Construction Work in Progress (CWIP) for 12/1/16 through 11/30/17. If the CWIP balances for any of the Companies or the Service Company have increased from 12/1/16 to 11/30/17, please provide a narrative and any support documentation explaining the increase.
FE-01.21	Replacement Programs: Did the companies have any large construction and/or replacement programs in 2017, such as pole replacement, meters, underground line, etc? If so, please identify the program, company, and work orders associated with the program.
FE-01.22	Insurance Recoveries: For each company and the Service Company, please provide a list of any insurance recoveries charged to capital from 12/1/16 through 12/31/17.
FE-01.23	Insurance Recoveries: For each company and the Service Company, please provide a list and explanation of any 2017 pending insurance recoveries not recorded or accrued that would be charged to capital. Indicate the type of recovery, estimated amount, and when receipt is expected.

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FE-01.24	Depreciation: For each company and the Service Company, please provide the approved depreciation accrual rates by FERC 300 account from 12/1/16 through 11/30/17. Note any changes in rates during the year. Please provide the Commission order that approved the rates for each company and the Service Company.
FE-01.25	Depreciation: Does any company use a depreciation rate for any 300 sub-account that has not been approved by the Commission? If so, please provide the following for any changes made in 2017: a. FERC 300 account, sub account and company b. Depreciation accrual rate used c. Analysis supporting the use of the accrual rate d. Effective date of the rate e. Any filings with the commission for approval
FE-01.26	Property Tax Rates: Please provide the supporting documents and calculation for the tax rates used to calculate the actual 11/30/17 and estimated 2/28/18 Rider DCR Revenue Requirement.
FE-01.27	Approval Signatures: Please provide the level of signature authority (LOSA) document that supports the approval of capital projects put in service from 12/1/16 through 11/30/17.
FE-01.28	Exclusions: Please provide the supporting documentation for the amounts associated with the ATSI Land Lease for actual 11/30/17 and estimated 2/28/18.
FE-01.29	Excluded Riders: Please provide the supporting documentation for the amounts excluded from CEI for Rider AMI for actual 11/30/17 and estimate 2/28/18.
FE-01.30	Excluded Riders: Please provide the supporting documentation for the amounts excluded for EDR(g).
FE-01.31	Unitization Backlog: Please provide by company information regarding the backlog in the unitization of workorders for 2017. Please provide the number of workorders and the length of time in months by functional area (i.e., Distribution, Transmission, General, and Other).
FE-01.32	Unitization Backlog: Please provide the dollar value of the workorder backlog, by operating company and by workorder classification (distribution, transmission, and general/other).
FE-01.33	Tax Rates: Please provide the supporting documentation and calculations for the tax rate used for Actual 11/30/17 and Estimated 2/28/18.
FE-01.34	Tax Rates: Please explain how the Company will incorporate the changes in the recently passed tax overhaul bill. For example, the reduction in the corporate tax rate from 35% to 21%.
FE-01.35	ADIT: The Tax Increase Prevention Act of 2014 extended the 50% bonus tax depreciation for qualified property placed into service before January 1, 2016. The Protecting Americans from Tax Hikes Act of 2015, further extended the 50% bonus tax depreciation for qualified property placed in service during 2016, 2017, and 2018. Please provide an explanation on how these tax provisions that extended 50% bonus tax depreciation for qualified property placed into service were recognized in the determination of ADIT in the Companies' Rider DCR filing.
FE-01.36	Other Riders: a. Has the Company requested and received Commission approval for any other riders than those in the following list? b. For any new Commission approved riders, please provide an explanation and associated calculations on how the new rider is calculated. c. Please confirm that no cost recovered through the following riders has capital additions included within the Rider DCR.
FE-02.01	Variance Analysis: Follow-up to Data Request 1-INT-18, Attachment 1 - Confidential—Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following plant accounts: a. CEI Account 364 Poles, towers, and fixtures—Adjustments of $360,482

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	b. CEI Account 365 Overhead conductors, devices—Adjustments of $299,953 c. CEI Account 367 Underground conductors, devices—Adjustments of $426,079 d. CEI Account 368 Line transformers—Adjustments of $174,677 e. CEI Account 370 Meters—Adjustments of $1,315,955 f. CEI Account 394 Tools, shop, garage equipment—Adjustments of $1,517,147 g. CEI Account 397 Communication equipment—Additions of 8,861,041 h. CEI Account 303 Misc intangible plant—Additions of $6,608,631 i. OE Account 362 Station equipment—Adjustments of $359,534 j. OE Account 368 Line transformers—Negative Adjustments of $522,445 k. OE Account 390 Structures and improvements—Negative Additions of $647,060 and Negative Adjustments of $2,163,697 l. OE Account 392 Transportation equipment—Additions of $607,234 m. OE Account 397 Communication equipment—Additions of $13,625,363 n. OE Account 303 Misc intangible plant—Additions of $9,690,408 o. TE Account 392 Transportation equipment—Additions of $183,616 p. TE Account 397 Communication equipment—Additions of $1,084,281 q. TE Account 303 Misc intangible plant—Additions of $2,191,966 r. FESC Account 390 Structures and improvements—Additions of $2,679,747 (with no retirements) and Adjustments of $2,157,227 s. FESC Account 391 Office furniture, equipment—Additions of $19,618,396 and Retirements of $16,268,728 t. FESC Account 392 Transportation equipment—Additions of $425,502 u. FESC Account 397 Communication equipment—Additions of $10,070,553 v. FESC Account 303 Misc intangible plant—Additions of $32,370,033
FE-02.02	Variance Analysis: Follow-up to Data Request 1-INT-19, Attachment 1 - Confidential—Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following reserve accounts: a. OE Account 360 Land & Land Rights—Balance of $9,193: Why does this land account have a reserve since land is not depreciable? b. OE Account 389 Land & Land Rights—Balance of $(74,752): Why does this land account have a reserve since land is not depreciable? c. OE Account 369 Services—reduction in reserve of $1,200,141 d. OE Account 370 Meters—reduction in reserve of $4,188,312 e. OE Account 373 Street Lighting and Signal Systems—reduction in reserve of $1,333,175 f. TE Account 370 Meters—reduction in reserve of $498,467 g. TE Account 390 Structures and improvements—reduction in reserve of $1,092,056
FE-03.01	Priority Data Request - For the attached work order list (BRC Set 3 - 2017 Workorders SAMPLE Confidential.xlsx), please provide the following information in Microsoft Excel spreadsheets. a. A work order sample summary. i. The individual work order or project approval, written project justification, including quantification of efficiency and cost savings, present value analysis, and/or internal rate of return calculations for projects other than annually budgeted work orders. ii. The individual work order or project estimated and actual in-service dates with explanations for delays > 90 days. iii. The individual work order or project, budget vs. actual costs, with explanations for cost variances +/- 15%. iv. If the information in a i-a iii cannot be provided individually please provide the information requested in item b. below. b. A report at a project level with a reference to the sample workorder that includes i. Approval

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	ii. Project justification iii. Budget and actual costs with explanation for cost variances +/- 15% iv. Estimated and actual in-service dates with explanation for delays > 90 days. c. Estimates for cost of construction, (material, labor), AFUDC, overheads, retirements, cost of removal, salvage and CIAC's. d. Supporting detail for assets (units and dollars by FERC account for all FERC accounts within the workorder) added to utility plant from the Power Plant system. e. Supporting detail for retirements, cost of removal and salvage, if applicable, charged or credited to plant (units and dollars) for replacement workorders from the Power Plant system. f. An updated list of cost elements g. Cost element detail that shows the individual workorder, FERC account, and amount as selected in the sample. Considering that a workorder may consist of more than one FERC account, the cost element detail can also include other WBS or Projects as long as the individual FERC account charge selected in the sample is visible.
FE-04.01	SOX Audits: Follow up to Data Request BRC Set 1-INT-017, attachment 1 and attachment 2: For the following SOX audits, please provide a summary of any significant control deficiencies, along with how those deficiencies were corrected or mitigated. a. Property Accounting: All Control ID's. (Attachment 2) b. FEU Accounting policy and services: All Control ID's. (Attachment 1).
FE-04.02	Internal Audits: Follow up to Data Request response BRC Set 1-INT-016, Attachment 1: For the following audits, please provide the executive summary of findings and recommendations. a. Audit of the Distribution Portfolio Planning Process b. Sarbanes-Oxley 404 Assessment of Internal Controls over Financial Reporting: Sox Controls for the period of 01/01/2016 to 12/31/2016 c. 2016 SOX Annual Progress Report: 2016 SOx Program d. Audit of Accounts Payable for the Year Ended December 31, 2016 e. Fleet Investment Strategy Review f. 2016 GRC ARA Ruleset Review Amended Memo g. FirstEnergy Utilities Major Storm Back Office Review Process h. 2017 First Quarter Sarbanes-Oxley Assessment of Internal Controls over Financial Reporting i. PowerPlan Upgrade - Go No Go Decisions Support j. 2016 Governance Risk & Compliance Segregation of Duties Access Risk Analysis Risk Assessment k. FirstEnergy Utilities Mutual Assistance Billing and Invoice Process l. PowerPlan Pre-Implementation Audit m. 2017 Second Quarter Sarbanes-Oxley Assessment of Internal Controls over Financial reporting n. Contractor Information Management System Audit o. 2017 Third Quarter Sarbanes-Oxley Assessment of Internal Controls over Financial Reporting p. Revenew's Payment Recovery Audit for Accounts Payable q. Audit of Capital and Operation & Maintenance Expenses, r. Consulting Services on North American Reliability, Corporation Risk-Based Internal Controls Program and Governance structure - Phase 1
FE-05.01	**FTCJA:** Does the January 12, 2018, submission ("replacement filing") include any other changes than the impact of the Federal Tax Cuts and Jobs Act (FTCJA)? Please walkthrough the updated elements.

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FE-05.02	**FTCJA:** Why did the consolidated revenue requirement on estimated rate base additions increase by $39 million relative to the January 2, 2018, submission ("original filing") given that the federal income tax rate declined from 35% to 21%? Does FE consider the direction and magnitude of the change to be reasonable?
FE-05.03	**FTCJA:** Does the replacement filing represent FE's position as to the proper accounting and ratemaking treatment for the FTJCA? If no, please explain what other adjustments should be made to reflect the full impact of the FTJCA on the DCR and/or on other components of the companies' rates/tariffs?
FE-05.04	**FTCJA:** The change in the law requires recalculation of deferred tax liabilities leading to excess deferred tax reserves after a federal income tax rate reduction. How will FE account for excess deferred taxes from a taxation, financial reporting and from a ratemaking perspective?
FE-05.05	**FTCJA:** Please explain FE reasoning for excluding the impact of excess deferred taxes reserve and any potential reduction in the revenue requirement in the replacement filing?
FE-05.06	**FTCJA:** Does the replacement filing, which does not reflect a regulatory liability for excess deferred taxes in rate base, represent the position that it should be excluded?
FE-05.07	**FTCJA:** What technical guidance, regulatory precedent or tax authority did FE rely upon to support its treatment of the FTCJA in the replacement filing? Please cite and provide supporting documents, analysis and advice from outside experts.
FE-05.08	**FTCJA:** What method will FE employ in recalculating the value of its deferred tax balances in its accounting system? Please cite any relevant paragraphs in the law or tax code.
FE-05.09	**Jobbing and Contracting Activities** Please explain how the companies account for Jobbing and Contracting activities associated with Special Customer Services for non-regulated activities and for regulated activities.
FE-05.10	Jobbing and Contracting Activities For Jobbing and Contracting costs related to the regulated utilities and/or captured for the benefit of an unregulated company, please provide the following information: a. Please explain what specific controls are in place to ensure that those costs do not become part of the Rider DCR or any other Rider. b. Please provide a copy of the specific settlement rules that move all the expenses on the work order to FERC 416 (Costs and expenses of merchandising, jobbing, and contract work). c. Please provide the detailed FERC accounting (debits/credits) for the following: i. Accumulation of Jobbing and Contracting costs ii. Billing of Jobbing and Contracting costs iii. Recording the difference between the estimated and actual cost for Jobbing and Contracting costs iv. Recording the receipt of monies for Jobbing and Contracting
FE-05.11	**Jobbing and Contracting Activities** Please provide a list of all work orders used to accumulated Jobbing and Contracting activities.
FE-05.12	**Mutual Aid:** Please explain, if different from jobbing and contracting work, how mutual aid costs are accumulated and billed.
FE-05.13	**Jobbing and Contracting Activities** Please explain if net revenues from regulated jobbing and contracting costs benefit Rider DCR and, if so, why and, if not, why not?
FE-05.14	**Jobbing and Contracting Activities:** Are any jobbing and contracting costs ever associated with work that ends up as Utility Plant in Service? If so, please explain in detail how that happens and also provide the associated accounting.
FE-06.01	**Depreciation**: Schedules B-3.2 (Actual). Please explain why some accounts have negative net plant balances? For example, see CEI Account No. 354, Towers & Fixtures.
FE-06.02	**Depreciation**: Schedules B-3.2 (Actual). Column G calculates depreciation expense for each plant account, including those with negative or zero net plant balances. Please explain if or why depreciation in excess of total cost should be recovered in revenue requirements.

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FE-06.03	**Depreciation**: Schedules B-3.2 (Actual). Column G calculates 12 months of depreciation expense for each plant account. Please explain if or why it is appropriate to recover 12 months of depreciation expense when the total remaining plant cost is less. For example, see CEI Account No. 391.1, Office Furniture & Equipment.
FE-07.01	Priority Data Request - For the below two workorders please provide the following information in Microsoft Excel spreadsheets. Company FERC Work Order Work Oder Description Type In Service Activity OECO 303 OE-700386 IT GIS Upgrade Addition 10/5/17 $1,440,497 FECO 397 XIT-000066-1 Telecommunication Transformation Initiat Addition Blanket $2,367,666 a. A work order sample summary. i. The individual work order or project approval, written project justification, including quantification of efficiency and cost savings, present value analysis, and/or internal rate of return calculations for projects other than annually budgeted work orders. ii. The individual work order or project estimated and actual in-service dates with explanations for delays > 90 days. iii. The individual work order or project, budget vs. actual costs, with explanations for cost variances +/- 15%. iv. If the information in a i-a iii cannot be provided individually please provide the information requested in item b. below. b. A report at a project level with a reference to the sample workorder that includes i. Approval ii. Project justification iii. Budget and actual costs with explanation for cost variances +/- 15% iv. Estimated and actual in-service dates with explanation for delays > 90 days. c. Estimates for cost of construction, (material, labor), AFUDC, overheads, retirements, cost of removal, salvage and CIAC's. d. Supporting detail for assets (units and dollars by FERC account for all FERC accounts within the workorder) added to utility plant from the Power Plant system. e. Supporting detail for retirements, cost of removal and salvage, if applicable, charged or credited to plant (units and dollars) for replacement workorders from the Power Plant system. f. An updated list of cost elements g. Cost element detail that shows the individual workorder, FERC account, and amount as selected in the sample. Considering that a workorder may consist of more than one FERC account, the cost element detail can also include other WBS or Projects as long as the individual FERC account charge selected in the sample is visible.
FE-07.02	Variance Analysis: Follow-up to Data Request BRC Set 2-INT-2, a: The Company response indicated the reserve balance in FERC 360 is associated with salvage, and when the transaction is closed, the balance will be removed from the reserve. a. Please explain what created the salvage and why the salvage would be charged to a reserve account since land is not depreciated and, therefore, should not have a reserve. b. When the transaction is closed, to which account will the $9,193 in the reserve be moved?
FE-07.03	Variance Analysis: Follow-up to Data Request BRC Set 2-INT-2, b: The Company explanation indicated that the reserve balance is associated with a retirement recorded to the reserve. Please explain what was retired and why the $74,752 would be charged to a reserve account for Land and Land Rights since land is not depreciable and, therefore, should not have a reserve.
FE-07.04	Variance Analysis: Follow up to Data Request BRC Set 2-INT-2, g: The Company response indicated that part of the reason for the change in the reserve balance for FERC 390 was $364,467 in impairments.

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	a. Please explain what assets were impaired and why. b. How would the accounting for an impaired asset affect the reserve for depreciation?
FE-07.05	**Variance Analysis**: Follow-up to Data Request BRC Set 2-INT-1, a through f: The Company response indicated that amounts had been originally charged to 394 before being transferred. Please clarify as to why the amounts were originally charged to account 394.
FE-07.06	**Variance Analysis**: Follow-up to Data Request BRC Set 2-INT-1, i: The Company response indicates spares were transferred from ATSI to Plant. Please explain the reason for these transfers.
FE-08-01	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended November 30, 2017. Please explain the process by which Schedule M items are functionalized, allocated and/or assigned to the Ohio Rider DCR. Also, provide supporting workpapers tracing total ADIT by FERC account to amounts reflected in Attachment 8.
FE-08-02	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended November 30, 2017. Please describe each Schedule M item summarized below. How does each relate to Plant in Service and why should it be reflected in the Ohio Rider DCR?
FE-08-03	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended November 30, 2017. The following Schedule M items under the Ohio and Toledo EDU's appear to be in connection with another jurisdiction—Pennsylvania. Why should they be reflected in the revenue calculation for the Ohio Rider DCR?
FE-08-04	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended November 30, 2017. The following Schedule M items summarized below in relation to the Service Company contain amounts associated with other jurisdictions. Why should amounts for DC, MD, NJ, PA and WV be reflected in the revenue calculation for the Ohio Rider DCR?
FE-08-05	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended November 30, 2017. The ATSI Land Lease is listed in the Company's filing under "Exclusions per Case No. 14-1297-EL-SSO". Should the corresponding deferred tax balance be reflected in the Ohio Rider DCR? If no, please calculate the impact on revenue requirements.
FE-08-06	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended February 28, 2018. Please describe the method by which the projected ADIT balances were developed (prior to the adjustment for the Federal income tax rate change).
FE-08-07	ADIT. Reference Set 1-INT-001, Attachment 8, for the period ended February 28, 2018. Please describe the following Schedule M item summarized below. How was it functionalized, allocated and/or assigned to the Ohio Rider DCR?
FE-09.01	Follow-up to Data Request 3-1 and Data Request 1-27. Please provide a list of who approved each workorder in the sample along with the approver's job title.
FE-09.02	Follow-up to Data Request 3-1, attachment 3 – Cost Details. Please explain what is included under the caption "Other Company Overheads" in attachment 3 Column L.
FE-09.03	Follow-up to Data Request 3-1, attachment 3 – Cost Details - CECO work order CE-900186-VMPL-DIST. Please explain what "36510 - Clearing, Grading of Land" represents (e.g., new construction, expansion of existing construction, or other).
FE-09.04	Follow-up to Data Request 3-1, attachment 3 – Cost Details and attachment 4 – Retirements. Please explain how the Company differentiates clearing and grading of land that is a capital activity vs. O&M activity.
FE-09.05	Follow-up to Data Request 3-1, attachment 3 – Cost Details - OECO work order 14434236 - OE Implement New Mobile Radio System. Please explain why M&S was approximately 50% of the total cost.
FE-09.06	Follow-up to Data Request 3-1, attachment 3 – Cost Details - OECO work Order IF-SC-000144-1. - SvcCo 0 Rpl MR-24 Roof. Please explain what created the credit of $(1,063,869).
FE-09.07	Follow-up to Data Request 3-1, attachment 3 – Cost Details - CECO Work Order 14434161-CE Implement new Mobile Radio System. - $5,972,286. Please provide a list by vendor

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	and/or type of charge for the $1,031,182.88 included in attachment 3 in column entitled Other Company Overheads.
FE-09.08	Follow-up to Data Request 3-1, attachment 3 – Cost Details. For the following three workorders, please explain why Other Company Overheads were over 50% of the activity costs:
FE-09.09	Follow-up to Data Request 3-1, attachment 3 – Cost Details and attachment 1 - TECO Work Order TW-750179 – IT OPS Vehicle Replacement for TE - $183,631. Based on the single line description and account charged (FERC 362 – Transportation Equipment) this appears to be vehicle replacement. Please explain why $158,385 was charged to stock materials.
FE-09.10	Follow-up to Data Request 3-1, attachment 3 – Cost Details. Please provide the cost detail that supports 100% charges to Other Direct Costs for the following two work orders:
FE-09.11	Follow-up to Data Request 3-1, Attachment 1 – variances (confidential) CECO work Order CE-900186-VMPL-DIST – Total Project. The explanation for the work order indicates in part that the planned vegetation management was as follows: "This program covers distribution circuit vegetation management beyond the normal CEI tree trimming budget and will encompass the planned removal of overhanging branches and off corridor trees, both of which may be capitalized. / Includes ALL contractor dollars. (157 miles of Subtransmission clearing; 2,161 miles of Distribution clearing.)" a. Please explain why the Company considers the removal of overhanging branches without replacement of pole, wire, or transformer to be considered capital and not normal O&M in accordance with FERC accounting guidelines. b. Please indicate how much of the $8,070,533 spent on this activity is for removal of overhanging branches.
FE-09.12	Follow-up to Data Request 3-1, Attachment 1 – variances (confidential) TECO Work Order TW-9000186-VMPL-DIST – Total Project. The explanation for the work order indicates that "Prevention of tree contact with overhead conductors, saving the corporation money and providing customers with uninterrupted service." Please explain why this activity is categorized as capital and not O&M in accordance with FERC accounting guidelines.
FE-09.13	Follow up to Data Request 3-1, Attachment 1 – variances (confidential) - OECO Work Order OE-9000186-VMPL-DIST – Total Project. The explanation for the work order indicates it is for "Prevention of tree contact with overhead conductors, saving the corporation money and providing customers with uninterrupted service." Please explain why this activity is categorized as capital and not O&M in accordance with FERC accounting guidelines.
FE-09.14	Follow-up to Data Request 3-1, Attachment 1 – variances (confidential) - OECO Work Order IF-SC-000144-1 is a transfer of project cost to FECO work order IF-SC-000261 for the construction of Building O at the FECO call center. Please provide the same detailed information for the IF-SC-000261 as requested in BRC-Set 3-INT-1 for IF-SC-000144-1.
FE-09.15	Reference Company response to Data Request 3-1, attachment 1. (Confidential) - OECO Work Order 15293882 - PUCO UNSCHEDULED FIELD AUDIT FINDING was over budget by 91% or $36,112,213. The Company explained the reason or the overrun was "PUCO UNSCHEDULED FIELD AUDIT FINDING." Please explain in detail the nature of the audit finding and if there were other findings that had an impact on the DCR in 2017. .
FE-09.16	Reference Company response to Data Request 3-1, attachment 1. (Confidential) - OECO Work Order PA88740150 – PW FW: 389N-25-1638 Footville Richmond R. was over budget by 347.3% or approximately $9,827,037.05. The explanation for the variance: "Variance is driven by a budget issue in 2017 where blanket expenditures were not appropriately allocated across normal work types. Although we are seeing large variances in individual blanket categories, in total, blanket spend was 5% less than budget for the year." a. Please explain in more detail what blanket expenditures were not allocated across normal work types. Where were they allocated, and what caused the blanket expenditures to be allocated incorrectly?

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	b. Did any of the errors impact other operating companies? If so, provide an explanation of how. c. Please explain in more detail how the company arrived at the conclusion that blanket spending was 5% less than budget for the year. d. Would the blanket spend variance of 5% been greater if the expenditures were properly allocated? If so, by how much?
FE-09.17	Follow up to Data Request 3-1, Attachment – variances (confidential). The following two work orders were delayed, and the Company did not provide an explanation for the delay in the attachment. Please provide an explanation for the delays.
FE-09.18	Follow up to Data Request 3-1, Attachment 2 – variances (confidential) - CECO work order CE-700418 - IT 2016 EMS Upgrade/Patch Project. The in-service date of this work order was 5/18/2017 and the need date was 3/3/2017. The Company indicates that this project was completed on schedule. However according to the dates there was a 66-day delay. Please explain why the project was completed 66 days later than originally needed, yet it was considered to be completed on schedule.
FE-09.19	Follow-up to Data Request BRC Set 1-INT-14 c: The Company response indicates two changes to employee expense accounts regarding (1) donations and charitable contributions and (2) professional dues and memberships. Please confirm that the changes will not impact the DCR either through direct charges to capital or through an allocation. If that cannot be confirmed, please indicate how the changes will impact the DCR.
FE-09.20	Reference Service Co. Actual Depreciation Rate Schedule Please explain why dollars for 2018 are included in the 11/30/17 Actual balance. [Line 61 FECO 101/6-303 2018 Software].
FE-09.21	Reference Service Co. Actual Depreciation Rate Schedule: Please confirm that Account 304 shown in column (A), lines 60, 60, 61, and 62 is a misstatement and that the account should be 303. If not, please provide a description of Account 304 and provide the approval for the 14.29% depreciation accrual rate used for Account 304.
FE-09.22	Reference Service Co. Estimated Depreciation Rate Schedule: Please confirm that Account 304 shown in column (A), lines 61 and Account 305 on line 62 is a misstatement and that the account should be 303. If not, please provide a description of Account 304 and Account 305 and provide the approval for the 14.29% depreciation accrual rate used for both accounts.
FE-09.23	ADIT. Reference Set 1-INT-001, Attachment 8. Please provide a list of the ADIT with descriptions and amounts that were approved in Case No. 07-551-EL-AIR.
FE-10.01	FIELD VISITS: As a continuation of the audit process, we have selected certain work orders/projects for field verification from the work order sample. The purpose of the field verification is to determine whether the assets have been installed per the work order scope and description. The work order/project selection criteria primarily identified assets that can be physically seen. Experienced representatives from the Ohio PUC Staff will conduct the field verifications. To assist Staff in that endeavor, please provide or have available the following personnel and items: a. An individual(s) who can coordinate all the field verification with Staff b. Representatives from FE who can field assist Staff at each field location c. The Project Manager or a person who was responsible for the work on each project, available to answer Staff's questions d. Schematics, drawings, or any other visual diagrams that indicate what was built or installed e. A list of material and/or equipment installed, along with any applicable serial numbers f. Work Order cost data for direct cost (i.e., labor, material, equipment) If FE has questions about the selection, or any other requirement, please contact Joe Freedman via e-mail at jfreedman@blueridgecs.com or by phone at 607-280-3737 Cleveland Electric:

REQUEST #	REQUEST
	1) Work Order: 13857618 - CES-MOBILE SUB - 3 CEI (capital project) In-Service Date: 5/31/2017 RPA: NOH-11-110225-143554 Net Amount: $383,707.00 2) Work Order: 14697805 - "HP" 138-13kV Mod Sub - Region In-Service Date: 5/17/2017 RPA: CE-15-150129-092900 Net Amount: $1,919,715.00 3) Work Order: 14877367 - New OH Dist for New Harper Mod-Sub In-Service Date: 9/20/2017 RPA: CE-15-150129-092900 Net Amount: $697,287.00 Ohio Edison: 4) Work Order: 14777209 - Mod Sub In-Service Date: 8/23/2017 RPA: SOH-10-071211-073204 Net Amount: $3,066,823.00
FE-10.02	Follow up to Data Request 3-1, attachment 1, CECO work order 14434161 – CE Implement new mobile radio system. The Company has indicated that this work order represents an emergent project for $5,972,286, but it does not provide any justification for the project. a. Please provide the justification for this project, including why the project became an emergent project and was, therefore, not in the original capital budget plan. b. Did this project replace an equivalent dollar value project(s) in the capital budget, or was it added to the capital budget?
FE-10.03	Follow up to Data Request 3-1, attachment 1, OECO work order 14434236 – OE Implement new mobile radio system. The Company has indicated that this work order represents an emergent project for $6,834,326, but it does not provide any justification for the project. a. Please provide the justification for this project, including why the project became an emergent project and was, therefore, not in the original capital budget plan. b. Did this project replace an equivalent dollar value project(s) in the capital budget, or was it added to the capital budget?
FE-10.04	Follow up to Data Request 3-1, attachment 1, OECO work order 15037327 69KV. The Company has indicated that this work order represents an emergent project for $266,577, but it does not provide any justification for the project. a. Please provide the justification for this project, including why the project became an emergent project and was, therefore, not in the original capital budget plan. b. Did this project replace an equivalent dollar value project(s) in the capital budget, or was it added to the capital budget?
FE-10.05	Follow up to Data Request 3-1, attachment 1, OECO work order 14777209 –Mod Sub, for $3,066,823. The Company indicates in the project description the land for the substation was purchased in 2010 and the below grade work commenced in 2016. a. What was the cost of the land? b. When the land was purchased in 2010, in what FERC account was it recorded? c. If the cost of the land purchased in 2010 resided in Plant Held for Future Use (FERC 105), please indicate when the land was transferred to Utility Plant in Service (FERC 101) or CWIP (FERC 107). d. If the cost of the land purchased in 2010 resided in Utility Plant In Service (FERC 101), please explain why.

REQUEST #	REQUEST
FE-10.06	Follow up to Data Request 3-1, attachment 4 – retirements and attachment – 4 - Retirements and 5 – Cost of Removal. The following work orders appear to be replacement work and do not have any retirements or cost of removal recorded. Please explain why. a. CECO Work Order 15195180 - Equip Replacement - Transformer Oil b. CECO Work Order 15010905 – Equipment Replacement - PT c. TECO Work Order 14492230 - Replace transformer and protector
FE-10.07	Follow up to Data Request 3-1, attachment 4 – retirements and attachment – 4 Retirements and 5 – Cost of Removal. The following work orders had cost of removal charged but not retirements. Please explain why. a. CECO Work Order 14017963 - Sub - Replace Voltage Regulation b. CECO Work Order 15348305 – Cable Replacement – UD5098
FE-11.01	Variance Analysis: Follow-up to Data Request BRC Set 7-INT-2: The Company response states, "The salvage amount received for $9,193 was from a portion of the sale of two properties. These amounts are automatically processed to the reserve, so they can be recorded appropriately with the retirement and cost of removal." Regarding this response, please respond to the following items: a. Please identify the FERC accounting guideline that allows the proceeds from the sale of land to be recorded to a reserve. b. Please describe more fully what "a portion of the sale of two properties" entails. c. If the Company received $9,193 for the sale of "a portion" of the land, what was the total received, and where was it recorded? d. Please explain why the sale of land would have "cost of removal" (as the response to 7-2 indicates).
FE-11.02	Follow up to Data Request response BRC Set 4-INT-002, Attachment 1, page 2 of 7 e, Fleet Investment Strategic Services: a. Internal Audit identified 11 opportunities for improvement in communications and oversight of non FEU groups. Please provide a summary of what those opportunities are and how, or if, they could impact the DCR.
FE-11.03	Rider GDR: Reference response to Data Request BRC Set-1-INT-36. The Government Directive Recovery Rider has the potential to impact the Rider DCR. a. Please provide a list of the costs by FERC account included in the Rider GDR. b. For any costs charged to FERC accounts included in the Rider DCR, please explain how those costs have been excluded from recovery through the DCR.
FE-11.04	Excluded Riders: Reference response to Data Requests BRC Set-1-INT 36 and BRC Set-1-INT-6. The Companies stated that it had not requested Commission approval for any other riders (beyond the list of 40 provided in the data request). BRC Set-1-INT 6 identifies an Experimental Company Owned LED Lighting Program that is not included as a rider. a. How are the Companies recovering the costs associated with the Experimental Company Owned LED Lighting Program? b. If this is a Commission approved rider, please provide a copy of the Order approving the rider.
FE-11.05	Property Taxes: Reference Blue Ridge 2016 Report dated May 1, 2017, page 70, Response to BRC Set-1 INT 12, and the following table pulled from data in Response to BRC Set-1 INT-1, property tax calculations. In the 2016 audit, the Companies explained the real property tax rate is calculated as real property taxes paid over real property capitalized cost. The increase in the TE real property tax rate was due primarily to the removal of plant associated with Toledo Edison Plaza (located in FERC Accounts 389 and 390) from Account 101 (Plant In-Service) to Account 102 (Electric Plant Purchased or Sold). The resulting decrease in the denominator (plant balance) between the December 31, 2015, Rider DCR filing and the December 30, 2016, Rider DCR filing, combined with an immaterial change to the numerator (real property taxes paid) between the two filings, resulted in a higher real property tax rate.

REQUEST #	REQUEST
	The rate was expected to decline in 2017. The TE property tax rate did decline as shown in the following table, but is still significantly higher than the 2015 property tax rate. Please explain why the TE property tax is still 9.35% higher than the 2015 property tax rate.
FE-11.06	Annual DCR Revenue: Reference DCR Compliance filings dated January 12, 2018, page 57. Please provide supporting documentation for the Annual Revenue Thru 11/30/2017 for each operating company.
FE-11.07	Depreciation: Reference response to BRC Set 6-2. The Companies stated, "Consistent with the Companies' last distribution rate case, depreciation expense in Rider DCR is calculated by taking gross plant-in-service multiplied by the associated accrual rate." Please provide the approved depreciation expense schedules in the last distribution rate case that demonstrate that the Commission's approval of using gross plant when calculating depreciation expense.
FE-11.08	Depreciation: Reference response to BRC Set 6 – INT-1 and BRC Set 1-1 DCR Workpapers Schedules B3.2. For **each** of the FERC accounts listed below, is it the Companies' position to include depreciation expense in the Rider DCR for FERC accounts in which net plant is zero or negative before recording depreciation because it was done that way in the Companies' last distribution rate case?
FE-11.09	Depreciation: Reference response to BRC Set 6 – INT-1. For each of the FERC accounts listed above by Company, provide a breakout of the items (cost of removal, depreciation, etc.) included in the corresponding reserve balance for the estimated period.
FE-11.10	Depreciation: Reference response to BRC Set 6 – INT-2. The Companies' response stated that FERC 390.3 Leasehold Improvements depreciation was calculated using **net** plant in-service multiplied by the associated accrual rate. A review of the Companies' Schedules B3.2 Actual and Estimated revealed the schedules use **gross** plant to calculate depreciation. Please explain what the companies intend to correct and reconcile in the next filing.
FE-11.11	Depreciation: Reference response to BRC Set 6 – INT-3. The Companies' response stated that FERC 391.1 Office Furniture depreciation was calculated using **net** plant in-service multiplied by the associated accrual rate. A review of the Companies' Schedules B3.2 Actual and Estimated revealed the schedules use **gross** plant to calculate depreciation. Please explain what the Companies intend to correct and reconcile in the next filing.
FE-11.12	Depreciation: Reference BRC Set 1-1 DCR Workpapers, Schedules B3.2 and Service Co. Depr Rate: The Companies calculated the Service Company depreciation based on net plant with a conditional formula that resulted in the calculated depreciation not exceeding the amount remaining in net plant and avoided calculating depreciation expense for negative net plant balances. This methodology was not used in the CEI, OE, or TE calculation of depreciation expense resulting in incidences when depreciation expense was in excess of the net plant balance. Please explain the reasoning behind the differences in the methodologies used to calculate depreciation expense for the Service Company and CEI, OE, and TE.
FE-11.13	Work Order Population Rider LEX: Work Order 13755003 LINE EXTENSION – a zero balance was included in the population of DCR work orders. This work order appears to be related to Rider LEX. Please confirm that the population of work orders does not contain any LEX work orders other than the work order listed above.
FE-11.14	Work Order Population for Rider EDR(g): Cleveland Clinic Foundation. The following work orders, which appear to be related to Rider EDR (g), were included in the population of work orders for the DCR. Please explain why these work orders belong in the DCR. If the work orders should not be in the DCR, please explain what internal control(s) failed that allowed them to be included.
FE-11.15	Work Order Population for Rider AMI: The following work orders, which appear to be related to Rider AMI, were included in the population of work orders for the DCR. Please explain why these work orders belong in the DCR. If the work orders should not be in the DCR, please explain what internal control(s) failed that allowed them to be included.
FE-12.01+	DR Rescinded

REQUEST #	REQUEST
FE-13.01	Reference BRC Set 8-INT-1. The Company's response states that Capitalized Leased Vehicles are not included in Rider DCR. Please provide the spreadsheet tab and line number with description where the exclusion is "made at the bottom of the workpaper provided in BRC Set 1-INT-001 - Attachment 8 – Confidential."
FE-13.02	Reference BRC Set 8-INT-2. The Company's response states that Item 2, Capitalized Lease Vehicle Book Expense, is excluded from Rider DCR. Please explain where the following items for capitalized vehicles are excluded. If the exclusion is in BRC Set 1-INT-001 - Attachment 8 – Confidential," provide the spreadsheet tab and line number of the exclusion.
FE-13.03	Reference BRC Set 8-INT-2. The Company's response with respect to Items 3-6 states that the "capitalized component with respect to share-based equity compensation to employees supporting investments in plant-service" should be reflected in Rider DCR. Please confirm the Schedule M Items highlighted in gray below do not include any portions that are expensed to O&M.
FE-13.04	Reference BRC Set 8-INT-2. The Company's response states that the following with respect to Items 10, 11, 15 represent the "capital portion of employee benefits allocated to Capital Projects that are place in-service and included in Rider DCR." Please confirm the Schedule M Items highlighted in gray below do not include any portions that are expensed to O&M.
FE-13.05	Reference BRC Set 8-INT-2. The Company's response states, with respect to Item 12, "The majority of the balance is associated with the item labeled 'Fed Nuke Difference'. This is a legacy item associated with tax assets that are fully amortized with an offsetting ADIT amount that resides in the item labeled 'Accelerated Tax Depr-Fed-Norm.' Therefore, these items have a net ADIT balance of zero, and no impact on Rider DCR." Please indicate where "Fed Nuke Difference" is reflected below. If there are other components within ADIT that must be included to reconcile to the zero net ADIT balance, please provide a reconciliation including the spreadsheet Tab and line number that reconciles to a net zero ADIT balance.
FE-13.06	Reference BRC Set 8-INT-3. The Company's response states, "in previous years, OE's and TE's effective income tax rate included a small apportionment to PA due to activities the Company had in PA." Please describe the activities that resulted in the apportionment of Pennsylvania taxes to OE and TE. How do the activities support plant in-service?
FE-13.07	Reference BRC Set 8-INT-4. The Company's response states that the "Service Company has assets located in various jurisdictions including DC, MD, NJ, PA, and WV." Please describe the assets in question. Do any of the assets support non-utility and non-plant activities? If yes, are the non-utility and non-plant portions removed prior to being allocated to the EDU's?
FE-14.01	Follow up to Data Request BRC-Set 4-INT-002, Attachment 1 - Confidential, a. Audit of the Distribution Portfolio and Planning Process. The Company response indicated that the audit was currently in progress and would address Blue Ridge's prior audit recommendations 6, 7, and 10 issued on May 1, 2017. Please provide an update of the audit status and, if possible, the expected completion date and when summary findings and recommendations would be available.
FE-15.01	Follow-up to Data Request BRC Set 3-INT-001, attachment 1. Work Order CECO 14671767 - (PID#10900). This project was over budget by $1,120,171. The Company explained that the annual Pension Mark-to-Market adjustment allocated to this project was the main driver of the unfavorable variance—actual to budget of $1.120 million. a. Please provide a line-item description, along with the individual amounts, of what makes up the $1.120 million variance by subject line item and dollar amount. b. If the entire variance is Pension Mark-To-Market, please explain why $1.120 million was assigned to one work order.
FE-15.02	Follow-up to Data Request BRC Set 3-INT-001, attachment 1, IT 2016 EMS Upgrade/Patch Project. This project was over budget by $55,464. The Company explained a large pension adjustment was made in December 2016, resulting in the overhead variance. Please provide the amount of the pension adjustment.

REQUEST #	REQUEST
FE-15.03	Follow-up to Data Request BRC Set 10-INT-007. CECO Work Order 15348305 – Cable Replacement UD5098 - $56,324. This work order, according to the data request response, should have had retirements. The processing of recording retirements failed during the auto-retirement process. This error was fixed in March 2018, and the Company stated it will include a reconciliation in a future DCR filing to reflect the cumulative revenue requirement impact had the retirements not been delayed. Please provide the amount of the retirements.
FE-15.04	Follow-up to Data Request BRC Set 10-INT-007. The Company explained that the work order estimates have been updated to include an estimate for cost of removal and the charges transferred. Retirements were also recorded. Please provide the amount of the retirements and cost of removal for the following work orders: a. CECO Work order 15195180 – Equipment replacement – Transformer Oil - $79,563 b. CECO Work Order 15010905 – Equipment Replacement – PT - $59,535 c. TECO Work Order 14492230 – Replace Transformer and protector - $233,972
FE-15.05	Follow-up to Data Request BRC Set 3-INT-001, attachment 1, OECO 13259124 - PARK SUB ADAPTIVE RELAY 2012. Capital Project Cost: $836,741.00. The Company's data request response indicated the project was deferred due to reallocation of labor resources. The project accrued $138,842 in AFUDC. When the project was deferred, was AFUDC either stopped or reversed? If neither, why not?
FE-15.06	Follow-up to Data Request BRC Set 3-INT-001, attachment 1, OECO 13847485 - Ordnance Sub - SCADA C/I and Adaptive Re, Capital Project Cost: $515,853.00. This work order accrued $75,562 in AFUDC. When the project was deferred, was AFUDC either stopped or reversed? If neither, why not?
FE-16.01	Follow up to Data Request response BRCS Set 15-INT-1. The Company response indicated that "the total capitalized amount of the 2016 Pension Mark-to-Market entry for CECO was spread across all eligible work orders that had capital activity in 2016". a. Please explain in detail how the Pension Mark to Market allocation process works, including i. How the adjustment is allocated among FE Ohio operating Companies and other FE companies outside of Ohio ii. How the adjustment is allocated among FE Ohio operating companies iii. How the adjustment is allocated to work orders within an operating company. iv. What work orders are eligible for the Pension adjustment v. The basis (formula) for the adjustment vi. The accounting entry that books the charge to the individual work orders b. Is the Pension adjustment considered in the annual budget? c. Who determines the total Pension adjustment to be allocated to Capital and how is that done? d. Are similar adjustments allocated to operating expense? If so, how and if not, why not?

APPENDIX D: WORK PAPERS

Blue Ridge's workpapers are available on a confidential CD. Blue Ridge's analysis included a detailed validation / verification of the Microsoft Excel® spreadsheets provided by FirstEnergy that support the Rider DCR Compliance Filing. The Filing included the following spreadsheets.

- Summary
- DCR Rider Workpaper
- Quarterly Reconciliation
- Billing Units
- Act-Summary
- Act-CEI Sch B2.1 (Plant in Service)
- Act-CEI Sch B3 (Depreciation Reserve)
- Act-CEI Sch B3.2 (Depreciation Expense)
- Act-CEI Sch C3.10 (Property Tax)
- Act-OE Sch B2.1 (Plant in Service)
- Act-OE Sch B3 (Depreciation Reserve)
- Act-OE Sch B3.2 (Depreciation Expense)
- Act-OE Sch C3.10 (Property Tax)
- Act-TE Sch B2.1 (Plant in Service)
- Act-TE Sch B3 (Depreciation Reserve)
- Act-TE Sch B3.2 (Depreciation Expense)
- Act-TE Sch C3.10 (Property Tax)
- Act-Exclusions
- Act-ADIT Balances
- Act-Service Company
- Act-Service Co. Depr Rate
- Act-Service Co. Prop Tax Rate
- Act-Service Co. Incremental
- Act-Intangible Depr Expense
- Est-Summary
- Est-CEI Sch B2.1 (Plant in Service)
- Est-CEI Sch B3 (Depreciation Reserve)
- Est-CEI Sch B3.2 (Depreciation Expense)
- Est-CEI Sch C3.10 (Property Tax)
- Est-OE Sch B2.1 (Plant in Service)
- Est-OE Sch B3 (Depreciation Reserve)
- Est-OE Sch B3.2 (Depreciation Expense)
- Est-OE Sch C3.10 (Property Tax)
- Est-TE Sch B2.1 (Plant in Service)
- Est-TE Sch B3 (Depreciation Reserve)
- Est-TE Sch B3.2 (Depreciation Expense)
- Est-TE Sch C3.10 (Property Tax)
- Est-Exclusions
- Est-ADIT Balances
- Est-Service Company
- Est-Service Co. Depr Rate
- Est-Service Co. Prop Tax Rate
- Est-Service Co. Incremental
- Est-Intangible Depr Expense

<u>DRAFT</u> Docket No. 17-2009-EL-RDR
Compliance Audit of the 2017 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

Workpapers that support Blue Ridge's analysis are listed below. All workpapers were delivered to PUCO Staff per the RFP requirements.

- BRCS WP FE DCR CF Variance 2017 - Confidential.xlsx
- Case 16-2166-EL-RDR FE AMI 2017 Plant Balances.pdf
- COMPANY WP BRC Set 1-INT-002 and 1-INT-006 Comparison.xlsx
- FE DCR TCJA Impact_Revenue Comparison_041118.xlsx
- Interview McMillen FINAL
- TCJA Impact_Tables.xlsx
- WP ADIT Year to Year Comparison.xlsx
- WP BRC Set 1-INT-001 ATT 1 and 3 and 1-INT-006 Comparison.xlsx
- WP FEOH 2017 Adjustments to Plant and Reserve-Confidential R3.xlsx
- WP FEOH 2017 Pre-Date Certain Pension Impact Analysis 2012-2017 - CONFIDENTIAL.xlsx
- WP FEOH 2017 Sample Size Calculation Work Orders through 11-30-17 - CONFIDENTIAL R0.xlsx
- WP FEOH 2017 Workorder Testing Matrix FINAL
- WP Impact of Adjustments BRC Set 1-INT-001 Attachment 1 - FE DCR Compliance Filing 1.12.2018 - Confidential R2.xlsx

WP V&V FE DCR Compliance Filing 01.12.2018 - Confidential R3.xlsx

The following data responses were obtained in prior audits and were relied upon in the examination of the filings under review in this audit.

- WP FE Response to 2011 Audit Data Request BRC-10-10 and 10-11.pdf
- WP FE response to 2011 Audit Data Request BRC-14-1.pdf
- WP FE Response to 2011 BRC 1-3a - Attachment 1 - Capitalization Policy - Confidential.pdf
- WP FE Response to 2011 BRC 1-3b - Attachment 1 - Work Management Process - Confidential.pdf
- WP FE Response to 2011 BRC 1-3b - Attachment 2 - CREWS Work Request Narratives - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c - Attachment 1 - Creating Multi-Year Enterprise Capital Portfolio - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c – Attachment 2 – FE Capital Portfolio Development and Capital Management Procedure - Confidential.pdf
- WP FE Response to 2011 BRC 1-3c-Attachment 3 - Energy Delivery Capital Allocation Process - Confidential.pdf
- WP FE Response to 2011 BRC 1-3d - Attachment 1 - Accounting For Capitalized Financing Costs During Construction - Confidential.pdf
- WP FE Response to 2011 BRC 1-3e - Attachment 1 - Invoicing Process Flow Chart - Confidential.pdf
- WP FE Response to 2011 BRC 1-3h – Attachment 1 – Procedure for Enterprise Sourcing of Materials and Services - Confidential.pdf
- WP FE Response to 2011 BRC 1-3m – Attachment 1 – Income Tax Policy and Procedure. - Confidential.pdf
- WP FE Response to 2011 BRC 1-3n – Attachment 1 – Ohio Property Tax Returns - Confidential.pdf

- WP FE Response to 2011 Data Request BRC 11-1.pdf
- WP FE Response to 2011 Data Request BRC 11-2.pdf
- WP FE Response to 2011 Data Request BRC 11-3.pdf
- WP FE Response to 2011 Data Request BRCS-11-2.pdf
- WP FE Response to 2012 BRC-1-19 Depreciation Accrual Rates from Staff's Reports.pdf
- WP FE Response to 2012 Data Request BRC-1-19 Depreciation Accrual Rates from Staff's Reports.pdf
- WP FE Response to 2013 BRC Set-1-INT-032 Supplemental - Confidential.docx
- WP FE Response to 2014 BRC Set 1-INT-015 - Confidential.pdf
- WP FE Response to 2014 Data Request BRC-1-5.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 1-Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 2 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012 Attachment 3 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-012-Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-013 Attachment 3 - Confidential.pdf
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-014.pdf
- WP FE Response to 2015 Audit Data Request BRC Set-13-INT-004.pdf
- WP FE Response to 2016 BRC Set 1-INT-007 Attachment 1 - Confidential.xlsx
- WP FE Response to 2016 BRC Set 1-INT-007 Supplemental.pdf
- WP FE Response to 2016 BRC Set 1-INT-013 - Final Partial Response.pdf
- WP FE Response to 2016 BRC Set 1-INT-013 Attachment 3 - Confidential.docx
- WP FE Response to 2016 BRC Set 2-INT-007.pdf
- WP FE Response to 2016 BRC Set 9-INT-003.pdf
- WP FE Response to 2016 BRC Set 10-INT-001.pdf

The following personnel had key roles supporting the Rider DCR. Blue Ridge conducted interviews in 2012 (see names with *). For individuals that assumed the role in later years, Blue Ridge requested updates for any change in the role and responsibilities.

Personnel in Key Roles Supporting the Rider DCR

#	Name	Title
1	Douglas Burnell*	Director, Business Services
2	Timothy Clyde* Amy Patterson[222]	Manager, Property Accounting
3	Randal Coleman*	Manager, Distribution Standards
4	Santino Fanelli* Joanne Savage[223]	Manager, OH Revenue Requirements
5	Joseph Loboda[224]* Michele Jones*[225] Sandra Hemberger[226]	Manager, Corporate Services Sourcing Manager, Corporate Services Sourcing Director, Corporate Sourcing
6	Thomas McDonnell* Peter Nadel[227]	Manager, Insurance and Operational Risk Management
7	Eileen Mikkelsen[228]* Santino Fanelli[229]*	VP, Rates & Regulatory Affairs Director Rates & Regulatory Affairs
8	Erica Millen* Peter Blazunas[230] Brandon McMillen[231]	OH State Regulatory Analyst
9	John Nauer*	Director, Utilities Sourcing

222 Timothy Clyde was in the position from December 2012 through February 2016. Amy Patterson assumed the position effective February 2016.

223 As of May 2016, Joanne Savage assumed the position of Manager, Ohio Revenue Requirements that was previously held by Santino Fanelli.

224 Joseph Loboda was in the position from 1/1/2012 through 2/12/2012.

225 Michele Jones was in the position from 2/13/2012 through 12/31/2012. Michele Jones left the position of Manager, Corporate Services Sourcing on January 27, 2013. Sandra Hemberger (Director, Corporate Services) kept her existing title, but assumed all of Ms. Jones' responsibilities for corporate services relevant to Rider DCR through the end of 2013.

226 Michele Jones left the position of Manager, Corporate Services Sourcing on January 27, 2013. Sandra Hemberger (Manager, Corporate Services & Energy Efficiency) kept her existing title, but assumed all of Ms. Jones' responsibilities for corporate services relevant to Rider DCR through the end of 2013.

227 As of February 2016, Peter Nadel assumed Thomas McDonnell's position as Manager, Insurance and Operational Risk Management.

228 As of May 2016, Eileen Mikkelsen is the VP, Rates & Regulatory Affairs. Eileen Mikkelsen participated in the interview with Erica Millen and Santino Fanelli. No separate interview notes were developed.

229 Santino Fanelli is the Director of Rates & Regulatory Affairs. The position was previously held by Eileen Mikkelsen.

230 Peter Blazunas replaced Erica Millen. He updated the interview notes from the prior year's audit.

231 Brandon McMillen assumed Peter Blazunas's responsibilities as it related to Rider DCR. He was interviewed and the notes are included with the workpapers.

#	Name	Title
10	Albert Pompeo*	FEU Business Services Policy and Control Lead
11	William Richards* Tom Pesich[232] Nicholas Fernandez[233]	Manager, Business Unit Financial Performance Manager, Financial Modeling Executive Director, Strategy and LT Planning[234]
12	Steve Vucenovic* Mark Golden[235]	Manager, General Accounting

*Interview conducted in 2012. Notes provided in previous audit workpapers.

[232] Starting 11/1/2012, Tom Pesich (Manager, Financial Modeling) assumed the responsibilities for capital forecasting formerly held by Mr. Richards. There was no change to Mr. Pesich's role relevant to Rider DCR in 2013.
[233] Starting 8/22/2014, Nicholas Fernandez (Director, Business Planning & Performance) assumed the responsibilities as it relates to the capital forecast formerly held by Mr. Pesich. There was no change to Mr. Fernandez's role relevant to Rider DCR in 2014.
[234] Nicholas Fernandez is an Executive Director, Strategy and LT Planning as of May 2015. There was no change to Mr. Fernandez's role related to Rider DCR in 2015.
[235] As of March 2016, Mark Golden assumed Steve Vucenovic's role as it relates to Rider DCR.

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