Docket No. 16-2041-EL-RDR

Compliance Audit of the 2016 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company

FINAL REPORT

May 1, 2017

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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 provides the following: 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. The Overview also includes an update on the recommendations from the prior compliance audit.
- *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, and 2015 Rider 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 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 variance analysis reviews the significant changes in net plant by individual FERC account.

The scope also includes review of each component of Rider DCR. The Rider DCR specific exclusions are addressed in the section labeled Riders LEX, EDR, AMI, and General Exclusions, followed by analyses of gross plant-in-service, accumulated reserve for depreciation, accumulated deferred income taxes, depreciation expense, property tax expense, allocated Service Company plant and reserve, commercial activity tax 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 2017.

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, 2016, and estimated plant in service through February 28, 2017. 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, in Case No. 14-1297-EL-SSO.

Under the agreement, FirstEnergy agreed to submit to 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 2016 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, and 2015 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2015.

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 to several work orders, corrections to income tax and property tax rates, and removal of items that should not be depreciated. 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	**$ 111,809,308**	**$ 119,012,430**	**$ 29,242,534**	**$ 260,064,272**
1	AMI Not Excluded	28	(0)	(0)	28
2	ATSI Not Excluded	(0)	(1,047)	(16)	(1,063)
3	AFUDC Overstated	(0)	(4,929)	(0)	(4,929)
4	FAS109 "Land"	(0)	(32,358)	(0)	(32,358)
5	Incorrect Property Tax Rate	(0)	282,612	(0)	282,612
6	Incorrect Income Tax Rate	(0)	(0)	(19,160)	(19,160)
7	COR included in Additions	(0)	(0)	(1,627)	(1,627)
8	AFUDC Overstated-Service Co.	(196)	(238)	(105)	(539)
	Impact of All Adjustments	**(169)**	**244,041**	**(20,907)**	**222,965**
	Recommended Adjusted Rider DCR Revenue Requirements	**$ 111,809,140**	**$ 119,256,471**	**$ 29,221,627**	**$ 260,287,237**

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. Blue Ridge concluded that the Companies' controls were adequate and not unreasonable.

VARIANCE ANALYSIS

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, 2015, across the four quarterly reports of 2016 (February 28,2016; May 31, 2016; August 31, 2016; and November 30, 2016).

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 adjusted plant (including allocation of Service Company Plant) by $100.1 million, $136.6 million, and $37.5 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 3.5%, 4.2%, and 3.3% for CE, OE, and TE, respectively.

Table 2: Adjusted Plant Change from 11/30/2015 to 11/30/2016

	(a)	(b)	(c)	(d)	(e)
Line No.	Account Title	Adjusted Balance 11/30/15	Adjusted Balance 11/30/16	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 417,288,386	$ 431,628,975	$ 14,340,588	3.4%
3	Distribution	2,146,090,268	2,217,333,891	71,243,623	3.3%
4	General	149,771,872	156,348,800	6,576,928	4.4%
5	Other	53,736,519	56,089,957	2,353,438	4.4%
6	Service Company Allocated	88,149,759	93,710,646	5,560,887	6.3%
7	**Total Cleveland Electric Illuminating Company**	**$ 2,855,036,804**	**$ 2,955,112,269**	**$ 100,075,464**	**3.5%**
8	**Ohio Edison Company**				
9	Transmission	$ 211,123,376	$ 213,163,308	$ 2,039,932	1.0%
10	Distribution	2,661,407,297	2,764,255,371	102,848,074	3.9%
11	General	162,421,589	178,984,926	16,563,337	10.2%
12	Other	72,768,268	81,134,820	8,366,553	11.5%
13	Service Company Allocated	106,821,875	113,560,685	6,738,810	6.3%
14	**Total Ohio Edison Company**	**$ 3,214,542,405**	**$ 3,351,099,110**	**$ 136,556,706**	**4.2%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,702,214	$ 22,474,270	$ (227,944)	-1.0%
17	Distribution	956,752,720	986,294,036	29,541,316	3.1%
18	General	70,504,605	74,463,450	3,958,845	5.6%
19	Other	25,500,420	26,720,165	1,219,745	4.8%
20	Service Company Allocated	47,021,476	49,987,804	2,966,328	6.3%
21	**Total Toledo Edison Company**	**$ 1,122,481,433**	**$ 1,159,939,725**	**$ 37,458,292**	**3.3%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,192,060,642**	**$ 7,466,151,104**	**$ 274,090,462**	**3.8%**

In the current audit of the DCR year 2016, Blue Ridge evaluated several yearly changes and variances in account balances. The results of those reviews are as follows:

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

  In our analysis of specific account variances from November 30, 2015, through November 30, 2016, Blue Ridge submitted questions and received responses from FirstEnergy regarding three variances of concern regarding Intangible Software (account 303) among the three FirstEnergy operating companies.

  Although the amount of change from one year to the next was not significant, cumulative increases over the past couple of years raised concern regarding the Intangible Plant of FERC account 303. For example, TE's account 303 had already increased 13.5% from 2014 to 2015, thus resulting in a 19.0% total increase from November 30, 2014 to November 30, 2016. FirstEnergy provided documented work order detail supporting the addition change in account balance (as they had during the previous DCR year). Blue Ridge verified work order identification and accuracy of account totals supporting the DCR filing and was satisfied that the presentation was not unreasonable for the operating companies. The majority of Account 303 work is performed under FECO work orders. For that reason, Blue Ridge normally tests FECO intangible work orders more than those of the operating companies. The results of those tests are reported in the work-order-testing portion of this report.

- Year-to-Year DCR Filing Reserve Balances

  In our analysis of specific reserve account variances from November 30, 2015, through November 30, 2016, Blue Ridge submitted questions and received responses from FirstEnergy regarding three variances of concern regarding accounts 370 (Meters), 393 (Stores Equipment), and 395 (Laboratory Equipment) for TE. Explanations of these variances proved to be not unreasonable.

- 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 2015 DCR Filing to 2015 FERC Form 1 Plant-in-Service Balances

  Blue Ridge asked FirstEnergy to provide a reconciliation between the 2015 plant-in-service account balances in the Companies' DCR Compliance Filings to their 2015 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 2015 end-of-year DCR filings matched the balances of the 2015 FERC Forms 1.

- 2016 Work Order Population totals to 2016 DCR Filing Year-to-Year Plant-In-Service Activity

  Blue Ridge compared the difference between the DCR November 30, 2016, gross plant balances and the November 30, 2015, gross plant balances for all Companies with the Work Order totals for the same period. Blue Ridge found that the balances matched.

- 2016 Plant Additions, Retirements, Transfers, and Adjustments

  Blue Ridge also investigated plant additions, retirements, transfers, and adjustments in order to understand changes to the unadjusted plant balances. In its examination, Blue Ridge asked a multi-part data request concerning these items to which FirstEnergy provided explanations that were not unreasonable.

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.

Minor adjustments should be made to the exclusions associated with Rider EDR(g), Rider AMI, and ATSI Land Lease work orders. Individually, these adjustments would not be material to Rider DCR. The cumulative impact is included in the overall findings and recommendations associated with this report in Adjustment #1 and #2.

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 11/30/15 to 11/30/16[1]

Company	11/30/15	11/30/16	Incremental
Cleveland Electric Illuminating Company	2,855,036,804	2,955,112,270	100,075,465
Ohio Edison Company	3,214,542,405	3,351,099,110	136,556,705
The Toledo Edison Company	1,122,481,433	1,159,939,724	37,458,291
Total	7,192,060,642	7,466,151,104	274,090,461

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.

Additional Validation Testing from Sampled Work Orders

The Companies provided a list of work orders that support gross plant in service for December 2015 through November 2016. Blue Ridge selected a sample of 71 work orders from the Companies' and the Service Company's population of addition and replacement work orders for 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 the work is includable in Rider DCR for all but one AMI work order (as discussed in observation 2 below).
2. Regarding exclusions for Rider AMI, Blue Ridge found that the work order sample contained one AMI (or SmartGrid) work order. The CECO FERC account 362 work order should have been excluded from the Rider DCR filing. While the amount is immaterial to the Rider DCR, the Company stated, and Blue Ridge recommends, that a reconciliation be included in the Rider DCR revenue requirement in the next filling that incorporates the effect on revenues had the activity been appropriately excluded.
3. Regarding exclusions for Rider LEX, Blue Ridge found that the population of work orders that comprise utility plant for the DCR did not include any LEX work orders. 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.
4. Regarding exclusions for Rider EDR, Blue Ridge found no work orders in the sample that were related to EDR.
5. Blue Ridge found no work orders in the sample that were related to generation work.

[1] WP V&V FE DCR Compliance Filing 12.31.2016-Confidential.

6. Blue Ridge found that the Company has adequate procedures in place to approve work orders. That procedure has 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 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.

   Five work orders included in the sample referred to adjustments charged to existing assets that were previously unitized. For two of those work orders, Blue Ridge was unable to determine the impact of retirements on the depreciation reserve. Therefore, Blue Ridge recommends that the Company calculate the impact of those retirements on the revenue requirement and include a reconciliation in the next rider DCR filing.
8. In reviewing whether project costs were within the approved budget, Blue Ridge found that many of the project costs in the sample were within +/- 15% of the approved budget. However, 19 of the 71 work orders in the sample were over budget by more than 15%. FirstEnergy provided explanations for the overages. The reasoning for the actual costs exceeding the budget for most of the projects was specific, unique to that project, and not unreasonable. However, the large percentage of projects that were over budget greater than 15% in relation to the total work orders sampled raised a potential concern related to the planning process. Labor, contractor, and/or material costs were either greater than planned or the budget did not include all categories of costs. Blue Ridge is not recommending an adjustment to these projects in regard to the Rider DCR. However, Blue Ridge does recommend that the Companies review their project planning process to ensure that the methodology allows for projects to be fully scoped prior to execution.

   In addition, 13 of the 71 work orders were considered emergent projects and neither had budgets nor were in the original capital budget. The explanations for the emergent projects were not unreasonable, but the number of emergent projects in relationship to the work order sample is significant (18%). Blue Ridge recommends that the Companies conduct a more thorough review of the conditions of infrastructure during the capital budget cycle to ensure, whenever possible, these type projects are budgeted and, therefore, part of the approved capital budget.
9. In reviewing whether cost detail supported the work order charge and the categories of cost were not unreasonable, Blue Ridge noted, except for one work order, the costs in PowerPlant support the work order charge and the categories of cost are not unreasonable. The one work order of exception had cost of over $3 million charged entirely to stock materials. Upon further review, FirstEnergy determined that 50% of the charges belonged in other plant accounts. FirstEnergy corrected the error. The reclassification does not affect Rider DCR.

   Several work orders included within the sample did not agree to the cost detail. In previous Blue Ridge examinations, the Companies explained that those differences were related to retirements for each work order. We were able to confirm this during testing.
10. Blue Ridge found that, for replacement work orders, assets were retired and, except for one work order, cost of removal was properly charged. The one work order whose cost of removal was not properly charged is discussed in observation 12 below.

11. Regarding the dates assets were retired, Blue Ridge found that all sixteen replacement workorders in the sample had asset retirement dates, cost of removal dates, and in-service dates of new assets that were all in alignment (except for the one work order as noted in observation 12 below).
12. Blue Ridge found that one replacement work order in the sample did not have cost of removal charged at the time the assets were placed in service. Upon unitization of the work order, however, the Companies transferred an amount from additions to cost of removal. The delay in recording the cost of removal does not affect net plant and has an immaterial impact to depreciation expense and, thus, the reserve. Although immaterial, the adjustment has been included within the total impact calculations in this report [**ADJUSTMENT #7**].
13. Blue Ridge found that all work orders, except for two, were closed to the proper FERC accounts based on the descriptions of the work being performed. One of the two work orders not closed correctly was discussed already under observation 9. Based on further analysis, the Companies indicated that the other of the two work orders had expenses applied to other FERC accounts in 2017. Blue Ridge reviewed the detail supporting the transfer and found it not unreasonable.
14. Blue Ridge found that 11 work orders had in-service dates greater than 90 days delayed from the estimated in-service dates. The Company provided explanations for each work order, and Blue Ridge found those explanations to be not unreasonable. Blue Ridge understands that in some instances delays cannot be avoided. However, some of the workorders had significant delays, and almost half the projects were not completed by the estimated due dates. Blue Ridge recommends that the Companies place additional emphasis on completing projects timely when they have direct control of the projects and can mitigate delays.
15. Blue Ridge found that all project work orders were closed to EPIS within a reasonable timeframe from project completion, and any potential impact on AFUDC was minimal for those workorders that accrued AFUDC. Only 16 of the 71 workorders sampled accrued AFUDC.

Field Inspections

Blue Ridge selected nine projects for field verification from the work order sample. The nine 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 experienced a significant increase in the unitization backlog from the prior 2015 audit. 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. While most of the work orders are Distribution (89%) and individually would not be material to the accumulated reserve for depreciation, on an aggregate basis, the work orders in the backlog total over $62 million, which is significant. Blue Ridge was unable to quantify the 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 have not been unitized.

Blue Ridge recommends that the Companies make a concerted effort to reduce the volume of backlog workorders both in quantity and dollar value.

Insurance Recoveries

There are currently no pending insurance recoveries that have not been recorded or accrued for TECO or the Service Company. However, an insurance claim, associated with a 2012 storm event that was resubmitted in 2015, has settled and could potentially result in recoveries for OE and CE. These potential recoveries have not yet been recorded or accrued since a settlement agreement that has been made has not yet fully executed. The potential estimated amounts of recovery that would be charged to capital for the two Ohio operating companies are as follows:

Ohio Edison Company	$ 6,395
The Cleveland Electric Illuminating Company	$10,210

While the potential recovery is immaterial, Blue Ridge recommends that any recovery reduce plant in service and be recognized in a future Rider DCR.

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 11/30/15 to 11/30/16

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	(1,205,294,293)	(1,269,202,085)	(63,907,792)
Ohio Edison Company	(1,259,058,319)	(1,317,426,765)	(58,368,447)
The Toledo Edison Company	(549,228,366)	(591,085,970)	(41,857,604)
Total	(3,013,580,977)	(3,177,714,820)	(164,133,844)

Blue Ridge found adjustments that should be made to the reserve balances to ensure that net plant is appropriately reflected in the DCR. The specific adjustments are discussed, as necessary, in the Exclusions and Gross Plant in Service sections.

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 11/30/15 to 11/30/16

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	(457,939,051)	(466,717,532)	(8,778,481)
Ohio Edison Company	(547,713,158)	(569,578,802)	(21,865,644)
The Toledo Edison Company	(146,538,304)	(151,388,071)	(4,849,767)
Total	(1,152,190,514)	(1,187,684,405)	(35,493,892)

Blue Ridge concludes that the ADIT is not unreasonable. The Companies recognized the significant impact of the extension of bonus depreciation on the ADIT balances.

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 11/30/15 to 11/30/16

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	92,035,989	95,176,216	3,140,227
Ohio Edison Company	96,378,099	100,891,710	4,513,611
The Toledo Edison Company	36,831,596	38,032,714	1,201,119
Total	225,245,684	234,100,640	8,854,956

Blue Ridge found that the calculation of depreciation expense is not unreasonable. However, the Companies should exclude the FAS109 *Land* balances from the calculation of intangible depreciation expense. The Rider DCR uses 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 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 from a prior Rider DCR audit.

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 11/30/15 to 11/30/16[2]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	101,323,045	102,669,541	1,346,496
Ohio Edison Company	88,498,186	88,980,613	482,428
The Toledo Edison Company	29,195,338	30,026,201	830,863
Total	219,016,569	221,676,355	2,659,786

Blue Ridge found that, while the calculation of property tax is not unreasonable, there are corrections that should be made to OE's property tax rates and a reconciliation of the impact of the transcription error that should be made in a future filing. 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.

[2] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

Table 8: Incremental Change in CAT and Income Tax Expense from 11/30/15 to 11/30/16

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	8,519,491	9,278,567	759,075
Ohio Edison Company	9,857,073	11,517,635	1,660,561
The Toledo Edison Company	1,276,607	1,015,662	(260,945)
Total	19,653,171	21,811,863	2,158,692

Blue Ridge found that the commercial activity tax was correctly calculated. The composite tax rate for actual balances of November 30, 2016, for all three operating companies and estimated balances as of February 28, 2017, for CE and OE were correctly calculated and are not unreasonable. However, the composite tax rate for TE's estimated balances as of February 28, 2017, used an incorrect tax rate and should be corrected. In addition, any adjustments discussed in other sections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

Return

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

Table 9: Incremental Change in Return on Rate Base from 11/30/15 to 11/30/16

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	24,095,993	26,418,706	2,322,713
Ohio Edison Company	28,313,336	33,089,719	4,776,383
The Toledo Edison Company	3,589,733	2,805,374	(784,359)
Total	55,999,062	62,313,799	6,314,737

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, 2016, and estimated February 28, 2017, 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, 2016, 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 2017. To develop the first quarter 2017 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2017, the most recent forecast from PowerPlant. The estimated February 28, 2017, 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 within the first two months of 2017 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. 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. (2016 DCR Report, p. 44)

Rec-02. 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. (2016 DCR Report, pp. 44 and 50)

Rec-03. 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. (2016 DCR Report, p. 47)

Rec-04. 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 accrual of depreciation, relative to the CECO work order HE123, and adjust the subsequent DCR filling accordingly. (2016 DCR Report, p. 52)

Rec-05. 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. (2016 DCR Report, p. 52)

Rec-06. 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. (2016 DCR Report, pp. 52–53)

Rec-07. 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. (2016 DCR Report, p. 57) 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.

Rec-08. 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. (2016 DCR Report, p. 59)

Rec-09. 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. (2016 DCR Report, pp. 59–60)

Rec-10. 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. (2016 DCR Report, p. 61)

Rec-11. 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. (2016 DCR Report, p. 64)

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

Rec-13. 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. (2016 DCR Report, p. 69)

Rec-14. 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. (2016 DCR Report, p. 70)

Rec-15. 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. (2016 DCR Report, p. 71)

Rec-16. 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. (2016 DCR Report, p. 74)

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, 2016, and estimated plant in service through February 28, 2017. 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, in Case No. 14-1297-EL-SSO.

Under the agreement, FirstEnergy agreed to submit to 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 2016 compliance audit. Blue Ridge also performed the 2011, 2012, 2013, 2014, and 2015 Rider DCR compliance audits, covering plant in service since the last distribution rate case (the audits covered June 1, 2007, through November 30, 2015).

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."[3]

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, and the Compliance Audit of the DCR Rider filed in Case No. 15-1739-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, 2015, through November 30, 2016. The information was included in the December 30, 2016, quarterly filing.
- All appropriate documentation relating to the issues identified in the Auditor's Report in Case No. 15-1739-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

[3] 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 December 30, 2016, 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. 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 10: Rider DCR Revenue Requirements Actual 11/30/16 and Projected 2/28/17[4]

	Revenue Requirements		
Operating Company	**Actual 11/30/16**	**Projected 2/28/17**	**Total**
The Cleveland Electric Illuminating Company	$ 108,578,029	$ 3,231,279	$ 111,809,308
Ohio Edison Company	$ 115,108,677	$ 3,903,754	$ 119,012,430
The Toledo Edison Company	$ 27,257,952	$ 1,984,582	$ 29,242,534
Total	$ 250,944,658	$ 9,119,614	$ 260,064,272

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 section 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 that would allow conclusions to be drawn in regard to the total population. Additional work orders were selected based on professional judgment. The results of the transactional testing are included in the section 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 section.

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.

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[4] WP V&V FE DCR Compliance Filing 12.30.2016 – Confidential.

PRIOR COMPLIANCE AUDITS RECOMMENDATIONS STATUS

Blue Ridge performed the Rider DCR compliance audit that covered capital additions from December 1, 2014, through November 30, 2015. Blue Ridge's report included several findings and recommendations and was filed in Case No. 15-1739-EL-RDR. The following list includes those recommendations. Following each recommendation is FirstEnergy's response regarding the recommendation's status[5] and Blue Ridge's associated comments based upon observations from this compliance audit.

a) Recommendation 01, 2015 DCR Report, p. 44: Blue Ridge recommends that the TE account 390 gross plant leasehold improvements exclusion overstatement of $106,751 be corrected in future Rider DCR filings.

   FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process such that the gross plant exclusions for Account 390 in regard to leasehold improvements are no longer overstated by $106,751. The Companies' July 1, 2016, Rider DCR filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

   Blue Ridge's Comments: Blue Ridge's finding arose due to the fact that the TE Plaza was removed from service pending an anticipated sale of the facility resulting in an overstatement of the exclusion adjustment. Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[6] No additional work is recommended.

b) Recommendation 02, 2015 DCR Report, pp. 45–46: Blue Ridge recommends that the overstatement of $5,977 regarding the TE account 390 exclusion for reserve associated with leasehold improvements be corrected in future Rider DCR filings.

   FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process such that the reserve exclusions for Account 390 in regard to leasehold improvements are no longer overstated by $5,977. The Companies' July 1, 2016, Rider DCR filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

   Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[7] No additional work is recommended.

c) Recommendation 03, 2015 DCR Report, p. 52: Blue Ridge recommends that a reconciliation of the Rider DCR revenue requirement be included in the next filing that incorporates the cumulative effect of the corrections needed to be made to the EDR(g) exclusions.

   FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with Rider EDR(g). The Companies' July 1, 2016, Rider DCR

[5] All FirstEnergy status remarks are obtained from FirstEnergy's response to Data Request BRC Set 1-INT-10 – Confidential.
[6] FirstEnergy's response to Data Request BRC Set 12-INT-001.
[7] FirstEnergy's response to Data Request BRC Set 12-INT-001.

filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[8] In the December 30, 2016, DCR filing, the Companies identified additional activity associated with the Rider EDR(g) that was not properly excluded from Prior DCR filings. A recommendation regarding this oversight is included in this year's audit recommendations.

d) Recommendation 04, 2015 DCR Report, p. 53: Blue Ridge recommends that a reconciliation of the Rider DCR revenue requirement be included in the next filing that incorporates the effect on revenues had the additional $3,413.43 of AMI-related charge been appropriately excluded.

FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the $3,413.43 AMI-related charge. The Companies' July 1, 2016, Rider DCR filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[9] No additional work is recommended.

e) Recommendation 05, 2015 DCR Report, p. 55: Blue Ridge recommends that a reconciliation of the Rider DCR revenue requirements be included in the next filing that incorporates the effect on revenues had the December 2014 through February 2015 ATSI Land Lease exclusion value activity been incorporated beginning with the actual February 28, 2015, plant balances.

FirstEnergy Response: The Companies' July 1, 2016, Rider DCR filing included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[10] While the Companies removed the cumulative revenue requirement impact associated with the ATSI Land Lease Exclusions, the Companies' failed to update the November 30, 2015, balances used for the 2016 Rider DCR filings.[11] A recommendation regarding this oversight is included in this year's audit.

f) Recommendation 06, 2015 DCR Report, p. 59: Blue Ridge recommends that a reconciliation calculation be included in the next Rider DCR filing to reflect the cumulative revenue requirement impact regarding the non-jurisdictional work under FECO ITS-SC-M-00041-1 that should have been excluded from Rider DCR.

[8] FirstEnergy's response to Data Request BRC Set 12-INT-001 (Identified as Cleveland Clinic Plant Adjustment in document).
[9] FirstEnergy's response to Data Request BRC Set 12-INT-001.
[10] FirstEnergy's response to Data Request BRC Set 12-INT-001.
[11] FirstEnergy's response to Data Request BRC Set 1-INT-027.

FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the with non-jurisdictional work order FECO ITS-SC-M-00041-1. The Companies' July 1, 2016, Rider DCR filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[12] Blue Ridge also confirmed that the adjustment was appropriately reflected in this year's Rider DCR filings.[13] No additional work is recommended.

g) Recommendation 07, 2015 DCR Report, p. 59: Blue Ridge recommends that a reconciliation calculation be included in the next Rider DCR filing to reflect the cumulative revenue requirement impact regarding the non-jurisdictional work under FECO IF-SC-000178-1 that should have been excluded from Rider DCR.

FirstEnergy Response: Starting with the July 1, 2016, Rider DCR filing, the Companies updated their Rider DCR preparation process to reflect the correct gross plant and reserve balance exclusions associated with the with non-jurisdictional work order FECO IF-SC-000178-1. The Companies' July 1, 2016, Rider DCR filing also included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[14] Blue Ridge also confirmed that the adjustment was appropriately reflected in the Rider DCR filings.[15] No additional work is recommended.

h) Recommendation 08, 2015 DCR Report, p. 61: Blue Ridge recommends that a reconciliation calculation be included in the next Rider DCR filing to reflect the cumulative revenue requirement impact (in the form of depreciation and property tax expense) that results from the inclusion of the pension adjustments that did not have retirements recorded.

FirstEnergy Response: The Companies' July 1, 2016, Rider DCR filing included an adjustment to remove the cumulative revenue requirement impact associated with the aforementioned correction.

Blue Ridge's Comments: Blue Ridge verified that the July 1, 2016, filing reflected the cumulative impact to the Rider DCR of the overstatement.[16] No additional work is recommended.

i) Recommendation 09, 2015 DCR Report, p. 61: Blue Ridge recommends that FirstEnergy move the residual pension asset balances associated with FERC account 303 that were residing in unspecified locations as of September 2015 to specified locations.

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[12] FirstEnergy's response to Data Request BRC Set 12-INT-001.
[13] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachments 3 and 6-Confidential.
[14] FirstEnergy's response to Data Request BRC Set 12-INT-001.
[15] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachments 3 and 6-Confidential.
[16] FirstEnergy's response to Data Request BRC Set 12-INT-001.

FirstEnergy Response: FirstEnergy responded that upon further review, they have determined that the residual pension asset balances associated with FERC 303 that were residing in unspecified locations were, in fact, moved to specified locations in August 2015.

Blue Ridge's Comments: FirstEnergy's recent determination that the residual pension asset balances associated with FERC 303 were moved to specified locations in August 2015 appears to contradict their response in the 2015 audit to Data Request 12-INT-4, part h: "Furthermore, the Companies have determined that there are residual pension asset balances associated with FERC Account 303 residing in unspecified locations as of September 2015." Additionally, FirstEnergy supplied a table of those amounts, totaling $1,948,984. As the amounts were removed in either August or September 2015, there would be no effect to the DCR calculation for 2016, and therefore, Blue Ridge is accepting FirstEnergy's statement of recent determination. No additional work is recommended.

j) Recommendation 10, 2015 DCR Report, p. 66: The Companies made modifications to their IT budget process that were completed as of March 31, 2016. However, Blue Ridge recommends that the Companies review their project planning process on non-IT-related projects to ensure that the methodology allows for projects to be fully scoped prior to execution.

FirstEnergy Response: The Companies 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.

Blue Ridge's Comments: Blue Ridge recommends that the Companies initiate the internal audit specified in their response.

k) Recommendation 11, 2015 DCR Report, p. 67: Blue Ridge recommends that the Companies evaluate the process used to record retirements so that the recording of retirements takes place at or before the plant additions are recorded to plant in service to ensure that both the replacement asset and the retired asset are not recording depreciation at the same time.

FirstEnergy Response: The Companies' response to this recommendation is to provide information concerning the current process used to ensure the recording of retirements:

1. The Companies' system does not allow retirements to be booked any sooner than the in-service date of a work order.
2. The Companies maintain internal controls to mitigate the risk that a replacement asset and a retired asset would record depreciation of an asset at the same time. These internal controls cover the processes used to record items such as retirements, depreciation expense, and accumulated reserve for depreciation. For example, work orders generated by the CREWS system undergo an "Automated Review at Closeout" (ARC). Specific ARCs are set up to identify and flag work orders with cost of removal and no associated retirements for further review.
3. Many of the Companies' internal controls are audited on an annual basis by a third party and by the Companies' Internal Audit Department. The internal controls provide reasonable assurance that the Companies' financial statements are not materially misstated. In 2016, the Companies continued to monitor the process used to record retirements as a part of their annual SOX control tests.

Blue Ridge's Comments: While Blue Ridge acknowledges the Companies current controls, the recommendation was made in regard to last year's audit discovery of two work orders that had assets retired greater than six months after the replacement assets were put into service.[17] While the impact on Rider DCR associated with the delay in recording retirements was immaterial, the purpose of Blue Ridge's recommendation was to prevent additional delays from recurring. The primary thrust of Blue Ridge's recommendation, therefore, was for the Companies' to "evaluate the process used to record retirements." The Companies have done the evaluation as evidenced by their response. As a result, Blue Ridge accepts the Companies' explanation of process control.

l) Recommendation 12, 2015 DCR Report, p. 75: Blue Ridge recommends that the formulas in the Estimated first quarter Intangible Depreciation Expense—CECO net plant calculation for 101/6-303 Software be inserted so that these cells may be used to turn off/on the depreciation expense calculation to ensure that depreciation expense is calculated or not calculated depending on whether the assets are fully amortized.

FirstEnergy Response: The Companies implemented this recommendation beginning with the April 1, 2016 Rider DCR filing.

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

[17] Blue Ridge report "Compliance Audit of the 2015 Delivery Capital Recovery (DCR) Riders of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company," Docket No. 15-1739-EL-RDR, dated April 22, 2016, page 66.

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. The 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 2017.

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[18]) 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").[19]
>
> 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.[20]
>
> The filing shall show the Plant in Service account balances and accumulated depreciation reserve balances compared to that approved in the last distribution

[18] 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.
[19] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[20] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.

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.[21]

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 2015 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' cost controls were adequate and not unreasonable.

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-2015 modifications to those policies, procedures, and/or process flow diagrams to determine whether any concerns were raised in connection to the impact of those changes with regard to the Rider DCR calculations. The policies, procedures, and process flow diagrams reviewed related to the following areas:

1. Plant Account
    a. Capitalization

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

   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)[22]

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."[23]

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 (CPR). This CPR is a PowerPlant[24] 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

[22] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy – Confidential.
[23] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, a, Attachment 1, Capitalization Policy – Confidential.
[24] "PowerPlant" is a commercially available computer software application used in plant accounting.

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 2016.[25]

FirstEnergy did make a minor accounting revision to reimbursement costs related to the attendance of business and/or community functions.[26]

Preparation and Approval of Work Orders[27]

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 2016.[28]

Contributions in Aid of Construction (CIAC)[29]

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 2016.[30] However, FirstEnergy stated that, as of July 2016, it had completed the programming change to PowerPlant to eliminate the manual process that was used to move CIAC.[31]

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[25] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
[26] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential, c, including Attachment 1 – Confidential.
[27] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, b, Attachment 1, Work Management Process – Confidential and FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-3, b, Attachment 2, CREWS Work Request Narratives – Confidential.
[28] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
[29] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, e, Attachment 1, Invoicing Process Flow Chart – Confidential.
[30] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
[31] FirstEnergy's response to Data Request BRC Set 1-INT-011.

Application of AFUDC[32]

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 2016.[33]

Purchasing/Procurement[34]

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's Enterprise Sourcing of Materials and Services procedure was revised in 2016. FirstEnergy provided a copy of the revised procedure (Revision 6), which included a revision history on page 36 of the document. No changes were significant as related to their effect on the DCR process; the updates did not change the substance of the Companies' sourcing process and procedures.

Taxes (Accumulated Deferred Income Tax, Income Tax, and Commercial Activity Tax)[35]

In its Accounting for Income Taxes procedure, the Companies confirmed 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 2016.[36]

Insurance Recovery[37]

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 2016.[38]

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[32] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, d, Attachment 1, Accounting For Capitalized Financing Costs During Construction – Confidential.
[33] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
[34] FirstEnergy's response to Data Request BRC Set 1-INT-013, b, including Attachment 3, Procedure for Enterprise Sourcing of Materials and Services – Confidential.
[35] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, m, Attachment 1, Income Tax Policy and Procedure – Confidential.
[36] FirstEnergy's response to Data Request BRC 1-INT-013 – Confidential.
[37] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, a - Confidential.
[38] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.

Property Taxes[39]

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 2016.[40]

Service Company Allocations[41]

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."[42] 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 2016.

Budgeting/Projections[43]

The Rider DCR Compliance Filings include three months of projected data through the end of February 2017. The estimate is based on the 2016 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.[44] 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 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.

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39 FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, n, Attachment 1, Ohio Property Tax Returns – Confidential.
40 FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
41 FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
42 Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 15.
43 FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Confidential; FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure – Confidential; and FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 3, Energy Delivery Capital Allocation Process – Confidential.
44 DCR Filings: CE 12-30-16 DCR Filing.pdf, OE 12-30-16 DCR Filing.pdf, and TE 12-30-16 DCR Filing.pdf.

FirstEnergy's capital budgeting is known internally as "Multi-Year Enterprise Capital Portfolio."[45] Individual business unit programs drive the approval of the capital budgets at the business unit level.[46] 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."[47]

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.[48] Additionally, FirstEnergy made no significant procedural or policy change in 2016.[49]

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 are approved, FirstEnergy manages the project according to the new forecast (both cost and schedule).[50]

FirstEnergy introduced two changes to the IT process during the 2016 DCR period. First, the process documentation updates were made to improve project charter value statements (for projects justified on the basis of an increase in efficiency and savings). Second, the Change Control process was enhanced to include a mechanism for identifying when a change has affected the value statement.[51]

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

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[45] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Confidential.
[46] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 2, FE Capital Portfolio Development and Capital Management Procedure – Confidential.
[47] FirstEnergy's response to 2011 audit Data Request BRC Set 1-INT-003, c, Attachment 1, Creating Multi-Year Enterprise Capital Portfolio – Section C.2 – Confidential.
[48] FirstEnergy's response to 2014 Data Request BRC Set 1-INT-015 – Confidential.
[49] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.
[50] FirstEnergy's response to 2013 audit Data Request BRC Set 1-INT-032 – Confidential.
[51] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential.

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:[52]

- 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)
- 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.

[52] 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.

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.[53] For this year, that effort included the following:

- Exclusion of gross plant and reserve balances associated with activity that is non-jurisdictional to Rider DCR
- Inclusion of any other permanent or ongoing adjustments due to the overstatement of gross plant or reserve activity due to any other reasons identified in the audit report of the 2015 Rider DCR

Internal Audit and SOX Compliance

Blue Ridge reviewed the list of internal audits performed in 2016 regarding controls that would affect Rider DCR.[54] In particular, we examined and were satisfied with the findings and recommendations associated with three of the audits: Audit Nos. 26573, 25382, and 26329.[55]

Audit 26573 regarded a review of Accounts Payable during the period January 1, 2016, through February 10, 2016. No adjustments were required and no recommendations were determined. Audit 25382 was a Process Review as of March 31, 2016, following a PowerPlant system change. Operational improvements were recommended and implemented. The impacts to the business processes as a result of the recent PowerPlant system change did not modify the SOX controls. Audit 26329 was a review of payment recovery for Accounts Payable. Processing accuracy was rated above average, and no recommendations resulted from the audit.

Additionally, Blue Ridge requested information regarding control deficiencies resulting from four audits related to quarterly Sarbanes-Oxley assessments (i.e., audits 26482, 26489, 26493, and 26501). Only one of the four had a significant deficiency; however, the deficiency had no effect on Rider DCR.[56]

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. Blue Ridge concluded that the Companies' controls were adequate and not unreasonable.

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.

[53] FirstEnergy's response to Data Request BRC Set 1-INT-012.
[54] FirstEnergy's response to Data Request BRC Set 1-INT-015, Attachment 1 – Confidential.
[55] FirstEnergy's response to Data Request BRC Set 2-INT-005, Attachment 1 – Confidential.
[56] FirstEnergy's response to Data Requests BRC Set 1-INT-16 and BRC Set 2-INT-006 – Confidential.

In the current audit of the DCR year 2016, Blue Ridge evaluated several yearly and/or quarterly changes and variances in account balances:

- Year-to-Year and Quarter-to-Quarter DCR Filing Plant-In-Service Balances
- Year-to-Year and Quarter-to-Quarter DCR Filing Reserve Balances
- Year-to-Year and Quarter-to-Quarter DCR Filing ADIT Balances
- Year-to-Year and Quarter-to-Quarter DCR Filing Service Company Balances
- End-of-year 2015 DCR Filing to 2015 FERC Form 1 Plant-in-Service Balances
- 2016 Work Order Population totals to 2016 DCR Filing Year-to-Year Plant-In-Service Activity
- 2016 Plant Additions, Retirements, Transfers, and Adjustments

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, 2015, across the four quarterly reports of 2016 (February 29, 2016; May 31, 2016; August 31, 2016; and November 30, 2016).

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 $100.1 million, $136.6 million, and $37.5 million for CE, OE, and TE, respectively. These increases represent a year-over-year percentage increase of 3.5%, 4.2%, and 3.3% for CE, OE, and TE, respectively.

Table 11: Adjusted Plant Change from 11/30/2015 to 11/30/2016[57]

	(a)	(b)	(c)	(d)	(e)
Line No.	Account Title	Adjusted Balance 11/30/15	Adjusted Balance 11/30/16	Difference (c)-(b)	% (d)/(b)
1	**The Cleveland Electric Illuminating Company**				
2	Transmission	$ 417,288,386	$ 431,628,975	$ 14,340,588	3.4%
3	Distribution	2,146,090,268	2,217,333,891	71,243,623	3.3%
4	General	149,771,872	156,348,800	6,576,928	4.4%
5	Other	53,736,519	56,089,957	2,353,438	4.4%
6	Service Company Allocated	88,149,759	93,710,646	5,560,887	6.3%
7	**Total Cleveland Electric Illuminating Company**	**$ 2,855,036,804**	**$ 2,955,112,269**	**$ 100,075,464**	**3.5%**
8	**Ohio Edison Company**				
9	Transmission	$ 211,123,376	$ 213,163,308	$ 2,039,932	1.0%
10	Distribution	2,661,407,297	2,764,255,371	102,848,074	3.9%
11	General	162,421,589	178,984,926	16,563,337	10.2%
12	Other	72,768,268	81,134,820	8,366,553	11.5%
13	Service Company Allocated	106,821,875	113,560,685	6,738,810	6.3%
14	**Total Ohio Edison Company**	**$ 3,214,542,405**	**$ 3,351,099,110**	**$ 136,556,706**	**4.2%**
15	**The Toledo Edison Company**				
16	Transmission	$ 22,702,214	$ 22,474,270	$ (227,944)	-1.0%
17	Distribution	956,752,720	986,294,036	29,541,316	3.1%
18	General	70,504,605	74,463,450	3,958,845	5.6%
19	Other	25,500,420	26,720,165	1,219,745	4.8%
20	Service Company Allocated	47,021,476	49,987,804	2,966,328	6.3%
21	**Total Toledo Edison Company**	**$ 1,122,481,433**	**$ 1,159,939,725**	**$ 37,458,292**	**3.3%**
22	**FirstEnergy Ohio Operating Companies**	**$ 7,192,060,642**	**$ 7,466,151,104**	**$ 274,090,462**	**3.8%**

In our analysis of specific account variances from November 30, 2015, through November 30, 2016, Blue Ridge submitted questions and received responses from FirstEnergy regarding three variances of concern among the three FirstEnergy operating companies. One other account (397 Communication Equipment) for both OE and TE had a change significant enough to warrant further investigation. Blue Ridge focused on that account in its evaluation of 2016 Plant Additions, Retirements, Transfers, and Adjustments (later in this report section) and, therefore, did not include that analysis here. Blue Ridge's questions and received responses from FirstEnergy for the account variances of concern resulted in the following determination:[58]

1. CEI account 303 Intangible Software: November 30, 2015, balance = $50,559,055 and November 30, 2016 balance = $52,912,494; difference = $2,353,439; increase of 4.7%
2. OE account 303 Intangible Software: November 30, 2015, balance = $68,862,709 and November 30, 2016, balance = $77,229,262; difference = $8,366,553; increase of 12.1%

[57] BRCS WP FE DCR CF Variance 2016– Confidential.xlsx, tab – PIS Summary. Source data for the table and supporting workpapers: DCR Compliance Filings 2/29/2016, 5/31/2016, 8/31/2016, and 11/30/2016 for all three Companies.
[58] FirstEnergy's response to Data Requests BRC Set 2-INT-004 – Confidential with Attachments.

3. TE account 303 Intangible Software: November 30, 2015 balance = $25,206,116 and November 30, 2016, balance = $26,425,862; difference = $1,219,746; increase of 4.8%

   Analysis: Although the amount of change from one year to the next was not significant, cumulative increases over the past couple of years raised concern regarding the Intangible Plant of FERC account 303. For example, TE's account 303 had already increased 13.5% from 2014 to 2015, thus resulting in a 19.0% total increase from November 30, 2014, to November 30, 2016. FirstEnergy provided documented work order detail supporting the addition change in account balance (as they had during the previous DCR year). Blue Ridge verified work order identification and accuracy of account totals supporting the DCR filing and was satisfied that the presentation was not unreasonable for the operating companies.

   Furthermore, Blue Ridge reviewed nine Account 303 work orders in our testing process along with 13 others that related to the general equipment accounts (i.e., accounts 390 through 398). The results of those testing activities are discussed in the work-order-testing portion of this report's Gross Plant in Service section.

   The majority of Account 303 work is performed under FECO work orders. For that reason, Blue Ridge normally tests FECO intangible work orders more than those of the operating companies. Specific to the Service Company, we reviewed 12 work orders (approximately 17%, totaling $7.6 million). The results of those tests are also reported in the work-order-testing portion of this report's Gross Plant in Service section.

Year-to-Year DCR Filing Reserve Balances

In our analysis of specific reserve account variances from November 30, 2015, through November 30, 2016, Blue Ridge submitted questions and received responses from FirstEnergy regarding three variances of concern among the three FirstEnergy operating companies,[59] resulting in the following determinations:

1. Reserve TE account 370 Meters: November 30, 2015 balance = $19,819,297 and November 30, 2016, balance = $19,433,375; difference = $385,922; Reduction in meter account balance

   Analysis: FirstEnergy explained that an increase in the provision for depreciation of $1,518,709, offset by $(1,309,829) in cost of removal charges and $(594,802) in retirements resulted in the reduction.

2. TE account 393 Stores Equipment: November 30, 2015, balance = $371,768 and November 30, 2016, balance = $369,458; difference = $2,310; Reduction in balance

   Analysis: FirstEnergy explained that an increase in the provision for depreciation of $18,242, offset by $(20,552) in retirements resulted in the reduction.

3. TE account 395 Laboratory Equipment: November 30, 2015, balance = $1,043,101 and November 30, 2016, balance = $1,036,667; difference = $6,434; Reduction in balance

   Analysis: FirstEnergy explained that an increase in the provision for depreciation of $46,522, offset by $(52,955) in retirements resulted in the reduction.

[59] FirstEnergy's response to Data Request BRC Set 2-INT-003 – Confidential.

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 2015 DCR Filing to 2015 FERC Form 1 Plant-in-Service Balances

Blue Ridge asked FirstEnergy to provide a reconciliation between the 2015 plant-in-service account balances in the Companies' DCR Compliance Filings to their 2015 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 2015 end-of-year DCR filings matched the balances of the 2015 FERC Forms 1.[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, 2016, gross plant balances and the November 30, 2015, gross plant balances for all Companies with the Work Order totals for the same period. Blue Ridge found that the balances matched.

2016 Plant Additions, Retirements, Transfers, and Adjustments

Blue Ridge also investigated plant additions, retirements, transfers, and adjustments in order to understand changes to the unadjusted plant balances. In its examination, Blue Ridge asked a multi-part data request concerning these items to which FirstEnergy provided explanations as follows:[61]

1. CEI Account 361 Structures and improvements—Additions of $1,512,706 with $0 change in Retirements

   Analysis: Blue Ridge reviewed the work orders making up the change and found the activity not unreasonable.

2. CEI Account 362 Station equipment—Transfers/Adjustments of $51,892

   Analysis: The positive transfer/adjustment balance was the result of a correction to an asset location assignment that resulted in the transfer of plant from ATSI to CEI.

3. CEI Account 391 Office furniture, equipment—Additions of $1,486,341 and Retirements of $1,194,294.

   Analysis: Blue Ridge reviewed the work order activity and found it not unreasonable. Additionally, the jurisdictional work order retirements were associated with the automatic annual retirement of amortized general plant assets.

4. CEI Account 394 Tools, shop, garage equipment—Additions of $1,486,341

   Analysis: Additions and transfers/adjustments did not appear unreasonable.

[60] FirstEnergy's response to Data Request BRC Set 6-INT-001 – Confidential with Attachments.
[61] FirstEnergy's response to Data Request BRC Set 2-INT-002, with Attachments 1 through 16 – Confidential.

5. CEI Account 397 Communication equipment—Additions of 2,100,240

   Analysis: Work order additions did not appear unreasonable.

6. OE Account 360 Land and land rights—negative Additions of $26,508

   Analysis: Work order activity included the transfer of dollars between FERC accounts as a result of the unitization process.

7. OE Account 361 Structures and Improvements—negative Transfers/Adjustments of $52,202

   Analysis: The negative transfer/adjustment balance was the result of a correction to an asset location assignment that resulted in the transfer of plant from account 361 to 367.

8. OE Account 362 Station equipment—Transfers/Adjustments of $325,550

   Analysis: Transfer of a breaker from ATSI to OE. Also, work order representing the net effect of transfers between OE and ATSI and between FERC accounts.

9. OE Account 390 Structures and improvements—Additions of $10,814,114

   Analysis: Work order additions did not appear unreasonable.

10. OE Account 397 Communication equipment—Additions of $7,293,584

    Analysis: Work order additions did not appear unreasonable.

11. TE Account 361 Structures and improvements—negative Additions of $3,525

    Analysis: Reversal of charges and associated overheads resulted in overall credit. Year-end respreads allocation credits resulted in overall credit.

12. TE Account 397 Communication equipment—Additions of $3,495,801

    Analysis: Work order additions did not appear unreasonable.

13. FESC Account 390 Structures and improvements—Transfers/Adjustments of $77,921

    Analysis: Positive transfer/adjustment balance was the result of a correction to an asset location assignment that resulted in the transfer of plant from OE to FECO.

14. FESC Account 391 Office furniture, equipment—Additions of $19,883,101 and Retirements of $15,915,947

    Analysis: Work order activity and retirements associated with automatic annual retirement of amortized general plant assets did not appear unreasonable.

15. FESC Account 397 Communication equipment—Additions of $8,121,531 and Retirements of $926,589

    Analysis: Work order additions did not appear unreasonable.

As a result of our analysis, Blue Ridge was satisfied with the changes in plant additions, retirements, adjustments, and transfers.

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]

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 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

[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 12/30/16, page 19.
[67] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1b.
[68] Case No. 10-0388-EL-SSO Stipulation and Recommendation, Section F.2, pages 27-28.

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]

In the preparation of the Companies' December 30, 2016, DCR filing, the Companies determined that there was activity associated with Rider EDR(g) funding project (CE-000303) that was not properly excluded from prior DCR filings. 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 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.[70] The Companies also confirmed that the actual November 30, 2016, and estimated February 28, 2017, balances were correct.[71]

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]

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.[73]

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.

During discovery, the Companies identified a work order (996216) charged to Account 362-Station Equipment that should have been excluded based on its funding project (CE-004000). While the dollar amount was minimal (i.e., $140), the Companies stated (and Blue Ridge recommends) that the amount be included in the reconciliation calculation in a future Rider DCR filing.[74] While the impact is immaterial to the Rider DCR revenue requirement calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #1**].

The work order sample testing included specific criteria to review project descriptions to ensure that the work orders did not include AMI work. One work order contained a minor amount associated with Smartgrid. This item is noted at testing step T1 below.[75]

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[69] CEI, OE, and TE Rider DCR Compliance Filings dated 12/30/16, pages 19 and 44.
[70] FirstEnergy's response to Data Request BRC Set 1-INT-029.
[71] FirstEnergy's response to Data Request BRC Set 9-INT-002.
[72] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1c.
[73] Case No. 09-1820-EL-ATA, et. al., Application pages 5-7.
[74] FirstEnergy's response to Data Request BRC Set 1-INT-005, part b.
[75] Additional Validation Testing from Sampled Work Orders, Testing Criteria T1a.

Other Riders

In addition to Riders LEX, EDR, and AMI, the Combined Stipulation (reaffirmed in Case Nos. 12-1230-EL-SSO[76] and 14-1297-EL-SSO[77]) 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.[78] In addition to the Riders DCR, LEX, EDR, and AMI, the Companies' tariffs include the following riders:

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 Critical Peak Pricing
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 do not include distribution capital additions or Service Company capital additions that are allocated to Rider DCR.[79] The list of riders above includes five new riders: Distribution Modernization Rider (Rider DMR); Government Directives Recovery Rider (Rider GDR); Ohio Renewable Resources Rider (Rider ORR); Commercial High Load Factor Experimental Time-of-Use Rider (Rider HLF); and Residential Critical Peak Pricing Rider (Rider RCP). 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. The Companies stated that to the extent the Rider GCR is populated in the future any costs included for recovery would exclude capital

[76] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[77] 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.
[78] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[79] FirstEnergy's response to Data Request BRC Set 1-INT-34.

additions or other components that are currently being recovered through Rider DCR.[80] Blue Ridge's review found there was no indication that these non-Rider-DCR tariffs would contain distribution plant.

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 12: ATSI Land Lease (FERC Account 350) Excluded from Rider DCR[81]

	Actual 11/30/16		Estimated 2/29/17	
Company	**Gross**	**Reserve[82]**	**Gross**	**Reserve**
CEI	56,405,971	0	56,405,971	0
OE	86,973,963	0	86,973,963	0
TE	15,628,387	0	15,628,387	0
Total	159,008,321	0	159,008,321	0

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.

Table 13: ATSI Land Lease-Change in Amounts from Case No. 07-551-EL-AIR and Prior Audits

Description	CEI	OE	TE
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
12/31/2011 Rider DCR Amounts	$ 57,266,431	$ 85,290,624	$ 15,628,800
12/31/2012 Rider DCR Amounts	$ 57,227,343	$ 85,471,094	$ 15,628,438
12/31/2013 Rider DCR Amounts	$ 59,306,092	$ 86,963,323	$ 16,373,799
12/31/2014 Rider DCR Amounts	$ 57,224,624	$ 85,567,532	$ 15,628,438
12/31/2015 Rider DCR Amounts-Corrected	$ 56,418,950	$ 86,956,515	$ 15,628,438
12/31/2016 Rider DCR Amounts-Corrected	$ 56,405,971	$ 86,982,409	$ 15,628,512
Change from 2015 to 2016 (Incremental Activity)	$ (12,979)	$ 25,894	$ 74
Difference 2016 vs Case 07-551-EL-AIR	$ (860,460)	$ 1,691,785	$ (288)

During the examination, the Companies found that ATSI balances as of November 30, 2015, used for the 2016 Rider DCR, had not been updated to correct errors identified in last year's audit.[83]

[80] FirstEnergy's response to Data Request BRC Set 10-INT-1.
[81] CEI, OE, and TE Rider DCR Compliance Filings dated 12/01/16, page 19 and page 44.
[82] The amounts removed are associated with land, thus there is no depreciation reserve.
[83] FirstEnergy's response to Data Request BRC Set 1-INT-027 – Confidential.

The following table shows the amount included in the exclusion and the amount that should have been included.

Table 14: Corrected Balances for ATSI Land Lease Exclusion[84]

Company	As Filed	Corrected	Difference
CEI	$ 56,405,971	$ 56,405,971	$ 0
OE	$ 86,973,963	$ 86,982,409	$ 8,446
TE	$ 15,628,387	$ 15,628,512	$ 125
Total	$ 159,008,320	$ 159,016,892	$ 8,572

Individually, the difference is immaterial to the Rider DCR revenue requirement calculations (OE—$8,446 and TE—$125) [**ADJUSTMENT #2**]. However, the adjustment has been included within the total impact calculations.

The Companies stated (and Blue Ridge recommends) that a reconciliation be included in the Rider DCR revenue requirements in a future filing that incorporates the effect on revenues had the oversight from the prior audit been incorporated beginning with the actual February 29, 2016, plant balances.

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

There were minor adjustments that should be made to the exclusions associated with Rider EDR(g), Rider AMI, and ATSI Land Lease work orders. Individually, these adjustments would not be material to Rider DCR. The cumulative impact will be included in the overall findings and recommendations associated with this report.

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.

[84] FirstEnergy's response to Data Request BRC Set 1-INT-027 – Confidential.

Table 15: Incremental Change in Gross Plant from 11/30/15 to 11/30/16[85]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	2,855,036,804	2,955,112,270	100,075,465
Ohio Edison Company	3,214,542,405	3,351,099,110	136,556,705
The Toledo Edison Company	1,122,481,433	1,159,939,724	37,458,291
Total	7,192,060,642	7,466,151,104	274,090,461

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 2016. Each company had normal, recurring replacement programs in 2016, including Pole Replacements, Underground Cable Replacement, Feeder Repair/Replacement, Worst Performing Circuit/CEMI Program, and Downtown Network Upgrades.[86]

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.[87]

Source Data Validation

Blue Ridge traced the values used for actual November 30, 2016 and estimated February 28, 2017, 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, 2017, estimate recognize a true up of forecast to actual November 30, 2016, balances and adjustments from prior audits.[88]

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

[85] WP V&V FE DCR Compliance Filing 12.31.2016-Confidential.
[86] FirstEnergy's response to Data Request BRC Set 1-INT-020.
[87] WP V&V FE DCR Compliance Filing 12.30.16-Confidential.
[88] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachment 3 – Confidential.

> 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.[89]

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.[90]

Additional Validation Testing from Sampled Work Orders

The Companies provided a list of work orders that support gross plant in service for December 2015 through November 2016.[91] Blue Ridge validated that the work order amounts reconciled to the Companies' DCR filing gross plant balances.[92] In addition, Blue Ridge reviewed the population of work orders for work order numbers that represent plant that is specifically excluded from Rider DCR; 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 by PPS; 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[93] and professional judgment, Blue Ridge selected 71 work orders representing 199 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 16: Work Orders and FERC Cost Line items in Population and Sample by Company[94]

	Population		Sample	
	Work Orders	**FERC Cost Line Items**	**Work Orders**	**FERC Cost Line Items**
Cleveland Electric	30,548	43,972	19	101
Ohio Edison	34,688	51,987	21	35
Toledo Edison	14,145	19,663	19	51
Service Company	183	229	12	14
Total	**79,564**	**115,851**	**71**	**201**

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

[89] WP FE response to 2011 Audit Data Request BRC Set 14-INT-001.
[90] WP FEOH 2016 Pre-Date Certain Pension Impact Analysis 2012-201 - CONFIDENTIAL.
[91] FirstEnergy's response to Data Request BRC Set 1-INT-002, Attachment 1 – Confidential.
[92] WP Population Recon –BRC Set-1-INT-006 Attachment 1 and FirstEnergy's response to Data Request BRC Set 1-INT-006.
[93] WP FEOH 2016 Sample Size Calculation Work Orders through 11-30-16-Confidential.xlsx.
[94] FirstEnergy's response to Data Request BRC Set 1-INT-002 and WP FEOH 2016 Sample Size Calculation Work Orders through 11-30-16-Confidential.xlsx

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.[95] 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 device
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

Project Testing

The sampled work orders were evaluated based on objective criteria identified as T1 through T10.[96] 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, one work order was identified that should have been excluded from Rider DCR.

The Companies identified work order activity of ($140) in CECO FERC Account 362 – Station Equipment that should have been excluded based on its funding project (CE-004000 – work order 996216), which identifies it as a SmartGrid project. 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 including the abovementioned costs.[97] While the impact is immaterial to the Rider DCR revenue requirements calculations, the adjustment has been included within the total impact calculations [**ADJUSTMENT #1**]

[95] WP FEOH 2016 Sample Work Order Testing Matrix-Confidential.
[96] WP FEOH 2016 Sample Work Order Testing Matrix-Confidential.
[97] FirstEnergy's response to Data Request BRC Set 1-INT-005, part b.

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 except for the work order listed in T1 above, the sample did not contain any AMI or SmartGrid work orders.[98]

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.[99]

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.[100]

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.[101]

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.[102]

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.

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. Five work orders included in the sample referred to adjustments.

- CECO work order CE-900477-CCOH-ADJ – Capital Related Payroll Overhead Adjust for $2,278,079 is an accounting work order to make Capital payroll related overhead adjustments manually that cannot be applied automatically. Blue Ridge reviewed the

[98] FirstEnergy's response to Data Request BRC Set 1-INT-005, part b.
[99] FirstEnergy's response to Data Request BRC Set 1-INT-005, part d.
[100] WP FEOH 2016 workorder testing matrix.
[101] WP FEOH 2016 workorder testing matrix and First Energy's response to Data Rrequest BRC Set-1-INT-005, part a.
[102] FirstEnergy's response to Data Request BRC Set 1-INT-013 – Confidential and BRC Set 1-INT-026.

detail that supports the accounting entries. Blue Ridge concludes that the Companies' explanations and support were not unreasonable.[103]

- CECO work order HE123 – CECO PROP ASSETS – PWR PLT TRNSF & ADJ for ($706,674) is an accounting entry to transfer/adjust between CEI and other companies as a result of the unitization process and SOX. Blue Ridge reviewed the detail that supports the accounting entries. Approximately $669,638 of the adjustment represents retirements of unspecified assets. All those retirements took place in November 2016. The detail indicated a single line description of the assets and the accounts from which those assets were retired. Blue Ridge was unable to determine whether the assets retired were related to replacement projects and whether those retirements were recorded timely. Blue Ridge recommends that the Companies determine the impact of the retirements on the depreciation reserve, and specifically on the over accrual of depreciation, and adjust the subsequent DCR filing accordingly.[104]
- CECO work order CN-001211-DO – DX Meter Program Rate Case – is an accounting entry to reverse an entry made in November 2015 related to AFUDC as a result of Rate Case compliance. Blue Ridge concludes that the explanation provided by the Companies was not unreasonable.
- OECO work order 14155744 – Equip Investigate / Repair – Recloser I for ($487,527) is an accounting entry to transfer overheads back to the overhead pool and reclassify costs from FERC 362 to FERC 367 as a result of unitizations. Blue Ridge reviewed the detail that supports the accounting entries. Blue Ridge concludes that the explanations provided by the Companies are not unreasonable.[105]
- TECO work order JC607 – PROP ASSETS-PWR PLT TRNSF & ADJ for ($334,967) is the same adjustment as HE-123 above but for TECO rather than CECO. Blue Ridge reviewed the detail that supports the accounting entries. The entire entry, except for $3,271, represents retirements of unspecified assets. All of the unspecified asset retirements took place in November 2016. The detail indicated a single line description of the assets and the accounts from which those assets were retired.[106] Blue Ridge was unable to determine whether the assets retired were related to replacement projects and whether those retirements were recorded timely. Blue Ridge recommends that the Companies determine the impact of the retirements on the depreciation reserve, and specifically the over accrual of depreciation, and adjust the subsequent DCR filing accordingly.

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

The following 13 work orders were considered emergent projects and neither had budgeted amounts nor were in the original capital budget.[107] These 13 workorders represent 18% of the projects/work orders in the sample selection. The Companies explained why each project was performed and why each was considered an emergent project. Some of the projects were to replace aging assets. The explanations were not unreasonable. However, the number of unbudgeted (emergent) work orders is significant in relation to the total work orders

[103] FirstEnergy's response to Data Request BRC Set 4-INT-002, Attachment 1.
[104] FirstEnergy's response to Data Request BRC Set 4-INT-003, Attachment 1.
[105] FirstEnergy's response to Data Request BRC Set 4-INT-006, Attachment 1.
[106] FirstEnergy's response to Data Request BRC Set 4-INT-007, Attachment 1.
[107] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 1 and 2.

sampled. Blue Ridge recommends that 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.

1. CECO – 14164717 - CEI Plant Employee Onboarding Expenses - $1,606,349
2. CECO – 14581787 - Clark Q-1-CK-T 138 kV Breaker Replacement - $1,021,299
3. OECO – 14619456 - Class A – High Voltage - $440,155
4. TECO – 14087593 - Commercial Upgrade - $95,516
5. OECO – 14627153 - E MARKET ST REPAOR DUCT BANK - $1,255,108
6. CECO – 14499354 - Imperial 71-IP-T Transformer Replacement - $1,020,605
7. OECO – 14292861 - Sub – Replace line relayin - $1,222,930
8. TECO – 13137497 - Reclocate streetlights on hi level bridg - $104,981
9. TECO – 14853199 - rpl 4 poles in swamp area at ryan sub - $38,524
10. CECO – 14479765 - SW - Grant #3-GT-T Transformer Replacemet- $2,316,564
11. TECO – 14624000 - Sylvania & Centennial Roundabout - $618,453
12. TECO – 13792687 - Talmadge Mobile Parking Expansion - $204,912
13. TECO – 14434237 - TE - Implement New Mobile Radio System - $1,557,910

Besides the 13 emergent projects that did not have budgets, Blue Ridge found another 10 of the 71 work orders / projects selected for testing that did not have budgets. Five of the 10 were accounting work orders that are not budgeted, two of the 10 were storm work orders that are not budgeted, another two represented work carried over from prior years and not budgeted, and one represented unbudgeted damage claims reimbursements. The explanations for these items were not unreasonable. Of the remaining 48 workorders, 19 were over budget by more than 15%.[108] The Companies provided explanations for the overages.

- FECO - ITF-SC-000092-SW15-1 - Hardware Upgrades 2015-CAP
  - Capital Project Cost: $447,654.18
  - Over budget by 100.0%: $447,654
  - Description: Capital portion of the Hardware upgrade fee
  - Reason for cost overrun: The vendor provided documentation that supported capitalization of a portion of the support fees. As such, there was no capital budget prepared previously.
- CECO – 14883452 - Cable Replacement UD-0573
  - Capital Project Cost: $4,888,376
  - Over budget by 39.6%: $1,386,703.74
  - Description: Replace failed URD cables at time of 3rd failure
  - Reason for cost overrun: Actual contractors and materials were greater than budgeted due to higher volume of cable replacement than originally assumed.
- CECO – 14746978 - Cable Replacement UD-2021
  - Capital Project Cost: $4,888,376
  - Over budget by 39.6%: $1,386,703.74
  - Description: Replace failed URD cables at time of 3rd failure
  - Reason for cost overrun: Actual contractors and materials were greater than budgeted due to higher volume of cable replacement than originally assumed.

[108] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 1 and 2.

- FECO - ITS-SC-000375-1 - Corporate Security Improvements - Cap
  - Capital Project Cost: $668,559.29
  - Over budget by 66.7%: $267,503
  - Description: A series of software, hardware, and data enhancements for the ETT Web - Physical Security processes
  - Reason for cost overrun: In order to meet the project schedule, additional contractors were required to replace internal labor subject matter experts that left the company. Additional contracted resources were obtained to address emergent business requirements.
- FECO - ITS-SC-000391-1 - Identity Mgt Initiative-Phase 3.2 - Cap
  - Capital Project Cost: $104,808.77
  - Over budget by 100.0%: $104,809
  - Description: Implementation of Service Manager/FIM SVC Catalog integration.
  - Reason for cost overrun: The budget for this project covers both ITS-SC-000390 & ITS-SC-000391. The original work order (ITS-SC-000390) was placed in service as components of the project were moved to production. After the initial design phase, some hardware to support the project was deemed unnecessary, resulting in savings of both hardware and the related labor costs. Additionally, labor-intensive areas of the project were completed with less complexity than originally planned, resulting in further decrease in labor hours.
- OECO - OE-730023 - IT CIP 14 Upgrades - Physical Security
  - Capital Project Cost: $147,923.65
  - Over budget by 72.4%: $62,144
  - Description: Third party security assessments to support NERC CIP standards
  - Reason for cost overrun: In order to meet CIP requirements a change in methodology required additional locations to be assessed.
- CECO - CE-710001 - IT ED Legacy Circuit Replacements
  - Capital Project Cost: $1,908,323.99
  - Over budget by 155.5%: $1,161,563
  - 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.
  - Reason for cost overrun: The initial budget for this project assumed that costs would be spread evenly over the four-year term of the project (2015-2018). However, project work focused on circuits in the Cleveland Electric and Toledo Edison operating companies during this audit period. Since actual costs are being charged to the specific operating company, a current period discrepancy exists between the specific actual charges and the evenly spread budget charges. The expectation is that future costs associated with this work order will be lower than originally budgeted and that over the life of the project, the total project costs will be in line with expectations at the time of the original budget. Note that as of June 2016, the budget reflects a company-specific approach to more accurately depict actual spend.
- TECO - TW-710001 - IT ED Legacy Circuit Replacements
  - Capital Project Cost: $2,007,423.59
  - Over budget by 386.0%: $1,594,374

  - 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.
  - Reason for cost overrun: The initial budget for this project assumed that costs would be spread evenly over the four-year term of the project (2015-2018). However, project work focused on circuits in the Cleveland Electric and Toledo Edison operating companies during this audit period. Since actual costs are being charged to the specific operating company, a current period discrepancy exists between the specific actual charges and the evenly spread budget charges. The expectation is that future costs associated with this work order will be lower than originally budgeted and that over the life of the project, the total project costs will be in line with expectations at the time of the original budget. Note that as of June 2016, the budget reflects a company-specific approach to more accurately depict actual spend.
- OECO - OE-700362 - IT Improve GAAP to FERC Accounting
  - Capital Project Cost: $810,111.51
  - Over budget by 205.3%: $544,792
  - Description: Implement the CO model in the SAP FERC module
  - Reason for cost overrun: Although labor was included in the original plan, it was inadvertently excluded from our budget system, which caused overheads to be excluded from the budget as well. Additionally, a large pension adjustment was made in December 2015 resulting in the remaining overhead variance.
- OECO - OE-700402 - IT WMI Enhancements
  - Capital Project Cost: $526,435.89
  - Over budget by 379.6%: $416,670
  - Description: Enhance the WMI suite of applications as agreed upon by the ED Business owners
  - Reason for cost overrun: The difference in actual versus budgeted costs on this project is primarily attributable to timing differences. At the end of 2015, additional wireless access points were purchased on this work order that were originally planned to be purchased at a later date and on a separate work order (ITS-ED-000404). As a result, actual costs were higher than budgeted for this work order and the budget on the subsequent work order was reduced accordingly to account for the impact making the hardware purchased earlier than originally estimated. Additionally, a large pension adjustment was made in December 2015 resulting in the remaining overhead variance.
- FECO - ITF-SC-000065-SW16-1 - Upgrade Fee 2016-CAP
  - Capital Project Cost: $104,911.02
  - Over budget by 128.1%: $58,911
  - Description: Capital portion of the software upgrade fee
  - Reason for cost overrun: After the original budget was established, the contract was renegotiated and mapping software was added.
- OECO – 14367455 - OE- SUB TRANSFORMER REPLACEMENT
  - Capital Project Cost: $1,815,410
  - Over budget by 57.2%: $660,548.62

  - Description: Replace mismatched parallel 138/12.47 kV transformers at substation with a single 22.4/28 MVA transformer. Also replace existing distribution regulators to 437 Amp units.
  - Reason for cost overrun: Overheads, including impact of annual Pension Mark-to-Market adjustment, greater than planned.
- OECO - PA85455260 - PO FW: 59CJ1D-10 MDT Comments
  - Capital Project Cost: $13,506,734.67
  - Over budget by 619.6%: $11,629,757.45
  - Description: OE - Blanket - Forced - N-Line Follow up from PowerON
  - Reason for cost overrun: Higher volume of Power On Follow-ups than anticipated in original budget.
- TECO - PA85558090 - PO FW: Elbow Installation UD100-T-17 ABC
  - Capital Project Cost: $4,981,039
  - Over budget by 34.3%: $1,271,181.59
  - Description: TE Blanket Forced Failures Other
  - Reason for cost overrun: Higher volume of Power On Follow-ups than anticipated in original budget.
- TECO - PA84378970 - PO FW: Fuse Installation F505ABC 50N See
  - Capital Project Cost: $4,981,039
  - Over budget by 34.3%: $1,271,181.59
  - Description: TE Blanket Forced Failures Other
  - Reason for cost overrun: Higher volume of Power On follow-ups than anticipated in original budget.
- TECO – 15060720 - PowerOn Follow-up
  - Capital Project Cost: $1,529,550
  - Over budget by 144.5%: $903,964.00
  - Description: TE-Blanket-Streetlight-Unscheduled Repair
  - Reason for cost overrun: Higher volume of streetlight replacements than anticipated in original budget.
- OECO – 14709852 - Residential Development
  - Capital Project Cost: $8,763,571
  - Over budget by 1491.2%: $8,212,803.63
  - Description: OE - Blanket - New Business - Residential
  - Reason for cost overrun: Higher volume of new residential connections than assumed in original budget.
- OECO – 14229840 - Mod Sub
  - Capital Project Cost: $4,245,630
  - Over budget by 567.9%: $3,609,991.79
  - Description: Construct one new 14MVA, 2 circuit mod sub - in advance of Sub removal
  - Reason for cost overrun: Additional labor and material costs to provide circuit ties to new substation.
- TECO – 13645860 - Replace 12kv breakers
  - Capital Project Cost: $250,304
  - Over budget by 64.9%: $98,540.90
  - Description: Replace breakers 1273, 1274 and 1275 at substation

- Reason for cost overrun: Overheads, including impact of annual Pension Mark-to-Market adjustment, greater than planned.

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 40% of the projects that had budgets were over budget by greater than 15%. The large percentage is a potential concern related to the planning process. Blue Ridge is not recommending an adjustment to these projects in regard to the Rider DCR. However, Blue Ridge recommends that the Companies review their project planning process to ensure that the methodology allows for projects to be fully scoped prior to execution.

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

Blue Ridge determined that, except for one work order noted below, the costs in PowerPlant support the work order charge and the categories of cost are not unreasonable.[109] The costs for replacement work orders that had retirements did not agree to the cost detail. Blue Ridge was able to tie out the total costs net of retirements.

- FECO workorder ITF-SC-000040-SW15-1 – SW Upgrade 2015-CAP for $3,184,014 was charged entirely to stock materials. According to the Companies, 100% of the cost of the project was inadvertently charged to stock materials. 50% of the cost of the project should have been charged to software (FERC 303). The Companies indicated the inadvertent allocation has no impact on the Rider DCR. Stock materials issued generally accrue a stores overhead loader for the cost of the storeroom and staff. No stores overhead was charged to the work order.[110] The determination of what should be a capital cost and what should be expensed was made through discussions with the vendor and through an analysis independent of the vendor. Blue Ridge does not believe that the vendor should be the only source to determine what the capital/expense split should be. With this in mind, FirstEnergy explained how the split between capital and expense was analyzed independent of the vendor. The explanation was not unreasonable. [111],[112]

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

Blue Ridge found that, for replacement work orders, assets were retired and cost of removal was charged for all except one work order whose original estimate did not budget cost of removal (discussed more fully in step T6b below). Scrap sales are not recorded on an individual work order. Scrap from multiple operating companies is charged to a separate workorder, 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.[113]

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[109] FirstEnergy's response to data request BRC Set 2-INT-001, Attachments 3 and 4. Cost detail in BRC Set 2-INT-001, Attachment 3 less the retirements in BRC Set 2-INT-001, Attachment 4 = the workorder selection for replacement workorders
[110] FirstEnergy's response to Data request BRC Set-11-INT-1b.
[111] FirstEnergy's response to Data Request BRC Set-11-INT-1a.
[112] FirstEnergy's response to Data Request BRC Set-4-INT-11, a.
[113] FirstEnergy's response to 2015 Audit Data Request BRC Set 1-INT-013 and BRC Set 1-INT-014.

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.

Blue Ridge found that all sixteen replacement workorders in the sample had asset retirement dates, cost of removal dates, and in-service dates of new assets that were all in alignment (except for the one work order discussed in step T6b below).[114]

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

Blue Ridge found that one replacement work order in the sample had retirements without cost of removal charged.

- Work order 13645860 – Replace 12kv breakers – for $337,194.62 had retirements but no cost of removal charged. The Companies indicated that the original estimate did not budget cost of removal, and therefore, when the assets were placed in service, no cost of removal was charged. The Company stated that, upon unitization of the work order, it would record cost of removal. That recording will be done by transferring money from additions to removal.[115] Through follow-up, Blue Ridge found that in March 2017, the Companies did transfer $21,939 from additions to cost of removal.[116] While both gross plant and the reserve would be adjusted with no net change to net plant, the delay in recording the cost of removal does have an immaterial impact to depreciation expense and the reserve ($452). The Rider DCR revenue requirements should be reduced by $1,627 [**ADJUSTMENT #7**].

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

Blue Ridge found that all work orders in the sample, except for two, were closed to the proper FERC accounts based on the description of the work performed.[117] The types of work orders identified in test step T3 were pension adjustments, transfers, or accounting work orders and do not represent project work. While Blue Ridge cannot determine whether the charges were made to the proper FERC account, no indication exists of any material impact to Rider DCR.

- FECO workorder ITF-SC-000040-SW15-1 – SW Upgrade 2015-CAP for $3,184,014. Please see further discussion at testing step T5 above.
- CECO workorder 14164717 – CEI Plant Employee Onboarding Expenses for $1,606,349 had 100% of the workorder charges go to FERC account 394 (Shop Tools and Garage Equipment) in error. The Companies indicates that upon further analysis, in 2017, the expenses have been applied to other FERC accounts. Blue Ridge reviewed the detail supporting the transfer and finds it not unreasonable. [118]

[114] WP FEOH 2015 Sample Work Order Testing Matrix-Confidential.
[115] FirstEnergy's response to Data Request BRC Set 4-INT-012.
[116] FirstEnergy's response to Data Request BRC Set 11-INT-002.
[117] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachments 1 and 3 – Confidential.
[118] FirstEnergy's response to Data Request BRC Set 4-INT-010, Attachment a Confidential.

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

Blue Ridge found that 11 of the 32 workorders that had estimated in-service dates, or approximately 34%, had in-service dates that were over 90 days delayed from the estimates.[119] Of the remaining 60 work orders, 31 were blankets or projects and were closed on a routine basis, 16 were emergent projects and did not have estimated in-service dates, and the remainder had actual in-service dates that were reasonable.

- CECO – 13545763 - DCR #6 CU Reconductor H-2-HB
    - Description: DX Huntsburg H-2-HB Load Relief
    - Capital Project Cost: $152,760.24
    - In-Service Days after estimated date: 344
    - Reason for > 90-day delay: Work of higher priority forced delay to this project
- OECO – 14619456 - Class A - High Voltage
    - Description: Purchase a used transformer manufactured in 2015, 5/5.6 MVA, 34.5 - 4.16 kV, 55/65 degrees C without fans to replace the failed rectangular core, 5/6.25 MVA, 34.5 - 4.16 kV #1 Transformer at Sub in Marion. Add a fan package to increase the capacity of the transformer. The transformer has copper HV and LV disc windings.
    - Capital Project Cost: $440,155.46
    - In-Service Days after estimated date: 257
    - Reason for > 90-day delay: Delay due to purchase and delivery of transformer. Mobile utilized to maintain service.
- FECO - SC-000002-1 - ETF GO-13 Renovation Project
    - Description: Capital portion of the Hardware upgrade fee.
    - Capital Project Cost: $870,932.59
    - In-Service Days after estimated date: 121
    - Reason for > 90-day delay: The work was completed as of October 2015, within 90 days of the need date, but the action taken to close out the work order was not completed until January 2016. This three-month delay resulted in an overstatement of AFUDC equal to $9,184. The Companies stated (and Blue Ridge recommends) that a reconciliation be made in a future Rider DCR filing that incorporates the effect on revenues had the overstatement of AFUDC not occurred [**ADJUSTMENT #8**].
- OECO - OE-700402 - IT WMI Enhancements
    - Description: Enhance the WMI suite of applications as agreed upon by the ED Business owners
    - Capital Project Cost: $526,435.89
    - In-Service Days after estimated date: 152
    - Reason for > 90-day delay: On a quarterly basis, IT reviews projects that have an end date prior to the current date and undertake cleanup activities which include determining if a project (1) should have its end date extended or (2) needs to be TECO'ed. This work order was triggered during IT's Q1 2016 quarterly review. A notification e-mail was sent (March 29, 2016) to the owner of this work order requesting action be taken on any open work order. Action was not taken until June and an overstatement of AFUDC occurred, equating to $19,476.70. The Companies stated (and Blue Ridge recommends) that they include a reconciliation in the Rider

[119] FirstEnergy’s response to Data Request BRC Set 2-INT-001, Attachment 1 and Attachment 2.

DCR revenue requirement in a future filing that incorporates the effect on revenues had the overstatement of AFUDC not occurred.[120] The adjustment reduces the Rider DCR by $5,008 [**ADJUSTMENT #3**].

- TECO - TW-700417 - ITS - Inserter Replacement
  - Description: To install 2 MSE inserter machines
  - Capital Project Cost: $83,993.11
  - In-Service Days after estimated date: 110
  - Reason for > 90-day delay: Electrical power constraints for the new inserters delayed the implementation of the machines.
- OECO – 14367455 - OE-SUB TRANSFORMER REPLACEMENT
  - Description: Replace mismatched parallel 138/12.47 kV transformers at Substation with a single 22.4/28 MVA transformer. Also replace existing distribution regulators to 437 Amp units.
  - Capital Project Cost: $1,577,982.49
  - In-Service Days after estimated date: 214
  - Reason for > 90-day delay: Scheduling of outages to in service equipment.
- OECO – 14229840 - Mod Sub
  - Description: Construct one new 14MVA, 2 circuit mod sub - in advance of Sub removal
  - Capital Project Cost: $663,909.93
  - In-Service Days after estimated date: 167
  - Reason for > 90-day delay: Resource availability to tie reconductor circuit feeds to new substation caused delay in project completion.
- TECO – 14434237 - TE - Implement New Mobile Radio System
  - Description: Ohio MARCS (Multi Agency Radio Communications System) for CEI, OE, and TE
  - Capital Project Cost: $1,557,909.94
  - In-Service Days after estimated date: 91
  - Reason for > 90-day delay: The purchased radios were not available by the end of 2015 as was originally planned and budgeted.
- TECO – 13645860 - Replace 12kv breakers
  - Description: Replace breakers 1273, 1274 and 1275 at substation
  - Capital Project Cost: $337,194.62
  - In-Service Days after estimated date: 1,110
  - Reason for > 90-day delay: Originally planned to be done in 2014 but manpower did not allow for it to be completed, although material was purchased. Budgeted projects in 2015 were deemed to be higher priority.
- TECO – 14257239 - Substation - Replace (2) 34.5 kV
  - Description: Replace existing breakers 3567 and 3487 with new 38kV, 2000 amp, 31.5kA breakers Proposing replacement of breaker 3487 to be replaced in 2016; breaker 3567 was replaced in 2014 with remaining ancillary work to be completed in 2015.
  - Capital Project Cost: $212,082.06
  - In-Service Days after estimated date: 1,124

[120] FirstEnergy's response to Data Request BRC Set 2-INT-001, Attachment 2, line 12-Confidential.

  - Reason for > 90-day delay: Originally planned to be done in 2014, but manpower did not allow for it to be completed, although material was purchased. Budgeted projects in 2015 were deemed to be higher priority.
- OECO – 13313428 - 2012 SCADA Installations on Dx F
  - Description: Install SCADA Control and telemetering of watts, vars, amps, and volts on (3) distribution exit breakers and (1) transfer breaker. Install transformer telemetering where not already available. .
  - Capital Project Cost: $667,907.00
  - In-Service Days after estimated date: 817
  - Reason for > 90-day delay: Significant delays associated with OE's ability to gain approval from PJM for necessary outage to replace equipment as well as to ultimately schedule IT fiber optic connections caused delay in project completion.

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 almost half the projects with budgets were not completed by the estimated due dates. Blue Ridge recommends that the Companies place additional emphasis on completing projects timely when they have direct control of the projects and can mitigate delays.

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 found the following

- Four work orders were some form of an accounting adjustment and did not accrue AFUDC.
- Thirty-one work orders were project/blankets and did not accrue AFUDC.
- Seven 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.
- Nine projects had AFUDC accrued, but the charges were very minor, and the timing of closings would not impact the DCR.
- Four work orders with no AFUDC.

T10: For work performed in 2016, this project is a candidate for field verification to determine whether it is used and useful.

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

<u>Field Inspections</u>

Blue Ridge selected nine 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 - IF-CE-000054-1 - CE - Miles SC Metering Svcs Office Roof
    a. Description: Scope: Replace existing roof system at the Miles Service Center due to life expectancy and recommendation by roofing consultant after a roof assessment was performed and deemed this roof Failed.
    b. In-Service Date: May 9, 2016
    c. Capital Project Cost: $562,874.70
    d. Final Project Cost: $372,063.41
2. CECO – 14581787 - Clark Q-1-CK-T 138 kV Breaker Replacement
    a. Description: Clark Q-1-CK-T 138 kV Breaker Replacement
    b. In-Service Date: January 28, 2016
    c. Capital Project Cost: $1,021,299.34
    d. Final Project Cost: $1,084,486.34
3. CECO – 14499354 - Imperial 71-IP-T Transformer Replacement
    a. Description: Replace faulted 71-IP-T with new 138/13.2kV 16.8/22.4MVA 3-phase transformer with LTC. Replace protective relaying on 71-IP-T & 72-IP-T transformer with SEL501, SEL387 and SEL351. Install SCADA control and telemetering of Amps/Watts/VARs/Volts on both the 71-IP-T and 72-IP-T transformers
    b. In-Service Date: August 30, 2016
    c. Capital Project Cost: $1,020,605.45
    d. Final Project Cost: $1,020,605.45
4. OECO - IF-OE-000070-1 - OE Sandusky Roof Replacement
    a. Description: Scope: Replace existing roof system at the Sandusky Line Shop due to life expectancy and recommendation by roofing consultant after a roof assessment was performed and deemed this roof Failed.
    b. In-Service Date: January 29, 2016
    c. Capital Project Cost: $725,290.58
    d. Final Project Cost: $744,121.49
5. OECO – 14367455 - OE-SUB TRANSFORMER REPLACEMENT
    a. Description: Replace mismatched parallel 138/12.47 kV transformers at Substation with a single 22.4/28 MVA transformer. Also replace existing distribution regulators to 437 Amp units.
    b. In-Service Date: August 1, 2016
    c. Capital Project Cost: $1,577,982.49
    d. Final Project Cost: $1,815,410.00
6. OECO - IF-SC-000144-1 - SvcCo Fairlawn Bldg 0 Rpl MR-24 Roof
    a. Description: Scope: Replace existing roof system at the Building 0 FE Call Center due to life expectancy and recommendation by roofing consultant after a roof assessment was performed and deemed this roof Failed.
    b. In-Service Date: May 9, 2016
    c. Capital Project Cost: $1,063,868.68

   d. Final Project Cost: $606,790.66
7. CECO – 14479765 - SW - Grant #3-GT-T Transformer Replaceme
   a. Description: Replace the three single phase transformers that comprise #3-CK-T with a new 138/11.5kV 45MVA three phase transformer. XFMR to be installed in the #4 position due to construction constraints at #3 position.
   b. In-Service Date: August 16, 2016
   c. Capital Project Cost: $2,316,563.65
   d. Final Project Cost: $2,492,217.65
8. TECO – 13645860 - Replace 12kv breakers
   a. Description: Replace breakers 1273, 1274 and 1275 at substation
   b. In-Service Date: January 5, 2016
   c. Capital Project Cost: $337,194.62
   d. Final Project Cost: $250,304.11
9. TECO – 14257239 - Substation - Replace (2) 34.5 kV
   a. Description: Replace existing breakers 3567 and 3487 with new 38kV, 2000 amp, 31.5kA breakers Proposing replacement of breaker 3487 to be replaced in 2016; breaker 3567 was replaced in 2014 with remaining ancillary work to be completed in 2015.
   b. In-Service Date: January 29, 2016
   c. Capital Project Cost: $212,082.06
   d. Final Project Cost: $212,082.06

The nine 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 experienced a significant increase in the unitization backlog from the prior 2015 audit. 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.[121]

Table 17: Backlog Over 15 Months of Work Order Unitization[122]

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	
as of 12/31/16	4,032	$62,191,009

While most of the work orders are Distribution (89%) and individually would not be material to the accumulated reserve for depreciation, on an aggregate basis, the work orders in the backlog total over $62 million, which is significant. There could be a potential impact on the accumulated reserve for depreciation.

[121] FirstEnergy's response to Data Request BRC Set 2-INT-007.
[122] FirstEnergy's response to Data Request BRC Set-1-INT-30 and 31.

In addition, the backlog could create problems with recording the replacement of assets that are still in the backlog and had not been unitized.

Blue Ridge recommends that the Companies make a concerted effort to reduce the volume of backlog workorders 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, 2015, through December 31, 2016.[123]

There are currently no pending insurance recoveries that have not been recorded or accrued for TECO or the Service Company. However, an insurance claim, associated with a 2012 storm event that was resubmitted in 2015, has settled and could potentially result in recoveries for OE and CE. These potential recoveries have not yet been recorded or accrued since a settlement agreement has been made but not fully executed. The potential estimated amounts of recovery that would be charged to capital for the two Ohio operating companies are as follows:

Ohio Edison Company	$ 6,395
The Cleveland Electric Illuminating Company	$10,210[124]

While the potential recovery is immaterial, Blue Ridge recommends that any recovery reduce plant in service and be recognized in a future Rider DCR.

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 section 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 18: Incremental Change in Reserve for Depreciation from 11/30/15 to 11/30/16[125]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	(1,205,294,293)	(1,269,202,085)	(63,907,792)
Ohio Edison Company	(1,259,058,319)	(1,317,426,765)	(58,368,447)
The Toledo Edison Company	(549,228,366)	(591,085,970)	(41,857,604)
Total	(3,013,580,977)	(3,177,714,820)	(164,133,844)

[123] FirstEnergy's response to Data Request BRC Set 1-INT-21.
[124] FirstEnergy's response to Data Request BRC Set 1-INT-22.
[125] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

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.

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.[126]

Source Data Validation

Blue Ridge traced the values used for the actual November 30, 2016, and estimated February 28, 2017, 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 71 sampled work orders Blue Ridge obtained as part of the validation testing, 16 work orders were for replacement work. 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 one work order discussed in testing step T6b. 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.

[126] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

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 specific adjustments are also discussed, as necessary, in the Variance, Exclusions, and Gross Plant in Service sections. The impacts of these findings are discussed in the Overall Impact of Findings on Rider DCR Revenue Requirements section 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 19: Incremental Change in ADIT from 11/30/15 to 11/30/16[127]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	(457,939,051)	(466,717,532)	(8,778,481)
Ohio Edison Company	(547,713,158)	(569,578,802)	(21,865,644)
The Toledo Edison Company	(146,538,304)	(151,388,071)	(4,849,767)
Total	(1,152,190,514)	(1,187,684,405)	(35,493,892)

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 accumulated deferred income taxes associated with plant in service since the Companies' last distribution rate case.[128] [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.[129]

[127] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[128] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[129] Blue Ridge's Compliance Audit of the 2011 Delivery Capital Recovery (DCR) Rider, submitted April 12, 2012, page 52.

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.[130]

Source Data Validation

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

The Tax Increase Prevention Act of 2014 extended the 50% bonus tax depreciation for qualified property placed into service before January 1, 2015. The Protecting Americans from Tax Hikes Act of 2015 further extended the 50% bonus tax depreciation for qualified property placed in service during 2015, 2016, and 2017.

The Companies explained how it had applied the accelerated depreciation. The 2015 actual additions for January through November and estimated additions for December were processed through the Companies' tax depreciation compliance system (PowerTax). Fifty percent bonus tax depreciation was calculated on the estimated tax in service additions for 2015 that qualified for bonus depreciation. In Tax Year 2016, 2015 return to provision updates related to tax depreciation were incorporated, accounting for the difference between the accrual amount and the 2015 return. To project 2016 activity, FirstEnergy started with budgeted book activity for 2016, and processed it through the Companies' tax depreciation compliance system (PowerTax). Fifty percent bonus tax depreciation was calculated on the budgeted tax in service additions that qualified for bonus depreciation. For Tax Year 2017, FirstEnergy used the corporate budgeting system (UI Planner) to project tax year 2017 tax depreciation by calculating 50% bonus depreciation on estimated 2017 tax additions that qualified for bonus depreciation. For all three years, the timing difference between book and tax created by bonus depreciation affected the projected ADIT activity.[131] Blue Ridge found that the Companies' explanation was not unreasonable.

The Companies' ADIT supporting documentation included several line items with generic descriptions (e.g. Other Basis Differences, Tax Interest Capitalized). Blue Ridge found that the Companies' explanation of why these items should be included within Rider DCR not unreasonable.[132]

Blue Ridge reviewed the Companies ADIT-supporting documentation and 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 excluded deferred taxes in CWIP. Blue Ridge found the items included in ADIT not unreasonable. [133]

[130] WP V&V FE DCR Compliance Filing 12.30.16-Confidential.
[131] FirstEnergy's response to Data Request BRC Set 1-INT-033.
[132] FirstEnergy's response to Data Request BRC Set 9-INT-005 – Confidential.
[133] WP BRC Set 1-INT-001 Attachment 7-Confidential (ADIT).

Conclusion

Blue Ridge concludes that the ADIT is not unreasonable. The Companies recognized the significant impact of the extension of bonus depreciation on the ADIT balances.

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 20: Incremental Change in Depreciation Expense from 11/30/15 to 11/30/16[134]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	92,035,989	95,176,216	3,140,227
Ohio Edison Company	96,378,099	100,891,710	4,513,611
The Toledo Edison Company	36,831,596	38,032,714	1,201,119
Total	225,245,684	234,100,640	8,854,956

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 nothing that affected Rider DCR revenue requirements. 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.[135]

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.[136]

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.[137] 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

[134] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[135] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[136] FirstEnergy's response to Data Request BRC Set 1-INT-023.
[137] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

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.

Blue Ridge noted that both Actual and Estimated OE Intangible Deprecation included line item descriptions "FAS109 Dist Land," "FAS109 General Land," and "FAS109 Trans Land." While land is typically not depreciated, the Companies explained these assets, classified under FERC 303, are not *land* accounts as indicated in the description. The intangible assets were recorded in 1993 related to the adoption of FAS 109. At the time of adoption OE elected to record the impacts of FAS 109 as an intangible asset. Any accounts associated with land are not being depreciated on the Companies' books. The Companies, upon further review in preparation of this response, determined that depreciation expense has been inadvertently calculated for these accounts when it should not have been. This resulted in an overstatement of depreciation expense equal to $32,274 in the December 30, 2016, Rider DCR filing. The Companies intend (and 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 for these accounts going back to the first instance of the inadvertent calculation in the July 1, 2016 Rider DCR filing. The adjustment reduces the Rider DCR by $32,358. [**ADJUSTMENT #4**]

Conclusion and Recommendation

Blue Ridge found that the calculation of depreciation expense is not unreasonable. However, the Companies should exclude the FAS109 *Land* balances from the calculation of intangible depreciation expense. The Rider DCR uses 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 balances as of May 31, 2007. The Companies updated the depreciation study using plant as of December 31, 2013, and filed the updated study with the Commission on June 1, 2015, fulfilling the Companies' obligation.[138]

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.

[138] FirstEnergy's response to 2015 Data Request BRC Set 1-INT-12 – Confidential.

Table 21: Incremental Change in Property Tax Expense from 11/30/15 to 11/30/16[139]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	101,323,045	102,669,541	1,346,496
Ohio Edison Company	88,498,186	88,980,613	482,428
The Toledo Edison Company	29,195,338	30,026,201	830,863
Total	219,016,569	221,676,355	2,659,786

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.[140]

Source Data Validation

Blue Ridge found the workpapers were well organized and fully sourced. During discovery, the Companies identified a transcription error that affected OE's personal property tax rate. The error affected the calculation of the Rider DCR revenue requirements based on estimated balances at November 30, 2016, in the September 30, 2016, Rider DCR filing. The error also affected the calculation of the actual and estimated revenue requirements in the December 30, 2016, Rider DCR filing. The Companies stated (and Blue Ridge recommends) that a reconciliation will 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. Blue Ridge calculated the impact of the transcription error on the December 30, 2016, filing and found that the Rider DCR revenue requirements should be increased by $282,612. [**ADJUSTMENT #5**]

Blue Ridge noted that the personal property tax rates changed significantly for TE from the prior year as shown in the following table.

Table 22: Comparison of Personal Property Tax Rate 2016 vs. 2015

Description	CE	OE	TE
2015 Tax Rate	1.7652%	0.9530%	1.1310%
2016 Tax Rate	1.6935%	1.0061%	1.5338%
Difference	-0.072%	0.053%	0.403%
% increase	-4.06%	5.57%	35.62%

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

[139] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[140] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

rate.[141] Blue Ridge found the Companies' explanation reasonable and would expect the property tax rate next year to decline as TE should no longer pay property taxes on the assets that were removed from plant in service. Blue Ridge recommends that this item be reviewed in a future Rider DCR compliance audit.

Conclusion

Blue Ridge found that, while the calculation of property tax is not unreasonable, there are corrections that should be made to OE's property tax rates and a reconciliation of the impact of the transcription error that should be made in a future filing. 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

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.

[141] FirstEnergy's response to Data Request BRC Set 9-INT-003.

Table 23: Change in Service Company Rate Base and Expense from 11/30/15 to 11/30/16[142]

Description	CEI	OE	TE	Total
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**
Actual 11/30/15				
Gross Plant	88,149,759	106,821,875	47,021,476	241,993,110
Reserve	38,492,298	46,645,839	20,532,837	105,670,975
ADIT	8,818,672	10,686,667	4,704,119	24,209,459
Rate Base	**40,838,788**	**49,489,369**	**21,784,519**	**112,112,676**
Depreciation Expense	4,096,383	4,964,090	2,185,122	11,245,595
Property Tax Expense	44,339	53,731	23,652	121,722
Total Expenses	**4,140,722**	**5,017,821**	**2,208,774**	**11,367,317**
Incremental				
Gross Plant	5,560,888	6,738,810	2,966,329	15,266,026
Reserve	6,832,201	8,279,416	3,644,481	18,756,098
ADIT	1,892,572	2,293,462	1,009,550	5,195,584
Rate Base	**(3,163,885)**	**(3,834,068)**	**(1,687,702)**	**(8,685,656)**
Depreciation Expense	319,421	387,081	170,388	876,889
Property Tax Expense	9,921	12,023	5,292	27,236
Total Expenses	**329,342**	**399,104**	**175,680**	**904,125**

The Compliance Filings include actual November 30, 2016, and estimated February 28, 2017, schedules that accumulate Service Company general and intangible gross plant, reserve, ADIT, and 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[143] and 14-1297-EL-SSO[144]) 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,

[142] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[143] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[144] Case No. 14-1297-EL-SSO Commission Opinion and Order, March 31 2016, page 119.

> 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.[145] (Emphasis added.)

The following allocation factors were used in Case No. 07-551-EL-AIR[146] and were appropriately used in accordance with the Combined Stipulation to allocate Service Company costs in Rider DCR:

Table 24: 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.[147]

Source Data Validation

The Actual November 30, 2016, and Estimated February 28, 2017, general and intangible gross plant balances, reserve, and ADIT were reconciled to their source documentation.[148]

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.

Additional Validation Testing

As discussed in the Gross Plant section 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

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[145] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[146] WP FE response to 2011 Audit Data Request BRC-10-10 and 10-11.
[147] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[148] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

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

Table 25: Incremental Change in CAT and Income Tax Expense from 11/30/15 to 11/30/16[149]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	8,519,491	9,278,567	759,075
Ohio Edison Company	9,857,073	11,517,635	1,660,561
The Toledo Edison Company	1,276,607	1,015,662	(260,945)
Total	19,653,171	21,811,863	2,158,692

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[150] and 14-1297-EL-SSO[151]) 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. . . .[152] (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.[153] 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 composite tax rates include federal, Ohio, and municipalities' tax rates. During discovery, the Companies discovered that the effective income tax rate for the Toledo Edison Company used for the calculation of the revenue requirement based on estimated February 28, 2017, balances was incorrect. The rate used was 36.067845%. It should have been 35.685476%. The Companies stated (and Blue Ridge recommends) that it will 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 calculation.[154] ,[155] Blue Ridge calculated the impact of the TE tax rate error on the December 30, 2016, filing. The Rider DCR revenue requirement should be reduced by $19,160. [**ADJUSTMENT #6**].

[149] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[150] Case No. 12-1230-EL-SSO Commission Opinion and Order, July 18, 2012, pages 10-11.
[151] 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.
[152] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 13.
[153] WP V&V FE DCR Compliance Filing 12.31.2015-Confidential.
[154] FirstEnergy's response to Data Request BRC Set 1-INT-032 – Confidential.
[155] FirstEnergy's response to Data Request BRC Set 1-INT-032 – Confidential.

Conclusion

Blue Ridge found that the commercial activity tax was correctly calculated. The composite tax rate for actual balances of November 30, 2016, for all three operating companies and estimated balances as of February 28, 2017, for CE and OE were correctly calculated and are not unreasonable. However, the composite tax rate for TE's estimated balances as of February 28, 2017, used an incorrect tax rate and should be corrected. In addition, any adjustments discussed in other sections of this report will impact the final commercial activity tax and income tax included within the Rider DCR.

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 26: Incremental Change in Return on Rate Base from 11/30/15 to 11/30/16[156]

Company	11/30/15	11/30/16	Incremental
The Cleveland Electric Illuminating Company	24,095,993	26,418,706	2,322,713
Ohio Edison Company	28,313,336	33,089,719	4,776,383
The Toledo Edison Company	3,589,733	2,805,374	(784,359)
Total	55,999,062	62,313,799	6,314,737

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[157]) 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.[158]

Mathematical Verification

The rate of return and the return on plant is calculated correctly in accordance with the Combined Stipulation.[159]

Source Data Validation

[156] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
[157] 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.
[158] Case No. 10-0388-EL-SSO Stipulation and Recommendation, March 23, 2010, page 14.
[159] WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.

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

Conclusion

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

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, 2016, and estimated February 28, 2017, balances. The Annual Rider DCR Revenue is compared against the Commission-approved Revenue Cap in the Companies' filings[160]

Mathematical Verification

The various actual November 30, 2016, and estimated February 28, 2017, components, including gross plant, reserve, ADIT, depreciation, and property tax expense, were discussed in other sections 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].[161]

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.[162]

[160] CEI, OE, and TE Rider DCR Compliance Filings dated 12/30/16, page 57.
[161] Case No. 12-12-1230-EL-SSO Opinion and Order, July 18, 2012, page 10.
[162] Case No. 14-1297-EL-SSO Opinion and Order, March 31, 2016, page 25.

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 2016 DCR as follows:

Table 27: Companies' Calculation of Annual Cap Prior to Under (Over) Recovery Adjustment[163]

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

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.[164]

The December 30, 2016, Rider DCR Compliance Filing cover letter states, “The attached schedules demonstrate that the year-to-date revenue is below the permitted cap for 2016.” Blue Ridge confirmed that the Companies has not exceeded the Commission-approved DCR Revenue Cap.

The annual cap analysis included in the December 30, 2016, filing included revenues through November 30 2016. Using the actual annual revenue through December 31 for years 2015 and 2016, the Companies have a cumulative under recovery of $5,283,101 as shown in the following table.[165]

Table 28: Annual DCR Revenues vs. Annual Cap through December 31, 2016

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

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 cap (adjusted for the cumulative under [over] recovery) and the allocated Companies’ caps through

163 WP V&V FE DCR Compliance Filing 12.30.2016-Confidential.
164 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.
165 FirstEnergy’s response to Data Request BRC Set 9-INT-001.

December 31, 2016. Each of the operating companies' DCR revenues through December 31, 2016, are below the annual cap.

Table 29: 2016 Annual DCR Revenue to Aggregate and Allocated Caps through December 31, 2016[166]

Period	Aggregate Annual Cap	CEI	OE	TE
% of Aggregate Annual Cap		70%	50%	30%
2016 Annual Cap	$ 227,500,000			
Under (Over)-2015	$ (5,535,795)			
Adjusted 2016 Annual Cap	$ 221,964,205	$ 155,374,944	$ 110,982,103	$ 66,589,262
2016 Annual Revenue	$ 216,681,105	$ 92,491,368	$ 100,468,719	$ 23,721,018
Under (Over) 2016 Revenue Cap	$ 5,283,100	$ 62,883,575	$ 10,513,383	$ 42,868,243

Conclusion

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, 2016, 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 2017. To develop the first quarter 2017 estimates, the Companies used estimated plant-in-service and reserve balances as of February 28, 2017, the most recent forecast from PowerPlant. The estimated February 28, 2017, 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.[167]

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. [168]

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

[166] FirstEnergy's response to Data Request BRC Set 9-INT-1.
[167] FirstEnergy's response to Data Request BRC Set 1-INT-001, Attachment 3 – Confidential.
[168] Case No. 12-1230-EL-SSO Stipulation and Recommendation April 13, 2012, page 22.

reviewed the estimated February 28, 2017, schedules while performing specific tasks in each of the previous sections. Specific observations and findings are discussed in the appropriate sections.

Conclusion

Blue Ridge found that the projected amounts included through February 2017 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 to several work orders, corrections to income tax and property tax rates, and removal of items that should not be depreciated. The flow through of these adjustments has the following impact on the DCR.

Table 30: Impact of Blue Ridge's Findings on Rider DCR Revenue Requirement[169]

Adj #	Description	CEI	OE	TE	Total
	As Filed	**$ 111,809,308**	**$ 119,012,430**	**$ 29,242,534**	**$ 260,064,272**
1	AMI Not Excluded	28	(0)	(0)	28
2	ATSI Not Excluded	(0)	(1,047)	(16)	(1,063)
3	AFUDC Overstated	(0)	(4,929)	(0)	(4,929)
4	FAS109 "Land"	(0)	(32,358)	(0)	(32,358)
5	Incorrect Property Tax Rate	(0)	282,612	(0)	282,612
6	Incorrect Income Tax Rate	(0)	(0)	(19,160)	(19,160)
7	COR included in Additions	(0)	(0)	(1,627)	(1,627)
8	AFUDC Overstated-Service Co.	(196)	(238)	(105)	(539)
	Impact of All Adjustments	**(169)**	**244,041**	**(20,907)**	**222,965**
	Recommended Adjusted Rider DCR Revenue Requirements	**$ 111,809,140**	**$ 119,256,471**	**$ 29,221,627**	**$ 260,287,237**

[169] WP FEOH 2016 Adjustments to Plant and Reserve-Confidential and WP Impact of Findings BRC Set 1-INT-001 Attachment 1 – FE DCR Compliance Filing 12.30.2016-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)[170] 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

170 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.

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)[171] and customer average interruption duration index (CAIDI)[172] 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 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.

[171] Represents the average number of interruptions per customers.
[172] Represents the average interruption duration.

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[173] 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 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

[173] 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.

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
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
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.

DR	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, 2016, 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 12/1/15 through 11/30/16. 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 2016. 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 2015 and January through November 2016: 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, 2016, DCR filing.
FE-01.07	**FERC Form 1 Reconciliations**: Please provide a reconciliation of the Rider DCR balances to the balances in the 2016 FERC Form 1.
FE-01.08	**Budget**: Please provide the 2016 budget supporting the 2016 Compliance Filings. Also, please include the assumptions supporting the budget/projected data.
FE-01.09	**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 2016.
FE-01.10	**Status of 2015 Recommendations**: Please provide a narrative on how the companies have addressed the recommendations listed on page 21 in Blue Ridge's Compliance Audit of the 2015 DCR Riders dated April 22, 2016.
FE-01.11	**CIAC Process Change**: What is the status of the Companies' plan to make a programming change to PowerPlant to eliminate the manual process used to move CIACs?
FE-01.12	**DCR Filings**: Please provide a narrative of any changes made to the development process of the 2016 Rider DCR Compliance Filings and schedules from the development process of

DR	Request
	the 2015 DCR Compliance Filing and schedules.
FE-01.13	Policies and Procedures: For each company and the Service Company, please provide any changes for 2016 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-01.14	**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-01.15	**Internal Audits**: For each company and the Service Company, please provide a list of Internal Audits performed for 2016. List the name of the audit, scope, objective, and when the work was performed.
FE-01.16	**SOX Compliance Audits**: For each company and the Service Company, please provide a list of SOX compliance work performed during 2016. List the name of the audit, scope, objective, and when the work was performed.
FE-01.17	**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 12/1/15 through 11/30/16.
FE-01.18	**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 12/1/15 through 11/30/16.
FE-01.19	**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 12/1/15 through 11/30/16. If the CWIP balances for any of the Companies or the Service Company have increased from 12/1/15 to 11/30/15, please provide a narrative and any support documentation explaining the increase.
FE-01.20	**Replacement Programs**: Did the companies have any large construction and/or replacement programs in 2016, such as pole replacement, meters, underground line, etc? If so, please identify the program, company, and work orders associated with the program.

DR	Request
FE-01.21	**Insurance Recoveries**: For each company and the Service Company, please provide a list of any insurance recoveries charged to capital from 12/1/15 through 12/31/16.
FE-01.22	**Insurance Recoveries**: For each company and the Service Company, please provide a list and explanation of any 2016 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.
FE-01.23	**Depreciation**: For each company and the Service Company, please provide the approved depreciation accrual rates by FERC 300 account from 12/1/15 through 11/30/16. 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-01.24	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 2016: 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-01.25	**Property Tax Rates**: Please provide the supporting documents and calculation for the tax rates used to calculate the actual 11/30/16 and estimated 2/28/17 Rider DCR Revenue Requirement.
FE-01.26	**Approval Signatures**: Please provide the level of signature authority (LOSA) document that supports the approval of capital projects put in service from 12/1/15 through 11/30/16.
FE-01.27	**Exclusions**: Please provide the supporting documentation for the amounts associated with the ATSI Land Lease for actual 11/30/16 and estimated 2/28/17 on pages 19 and 44 of the DCR filing.
FE-01.28	**Excluded Riders**: Please provide the supporting documentation for the amounts excluded from CEI for Rider AMI for actual 11/30/16 and estimate 2/28/17 (page 19 and 44 of DCR filing).
FE-01.29	**Excluded Riders**: Please provide the supporting documentation for the amounts excluded for EDR(g) included on pages 19 and 44 of the DCR filing.
FE-01.30	**Unitization Backlog**: Please provide by company information regarding the backlog in the unitization of workorders for 2016. Please provide the number of workorders and the length of time in months by functional area (i.e., Distribution, Transmission, General, and Other).
FE-01.31	**Unitization Backlog**: Please provide the dollar value of the workorder backlog, by operating company and by workorder classification (distribution, transmission, and general/other).
FE-01.32	**Tax Rates**: Please provide the supporting documentation and calculations for the tax rate used for Actual 11/30/16 and Estimated 2/28/17.

DR	Request
FE-01.33	**ADIT:** The Tax Increase Prevention Act of 2014 extended the 50% bonus tax depreciation for qualified property placed into service before January 1, 2015. The Protecting Americans from Tax Hikes Act of 2015, further extended the 50% bonus tax depreciation for qualified property placed in service during 2015, 2016, and 2017. 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-01.34	Other Riders: a. Has the Company requested and received Commission approval for any other riders than those in the following list? b. Please confirm that no cost recovered through the following riders has capital additions included within the Rider DCR.
FE-02.01	Priority Data Request - For the attached work order list (BRC Set 2 - 2016 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 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.

DR	Request
FE-02.02	Variance Analysis: Follow-up to Data Request 1-INT-17, Attachment 1 - Confidential—Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following accounts: a. CEI Account 361 Structures and improvements—Additions of $1,512,706 with $0 change in Retirements b. CEI Account 362 Station equipment—Transfers/Adjustments of $51,892 c. CEI Account 391 Office furniture, equipment—Additions of $1,486,341 and Retirements of $1,194,294. d. CEI Account 394 Tools, shop, garage equipment—Additions of $1,486,341 e. CEI Account 397 Communication equipment—Additions of 2,100,240 f. OE Account 360 Land and land rights—negative Additions of $26,508 g. OE Account 361 Structures and Improvements—negative Transfers/Adjustments of $52,202 h. OE Account 362 Station equipment—Transfers/Adjustments of $325,550 i. OE Account 390 Structures and improvements—Additions of $10,814,114 j. OE Account 397 Communication equipment—Additions of $7,293,584 k. TE Account 361 Structures and improvements—negative Additions of $3,525 l. TE Account 397 Communication equipment—Additions of $3,495,801 m. FESC Account 390 Structures and improvements—Transfers/Adjustments of $77,921 n. FESC Account 391 Office furniture, equipment—Additions of $19,883,101 and Retirements of $15,915,947 o. FESC Account 397 Communication equipment—Additions of $8,121,531 and Retirements of $926,589
FE-02.03	Variance Analysis: Follow-up to Data Request 1-INT-018, Attachment 1—Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following reserve accounts: a. Reserve TE Account 370 Meters—Reduction from 11/30/2015 balance of $19,819,297 to 11/30/2016 balance of $19,433,375 b. Reserve TE Account 393 Stores Equipment—Reduction from 11/30/2015 balance of $371,768 to 11/30/2016 balance of $369,458 c. Reserve TE Account 395 Laboratory equipment—Reduction from 11/30/2015 balance of $1,043,101 to 11/30/2016 balance of $1,036,667

DR	Request
FE-02.04	Variance Analysis: Follow-up to Data Request 1-INT-001 Attachment 1 – FE DCR Compliance Filing 12.30.2016 - Confidential (as compared to the 11/30/15 account balances in the Companies' December 31, 2015 DCR filings)—Please provide detailed narratives (along with supporting documentation) explaining and justifying the reasons for the changes in the following account balances: a. CEI Account 303 Intangible Software—11/30/15 balance = $50,559,055; 11/30/16 balance = $52,912,494; increase of $2,353,439 (4.7%). Additionally, please explain this year's increase in light of the already significant 11.2% increase from 2014 to 2015, making the total increase since 11/30/14 16.4% (11/30/14 balance = $45,462,777). b. OE Account 303 Intangible Software—11/30/15 balance = $68,862,709; 11/30/16 balance = $77,229,262; increase of $8,366,553 (12.1%). Additionally, please explain this year's increase in light of the already significant 14.4% increase from 2014 to 2015, making the total increase since 11/30/14 28.3% (11/30/14 balance = $60,216,076). c. TE Account 303 Intangible Software—11/30/15 balance = $25,206,116; 11/30/16 balance = $26,425,862; increase of $1,219,746 (4.8%). Additionally, please explain this year's increase in light of the already significant 13.5% increase from 2014 to 2015, making the total increase since 11/30/14 19.0% (11/30/14 balance = $22,213,630).
FE-02.05	Internal Audits: Follow up to Data Request response BRC Set 1-INT-015, Attachment 1. For the following audits please provide the executive summary of findings and recommendations. a. Project 26573 b. Project 25382 c. Project 26329.
FE-02.06	For the following audits please provide a summary of any significant control deficiencies, along with how those deficiencies were corrected and /or mitigated. a. Project 26482 b. Project 26489 c. Project 26493 d. Project 26501
FE-02.07	Follow up to Data Request response BRC-Set 1-INT-30. Reference the 2015 DCR Audit Report dated April 22, 2015, page 29, table 11. Please explain the reason(s) why the unitization back log increased from 983, as of November 30, 2015 to 4,032 as of November 30, 2016.

DR	Request
FE-3.01	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)
FE-04.01	Reference Company response to Data Request BRC-SET 2-INT-001, attachment 2, line 8, TECO project ITF-SC-000092-SW15-1, Hardware Upgrades 2015-CA, $447,654.28. The company response indicated the following: "The vendor provided documentation that supported capitalization of a portion of the support fees..." a. Please provide the detail documentation supporting how capitalization of a portion of the fees was appropriate. Include the total fees and how the fees were split between capital and expense and the rationale that conforms to company policy.
FE-04.02	Reference Company response to Data Request BRC-SET 2-INT-001, attachment 1, line 22, CECO workorder CE-900477, CCOH-ADJ, Capital Related Payroll Overhead Adjustment, $2,278,079.36. The Company response indicated "This is an accounting work order that represents the manual allocation of capitalized labor related overheads that cannot be applied through the normal allocation process…" a. Please provide the detailed accounting entry(s) that support this adjustment.
FE-04.03	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 21, CECO work order HE123, $(706,674.31), CECO PROP ASSETS-PWR PLT TRNSF & ADJ. The Company response indicated "This is an accounting work order that represents transfers and other asset activity between CEI and other companies resulting, in part, from the unitization process and SOX related activities…" a. Please provide the detail accounting entry(s) that support this adjustment. b. What SOX related activities were in part related to this adjustment? c. Were any of the transfers outside to any company outside of Ohio? If so please explain where the transfer(s) went and why.
FE-04.04	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 7, CECO work order CN-001211-DO, DX Meter Program - Rate Case, $718,453.48. Company response indicated "The addition recorded in Dec '15 was related to an AFUDC adjustment to reverse an entry made in Nov '15 for AFUDC that was erroneously adjusted associated with unitization activities. This had no impact on the cumulative balances used in Rider DCR"

DR	Request
	a. Please provide the detail accounting entry that supports this adjustment.
FE-04.05	Reference Company response to Data, Request BRC-SET-2-INT-001, attachment 1, line 58. FECO work order SC-000002, ETF GO-13 Renovation Project, $870,932.59. Company response indicated "Three departments were relocated off of GO-13, the floor was updated with new carpet and paint, and new furniture was installed" a. Please detail the nature of the costs charged to FERC 390, 391 and 397. b. Please explain why relocating employee's is a capital activity? c. Please provide the accounting entries to support the charges.
FE-04.06	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 41, OECO work order 14155744, ($1,067,022.36) -Equip Investigate / Repair - Recloser I. Company response indicated " The activity associated with this work order represents accounting adjustments made during the unitization process. The purpose of the adjustments was to (1) transfer overheads costs back to the source pool for redistribution over other work orders and (2) the transfer of assets from Account 362 to Account 367…" a. Please provide the accounting entries that support the adjustment that transfers overheads costs back to the source pool for redistribution over the other work orders.
FE-04.07	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 55, TECO work order JC607, $(334,966.72) - TECO PROP ASSETS-PWR PLT TRNSF & ADJ. "This is an accounting work order that represents transfers and other asset activity between TE and other companies resulting, in part, from the unitization process and SOX related activities…" a. Please provide the detail accounting entry(s) that support this adjustment. b. What SOX related activities were in part related to this adjustment? c. Were any of the transfers outside to any company outside of Ohio? If so please explain where the transfer(s) went and why
FE-04.08	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 18. CECO work order CE-900606-JUS-DOV, ($717,771.19) – Company response indicated "Costs/Reimbursements associated with Damage Claims, Joint Use, Salvage Credits, Capital Portfolio Development, Unplanned Vegetation Management, Warehouse Storekeeper labor, and Telecom capital expenditures." a. Please provide the Budget and the detail for damage claims that exceeded the budgeted amount.
FE-04.09	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 33, OECO work order 14292861 - $1,222,930.37, Replace line relaying. Company response indicated "Power Plant is closing. Ohio Edison and First Energy will need to continue support and ownership of the 138 kV substation yard at Plant…" a. Is the substation located inside the Power Plant facility (inside the fence)? b. What FERC account(s) is the substation currently recorded in?

DR	Request
FE-04.10	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 1, line 15 and attachment 3, line 77, CECO work order 14164717- CEI Plant Employee Onboarding Expenses -$1,606,349.13. The Company response indicated "To record the costs associated with transitioning former FirstEnergy Lake Plant employees to The Illuminating Company. The transitioned employees will support CEI distribution service." a. Please provide the detail associated with the "Onboarding Expenses" b. Please explain why those costs are charged to FERC 374 – Tool, shop and garage equipment. c. Please explain why the transition costs are considered capital. d. Please explain why overheads were 37% of the total project costs ($595,721 in overheads).
FE-04.11	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 2, Line 6, attachment 3, line 93. TECO work order ITF-SC-000040-SW15-1, $3,184,013.73, SW Upgrade 2015-CAP. The Company response indicates "Capital portion of annual software renewal fee". a. Please explain, and provide support for, how the fee was divided up between capital and expense. b. Why was the entire cost charged to Stock Materials? (Att 3, line 93).
FE-04.12	Reference Company response to Data Request BRC-SET-2-INT-001. Attachment 4 – Retirements and attachment 5, Cost of Removal. TECO work order 13645860 - Replace 12kv breakers - $337,194.62 a. Please explain why this work order had assets retired and no cost of removal charged.
FE-04.13	Reference Company response to Data Request BRC-SET-2-INT-001, attachment 5 Cost of Removal, IF-OE-000070-1, OE Sandusky Roof Replacement, $725,290.58. a. Please explain why this replacement work order had assets retired and no cost of removal charged.

DR	Request
FE-05.01	[WITHDRAWN] ~~Variance Analysis: Please refer to attached spreadsheet "BRCS WP FE DCR CF Variance 2016.xlsx." The intent of this spreadsheet is to determine, by company, whether any difference exists between the DCR filing's reported Adjusted Plant for 2016 (11/30/15 through 11/30/16) and the Work Order Population we received as response to data request BRC 1-INT-002. The following questions relate to these differences:~~ ~~a. In column labeled "(h)" (spreadsheet column I), the items highlighted in green are those CEI accounts whose 2016 WO Population differs from the DCR Adjusted Plant for 2016. Please provide a reconciliation for each account, explaining this difference:~~ ~~i. Account 350: difference of $12,979~~ ~~ii. Account 356: difference of $(2,813)~~ ~~iii. Account 358: difference of $(165,766)~~ ~~iv. Account 362: difference of $188,862~~ ~~v. Account 364: difference of $59,521~~ ~~vi. Account 365: difference of $1,448,754~~ ~~vii. Account 367: difference of $169,611~~ ~~viii. Account 368: difference of $34,937~~ ~~ix. Account 370: difference of $706,546~~ ~~x. Account 371: difference of $6,159~~ ~~xi. Account 373: difference of $1,989~~ ~~xii. Account 390: difference of $30,092~~ ~~xiii. Account 397: difference of $43,926~~ ~~xiv. Account 303: difference of $(300,404)~~ ~~b. In column labeled "(m)" (spreadsheet column N), the items highlighted in green are those OE accounts whose 2016 WO Population differs from the DCR Adjusted Plant for 2016. Please provide a reconciliation for each account, explaining this difference:~~ ~~i. Account 350: difference of $(25,894)~~ ~~c. In column labeled "(r)" (spreadsheet column S), the items highlighted in green are those TE accounts whose 2016 WO Population differs from the DCR Adjusted Plant for 2016. Please provide a reconciliation for each account, explaining this difference:~~ ~~i. Account 390: difference of $66,692~~
FE-06.01	FERC Form 1 Reconciliation: Please provide a reconciliation of the Rider DCR balances in the 11/30/15 filing (which are the beginning balances for the 2016 DCR year) to the balances in the 2015 FERC Form 1. Please provide the reconciliation in the same format as was provided for last year's 2015 audit. (For ease of reference, the requested format is shown in the attached response to DR 1-INT-007 from last year's 2015 DCR audit.)
FE-07.01	Reference Company data request response BRC-Set 4-INT-2, attachment 1 – CONFIDENTIAL. The Company response indicates that the capitalized labor related overheads were charged in November 2016 to various FERC 300 accounts in Completed Construction Not Classified (FERC 106). a. Are the capitalized related overheads applied as they are incurred (monthly)? If not, why not? b. Since the adjustment add dollars to various FERC detailed 300 accounts associated with FERC 106 how are those dollars spread back to capital workorders since labor overheads do not represent a unit of property? c. What prohibits capitalized labor overheads from being applied to work orders through the normal allocation process?

DR	Request
FE-09.01	Annual Revenue Cap: The Under (Over) 2015 Revenue Cap was $12,338,638 as shown in the following table. The Under (Over) 2015 Revenue Cap is different than the amount carried forward to the 2016 filing, Column C. In prior years the Under (Over) has reconciled. This year the Under (Over) does not reconcile as shown in the following table. Based on this analysis, it would appear that the under recovery should be $37,755,190 not the $5,535,795. Please explain the difference.
FE-09.02	EDR(g) Rider: Follow up to BRC 1-29. The Companies identified EDR(g) activity that had not been excluded in previous DCR filings. a. Please confirm that the amount included within the December 30, 2016 filing have been corrected. b. What is the revenue requirement impact for the correction of the oversight?
FE-09.03	Property Tax Rate: The property tax rate for TE in last year's audit was 1.1310%. The property tax rate for TE in this year's audit is 1.5338% or a 35.74% increase. Please explain the significant increase in the property tax rate for TE.
FE-09.04	Intangible Deprecation: Please explain why the following land accounts have been depreciated: a. OECO 101/6-303 FAS109 Dist Land b. OECO 101/6-303 FAS109 G/P Land c. OECO 101/6-303 FAS109 Transm Land
FE-09.05	ADIT: Reference BRC 1-1, Attachment 7. Please explain the nature of the following components include in ADIT: a. CEI 11/30/16 Other Basis Differences-Fed-Norm $67,914,744 b. CEI 11/30/16 Tax Interest Capitalized-Fed-Norm-Incurred-CWIP $6,828,794 c. OE 11/30/16 Tax Interest Capitalized-Fed-Norm-Incurred-CWIP $16,096,182 d. OE 11/30/16 Tax Interest Capitalized-Fed-Norm $9,313,638 e. TE 11/30/16 PT Rebal-Reg Asset Recon - APB11 $1,681,533 f. TE 11/30/16 Tax Interest Capitalized-Fed-Norm-Incurred-CWIP $1,929,600 g. SC 11/30/16 Other Basis Differences $1,039,270 h. SC 11/30/16 Tax Interest Capitalized-Fed-Norm-Incurred-CWIP $1,099,445
FE-10.01	Other Riders: Follow up to data request BRC Set 1-INT-34. The tariffs for the new Riders DMR, ORR, and GDR do not indicate how these riders are calculated. Please provide a summary or the revenue requirements calculation that supports these riders to confirm that these rider do not include distribution capital additions or other components that are currently being recovery through Rider DCR.
FE-11.01	Follow up to Data Request response BRC-Set-4-INT-11, TECO work order ITF-SC-00040-SW15-1, $3,184,013.73. SW Upgrade 2015-CAP. a. Please analyze the charges to the work order in accordance with the CFR 18, and provide the resulting documentation the supports a cost allocation of 50% to capital. b. Please provide detail for the allocation change and demonstrate that no stores loading expense was included in the 50% cost that was transferred to FERC account 303 (Software).
FE-11.02	Follow up to Data Request response BRC Set-4-INT-12, TECO work order 13645860, - replace 12kv breakers, $337,194.62. Please indicate the amount that will be transferred

DR	Request
	from additions to cost of removal when the work order is unitized.
FE-11.03	Follow up to Data Request response BRC –Set-4-INT-10, b, CECO work order 14164717, CEI Plant Employees Onboarding Expenses - $1,606,349.13. Please provide the supporting detail for the reclassification entry of charges from FERC account 374 – Tool, shop and garage equipment, to the other FERC accounts.
FE-12.01	Please provide the workpaper referenced in the July 1, 2016 filing, that calculates the April 2016 DCR Audit Recommendations adjustments. The footnote source is "Cumulative revenue requirement impact of recommendations form the April 2016 Rider DCR audit report."

APPENDIX D: WORK PAPERS

Blue Ridge's workpapers are available on a confidential CD. Much of Blue Ridge's analysis was performed using 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

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 2016 - Confidential.xlsx
- WP BRC Set 1-INT-001 Attachment 7 - Confidential (ADIT).xlsx
- WP FEOH 2016 Adjustments to Plant and Reserve-Confidential R1.xlsx
- WP FEOH 2016 Pre-Date Certain Pension Impact Analysis 2012-2016 - CONFIDENTIAL.xlsx
- WP FEOH 2016 Sample Size Calculation Work Orders through 11-30-16 - CONFIDENTIAL R1
- WP FEOH 2016 Workorder Testing Matrix Final 170407.xlsx
- WP Impact of Findings BRC Set 1-INT-001 Attachment 1 - FE DCR Compliance Filing 12.30.2016 - Confidential R2.xlsx
- WP Population Recon - BRC Set-1-INT-006 Attachment 1 - Confidential
- WP V&V FE DCR Compliance Filing 12.30.2016 - Confidential R1.xlsx
- Directory with the work done regarding field observations.

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 2.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-013
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-014.
- WP FE Response to 2015 Audit Data Request BRC Set 1-INT-12 – Confidential.

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.

Table 31: Personnel in Key Roles Supporting the Rider DCR

#	Name	Title
1	Douglas Burnell*	Director, Business Services
2	Timothy Clyde* Amy Patterson[174]	Manager, Property Accounting
3	Randal Coleman*	Manager, Distribution Standards
4	Santino Fanelli* Joanne Savage[175]	Manager, OH Revenue Requirements
5	Joseph Loboda[176]* Michele Jones*[177] Sandra Hemberger[178]	Manager, Corporate Services Sourcing Manager, Corporate Services Sourcing Manager, Corporate Sourcing
6	Thomas McDonnell* Peter Nadel[179]	Manager, Insurance and Operational Risk Management
7	Eileen Mikkelsen[180]* Santino Fanelli[181]*	VP, Rates & Regulatory Affairs Director Rates & Regulatory Affairs
8	Erica Millen* Peter Blazunas[182]	OH State Regulatory Analyst III[183]
9	John Nauer*	Director, Utilities Sourcing
10	Albert Pompeo*	FEU Business Services Policy and Control Lead

[174] Timothy Clyde was in the position from December 2012 through February 2016. Amy Patterson assumed the position effective February 2016.

[175] As of May 2016, Joanne Savage assumed the position of Manager, Ohio Revenue Requirements that was previously held by Santino Fanelli.

[176] Joseph Loboda was in the position from 1/1/2012 through 2/12/2012.

[177] 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 (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.

[178] 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.

[179] As of February 2016, Peter Nadel assumed Thomas McDonnell's position as Manager, Insurance and Operational Risk Management.

[180] 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.

[181] Santino Fanelli is the Director of Rates & Regulatory Affairs. The position was previously held by Eileen Mikkelsen.

[182] Peter Blazunas replaced Erica Millen. He updated the interview notes from the prior year's audit.

[183] Peter Blazunas is an Ohio State Regulatory Analyst III as of 6/14/2015. There was no change to Mr. Blazunas' role related to Rider DCR in 2015.

#	Name	Title
11	William Richards* Tom Pesich[184] Nicholas Fernandez[185]	Manager, Business Unit Financial Performance Manager, Financial Modeling Executive Director, Strategy and LT Planning[186]
12	Steve Vucenovic* Mark Golden[187]	Manager, General Accounting

*Interview conducted in 2012. Notes provided in previous audit workpapers.

[184] 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.
[185] 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.
[186] 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.
[187] As of March 2016, Mark Golden assumed Steve Vucenovic's role as it relates to Rider DCR.

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