Case No. 19-439-EL-RDR

Compliance Audit of the Distribution Investment Rider (DIR) Period Covering October 1, 2015, through January 31, 2019, of The Dayton Power & Light Company

Submitted September 11, 2019

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

ORGANIZATION OF BLUE RIDGE'S REPORT

This report is organized according to the following major sections:

- *Executive Summary*: This section provides a summary of Blue Ridge's observations, findings, conclusions, and recommendations that are presented in more detail in the body of the report.
- *Overview of Investigation*: This section provides discussion of the following areas: background; project purpose; project scope; audit standard; information reviewed, including Rider DIR compliance filings; and a brief summary of the variance analyses, transactional testing, and other analyses.
- *Findings and Recommendations*: This section documents Blue Ridge's analysis that led to our observations, findings, and recommendations regarding the components that comprise the DIR.

The report also contains appendices.

The report includes an overview of the processes and controls, related policies and procedures, and internal audit reviews of the processes that feed into the Rider DIR calculations. A set of variance analyses reviews significant changes in net plant and reserve by individual FERC account. Results of the detailed transactional testing of sampled work orders supporting the gross plant in service is also provided. The scope also includes review of the Rider DIR Revenue Requirement components. It begins with an overview of methodology, including orders regarding the makeup of the DIR. Each component of the DIR revenue requirements is considered, including the rate base components of gross distribution plant, accumulated depreciation, accumulated deferred income tax; return on rate base; depreciation, taxes other than income, and O&M; property tax expense; and the Commercial Activity Tax. The report also presents the review of the annual caps and the percentage of base distribution revenue. The report concludes with the overall impact of findings on the Rider DIR Revenue Requirements.

EXECUTIVE SUMMARY

BACKGROUND

On October 20, 2017, the Public Utilities Commission of Ohio (PUCO or "Commission") issued an opinion and order in Case No. 16-395-EL-SSO in which it modified and approved the application of Dayton Power & Light Company (DP&L or "Company") for an electric security plan (ESP) that included the creation of a Distribution Investment Rider (DIR) for DP&L by which the Company would recover incremental distribution capital investments. The ESP set Rider DIR at zero and directed that all other matters related to the rider be addressed in DP&L's distribution rate case, Case No. 15-1830-EL-AIR.

As a result of examination of DP&L's application in Case No. 15-1830-EL-AIR, which included an original and one supplemental stipulation (Combined Stipulation), the Commission issued an Opinion and Order on September 26, 2018, approving the Combined Stipulation, including provisions related to the DIR. The DIR was ordered to be effective with the update to DP&L's base rates approved in the rate case and would be updated and reconciled quarterly. Also, as part of the approved Combined Stipulation, DP&L agreed to submit to an annual audit review of its DIR for the purpose of determining accuracy and reasonableness of the amounts for which recovery is sought. The audit would be conducted by an independent third-party auditor or the Commission's Staff at the Commission's discretion.

In accordance with the Opinion and Order in Case No. 15-1830-EL-AIR, the Commission sought proposals to review the accuracy and reasonableness of DP&L's compliance with its PUCO-approved Rider DIR with regard to the return earned on plant-in-service since the Company's date certain in its most recent rate case. Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the work.

PURPOSE OF PROJECT

The project purpose as defined in the RFP requires a review of the accuracy and reasonableness of DP&L's compliance with its Commission-approved Rider DIR with regard to the return earned on plant in service since the Company's date certain (i.e., September 30, 2015) in its most recent rate case (Case No. 15-1830-EL-AIR). This review is also to include the September 2018 DIR quarterly filing and the 2019 quarterly filing of April 1, 2019 (covering the quarter ended January 31, 2019).[1] Capital additions recovered through other riders authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from the DIR. The review will also include identification, quantification, and explanation of any significant net plant increases or decreases within individual accounts.

PROJECT SCOPE

The project scope as defined in the RFP is to determine whether DP&L has implemented its PUCO-approved DIR Rider and is in compliance with the Combined Stipulation agreement set forth in Case No. 15-1830-EL-AIR, et al., Opinion and Orders. The audit includes, but is not limited to, the following tasks:

- Review Case No. 15-1830-EL-AIR and related stipulation agreements
- Read all applicable testimony and associated workpapers

[1] While the RFP mentioned inclusion of filings up to and through the July 2019 filing, Staff clarified the scope period in the review startup meeting on April 30, 2019.

- Review all filings in Case No. 18-1468-EL-RDR
- Obtain and review all additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred between September 28, 2015, and June 30, 2019
- Verify with FERC Form 1
- Obtain and review all appropriate documentation relating to the Company's compliance with its PUCO-approved DIR
- Coordinate field inspection of plant with Staff to verify the used and usefulness of incremental plant in service
- Review all changes in capitalization policy and assess any impacts on the DIR, on the recovery of plant previously authorized as part of base rates, and on O&M expenses
- Review the Company's procedures for estimating and executing projects to ensure their accuracy and assess if cost controls are adequate within projects.
- Review the Company's unitization of plant, following DP&L Capitalization Guidelines
- Assess the impact of any accounting or tax changes upon the DIR with respect to changes enacted by the Company or opportunities not pursued by the Company which would have the effect of lowering the DIR rates to its customers.

Overall Impact of Findings on DIR Revenue Requirements

Blue Ridge's review of the accounting, accuracy, prudence, and compliance of DP&L with its Commission-approved DIR had findings and recommendations related to some of the components of the DIR revenue requirements that impact the amount that should be recovered through the DIR. These findings and the effect on the DIR Revenue Requirements are summarized below.

Adjustment #1–ADIT, missing basis allocation factor and corrections to multiple data input and processing errors in the life and method differences' financial model:

> Due to the unavailability of tax basis data at a level that would allow specific identification of DIR assets from other distribution plant, the Company applied a 67.68% basis adjustment for assets unitized as of September 30, 2015. The Company did not develop and apply a similar allocation factor to asset additions after October 1, 2015. The Blue Ridge adjustment assumed the same allocation factor as assets installed as of September 30, 2015. In addition, various omissions and errors in the financial model used to compute the life and method differences were corrected. Blue Ridge estimates the impact of the omissions and errors to be an understatement of the ADIT offset at January 31, 2019, by $(11,589,594). The estimated understatement changes the DIR revenue requirement by $(994,272).

Adjustment #2–Missing Protected Excess ADIT in DIR rate base and tax expense:

> The DIR rate base at January 31, 2019, does not reflect the Protected Excess ADIT the Company proposes to credit customers as an offset to the DIR revenue requirement per Case No. 19-0572-EL-UNC. Blue Ridge notes that the application does not make explicit whether the Company proposes to flow the Protected Excess ADIT through the DIR as 1) a dollar for dollar offset to the DIR revenue requirement or 2) part of the DIR revenue requirement. The latter would result in customers receiving no credit for the Protected Excess ADIT because, as the Company explained in Data Request 12-11(a), the DIR revenue requirement is significantly above the established revenue caps. Therefore, incorporating the Protected EDIT into the equation would have no impact on the level of revenues collected. Blue Ridge recommends the issue be presented in a transparent manner. For informational purposes, Blue Ridge is including a proforma adjustment to clarify the impact if the proposal or outcome

is a dollar for dollar offset to the DIR revenue requirement. The adjustment is an offset to DIR revenues collected in the amount of $(4,941,641).

Adjustment #3–Misstated return on rate base as of date certain:

The return on rate base as of date certain did not tie to the Stipulation, Exhibit 3 amounts. The Company confirmed that the difference of $5,532 is due to rounding of the pre-tax weighted average cost of capital used in the DIR Filings. Correcting the date certain return on rate base results in a $(5,532) change to the DIR revenue requirement.

The effect of Blue Ridge's recommended adjustments is summarized in the following table:

Table 1: Impact of Blue Ridge's Findings on the DIR Revenue Requirement

Description	DIR Revenue Requirment Impact	DIR Revenue Requirement Offset	Comment
As filed	$ 28,212,082	$ -	
1. ADIT Corrections	(994,072)	-	
2. Protected Excess ADIT	-	(4,941,641)	Outside Cap
3. Misstated Return on Rate Base	(5,532)	-	
Total Adjustment	$ (999,605)	$ (4,941,641)	
Revised Revenue Requirements	$ 27,212,477	$ (4,941,641)	
Annual Revenue Cap 2019	22,000,000	-	
Revenue Requirement Impact	**$ -**	**$ (4,941,641)**	

OTHER RECOMMENDATIONS

Recommendation 1: While reviewing the Company's internal audits for the audit scope period, one audit regarding DP&L vegetation management, was still in progress and therefore could not be reviewed. The Company stated it would provide the summary findings and recommendations when the audit report is issued. As of the date of this report, the Company has not provided the audit report. Blue Ridge recommends that the audit report be reviewed in the next DIR audit. (page 19)

Recommendation 2: An internal audit on the DPL Capex (CWIP Distribution) had audit findings and recommendations which the Company addressed. However, while the responses were not unreasonable, Blue Ridge cannot conclude whether the controls and process changes implemented by the Company will adequately address the audit recommendations. Blue Ridge recommends that the next DIR audit review the effectiveness of the changes to ensure that the transfer of projects from *in progress* to *in service* is performed in a consistent, timely manner for all concluded projects. (page 19)

Recommendation 3: When reviewing projects / work orders that had been placed in service more than 90 days after the estimated in-service date, the Company provided only various generic reasons regarding several of the delays. The Company should have been able to provide detailed explanations for all the projects / work orders that had delayed in-service dates. The generic reasons the Company cited do not tell whether the delays were caused by circumstances controllable, in which case corrective action should be taken, or outside the direct control of the Company. Blue Ridge recommends the Company institute a process in which large projects go through a post-closing review to determine specifically why in-service was delayed and what could be done to reduce the number of in-service delays. The review should identify the types of problems to determine whether the delay was outside the Company's control or controllable, in which case a process change should be made. (page 32)

Recommendation 4: When examining replacement work orders, Blue Ridge found that the Company was unable to provide dates assets were retired, cost of removal dates, or dates of replacement assets in service. Therefore, Blue Ridge could not assess the in-service date alignment with the asset replacement date. As a result, Blue Ridge was unable to determine whether assets were retired on a timely basis. When an asset is replaced and the old assets not retired timely, an over accrual of depreciation can occur. The Company has converted its existing Plant Accounting system to Power Plant. The new system has the capability to provide retirement dates. Blue Ridge recommends that this issue be reviewed during the next audit. (pages 32–33)

Recommendation 5: In examining insurance recoveries, Blue Ridge understands that past precedent has allowed the Company to treat insurance reimbursements as a reduction to the cost of service in a base rate case by reducing FERC Account 924 (Property Insurance). However, there is a concern that large insurance reimbursements between rate cases result in a windfall to the Company. The DIR allows the new assets to be placed in-service between rate cases and the Company to recover a return on and a return of an investment that it did not make. As this is a change in precedent, Blue Ridge is not recommending an adjustment at this time. However, Blue Ridge recommends that the treatment of insurance reimbursement between rate cases that affect the DIR should be reflected in future DIRs. (page 39)

Recommendation 6: The Company calculated the basis adjustments for assets unitized as of September 30, 2015, by applying a 67.68% allocation factor due to the unavailability of tax basis data at a level that would allow specific identification of DIR assets from other distribution plant. Blue Ridge found that the Company did not develop and apply a similar allocation factor to asset additions after October 1, 2015. The Company recognized the above situation and stated—and Blue Ridge recommends—that it will "incorporate this adjustment in the October 2019 filing. In addition, the Company's current plan for future DIR filings is to use a historic average factor until the final tax basis of each vintage is known." Blue Ridge recommends an adjustment to the ADIT balance. Our ADIT adjustment assumed the same 67.68% allocation factor for post-date-certain additions as assets installed as of September 30, 2015. (page 41)

Recommendation 7: Blue Ridge reviewed the Company's computation of the life and method differences for mathematical accuracy and completeness. Blue Ridge found that the supporting spreadsheets contained multiple data input and processing errors, which Blue Ridge verified with the Company. The errors were attributable to structural deficiencies in the financial model and user error. Absent a better system, Blue Ridge recommends the Company rebuild the financial model so that inputs are clearly defined and entered once and the processing of inputs to outputs is transparent and broken down into interim steps that are easy to follow. Without corrective action, similar errors will likely recur in future filings. Blue Ridge also recommends establishing an internal review process to eliminate basic user errors, such as the failure to update date and other input fields. (pages 41–42)

Recommendation 8: Regarding Property Tax Expense, Blue Ridge reviewed the methodology and supporting documentation used to calculate property tax. The average property tax rate is consistent with the method used in prior distribution rate cases. However, the Company did not update the 2018 average property tax rate and, instead, used the rate effective for 2017. In Case No. 15-1830-EL-AIR, Staff adjusted property tax expense to reflect the latest rates and valuation percentages in effect as of the test year and applied those rates to the plant in service as of date certain. Blue Ridge recommends that the Company use the most recent rates and valuation percentages when calculating property taxes. (page 46)

Recommendation 9: Regarding the annual cap, Blue Ridge found that in December 2018, the Company's DIR revenue collected exceeded the 2018 monthly cap of $1,200,000. However, the cumulative over/under recovery for October 2018–January 2018 was within the cumulative cap. Because of the potential of DIR revenue to be over or under the annual caps in a given year, Blue Ridge recommends clarification language on how to address DIR revenue over/under collections to the cap. (pages 47–48)

Recommendation 10: The DIR sunset provision, mentioned in the Stipulation of Case No. 15-1830-EL-AIR, et al., was not included in the Commission's order in that case. Blue ridge recommends that the sunset provision should be confirmed as relevant for future audits. (page 48)

Recommendation 11: The DIR rate base at January 31, 2019, does not reflect the Protected Excess ADIT the Company proposes to credit customers as an offset to the DIR revenue requirement per Case No. 19-0572-EL-UNC. Blue Ridge recommended that the Company clarify whether the impact of the quoted $49.6 million unamortized balance at December 31, 2018, and the corresponding annual amortization of $686,455 would be (1) a dollar-for-dollar offset to the DIR revenue requirement or (2) part of the DIR revenue requirement. If the Company proposes to include the Protected Excess ADIT as part of the DIR revenue requirement, the result would be that customers will receive no credit for the Protected Excess ADIT because the DIR revenue requirement is significantly above the established revenue caps. The Company should clarify its proposal to make the impact on the level of revenues collected from customers transparent. (page 48)

OVERVIEW OF INVESTIGATION

Dayton Power & Light (DP&L or "Company") prepared and submitted Compliance Filings regarding the Commission-approved Distribution Investment Rider (DIR) for actual plant in service covering the period October 1, 2015, through January 31, 2019. Blue Ridge Consulting Services, Inc. ("Blue Ridge") was retained to perform a compliance audit of the filings.

BACKGROUND

On October 20, 2017, the Public Utilities Commission of Ohio (PUCO or "Commission") issued an opinion and order in Case No. 16-395-EL-SSO in which it modified and approved the application of Dayton Power & Light Company (DP&L or "Company") for an electric security plan (ESP that included the creation of a Distribution Investment Rider (DIR) for DP&L by which the Company would recover incremental distribution capital investments. The ESP set Rider DIR at zero and directed that all other matters related to the rider be addressed in DP&L's distribution rate case, Case No. 15-1830-EL-AIR.

As a result of examination of DP&L's application in Case No. 15-1830-EL-AIR, which included an original and one supplemental stipulation (Combined Stipulation), the Commission issued an Opinion and Order on September 26, 2018, approving the Combined Stipulation, including provisions related to the DIR. The DIR was ordered to be effective with the update to DP&L's base rates approved in the rate case and would be updated and reconciled quarterly. Also, as part of the approved Combined Stipulation, DP&L agreed to submit to an annual audit review of its DIR for the purpose of determining accuracy and reasonableness of the amounts for which recovery is sought. The audit would be conducted by an independent third-party auditor or the Commission's Staff at the Commission's discretion.

In accordance with the Opinion and Order in Case No. 15-1830-EL-AIR, the Commission sought proposals to review the accuracy and reasonableness of DP&L's compliance with its PUCO-approved Rider DIR with regard to the return earned on plant-in-service since the Company's date certain in its most recent rate case. Blue Ridge Consulting Services, Inc. ("Blue Ridge") submitted a proposal and was selected to perform the work.

PURPOSE OF PROJECT

The project purpose as defined in the RFP requires a review of the accuracy and reasonableness of DP&L's compliance with its Commission-approved Rider DIR with regard to the return earned on plant in service since the Company's date certain (i.e., September 30, 2015) in its most recent rate case (Case No. 15-1830-EL-AIR). This review is also to include the September 2018 DIR quarterly filing and the 2019 quarterly filing of April 1, 2019 (covering the quarter ended January 31, 2019).[2] Capital additions recovered through other riders authorized by the Commission to recover delivery-related capital additions, will be identified and excluded from the DIR. The review will also include identification, quantification, and explanation of any significant net plant increases or decreases within individual accounts.

PROJECT SCOPE

The project scope as defined in the RFP is to determine whether DP&L has implemented its PUCO-approved DIR Rider and is in compliance with the Combined Stipulation agreement set forth

[2] While the RFP mentioned inclusion of filings up to and through the July 2019 filing, Staff clarified the scope period in the review startup meeting on April 30, 2019.

in Case No. 15-1830-EL-AIR, et al., Opinion and Orders. The audit includes, but is not limited to, the following tasks:

- Review Case No. 15-1830-EL-AIR and related stipulation agreements
- Read all applicable testimony and associated workpapers
- Review all filings in Case No. 18-1468-EL-RDR
- Obtain and review all additions, retirements, transfers, and adjustments to current date value of plant in service that have occurred between September 28, 2015, and June 30, 2019
- Verify with FERC Form 1
- Obtain and review all appropriate documentation relating to the Company's compliance with its PUCO-approved DIR
- Coordinate field inspection of plant with Staff to verify the used and usefulness of incremental plant in service
- Review all changes in capitalization policy and assess any impacts on the DIR, on the recovery of plant previously authorized as part of base rates, and on O&M expenses
- Review the Company's procedures for estimating and executing projects to ensure their accuracy and assess if cost controls are adequate within projects.
- Review the Company's unitization of plant, following DP&L Capitalization Guidelines
- Assess the impact of any accounting or tax changes upon the DIR with respect to changes enacted by the Company or opportunities not pursued by the Company which would have the effect of lowering the DIR rates to its customers.[3]

AUDIT STANDARD

During the course of the audit, Blue Ridge employed the standard that the audit will review the amounts for which recovery is sought to determine whether they are not unreasonable. Blue Ridge performed its review under this standard, adjudicating whether recovery sought was not unreasonable in light of the facts and circumstances known to the Company at the time such expenditures were committed.

INFORMATION REVIEWED

Blue Ridge reviewed the following information as required in the RFP.

- Case Nos. 15-1830-EL-AIR and 18-1468-EL-RDR
- All applicable testimony and associated workpapers
- All changes in capitalization policy and their impacts, if any, on the DIR and on O&M expenses

For ease of reference, excerpts from the Rider DIR portions of the Orders in the above cases are provided in Appendix A.

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 were provided to Staff.

RIDER DIR COMPLIANCE FILINGS REVIEWED

The Company filed and Blue Ridge reviewed the following quarterly DIR filings:

[3] Request for Proposal No. RA19-CA-2, *A Compliance Audit of the Distribution Investment Rider of Dayton Power & Light Company*, page 2.

1. Period ending June 30, 2018—Case No. 18-1468-EL-RDR filing dated September 28, 2018
2. Period ending June 30, 2018 (amended)—Case No. 18-1468-EL-RDR filing dated December 17, 2018
3. Period ending August 31, 2018—Case No. 18-1468-EL-RDR filing dated November 2, 2018
4. Period ending August 31, 2018 (amended)—Case No. 18-1468-EL-RDR filing dated December 17, 2018
5. Period ending January 31, 2019—Case No. 18-1468-EL-RDR filing dated April 1, 2019

Variance Analysis, Transactional Testing, and Other Analysis

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

In addition, Blue Ridge selected a sample number from the population of work orders that support the gross plant in service for detailed transactional testing. The sample was selected using a statistically valid sampling technique 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 Detailed Transactional Testing.

Blue Ridge also performed other various analyses, including mathematical verifications and source data validation, of the schedules that support the Rider DIR Compliance Filings. The report addresses each component of the DIR 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.

FINDINGS AND RECOMMENDATIONS

PROCESSES AND CONTROLS

The focus of this audit was to determine the accuracy and reasonableness of the amounts for which recovery is sought through the DIR. It was not a management audit (i.e., a diagnostic examination purposed to assess the effectiveness and efficiency of operation of a specific regulated utility). However, while Blue Ridge did not perform a management audit, we did review DP&L's processes and controls to ensure that they were sufficient so as not to adversely affect the costs in the DIR. Based on the documents reviewed, Blue Ridge was able to update its understanding of the Company's processes and controls (obtained from the Plant-in-Service Audit conducted for Case No. 15-1830-EL-AIR) that impact each of the plant balances and expense categories within the DIR. The following is a summary of the areas Blue Ridge reviewed.

DIR PREPARATION

Blue Ridge requested a narrative regarding how the DIR is prepared. DP&L responded with a detailed description of its process, highlighting the activities of four individuals who contribute to the major functions of the DIR preparation.[4] The Property Accounting Supervisor obtains asset activity through the Company's reporting tools for the applicable period. Asset additions are verified for inclusion according to the requirements of the DIR. The activity detail is tied to cash flow activity for additions to plant. Retirements are then also gathered and verified. The asset information is then provided to the Regulatory Department for preparation of schedules.

The book costs of assets includable for DIR recovery are limited to those which have been unitized to FERC 101 (Utility Plant in Service) and classified to certain specific fixed asset (300 series) subaccounts. Removed from this balance are the values in FERC Account 106 (Completed Construction Not Classified). A reconciliation to actual book values is performed, which details asset transfers. The dollar value of the asset unitizations by subaccount and general ledger date is summarized. Excluded from this summarization during this filing's preparation was the detail of meters contained in the book adjustment Meters Retired in Error. The dollar value of asset retirement by vintage year and general ledger date is summarized in a category of Asset Retirements for Tax. Also separately identified is the cost of Distribution land which was sold during the period.

Deferred taxes included in the DIR revenue requirement are computed taking into consideration the asset unitizations and asset retirements. For the post-DIR start assets (October 2015 and forward), the first step is to organize the data by vintage and calculate the net tax basis, which is the unitized assets less retirements. Tax depreciation is then calculated by multiplying the tax basis by vintage by the appropriate MACRS depreciation rate. The accumulated tax depreciation is subtracted from the tax basis to determine the net tax basis. The net tax basis amount is then subtracted from the net book basis amount to derive the temporary differences related to those vintages and then multiplied by the composite tax rate to calculate the deferred taxes on those temporary differences.

Similar to the post-DIR assets, the first step for the pre-DIR assets (placed in service before the DIR start date of October 2015) is to organize the data by vintage and calculate the net tax basis, which is the unitized assets less retirements and an adjustment for book / tax basis differences. Tax depreciation is then calculated by multiplying the tax basis by vintage by the appropriate MACRS depreciation rate. The accumulated tax depreciation is subtracted from the tax basis to determine

[4] DPL response to Blue Ridge Data Request 1.10.

the net tax basis. The net tax basis amount is then subtracted from the net book basis amount to derive the temporary differences related to those vintages and then multiplied by the composite tax rate to calculate the deferred taxes on those temporary differences.

The two deferred tax amounts are added together to determine the accumulated deferred income taxes on distribution plant included in the revenue requirement calculation.

To calculate the property taxes, the total assessed values for each parcel per the bills issued by each county are entered into a spreadsheet and the generation-related parcels are separated out. The assessed values of the remaining parcels are then multiplied by the net tax rate for the total tax due. The total tax due is then divided by the assessed value before that result is multiplied by 1,000 to derive the "average property tax rate per $1000" valuation.

Regulatory Operations takes the inputs created by the Property Accounting and Tax departments and develops the cost recovery schedules that are included in the DIR filing. Prior to filing, the schedules are reviewed by the preparing departments to verify accuracy.

Blue Ridge reviewed the detail of the response and was satisfied that the process is not unreasonable.

Current Policies and Procedures

During the Plant-in-Service Audit conducted for Case No. 15-1830-EL-AIR, Blue Ridge requested and received the policies and procedures for Company activity that provided input to distribution plant. Its response included policies and procedures for plant accounting, purchasing and procurement, AP and disbursements, accounting and journal entries, payroll, insurance recovery, allocations, work management system, and information technology.[5]

With regard to fixed assets, the Company provided several process flow diagrams including narrative defining the processes:

1. Capital Budgeting Process
2. Pricing and Invoicing for New T&D Construction
3. Financial Statement Close for Projects and Assets
4. A&G Expenses Transferred to CWIP
5. Overhead
6. Capitalization and Depreciation (including AFUDC)
7. Land Purchase
8. Land Disposition
9. Depreciable Asset Disposition
10. Asset Impairment Analysis
11. ARO Calculation and Removal Cost Obligations
12. Major Construction Project Accrual.

Additionally, other associated policies were examined regarding construction approval, additions and betterments to existing retirement property, test operations for new facilities, capitalized spare parts and equipment and development of depreciation rates were examined.

Blue Ridge also reacquainted itself with the Company's policies on procurement and supply chain, examining inventory, purchasing, and vendor maintenance policies and procedures.

[5] DPL response to 15-1830-EL-RDR Blue Ridge Data Request 1.8 CONFIDENTIAL.

The Company also maintains a Unit of Property Catalog that encompasses all its regulated property. The catalogue excludes the Company's generation assets. Modifications to the catalog are infrequent and would generally be required to address technological changes not addressed by the existing list of capital assets or to address a circumstance not previously identified.[6]

Blue Ridge, therefore, reacquainted itself with the Company's policies and procedures that would affect the DIR Rider to review its previous determination that they were not unreasonable.

POLICY AND PROCEDURE CHANGES

Blue Ridge reviewed the policies and procedures that the Company presented in response to Blue Ridge's May 2017 request in Case No. 15-1830-EL-RDR Plant-in-Service audit. In the current DIR audit, Blue Ridge requested any changes that had been made to those policies and procedures since issuance. The Company responded that there were no changes in their specified policies and procedures through January 31, 2019, except regarding the adoptions of ASU 2017-07 and ASU 2016-02 concerning leases.[7]

With regard to ASU 2017-07, this accounting-standard update amended the accounting for pension and OPEB costs, effective January 1, 2018, to limit the components of net periodic pension and postretirement benefit costs that are eligible for capitalization to only the service costs component. Previously, all components of net periodic pension and postretirement benefit costs (e.g., service cost, interest cost, expected return on plan assets) were eligible to be capitalized. The result of the accounting changes prescribed in ASU 2017-07 is that the portions of the costs that are no longer eligible to be capitalized increase the Company's operating expenses as compared to prior accounting. The Company explained that it adopted ASU 2017-07 in February 2018 with retroactive application to January 1, 2018. The Company modified its policies and procedures to reflect that non-service costs, which are no longer capitalizable for SEC reporting purposes, are no longer included in the allocation of construction overhead costs to capital projects. Instead, these costs are classified to GL Account 1013000 and are reported as regulatory assets for SEC reporting. The amounts classified to Account 1013000 are allocated between Transmission and Distribution property and are depreciated based upon the weighted average depreciation rates of Transmission and Distribution Plant Accounts. The amounts classified to Account 1013000 were not included in the Company's DIR filing. Furthermore, the Company stated that assets placed into service during 2018 and 2019 do not include non-service costs excludable under ASU 2017-07 that were recorded after December 2017.[8] Blue Ridge found the Company's explanation to be not unreasonable.

With regard to ASU 2016-02, this accounting standard update increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The Company noted the adoption of ASU 2016-02 had no impact on the accounting for FERC 300 subaccounts included in its DIR filing.[9] Blue Ridge found the Company's explanation to be not unreasonable.

In its report in Case No. 15-1830-EL-AIR, Staff recommends that DP&L be required to explain and quantify any impending capitalization policy changes in its DIR filings.[10] Such changes could be

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[6] DPL response to 15-1830-EL-RDR Blue Ridge Data Request 1.9.
[7] DPL response to Blue Ridge Data Request 1.8.
[8] DPL response to Blue Ridge Data Request 1.14.
[9] DPL response to Blue Ridge Data Request 1.8.
[10] Case No. 15-1830-EL-AIR, et al., Staff Report, page 9.

automatically approved with the filings, unless otherwise suspended by the Commission.[11] Blue Ridge reviewed the DIR filings, and no capitalization policy changes were disclosed. In addition, Blue Ridge also requested explanation of any major changes that have been made to the Company's capitalization policy from October 1, 2015, through January 31, 2019. The Company responded that, with the exception of the ASU 2017-07 and ASU 2016-02 adoptions mentioned earlier, no changes had been made to the policy.[12]

Rider DIR Internal Audit and SOX Audit

Blue Ridge requested and received a list of internal audits conducted during the audit scope period.[13] Of those, Blue Ridge requested the summary findings and recommendations on seven of the audits that could relate to the processes that support the DIR filing. The Company provided the summaries for all but one audit. The DPL Vegetation Management audit is in progress. The Company stated it would provide the summary findings and recommendations when the audit report is issued. As of the date of this report, the Company has not provided the audit report. Blue Ridge recommends that the audit report be reviewed in the next DIR audit.

With the exception of two audits that required additional review, the remaining audit recommendations appear reasonable and would have little if no impact on the DIR. The two audits requiring additional review were the Procurement Process and DPL Capex (CWIP Distribution).

Blue Ridge requested additional information regarding the Procurement Process remediation. The Company's response provided its action to address audit recommendations, which Blue Ridge found to be not unreasonable.[14]

The DPL Capex (CWIP Distribution) audit findings and recommendations (specifically, those of the T&D Projects Capitalization Process) directly impact the DIR. The audit found that "the required transfer of projects from in-progress to in-service was not performed in a consistent, timely manner for all concluded projects."[15] Blue Ridge reviewed how the Company had addressed the specific audit report findings.[16] While the Company's responses to the audit findings are not unreasonable, Blue Ridge cannot conclude whether the controls and process changes implemented by the Company will adequately address the audit recommendations. Blue Ridge recommends that the next DIR audit review the effectiveness of the changes to ensure that the transfer of projects from *in progress* to *in service* is performed in a consistent, timely manner for all concluded projects.

Blue Ridge also requested and received summaries of Sarbanes-Oxley (SOX) audits conducted during the audit scope period and found that any control deficiencies identified have been satisfactorily remediated.

Vegetation Management

Based on Blue Ridge's observation of how other Distribution companies in Ohio treat vegetation management costs, Blue Ridge separately requested that the Company describe the accounting for the initial clearing of a right-of-way and any policies and procedures that provide guidance on what

[11] Case No. 15-1830-EL-AIR, et al., Staff Report, page 9.
[12] DPL response to Blue Ridge Data Request 1.9.
[13] DPL response to Blue Ridge Data Request 1.16.
[14] DPL response to Blue Ridge Data Request 6.2 CONFIDENTIAL.
[15] DPL response to Blue Ridge Data Request 2-2 CONFIDENTIAL.
[16] DPL response to Blue Ridge Data Request 6-1 CONFIDENTIAL.

clearings are considered to be capital versus expense. The Company stated that it does not have a specific policy document pertaining to the initial clearing of a right of way. The Company follows FERC guidance for FERC Account 365 (Overhead Conductors and Devices), which allows for the capitalization of Item 9 "Tree trimming, initial cost including the cost of permits therefor." The Company vegetation management program specifications do, however, have a standard horizontal and vertical distance used for clearing rights-of-way:[17]

Primary Conductor

- It is assumed Purchaser has a ten (10) foot easement.
- Twelve (12) to fourteen (14) feet will be considered minimum clearance at time of trimming for fast growing trees located within the assumed ten (10) foot easement.
- Remove all overhang on fast growing/weak wooded species. On slow growing, hard wood trees flat hang shall be removed or elevated. All overhang on ash trees shall be removed. Any dead wood must be removed if it is in close proximity of the conductor.

Secondary

- The optimal clearance at time of trimming on secondary lines is ten (10) feet. When ten (10) feet of clearance is not obtainable then removing the tree should be considered.

When asked about the accounting for the initial clearing of a right-of-way, the Company explained that the costs incurred for the initial clearing of a right-of-way are capitalized as part of the cost of the associated Distribution lines. Costs which are subsequently incurred to expand an existing right-of-way are also capitalized. However, effective January 2015, the Company discontinued the policy of capitalizing the cost of removing "danger trees," which are trees outside the right-of-way but have the potential to impact the distribution line within the right-of-way.[18]

We asked follow-up questions related to the assumptions the Company makes regarding the horizontal and vertical areas within the right-of-way and the accounting for the clearing within the right-of-way. Upon initial clearing, the Company removes all trees within the right-of-way or trims them to create the right-of-way established width of 12–14 feet. The Company does not have a standard vertical height for tree removal. The Company agrees that any tree subsequently cleared within the right-of-way that had not been cleared initially would be considered expense in accordance with the FERC code of accounts (CFR 18).[19] Blue Ridge found the Company's explanation of its treatment of vegetation management costs not unreasonable.

Conclusion

From the documents reviewed, Blue Ridge was able to obtain an understanding of the Company's processes and controls that affect the DIR. Except for the findings in the audit of DPL Capex that we have recommended be revised in the next DIR audit, we were satisfied with actions taken with regard to internal audits and with the SOX-compliance testing. Blue Ridge concluded DP&L's controls were adequate and not unreasonable.

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[17] DPL response to Blue Ridge Data Request 2.1, c.
[18] DPL response to Blue Ridge Data Request 2.1.
[19] DPL response to Blue Ridge Data Request 7.1

VARIANCE ANALYSIS

Blue Ridge's variance analysis focused on identifying, quantifying, and explaining any significant net plant increases within the individual plant accounts. In its plan for analysis, Blue Ridge anticipated requesting from the Company explanations for any significant changes. Based on its investigative and analytic evaluation of the account changes and the Company's explanations, Blue Ridge would then arrive at its conclusions regarding the reasonableness of those changes.

Blue Ridge concentrated its efforts on five areas of account balance comparison in pursuing determination of variance reasonableness:

1. Compare DIR Beginning Balance to Case 15-1830-EL-AIR Ending Balance
2. Reconcile Annual Plant Balances for Scope Period to FERC Forms 1
3. Conduct Trend Analysis of Plant Balance Changes Year to Year
4. Evaluate Anomalies in Additions, Retirements, Transfers, and Adjustments for Year to Year Plant Balances
5. Compare Work Order Population Balance Totals to January 31, 2019, Filing Balance to Beginning Balance Difference

ANALYSIS: COMPARE DIR BEGINNING BALANCE TO CASE 15-1830-EL-AIR ENDING BALANCE

Blue Ridge compared the beginning plant and reserve balances (as of September 30, 2015) used in the DIR revenue requirements calculation to the ending balances reflected in the Staff Report Schedule B-2.1 and Schedule B-3 from Case No. 15-1380-EL-AIR. As shown in the following table, several recommendations made by Staff were not reflected in the individual FERC balances included within the DIR beginning balances. The Company used its recorded balances in the DIR calculation. However, the plant investment *total* matched the stipulated amount reflected in Exhibit 3 of the Stipulation that defines the revenue requirement calculation.

Table 2: Comparison of DIR Beginning Balances to Case No. 15-1830-EL-AIR Ending Balances[20]

					Case 15-1830-EL-AIR Staff's Report				
			DIR Beginning Balances 9/30/15		Schedule B-2.1	Schedule B-3	Difference		
Line No.	Acct. No.	Description	Plant Investment	Accumulated Reserve	Plant Investment	Accumulated Reserve	Plant Investment	Accumulated Reserve	Comment
(A)	(B)	(C)	(D)	(E)					
1	3601	Substation Land - NONE	$ 1,879,925	$ -	$ 1,879,925	$ -	$ -	$ -	
2	3602	Other Land - NONE	2,382	-	2,382	-	-	-	
3	3603	Land Rights - NONE	23,493,716	70,315	22,526,623	70,315	(967,093)	-	Staff's Adjusment
4	3610	S&I - NONE	9,424,899	4,871,850	9,424,899	4,871,850	-	-	
5	3620	Station Equip - NONE	135,835,303	51,235,961	134,063,137	50,214,031	(1,772,166)	(1,021,930)	Staff's Adjusment
6	3640	Poles, Towers & Fixt - NONE	260,613,653	153,937,606	258,296,991	152,310,440	(2,316,662)	(1,627,166)	Staff's Adjusment
7	3650	Ovhd Conductor & Dev - NONE	158,430,461	77,836,256	158,430,461	77,836,256	-	-	
8	3660	Underground Conduit - NONE	10,652,766	5,551,476	10,479,679	5,492,410	(173,087)	(59,066)	Staff's Adjusment
9	3670	Underground Conductor - NONE	203,324,254	99,060,724	201,042,702	97,643,310	(2,281,552)	(1,417,414)	Staff's Adjusment
10	3680	Line Transformers - NONE	271,712,937	96,911,140	271,712,937	96,911,140	-	-	
11	3691	Ovhd Electric Service - NONE	48,245,168	38,002,061	48,245,168	38,002,061	-	-	
12	3692	Underground Electric - NONE	158,964,844	85,593,622	158,964,844	85,593,622	-	-	
13	3700	Meters - NONE	46,780,659	13,712,156	46,780,659	13,712,156	-	-	
14	3711	Cust Install - Priv - NONE	15,594,843	15,245,663	15,594,843	15,245,663	-	-	
15	3712	Cust Install - Other - NONE	227,694	160,968	227,694	160,968	-	-	
16	3720	Leased Prop on Cust - NONE	47,450	47,450	47,450	47,450	-	-	
17	373	Street Lighting & Signal Sys							
18	374	Asset Retirement Costs for Dist. Plant							
19	108	Accumulated Reserve (b)	-	(70,315)					
20									
21		Total Applicable Distribution Plant	$ 1,345,230,954	$ 642,166,933	$ 1,337,720,394	$ 638,111,672	$ (7,510,560)	$ (4,125,576)	
			Total Agrees to Stipulation, Exhibit 3						

[20] WP Rev Req 1-31-19 Blue Ridge DR 01-3 – Attachment 5.

Another item reflected in the date certain balances was not reflected in the DIR balances. Line 19 in the above table shows Accumulated Reserve of $(70,315) that was not included on Schedule B-3 of Staff's report from Case No. 15-1380-EL-AIR. The Company explained that when certain land that had been classified to FERC Account 3601 (Land and Land Rights) was sold, the Company's Fixed Asset subsystem automatically classified the gain on the sale as a credit to FERC Account 108 (Accumulated Provision for Depreciation of Electric Utility Plant). This credit to Account 108 was reclassified through the General Ledger to FERC Account 421.1, Gain on Disposition of Property. Consequently, a reconciling adjustment of $70,315 was necessary at the date certain of September 30, 2015. The accounting entry that moved the gain on the sale of land from the reserve for depreciation to gain on disposition of property, which records the gain on the sale of land to the benefit of the stockholder, is in accordance with FERC accounting and not unreasonable.[21]

Thus, the plant investment totals reconciled to the stipulated amount reflected in Exhibit 3 of the Stipulation that defines the revenue requirement calculation.

Analysis: Reconcile Annual Plant Balances for Scope Period to FERC Forms 1

To identify any reporting differences between Distribution accounts in the DIR filings and the Company FERC Form 1 filings, Blue Ridge requested a reconciliation between the two filings for each year of the scope period (end of years 2015, 2016, 2017, and 2018). Blue Ridge examined the Company's response and is satisfied with the appropriateness of the balance differences.[22]

Analysis: Conduct Trend Analysis of Plant Balance Changes Year to Year

Blue Ridge found that the Company Plant Investment increased by an average of 4.59% per year.

Table 3:Gross Plant Balance Annual Increase Trend[23]

Account	Description	9/30/15	12/31/15	12/31/16	12/31/17	12/31/18	1/31/19
3601	Substation Land - NONE	1,879,925	1,879,925	1,879,925	1,879,925	1,906,570	1,906,570
3602	Other Land - NONE	2,382	2,382	2,382	2,382	2,382	2,382
3603	Land Rights - NONE	23,493,716	23,741,249	24,745,426	25,863,433	26,905,221	27,016,122
3610	S&I - NONE	9,424,899	9,424,899	9,964,648	10,030,387	10,276,162	10,276,162
3620	Station Equip - NONE	135,835,303	135,709,170	142,377,298	146,062,834	154,075,640	153,793,358
3640	Poles, Towers & Fixt - NONE	260,613,653	261,984,485	267,013,374	273,800,669	292,178,277	292,705,964
3650	Ovhd Conductor & Dev - NONE	158,430,461	160,105,437	161,982,843	163,772,463	166,099,983	166,190,283
3660	Underground Conduit - NONE	10,652,766	10,740,868	10,800,947	10,900,885	10,979,733	10,981,567
3670	Underground Conductor - NONE	203,324,254	205,658,608	212,751,452	220,320,817	231,048,252	232,552,065
3680	Line Transformers - NONE	271,712,937	278,711,388	285,720,547	300,677,077	315,271,454	316,640,190
3691	Ovhd Electric Service - NONE	48,245,168	48,248,192	50,085,428	50,080,285	52,785,266	52,837,320
3692	Underground Electric - NONE	158,964,844	158,958,278	172,851,688	172,814,104	201,668,150	202,921,311
3700	Meters - NONE	46,780,659	29,213,403	47,849,618	49,619,233	50,822,392	50,767,321
3711	Cust Install - Priv - NONE	15,594,843	15,594,787	17,791,339	17,798,332	18,797,663	18,859,552
3712	Cust Install - Other - NONE	227,694	227,694	227,694	227,694	227,694	227,694
3720	Leased Prop on Cust - NONE	47,450	47,450	47,450	47,450	47,450	47,450
		1,345,230,954	1,340,248,217	1,406,092,061	1,443,897,970	1,533,092,290	1,537,725,312
	% Year-to-Year Increase			4.91%	2.69%	6.18%	0.30%

[21] DPL response to Blue Ridge Data Request 9.1.
[22] DPL response to Blue Ridge Data Request 4.1 (Revised).
[23] WP DR 1.4 Gross Plant Balances.xlsx

Analysis: Evaluate Anomalies in Additions, Retirements, Transfers, and Adjustments for Year to Year Plant Balances

Blue Ridge examined plant balances, additions, and retirements to determine whether any Distribution plant-in-service account changes warranted further investigation. Blue Ridge divided our concerns into the following categories: Additions Significantly Greater Than Retirements, Negative Additions, Positive Retirements (Increasing Net Plant), and Retirements Greater Than Additions.[24] Data requests were developed by account for explanations of the anomalies.

Additions Significantly Greater Than Retirements

Several accounts over the audit period had additions significantly greater than retirements (2015: 3; 2016: 11; 2017:6; 2018:9). Blue Ridge examined the explanations by the Company and found in all cases the activity performed by the Company was not unreasonable.[25]

Negative Additions

In each of two years, Blue Ridge found two incidences in which accounts included negative additions. Blue Ridge found the Company's explanations, regarding timing issues, reflect normal occurrences and are not unreasonable.[26]

Positive Retirements (Increasing Net Plant)

One account (3680—Line Transformers) had positive retirements of $784,922 in the fourth quarter of 2015. The Company explained that in 2011, it had established Transformer Cutouts as separate retirement units. The dollar value of the existing cutout for each transformer was recorded as a separate asset with a credit offset being recorded associated with each transformer. However, the Company determined in 2015 that as transformers had been retired, the associated credit assets had not been retired along with them. Consequently, a catch-up of retirements for the credit assets was recorded in November 2015. At that time the Company's retirement procedures were also modified in order to ensure retiring transformer credit assets at the same time as the associated transformer.[27]

Blue Ridge followed up the explanation to ensure we fully understood the activity. Reclassifying parts of previously whole retirement units as their own retirement unit can be done, according to FERC guidelines (Title 18, Part 116), if these portions are separately identifiable, relatively costly, and not an integral part of the larger retirement unit. The Company determined that was the case for the Transformer Cutouts in question and so defined the cutouts in their Property Unit Catalog in 2011.[28] The Company also stated that the Property Unit Catalogs are maintained by the Controller's Department, and specific financial approval for the addition of line-related cutouts was authorized by the Senior Accounting Manager at the time of the addition. The Company has no written policy regarding how new retirement units of property may be established, DP&L follows the FERC guidelines and decisions are made by accounting personnel with the appropriate consulting input of engineering and operations personnel.[29]

When asked about the impact to net plant of not retiring the FERC account 368 credits timely, the Company noted that the timing difference resulted in a $24,004 reduction in the over accrual of

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[24] WP Var Analysis Blue Ridge DR 01-4 – Attachment 1.xlsx.
[25] DPL response to Blue Ridge Data Request 3.1.
[26] DPL response to Blue Ridge Data Request 3.2.
[27] DPL response to Blue Ridge Data Request 3.4.
[28] DPL response to Blue Ridge Data Request 8.1.
[29] DPL response to Blue Ridge Data Request 17.1.

depreciation expense from the September 30, 2015, date certain in rate case 15-1830-EL-AIR. While reviewing that effect, the Company also found that some of those assets had been recorded as offsets to assets already retired, resulting in a $1,902 reduction in depreciation expense after the September 30, 2015, date. Further, the credit offsets recorded in connection with regulators, reclosures, and capacitors had been recorded under FERC Account 3680 while the original cost of the underlying assets were classified to FERC Accounts 3620 (Station Equipment) and 3650 (Overhead Conductors and Devices). Those credit assets were retired in error in November 2015 since the underlying assets had not been identified as remaining within the Fixed Assets records as part of the review of FERC Account 3680. These retirements resulted in $24,945 in additional depreciation expense through to January 31, 2019. Combining these three amounts [$(24,004), $(1,902), and $24,945] results in an adjustment to plant book cost of $961.[30] The impact is immaterial to the Rider DIR revenue requirement calculations.

Retirements Greater Than Additions

Three accounts (one in 2015 and two in 2019) ended the year with retirements greater than additions for period. Blue Ridge examined the Company explanations and found them to be not unreasonable.

Analysis: Compare Work Order Period Population Totals to Filed Period Balance Differences

To ensure that the work order population cost totals for the period October 1, 2015, to January 31, 2019, aligned with the difference in plant balances between the period boundaries, Blue Ridge calculated the totals by account for the work order population. The totals matched the unitizations for the period after removing Account 106 totals.[31]

Conclusion

As noted, Blue Ridge found that several recommendations made by Staff (and recorded in Staff Report Schedule B-2.1 and Schedule B-3 from Case No. 15-1380-EL-AIR) were not reflected in the Company's *individual* FERC balances. The Company used its recorded balances in the DIR calculation. However, the plant investment *total* matched the stipulated amount reflected in Exhibit 3 of the Stipulation that defines the revenue requirement calculation.

Blue Ridge's review of variances revealed that the anomalies were largely as a result of normal work order activity and are not uncommon among utilities. Beyond the minor adjustment regarding the timing and other errors described of the retirement accounting activities, the changes in plant balances for the Company were not unreasonable.

[30] DPL response to Blue Ridge Data Request 8.1, part e, and Attachment 2.
[31] DPL response to Blue Ridge Data Request 10.1, Attachment 1.

DETAILED TRANSACTIONAL TESTING

WORK ORDER DETAILED TRANSACTIONAL TESTING

Blue Ridge's review of the plant balances included detailed transactional testing of a statistically significant sample from the population of work orders that support the gross plant in service. The Company provided a list of 8,624 work orders that support gross plant in service included in the DIR from October 1, 2015, through January 31, 2019.

(1) Determining Work Order Sample

From the population list, Blue Ridge selected 65 work orders, totaling $130,555,208 (34,778 individual cost line items), for transactional testing. Sixteen were selected using the statistically valid probability-proportional-to-size (PPS) sampling technique. An additional 49 work orders were selected based on professional judgment with a focus on the selection of individual (rather than blanket) work orders that have a high-dollar value [32] and, if possible, could also be inspected in the field to determine its used-and-useful status [33] (in accordance with work order testing step T11 discussed later in this document).

(2) Conducting Work Order Testing

The Company provided descriptions of the projects included in the work order sample. In general, the projects may be categorized based on the following types of additions, replacements, adjustments, and transfers.

1. Installation of underground and overhead conduit, conductors, and devices
2. Meters
3. Land and Land Rights
4. Station equipment
5. Poles, Towers and Fixtures, and Services
6. Line Transformers
7. Installation on customer premises
8. Structures and Improvements
9. Adjustments

The following areas were the determined focus for transactional testing review:

- Project descriptions to determine exclusions from the DIR
- Project justifications
- Project actual versus budgeted cost
- Variance explanations
- Reasonableness of the actual in-service dates in comparison to the estimated in-service dates
- Proper charge of the actual detailed cost to the proper FERC account
- AFUDC charge on the work order (and if so, was it appropriate)
- Timeliness of recording of asset retirements for replacement work orders
- Appropriate charge of cost of removal and salvage, if applicable

[32] WP 18-1468-EL-RDR DPL DIR Reconciliation, Sensitivity, Sample Size and PULLING Sample.
[33] WP DPL DIR Audit Work Order Testing Matrix FINAL.

To satisfy these areas of focused review, Blue Ridge formulated the objective criteria into ten transactional testing steps, labeled T1 through T10.[34] Testing step T11 assessed whether the project was a candidate for field verification. Blue Ridge's observations and findings against the criteria follow:

- T1: The work is appropriately includable in Rider DIR.
  - T1a: The DIR includes plant in service associated with distribution net investment associated with FERC Plant Accounts 360–373.
  - T1b: Project is a pre-approved battery storage project.
  - T1c: Project is Electric Vehicle (EV) charging infrastructure limited to $1 million.
  - T1d: Project is not recovered through other Commission approved riders.
  - T1e: Project is not for an affiliate.
- T2: For specific work orders (i.e., not blanket or multi-year projects, such as pole and meter replacements), the work order package contains project justification that supports it being necessary, reasonable, and prudent.
- T3: Project has an approved budget.
  - T3a: Project costs are within approved budget.
  - T3b: There are reasonable explanations for approvals for cost overruns of 20% or greater.
- T4: If the work order represents allocated charges, the allocations are reasonable.
- T5: Work orders and/or projects are properly approved.
- T6: Cost detail in Power Plant supports the work order charge, and the categories of cost are reasonable.
- T7: Actual in-service date is in line (at or before) with the estimate.
- T8: The work order was in service and closed to EPIS within a reasonable time frame from project completion, and if not, AFUDC was stopped.
- T9: Following completion of the work, the work was properly classified as capital and recorded to the proper FERC 300 account(s) as dictated by the FERC code of accounts (CFR 18)
- T10: Project detail for replacement projects indicates assets were retired and costs were incurred for cost of removal and salvage, if applicable.
  - T10a: For replacement work orders, the date assets were retired, cost of removal date, and date of replacement assets in service are in line with the asset replacement date.
  - T10b: For replacement work orders, cost of removal was charged.
- T11: Project is a candidate for field verification to determine whether it is used and useful.

The results of the detailed transaction testing performed on the work order sample are included in the workpapers.[35] Specific observations and findings about the testing are listed below.

T1: The work is appropriately includable in Rider DIR.

T1a: The DIR includes plant in service associated with distribution net investment associated with FERC Plant Accounts 360–373.

Blue Ridge found that all the projects/work orders included among the testing sample were associated with distribution.

[34] WP DPL DIR Audit Work Order Testing Matrix FINAL.
[35] WP DPL DIR Audit Work Order Testing Matrix FINAL.

T1b: Project is a pre-approved battery storage project.

Blue Ridge found that none of the projects/ work orders included among the work orders sampled were related to the battery storage project.

T1c: Project is Electric Vehicle (EV) charging infrastructure limited to $1 million.

Blue Ridge found that none of the projects/ work orders included among the work orders sampled were related to EV charging infrastructure.

T1d: Project is not recovered through other Commission approved riders.

Per the approved tariff, the Distribution Investment Rider is intended to compensate DP&L for incremental distribution capital investment incurred by the Company since the date certain established in Case No. 15-1830-EL-AIR, exclusive of distribution plant recovered in other riders. The Company provided a list of other riders and surcharges in effect from date certain September 30, 2015, through January 31, 2019, and stated that these other riders did not include recovery of distribution plant.[36] Blue Ridge compared the Company-provided information to the riders included in the Company's Electric Distribution Service Schedule of Rates, Classifications, Rules and Regulations (PUCO No. 17) on file with the Commission[37] as shown in the following table.

Table 4: Other Riders Reviewed for Recovery of Distribution Plant

Sheet No.	Version	Description	Effective Date	Review of Tariff Comments
D27	Fifth Revised	Uncollectible Rider	10/1/18	Non-payment
D28	Eighteenth Revised	Universal Service Fund Rider	1/1/18	Low-Income customers
D29	Fourteenth Revised	Smart Grid Rider	11/1/17	Placeholder
D30	Seventh Revised	Storm Cost Recovery Rider	1/1/19	Service Restoration and Repair
D31	Seventh Revised	Regulatory Compliance Rider	11/1/18	Case No. 18-1309-EL-RDR: Customer Education, Retail Settlement Systems costs, Green Pricing Program, Generation Separation costs, Bill Format Redesign
D32	Fourth Revised	Distribution Decoupling Rider	10/1/18	Change in number of customers
D33	Fourth Revised	Excise Tax Surcharge Rider	10/1/18	Excise Tax
D37	Fifth Revised	Distribution Modernization Rider	11/1/18	Case No. 16-395-EL-SSO (Order 10/20/17): Cash Flow support to pay interest on debt
D38	Ninth Revised	Energy Efficiency Rider	10/1/18	EE and peak demand reduction targets
D39	Twentieth Revised	Economic Development Rider	5/1/19	Incentives for Economic Development and Job Retention
D40	Second Revised	Reconciliation Rider	11/1/18	Case No. 16-395-EL-SSO (Order 10/20/17); deferred cpsts from OVEC

Blue Ridge found that the DIR is currently the only rider that recovers incremental distribution capital investments.

Blue Ridge found that none of the projects/ work orders included among the work orders sampled are recovered through other Commission riders.

T1e: Project is not for an affiliate.

Blue Ridge found that none of the projects/work orders included among the work orders sampled are for an affiliate.

[36] DPL response to Blue Ridge Data Request 1.18.
[37] WP Other Riders Review for Plant Recovery.

T2: For specific work orders (i.e., not blanket or multi-year projects, such as pole and meter replacements), the work order package contains project justification that supports it being necessary, reasonable, and prudent.

Blue Ridge found that all the specific projects / work orders sampled had documentation supporting the necessity, reasonableness, and prudence of the projects / work orders. Blanket projects / work orders are on-going and typically for routine day-to-day work necessary for continued operation of the system.

T3: Project has an approved budget.

Twenty-nine of the projects / work orders sampled were blankets for either on-going day-to-day work or storm work. On-going blankets have a hierarchical approval process. Funding for blanket projects is authorized through the Company's annual capital budgeting process. The remaining 36 specific projects / work orders had an approved budget.

T3a: Project costs are within approved budget.

Thirty-six projects / work orders were either under budget or over budget by not more than 20%. Twenty-nine projects / work orders were blankets and either had annual budgets or were for storms and did not have budgets. These included projects that are equipment failures and insurance reimbursable either in whole or in part.

T3b: There are reasonable explanations for approvals for cost overruns of 20% or greater.

The following project was overbudget in regard to the Original PEA. However, the Company followed proper procedures by creating two Supplemental PEAs to cover the costs of the project.

Project 30734191 – Indian Lake I/S Bk 1. The Company installed a 64/12kV, 30 MVA transformer at Indian Lake substation. The original budget was $1.546 million. The first supplement increased the project to $1.972 million. The second supplement increased the project to $2.322 million, and the actual expenditures were $2.401 million. Therefore, the actual project costs came in 55%, or $855,000, over the original budget. The Company cited several reasons for the increased cost:

- The first Supplemental PEA increased the project budget due to higher than anticipated external labor costs and the need to install a mobile substation during construction. The project was competitively bid, and the least cost vendor was awarded the project. Vendor cost was approximately 142% higher than estimated.
- The second Supplemental PEA increased the budget due to higher than anticipated internal labor costs associated with relay installations and the installation of a second mobile transformer.[38]
- Contract Labor: Additional contract labor costs were incurred to complete the mobile substation and electrical installations.
- Internal Labor: Internal labor exceeded the original estimate due to multiple variables, such as drive time, reporting location, and scope changes, which included the need to install two mobile substations and additional relays.

[38] DPL response to Blue Ridge Data Request 5.1, Attachment 1(x) CONFIDENTIAL.

- Mobile Substation: Mobile substations were installed to prevent potential loading issues and to avoid outages to customers. The original scope did not include the mobile installations but was revised after reviewing the project details.
- Switch Installation: During the construction, switching was necessary to de-energize various portions of the substation. To avoid an outage to a large commercial customer, a new transmission switch was installed. The switch was not part of the original scope.[39]

This project was also included among the projects that were field verified. Staff's engineers were informed that DP&L experienced higher bids on the work than they anticipated and had a myriad of problems during the construction phase. They uncovered some cables that needed to be dug up and removed from under the substation yard. The safety practices at AES changed during the construction which caused them to have to allow for additional changes in clearances inside the substation. A mobile transformer had to be brought in to ensure Honda of America stayed energized, and several additional 69KV poles and switch had to be installed to support that and were not originally foreseen.

Blue Ridge found that the abovementioned project is an isolated instance and that the issues that arose during construction were out of the control of the Company.

T4: If the work order represents allocated charges, the allocations are reasonable.

None of the work orders represented only allocated charges. However, DIR work orders include various overhead and indirect costs that are applied on top of the work order's direct charges. The percentage rates to be applied are developed through studies and can change as often as annually. The following table summarizes the overhead and indirect costs that are applied depending on the nature of the direct charge. For example, direct labor charges receive payroll overheads, bonus/non-productive, and S&E and A&G overheads. Another example of overhead and indirect costs is the minor materials overhead rate and stores handling rate applied to materials withdrawn from inventory. Other items impact which loading would be applied. For example, if a contractor is used to supervise a crew instead of an internal manager, no S&E would be applied.[40]

Table 5: Overhead and Indirect Costs Included in DIR Work Orders

Burden Name	Description	Rate
A&G	Administrative and General	3.22%
Bonus/NonProductive	Payroll bonus and time not charged directly to a project	12.84%
Minor Material	Nuts in Bolts in store room	10%
Payroll Overheads	All the normal Payroll benefits	41.96%
S&E	Supervisory and Engineering	9.24%
Stores Loading – WPA	Warehouse Labor handling inventory for Wright Patt Inventory	8%
Stores Loading – Other	Warehouse Labor handling inventory for T&D Inventory	23%

[39] DPL response to Blue Ridge Data Request 12.10.
[40] DPL response to Blue Ridge Data Request 1.25.

Blue Ridge reviewed the overhead and indirect cost allocations and found them to be not unreasonable.

T5: Work orders and/or projects are properly approved.

Blanket and specific project / work orders are approved through different processes. Twenty-nine of the projects / work orders sampled were for either on-going, day-to-day work or storm work. On-going blankets have a hierarchical approval process. Storm work orders are issued to capture storm-related costs and do not require specific approval other than issuing a project / work-order number to capture the storm-related capital costs. The policies for the approval process for blankets have not changed since the prior audit in 2017. Funding for blanket projects is authorized through the Company's annual capital budgeting process. The Level of Signatory Authority (LOSA) document would apply for approvals of individual jobs contained within a blanket for which the projected expenditures exceed blanket limitations. Funding for various ongoing programs, such as the cut-out and pole-replacement programs are approved annually through the Project Expenditure Authorization (PEA) process to which the LOSA document applies.[41] Specific projects are approved through the PEA process.

There were 36 specific projects. Two of the specific projects were under $250,000 and did not require specific approvals. The remaining specific projects were all properly approved in accordance with the applicable LOSA document.

T6: Cost detail in Power Plant supports the work order charge, and the categories of cost are reasonable.

Blue Ridge reviewed the work order charges and categories of costs and found that they were not unreasonable.

T7: Actual in-service date is in line (at or before) with the estimate.

Blue Ridge found that 22 of the specific projects / work orders were in-service either before the estimated in-service date or within a reasonable time frame after the estimated in-service date. Twenty-nine projects were blankets for either routine work or storms and did not have in-service dates.

The remaining 14 projects / work orders in the sample were placed in service more than 90 days after the estimated in-service date (representing 20% of the projects / work orders within the sample).

[41] DPL response to Blue Ridge Data Request 10.4.

Table 6: Work Order / Projects Not Placed in Service Timely

Project	Project Description	ADDITION	DPIS	Estimated In-Service Date	Delay
30734131	Vandalia-Install new AZ-1209 Circuit	$0	2/12/15	9/3/14	162
30734191	Indian Lake: I/S BK-1	$2,049,316	3/2/16	10/31/15	123
30734516	Mechanicsburg sub-R/P failed BK-1	$595,301	9/8/15	5/15/15	116
30734525	Eaker Sub:R/P BK-1	$1,098,291	11/16/15	5/1/15	199
30734526	Webster Sub:R/P BK-2	$1,097,229	3/17/16	11/1/15	137
30734527	Wilmington Sub: R/P BK-2	$567,756	3/29/16	12/30/15	90
30734743	WEBSTER ST BRIDGE R/P	$435,117	9/30/16	3/1/16	213
30734968	Treaty Sub: I/S BK-2	$1,840,418	12/1/17	4/1/17	244
30735090	Spare Transformer	$616,033	5/11/17	11/1/16	191
30735142	JEFFERSONVILLE - R/P JE1204E & JE1202E	$238,927	10/27/17	5/31/17	149
31029343	Keowee St. Rebuild (Helena to Stanley) - Copy of WO:10056375	$368,576	8/9/16	4/30/16	101
44635314	446-Delco Kettering Sub BK-2 Failure Insurance Claim	$733,508	12/1/17	12/16/16	350
31030031	AT12-6-3ph Reconductor along Shakertown Road	$189,206	1/26/17	10/15/16	103
31029760	Relocate Utilities for the Village of Ft. Loramie	($68,715)	2/16/17	10/31/16	108

For the first twelve projects / work orders in the list that were placed in service more than 90 days after the estimated in-service date, the Company did not have specific reasons why the in-service date was different from the estimated in-service date. The Company provided various generic reasons as to why the projects / work orders were not placed in-service timely:

- Longer than anticipated material lead times
- Delays in material deliveries from supplier(s)
- Request by the customer
- Availability of outages needed to complete certain work
- Ability to obtain the necessary right-of-way or easement[42]

For the last two projects / work orders in the list, the Company provided detailed explanations for the excessive delays:

- Project 31030031: AT12-6-3ph Reconductor along Shakertown Road. This project was in-service 103 days after the estimated in-service date. The recloser purchased for the project was received and identified as defective. Thus, the Company had to wait for a replacement unit to be delivered and installed before it could consider the entire project in-service.
- Project 31029760: Relocate Utilities for the Village of Ft. Loramie – Copy of WO:10088093. This project was in-service 108 days after the estimated in-service date. Village of Ft. Loramie requested that DP&L delay the start of the project until after their July 4 festivities and requested the project coordinate with the work of the Village's crews. The Village of Ft. Loramie paid 100% of the project costs.[43]

Blue Ridge found that the detailed explanations the Company provided for the two projects / work orders were not unreasonable. However, the Company should have been able to provide

[43] DPL response to Blue Ridge Data Request 11.4 and 5.1, Attachment 1(j) CONFIDENTIAL.

detailed explanations for all the projects / work orders that had delayed in-service dates. The generic reasons the Company cited do not tell if the delays were caused by circumstances controllable, in which case corrective action should be taken, or outside the direct control of the Company.

Blue Ridge recommends the Company institute a process in which large projects go through a post-closing review to determine specifically why in-service was delayed and what could be done to reduce the number of in-service delays. The review should identify the types of problems to determine whether the delay was outside the Company's control or controllable, in which case a process change should be made.

T8: The work order was in service and closed to EPIS within a reasonable time frame from project completion, and if not, AFUDC was stopped.

For the projects that had a delayed in-service date, the Company cited the FERC Uniform System of Account (USOA) instructions as to why AFUDC was continued until the in-service date. The Company stated that FERC Electric Plant Instruction No. 3.A.(17) provides for the accrual of AFUDC until a project is placed in operation or is completed and ready for service. The indicated date placed in service corresponds to the date the project was completed. Any difference between the actual date a project is completed and the project's forecasted completion date does not impact the accrual of AFUDC.[44]

Blue Ridge does not disagree with the Company's interpretation of the FERC USOA as it relates to the accrual of AFUDC so long as the projects were not suspended. However, the additional AFUDC that is accrued due to the delays increase the cost of the project. Blue Ridge recommends that the reason(s) for delays should be determined, documented, and fully understood to identify areas for improvement.

T9: Following completion of the work, the work was properly classified as capital and recorded to the proper FERC 300 account(s) as dictated by the FERC code of accounts (CFR 18).

Blue Ridge found that, based on the project detail provided, the projects / work orders were classified to the proper FERC 300 account in accordance with the FERC USOA (CFR18).

T10: Project detail for replacement projects indicates assets were retired and costs were incurred for cost of removal and salvage, if applicable.

Blue Ridge identified eleven projects / work orders, included in the work-order sample, that consisted of projects for new services, purchase of spare parts, insurance claims, land purchases, and the purchase of stock Distribution Transformers. Except for insurance claims, those work types do not have retirements, cost of removal, or salvage associated with them. The accounting for insurance claims is discussed in a separate section within this report.

The remaining fifty-four projects / work orders had retirements, and the Company provided retirement category, location, and number of units retired for them.

T10a: Replacement work orders: The date assets were retired, cost of removal date, and date of replacement assets in service are in line with the asset replacement date.

The Company was unable to provide dates assets were retired and cost of removal dates for retired assets. Therefore, Blue Ridge could not assess the in-service date alignment with the asset

[44] DPL response to Blue Ridge Data Request 11.4.

retirement date. As a result, Blue Ridge was unable to determine whether assets were retired on a timely basis. When an asset is replaced and the old asset is not retired timely, an over accrual of depreciation can occur. The Company has converted its existing Plant Accounting system to Power Plant. The new system has the capability to provide retirement dates. Blue Ridge recommends that this issue be reviewed during the next audit. The failure to provide dates affected approximately 16.7% (~$21.8 million) of Blue Ridge's sample. Blanket and Storm work orders that include replacements are automatically retired every 30 days in conjunction with additions to plant or when the storm work is complete. Retirements associated with insurance claims are recorded either before or when the insurance claims are filed. The purchase of capital Spares and additions (not replacement) of plant do not have retirements. Blue Ridge found that the inability to provide specific dates was not material to this audit. Any potential over accrual of depreciation would not reduce the calculated DIR revenue requirements by more than the approximate $5 million that the revenue requirements exceed the cap and would not impact the level of revenues collected.

T10b: For replacement work orders, cost of removal was charged.

Two project / work orders had retirements and would have been expected to have cost of removal charged, but no cost of removal was charged.

- Project 31028287 – GF1204 – BL# D6648-Extend two more phases into Sand Run - $83,665. The Company removed two assets but was unable to provide the cost of removal information.
- Project 31033377 – Remove DP&L facilities for Demo and Install Pole – $2,923. All expenditures for this project were unitized to the cost of the pole.[45]

The cost of removal for these two projects would be immaterial to the DIR revenue requirements.

For the remaining fifty-two projects / work orders, the Company provided retirement information (category, location, and number of units retired) and their associated cost of removal charges. Blue Ridge reviewed the Task 90 charges and found that the removal costs were not unreasonable.

[45] DPL response to Blue Ridge Data Request 18-1.

T11: Project is a candidate for field verification to determine whether it is used and useful.

Blue Ridge identified the following work orders for field verification:

Table 7: Work Orders selected for Field Verification

Project	Project Description	Total
30734191	Indian Lake: I/S BK-1	$ 2,049,307
30734515	Huber Hts sub-R/P failed BK-2 Insurance claim	$ 797,363
30734516	Mechanicsburg sub-R/P failed BK-1 Insurance claim	$ 595,301
30734525	Eaker Sub:R/P BK-1 insurance claim	$ 1,098,291
30734526	Webster Sub:R/P BK-2 Insurance claim	$ 1,097,370
30734878	Spare Transformer 2016	$ 619,472
30734968	Treaty Sub: I/S BK-2	$ 1,840,418
30735090	Spare Transformer	$ 616,033
36734187	Southtown sub-I/S for Fuyau glass plant	$ 1,708,364
36735185	367-Centerville BK-2 Replacement Insurance claim	$ 910,043
44635312	446-Jeffersonville Sub BK-1 Failure Insurance Claim	$ 1,118,026
44635313	446-Jeffersonville Sub BK-3 Failure Insurance Claim	$ 585,710
44635314	446-Delco Kettering Sub BK-2 Failure Insurance Claim	$ 733,508

FIELD INSPECTIONS

From the work order sample, Blue Ridge selected 13 projects for field verification from the work order sample. The purpose of the field verification was to determine whether the assets had 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 specified assets that can be physically seen and were installed within the scope period of this review. The judgment sample was based on large-dollar work orders. Work orders/projects were excluded from selection for the following reasons:

a. The work cannot be visually seen because it is underground or in some other way out of sight.
b. The work order is an adjustment or transfer of dollars and therefore no physical assets have been installed.
c. The work order is a blanket, and therefore, multiple assets have been installed at various locations. It would not be practical to try to find them. In addition, those assets are generally minor in terms of dollar value. An example is meters installed at multiple locations.
d. The work order is for a mass unitization where the total dollars are large but each workorder is small.
e. The work order was not selected based on professional judgement.

Experienced staff from the Public Utilities Commission of Ohio, with assistance from DP&L representatives, conducted the field verifications from August 12 through August 14. Staff was provided information for each work order/project and completed a questionnaire developed by Blue Ridge for each location. The questionnaire addressed the following areas:

- The assets were operational (used and useful) and providing service to the customer.
- The purpose of the project was reasonable.
- The assets that were installed were in accordance with the original scope of work and no assets were installed that were not in the original scope of work.
- The equipment that was installed matched the equipment that was capitalized to the DIR.

- Company personnel understood the scope of work and were able to provide staff with detailed answers to questions about the work.
- Problems identified during the process of construction were identified and discussed.
- The Company provided reasons (either to Staff or Blue Ridge) for any variances from budget that were greater than 20%.
- Photos were taken to support the field observations.

Where possible, Staff took pictures of the installed assets. The completed questionnaires and pictures are included as workpapers in the appendices of this report. The following projects were field inspected:

1. Field Obs 30734191 - Indian Lake
    a. Project Description: This project will install a 69/12kV, 30 MVA transformer at Indian Lake substation. Installation of this transformer requires the addition of one 69kV breaker and six 12kV breakers, which are needed to properly connect the transformer to existing facilities, to serve existing load and improve reliability in the area
    b. Final Costs = $2,365,495
    c. In-Service Date: 10/31/15
    d. Comments: DP&L indicated they had some unforeseen issues when the work was in progress. They experienced higher bids on the work than they anticipated as well as a myriad of problems during the construction phase. They uncovered some cables that needed to be dug up and removed from under the substation yard. The safety practices at AES changed during the construction which caused them to have to allow for additional changes in clearances inside sub. A mobile transformer had to be brought in to ensure a large customer stayed energized, and several additional 69KV poles and switch had to be installed to support that and were not originally foreseen. This work order is discussed in detail at testing step T3a.
2. Field Obs 30734515 - Huber Hts sub
    a. Project Description: Replacement of a failed 69/12 kV, 30 MVA transformer from spare inventory, installation of new foundation and oil pit for Huber Heights Substation. Since this is an insurance claim, costs will be collected within M&J account 446-97213-0011. This PEA authorizes charges from the M&J account to be transferred to a capital project.
    b. Final Costs = $838,960
    c. In-Service Date: 6/1/15
    d. Comments: None
3. Field Obs 30734516 - Mechanicsburg sub
    a. Project Description: Replacement of a failed 10/12.5 MVA transformer 138/12 kV from spare inventory for Mechanicsburg Substation. Since this is an insurance claim, costs have been collected within M&J account 446-97211-0011. This PEA authorizes charges from the M&J account to be transferred to a capital project.
    b. Final Costs = $669,216
    c. In-Service Date: 5/15/15
    d. Comments: There may be a typing error on the Project costs summary. The final cost is noted above as $45,340. This final cost is not accurate according to DP&L. DP&L keeps spare transformers on hand to be able to swap them out and be proactive. DP&L

used transformer #E3475 for repair and bought transformer E4502 which will now be a spare for future use and replacement of the previous spare that is now in use. This clerical error does not impact the DIR.

4. Field Obs 30734525 - Eaker sub
    a. Project Description: Replacement of a failed 69/12 kV transformer, installation of new foundation and oil pit Since this is an insurance claim, costs have been collected within M&J account 446-97207-0011, budget number 0954. This PEA authorizes charges from the M&J account to be transferred to a capital project.
    b. Final Costs = $1,129,190
    c. In-Service Date: 5/1/15
    d. Comments: None
5. Field Obs 30734526 - Webster sub
    a. Project Description: Replacement of a failed 69/12 kV transformer, installation of new foundation and oil pit Since this is an insurance claim, costs have been collected within M&J account 446-97207-0011, budget number 0954. This PEA authorizes charges from the M&J account to be transferred to a capital project.
    b. Final Costs = $1,143,629
    c. In-Service Date: 11/1/15
    d. Comments: None
6. Field Obs 30734878 - Spare Transformer 2016
    a. Project Description: Purchase two 69/12kV, 30 MVA transformers.
    b. Final Costs = $619,472
    c. In-Service Date: 11/1/16
    d. Comments: Estimate was based on two transformers, these costs are for one actual transformer. The transformer costs were split between two work orders.
7. Field Obs 30734968 - Treaty Sub
    a. Project Description: This PEA covers the cost to add a second 69/12kV, 30 MVA transformer, breakers and associated equipment at Treaty Substation.
    b. Final Costs = $1,910,918
    c. In-Service Date: 4/1/17
    d. Comments: None
8. Field Obs 30735090 - Spare Transformer
    a. Project Description: Purchase two 69/12kV, 30 MVA transformers.
    b. Final Costs = $616,033
    c. In-Service Date: 11/1/16
    d. Comments: Cost of two transformers include one transformer that was installed in service with project #30734968. DP&L used one purchase order to order both transformers. The other transformer is discussed in #6 above.
9. Field Obs 36734187 - Southtown sub
    a. Project Description: This project entails building a new substation in Moraine, Ohio with one 69/12kV, 30MVA transformer, a control building, two 69kV transmission breakers, one distribution breaker, and two transmission poles.
    b. Final Costs = $2,537,649

   c. In-Service Date: 7/30/16
   d. Comments: None

10. Field Obs 36735185 - Centerville BK
    a. Project Description: Replacement of a failed 138/12 kV transformer. Since this project is an insurance claim, costs are being collected within M&J account 446-97218-0011, budget number 0954. This PEA authorizes charges from the M&J to be transferred to a capital project.
    b. Final Costs = $948,718
    c. In-Service Date: 3/30/17
    d. Comments: None
11. Field Obs 44635312 - Jeffersonville Sub-2
    a. Project Description: Replace the failed 69/12kV, 7.5/10.5 MVA transformer at Jeffersonville Substation. The replacement transformer will be a 12/16/20 MVA with an LTC to meet increased customer load and established equipment standards. Since this is an insurance claim, costs will be collected within M&J account 446-97221-0011. This PEA authorizes charges to the M&J and then subsequent transfer to a capital project to unitize the costs (insurance claim).
    b. Final Costs = $1,212,314
    c. In-Service Date: 6/30/18
    d. Comments: The transformer initially had some internal faulty connections from the manufacturer. DP&L had reps from the manufacturer come in and look at the problems. DP&L personnel also failed to relieve the oil pressure after they filled it with oil causing some internal damage. In further discussion with Staff engineers, they could not definitely state whether the oil pressure issue was due to what the manufacturer reps did or to something the Company was responsible for. Therefore, Blue Ridge is unable to determine what, if any, additional costs were incurred or who was responsible for the error.
12. Field Obs 44635313 - Jeffersonville Sub-3
    a. Project Description: Replace the failed 69/12kV, 10/12.5 MVA transformer at Jeffersonville Substation. Since this is an insurance claim, costs will be collected within M&J account 446-97217-0011. This PEA authorizes charges to the M&J and then subsequent transfer to a capital project to unitize the costs (insurance claim).
    b. Final Costs = $595,529
    c. In-Service Date: 3/31/16
    d. Comments: None
13. Field Obs 44635314 - Delco Kettering Sub
    a. Project Description: Replace the failed 69/12kV, 18/ 24/30 MVA transformer at Delco Kettering Substation. Since this is an insurance claim, costs will be collected within M&J account 446-97220-0011. This PEA authorizes charges to the M&J and then subsequent transfer to a capital project to unitize the costs (insurance claim).
    b. Final Costs = $759,504
    c. In-Service Date: 12/16/16
    d. Comments: None

The 13 projects selected for field verification confirmed that the assets were installed and used and useful.

Unitization Backlog

The Company was unable to provide its unitization backlog. The Company stated that the portion of Distribution projects classified to FERC Account 106, which will ultimately be includable under the DIR, will not be known until those projects have been unitized.[46] However, projects included in FERC Account 106 are not included in the DIR until they are unitized.

Insurance Recoveries

There were eight insurance claims over $50,000 paid during the scope period.

1) Wilmington Transformer Failure—$158,077
2) Huber Heights Transformer Failure—$346,556
3) Jeffersonville Bk-3 Transformer Failure—$95,637
4) Delco Kettering Bk-2 Transformer Failure—$345,732
5) Centerville Bk-2 Transformer Failure—$467,737
6) Jeffersonville Bk-1 Transformer Failure—$57,672
7) Jeffersonville Bk-1 Utb Transformer Failure—$186,855
8) Woodstock Transformer Failure—$112,806

The insurance reimbursements totaled $1.77 million. The Company stated that the insurance reimbursements were received from the Miami Valley Insurance Company (MVIC) and do not impact the book cost of capital assets. (Both the Dayton Power and Light Company and MVIC are subsidiaries of DPL, Inc.) The insurance recoveries provided by the MVIC are accounted for as a reduction of insurance expense.[47] Each of the claims was recorded to FERC Account 924 (Property Insurance). The Company explained that the jurisdictional share of insurance reimbursements (24.54%) was treated as a cost-of-service credit in the Company's most recent Distribution base rate case filing and that the treatment of these insurance reimbursements in the DIR filing is consistent with the treatment in base rates.[48] The Company provided additional information:

- The jurisdictional allocation factor of 24.54% was approved by the Commission in the Company's Base Distribution rate case No 15-1830-EL-AIR. The treatment of insurance reimbursements received by the Company from MVIC as a cost of service credit was approved as part of the Company's DRC.
- The Company cited the following FERC guidelines (18 CFR) as applicable to the accounting for reimbursements related to the replacement of capital assets: Paragraph 8 of FERC Electric Plant Instruction No. 3.A. states that "insurance recovered or recoverable on account of property damages incident to construction shall be credited to the account or accounts charged with the cost of the damages." Paragraph B of the description of Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, states that Account 108 "shall be credited with the salvage value and any other amounts recovered, such as insurance" associated with retired depreciable assets. For the claims set forth in the Company's response to BRDR 13-1 a & b, DP&L did not record a loss or charge associated

[46] DPL response to Blue Ridge Data Request 1.32.
[47] DPL response to Blue Ridge Data Request 13.1.
[48] DPL response to Blue Ridge Data Request 1.33a.

with the insurance recoveries that were received. Therefore, the Company recorded the reimbursements through the income statement.[49]

Blue Ridge agrees that that the FERC guidelines cited apply to insurance reimbursements. However, Blue Ridge does not agree that Paragraph 8 of Electric Plant Instruction No 3.A. applies as the Company states. That instruction relates to damages incident to the construction of electric plant. But the insurance reimbursements received by the Company do not apply to damages incident to construction; they apply to the damaged assets that were retired and replaced.

Nevertheless, Blue Ridge understands that past precedent has allowed the Company to treat insurance reimbursements as a reduction to the cost of service in a base rate case by reducing FERC Account 924 (Property Insurance). However, there is a concern that large insurance reimbursements between rate cases result in a windfall to the Company. The insurance reimbursements totaled $1.77 million, which would typically reduce plant in service and the DIR rate base. The DIR allows the new assets to be placed in-service between rate cases and the Company to recover a return on and a return of an investment that it did not make. As this is a change in precedent, Blue Ridge is not recommending an adjustment at this time. However, Blue Ridge recommends that the treatment of insurance reimbursement between rate cases that affect the DIR should be reflected in future DIRs.

REVENUE REQUIREMENTS

OVERVIEW OF METHODOLOGY

On September 26, 2018, in Case No. 15-1830-EL-AIR, the Commission issued an Opinion and Order approving a Stipulation and Recommendation ("Stipulation") with provisions related to the DIR. Among other requirements, the Stipulation requires the DIR revenue requirements to be calculated using the methodology reflected in Exhibit 3 of the Stipulation.[50] Exhibit 3 reflected the following components in the calculation of the DIR revenue requirement.

- Rate Base
  - Gross Distribution Plant
  - Accumulated Depreciation on Distribution Plant
  - Accumulated Deferred Income Taxes on Distribution Plant
- Return on Rate Base
- Depreciation, Taxes Other than Income, and O&M
  - Depreciation Expense
  - Property Tax Expense
  - Commercial Activities Tax
- Revenue Requirements

The Stipulation also stated that the beginning balance will reflect the balance of qualifying incremental investments place in service as of October 1, 2015. The DIR is also subject to revenue caps.

The Company has calculated the DIR to be collected as a percentage of base distribution revenue.

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[49] DPL response to Blue Ridge Data Requests 14.1 and 14.2.
[50] A copy of Case No. 15-1830-EL-AIR, Stipulation, Exhibit 3 is included in Appendix A: Rider DIR Excerpts within Order and Combined Stipulation.

Each of these items are discussed in the following sections.

Rate Base

Gross Distribution Plant

The DIR Revenue Requirements reflects the additional stipulated Distribution Plant that was placed in service since September 30, 2015, as shown in the following table.

Table 8: Incremental Change in Gross Distribution Plant

Description	Date Certain 9/30/2015	1/31/19	Difference
Gross Distribution Plant	$ 1,345,230,954	$ 1,518,483,750	$ 173,252,796

Staff's Report in Case No. 15-1830-EL-AIR recommended, and the Commission approved, that the DIR include only FERC 101 Plant Account balances for FERC Accounts 360–374.[51] Blue Ridge found that the Gross Plant reflected in the DIR included only FERC 101 plant account balances for FERC Accounts 360–374. The date certain balance of September 30, 2015, agreed to the total amount reflected in Case No. 15-1830-EL-AIR stipulated DIR revenue requirement calculation (Exhibit 3 of the Stipulation).

The DIR Gross Distribution Plant is reduced by a Capitalization Incentive Adjustment. Staff's report in Case No. 15-1830-EL-AIR recommended that the Company apply the same adjustments from Operations and Maintenance (O&M) expenses relating to short-term bonus pay and long-term compensation (LTC) to all capitalized short-term bonus pay and LTC included in the DIR.[52] The Company's DIR Filing incremental Gross Plant and Reserve balances have been reduced by 0.7196% to reflect the Capitalized Incentive Adjustment Factor. Blue Ridge reviewed the calculation of and support for the Capitalized Incentive Adjustment Factor[53] and found it not unreasonable.

Blue Ridge evaluated the incremental Gross Distribution Plant from date certain through January 31, 2019, through our variance analysis and detailed transactional testing, which included statistical sampling of the work orders reflected within the gross plant. Our findings and recommendations regarding Gross Distribution Plant are discussed in those sections. Although the adjustments discussed in other subsections of this report may affect the Gross Distribution Plant balances, Blue Ridge found the Gross Distribution Plant schedule mathematically accurate and not unreasonable.

Accumulated Depreciation on Distribution Plant

The DIR Revenue Requirements reflect the additional Accumulated Depreciation on Distribution Plant since September 30, 2015, as shown in the following table.

Table 9: Incremental Change in Accumulated Depreciation

Description	Date Certain 9/30/2015	1/31/19	Difference
Accumulated Depreciation	$ 642,166,933	$ 738,078,102	$ 95,911,169

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[51] Case No. 15-1830-EL-AIR et. al, Staff Report, page 9.
[52] Case No. 15-1830-EL-AIR et. al, Staff Report, page 10.
[53] DPL response to Blue Ridge Data Request 9.2 and 10.3.

Blue Ridge found that the date certain balance of September 30, 2015, agreed to the amount reflected in the Case No. 15-1830-EL-AIR stipulated DIR revenue requirement calculation (Exhibit 3 of the Stipulation).

Blue Ridge evaluated the incremental accumulated depreciation from date certain through January 31, 2019, through our variance analysis and detailed transactional testing. Our findings and recommendations regarding the accumulated depreciation are discussed in those sections. Although the adjustments discussed in other subsections of this report may affect the accumulated depreciation balances, Blue Ridge found the accumulated depreciation not unreasonable.

Accumulated Deferred Income Tax on Distribution Plant

The DIR Revenue Requirements reflect the change in Accumulated Deferred Income Taxes on Distribution Plant since September 30, 2015, as shown in the following table.

Table 10: Incremental Change in Accumulated Deferred Income Taxes

Description	Date Certain 9/30/2015	1/31/19	Difference
Accumulated Deferred Income Taxes	$ (147,941,796)	$ (86,165,478)	$ 61,776,318

Blue Ridge found that the ADIT balance of September 30, 2015, agreed to the amount reflected in the Case No. 15-1830-EL-AIR stipulated DIR revenue requirement calculation (Exhibit 3 of the Stipulation).

The ADIT offset is attributable to (1) basis adjustments, such as current deductions for repairs that are capitalized on the general ledger and the exclusion of AFUDC from tax basis, and (2) depreciation life and method differences.[54] The Company calculated the basis adjustments for assets unitized as of September 30, 2015, by applying a 67.68% allocation factor due to the unavailability of tax basis data at a level that would allow specific identification of DIR assets from other distribution plant. Application of the allocation factor represents all book and tax basis differences and was developed using the total gross tax basis ($1,453,260,487) divided by the total gross book basis ($2,147,238,510) for tax year 2015.[55] Blue Ridge found that the Company did not develop and apply a similar allocation factor to asset additions after October 1, 2015.[56] Per Blue Ridge's inquiry, the Company recognized the above situation and stated—and Blue Ridge recommends—that it will "incorporate this adjustment in the October 2019 filing. In addition, the Company's current plan for future DIR filings is to use a historic average factor until the final tax basis of each vintage is known."[57] As discussed later, Blue Ridge recommends an adjustment to the ADIT balance. Our ADIT adjustment assumed the same 67.68% allocation factor for post-date-certain additions as assets installed as of September 30, 2015.

The Company calculates DIR depreciation life and method differences manually according to the process described under the DIR Preparation section of this report. Blue Ridge reviewed the Company's computation of the life and method differences for mathematical accuracy and completeness. Blue Ridge found that the supporting spreadsheets contained multiple data input and processing errors, which Blue Ridge verified with the Company.[58] The errors were attributable to

[54] DPL response to Blue Ridge Data Request 1.22.
[55] DPL response to Blue Ridge Data Request 12.14 and 12.14 Amended.
[56] DPL response to Blue Ridge Data Request 12.15.
[57] DPL response to Blue Ridge Data Request 12.15.
[58] DPL response to Blue Ridge Data Request 12.12 through 12.28.

structural deficiencies in the financial model and user error. Absent a better system, Blue Ridge recommends the Company rebuild the financial model so that inputs are clearly defined and entered once and the processing of inputs to outputs is transparent and broken down into interim steps that are easy to follow. Without corrective action, similar errors will likely recur in future filings. Blue Ridge also recommends establishing an internal review process to eliminate basic user errors, such as the failure to update date and other input fields.

Blue Ridge estimates the impact of the omissions and errors to be an understatement of the ADIT offset at January 31, 2019, by $(11,589,594) as shown in the table below. The estimated understatement translates to a revenue requirement overstatement of $994,072. **[ADJUSTMENT #1]**

Table 11: Blue Ridge Estimate of ADIT offset in DIR Rate Base[59]

	Surviving Assets Unitized as of 9/30/2015	Company	Blue Ridge	Difference
1	Book Basis	1,307,011,624	1,311,185,137	4,173,513
2	Book Reserve	722,258,332	722,258,332	-
3	Tax Basis	888,050,878	888,024,233	(26,645)
4	Tax Reserve	693,827,884	693,532,411	(295,473)
5	Net Basis Difference	390,530,298	394,434,983	3,904,685
6	Tax Rate	21.31%	21.31%	21.31%
7	Deferred Tax	(83,222,006)	(84,054,095)	(832,088)

	Rate Base Additions After 9/30/2015	Company	Blue Ridge	Difference
8	Book Basis	212,727,890	208,552,307	(4,175,582)
9	Book Reserve	16,514,949	16,514,949	-
10	Tax Basis	208,552,308	141,149,121	(67,403,187)
11	Tax Reserve	26,249,111	13,857,447	(12,391,664)
12	Net Basis Difference	13,909,745	64,745,685	50,835,940
13	Tax Rate	21.31%	21.31%	21.31%
14	Deferred Tax	(2,964,806)	(13,800,284)	(10,835,477)
15	Capitalized Incentive Adjustment	21,335	99,307	77,972

16	**Total Deferred Tax in DIR Rate Base**	**(86,165,478)**	**(97,755,072)**	**(11,589,594)**

The DIR rate base at January 31, 2019, does not reflect the Protected Excess ADIT the Company proposes to credit customers as an offset to the DIR revenue requirement per Case No. 19-0572-EL-UNC. Blue Ridge inquired about the Company's proposal and the pro forma DIR revenue requirement to document the expected impact for future DIR audits, but the replies were not responsive, as shown in the following series:

Data Request 12-11(a)

Q: The quarterly DIR filings to date do not reflect "for ratemaking purposes, a reduction to regulated rate base" for the Protected Excess ADIT. Had the offset been included, what is the impact on DIR revenues for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018?

[59] As discussed in the report, the Company did not apply an allocation factor to reflect tax basis adjustments for assets additions after October 1, 2015. Blue Ridge assumed the same allocation factor as assets installed as of September 30, 2015, in its estimate.

A: Per the Company's Application filed in Case No. 19-572-EL-UNC, DP&L proposes to credit the Protected Excess ADIT as an offset to the DIR revenue requirement. Per DP&L's filing, the amount of Protected Excess ADIT amortized on the Company's books for 2018 was $686,455. Since DP&L's DIR revenue requirement has remained significantly above the established revenue caps, reducing the DIR revenue requirement by $686,455 would not impact the revenue levels collected for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018.

Data Request 16-1(a)

Q: The response [to Data Request 12-11] addresses the impact of the EDIT amortization only. Wouldn't inclusion of the EDIT balance in DIR rate base also impact the revenue requirement before factoring in the cap?

A: Yes

Data Request 16-1(b)

Q: Provide the following balances and calculations (in electronic format with formulas intact) for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018:

i) Proforma EDIT balance in DIR rate base;

ii) Proforma EDIT amortization flowing through DIR tax expense; and

iii) Proforma impact on DIR revenue requirement before cap.

A: Attached is Blue Ridge DR 16-01 Attachment 1 – CONFIDENTIAL which details EDIT balances consistent with how the Company tracks this information and as provided for in the Company's pending tax case. Further, DP&L proposed specific EDIT calculations in its tax case and expects to resolve those issues as part of that case. [Blue Ridge notes that the information provided did not correspond to the data request.]

The Company's application in Case No. 19-0572-EL-UNC reads as follow regarding how the Protected Excess ADIT will be returned to customers:

> 11. The Protected Excess ADIT balance as of December 31, 2018 is $49.6 million, which is net of the $686,455 amortized on the Company's books during 2018. Both of these amounts will be returned to customers in the manner described below upon approval of this Application.
>
> 12. The Protected Excess ADIT will be credited to customers as an offset to the calculation of DP&L's Distribution Investment Rider ("DIR") revenue requirement, which will be updated quarterly in accordance with Section III.1.e. of the Rate Case Stipulation.
>
> 13. The DIR caps set forth in Section III.1.d. of the Rate Case Stipulation will remain unchanged.
>
> 14. The Protected Excess ADIT is treated, for ratemaking purposes, as a reduction to regulated rate base through a credit made to FERC Uniform System of Accounts, Accounts 281, 282 and 283, less any debits in FERC Account 190 for ADIT assets (together, the "Deferred Income Tax FERC Accounts"). Beginning January 1, 2018 and continuing until DP&L rates are adjusted to begin crediting Protected Excess ADIT to customers, any amortization of Protected Excess ADIT will continue to increase a regulatory liability in accordance with the Commission COI Entry. As the Protected Excess ADIT relating to future amortization is returned to customers each year, the

> corresponding amounts will be amortized out of the Deferred Income Tax FERC Accounts. Likewise, as the Protected Excess ADIT that was amortized into a regulatory liability is returned to customers each year, that regulatory liability account will be debited.[60]

Blue Ridge notes that the application does not make explicit whether the Company proposes to flow the Protected Excess ADIT through the DIR as (1) a dollar-for-dollar offset to the DIR revenue requirement or (2) part of the DIR revenue requirement. The latter would result in customers receiving no credit for the Protected Excess ADIT because, as the Company explained in Data Request 12-11(a), the DIR revenue requirement is significantly above the established revenue caps. Therefore, incorporating the Protected EDIT into the equation would have no impact on the level of revenues collected.

For informational purposes, Blue Ridge is including a proforma adjustment to clarify the impact if the proposal or outcome of Case No. 19-0572-EL-UNC is a dollar for dollar offset to the DIR revenue requirement based on the quoted $49.6 million unamortized balance at December 31, 2018, and the corresponding annual amortization of $686,455. The proforma adjustment would reduce the level of revenues collected through the DIR by $(4,941,641). [**ADJUSTMENT #2**]

In summary, Blue Ridge found that the ADIT balance in rate base at January 31, 2019, was appropriately related to utility plant but incomplete because it did not reflect the impact of basis adjustments for asset additions after the date certain balance. The financial model used to calculate book and tax-basis timing differences had structural deficiencies and user errors. Absent a better system, Blue Ridge recommends the Company rebuild the financial model so that inputs are clearly defined and entered once and the processing of inputs to outputs is transparent and broken down into interim steps that are easy to follow. Without corrective action, similar errors will likely recur in future filings. Blue Ridge also recommends establishing an internal review process to eliminate basic user errors, such as the failure to update date and other input fields. Blue Ridge estimates the impact of the omissions and errors understates the ADIT offset at January 31, 2019, by $(11,589,594). The ADIT reflected in the DIR revenue requirement should be adjusted and the revenue requirements overstatement corrected. Finally, the Company should clarify its proposal to make the impact on the level of revenues collected from customers transparent.

Return on Rate Base

Consistent with the Stipulation's Exhibit 3, the return on rate base is calculated by multiplying the Distribution Rate Base for the DIR by the pre-tax weighted average cost of capital (WACC) using the after-tax weighted average cost of capital reflected in Base Distribution Rates.[61] The incremental return is shown in the following table.

Table 12: Incremental Change in Return on Rate Base

Description	Date Certain 9/30/2015	1/31/19	Difference
Return on Rate Base	$ 47,623,955	$ 59,558,888	$ 11,934,933

The return on rate base as of date certain of $47,623,955 did not tie to the Stipulation, Exhibit 3 amounts. The Stipulated amount on Exhibit 3 was $47,629,487. The Company confirmed that the

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[60] Case No. 19-0572-EL-UNC, The Dayton Power & Light Company's Application (3/1/2019), pages 3–4.
[61] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, page 8.

difference of $5,532 is due to rounding of the pre-tax weighted average cost of capital used in the DIR Filings.[62] Blue Ridge recommends that the data certain amounts as of September 30, 2015, be adjusted to reflect the return on rate reflected in the Stipulation, Exhibit 3. Correcting the date certain return on rate base results in a $(5,532) change to the DIR revenue requirement [**ADJUSTMENT #3**].

In Case No. 15-1830-EL-AIR et. al, the Commission approved a rate of return for Base Distribution Rates of 7.27 percent, which incorporates a return on equity of 9.99 percent and a cost of long-term debt of 4.8 percent.[63] The WACC reflects an effective federal income tax rate of 21.31 percent based upon Case No. 15-1830-EL-AIR, Schedule A-2 and a statutory Commercial Activity Tax (CAT) rate of 0.26 percent.[64] The pre-tax WACC included in the DIR revenue requirements is shown in the following table.

Table 13: Pre-Tax Weighted Average Cost of Capital Used in the DIR

Description	% of Total Capital	Embedded Cost	Pre-Tax WACC
Common Equity	47.52%	9.99%	4.75%
Long Term Debt	52.48%	4.80%	2.52%
	100.00%		7.27%
Effective Tax Rate			21.31%
Commercial Activities Tax			0.26%
Pre-Tax Weighted Average Cost of Capital			8.58%

Although the adjustments discussed in other subsections of this report may affect the final return included within the DIR, Blue Ridge found that the pre-tax WACC and the calculation of the return on rate base included within the DIR revenue requirements is not unreasonable.

Depreciation, Taxes Other than Income, and O&M

Depreciation Expense

The DIR includes incremental depreciation expense calculated on the incremental net plant balances (gross plant balance less the accumulated reserve for depreciation). Depreciation expense reflected in the DIR revenue requirements is shown in the following table.

Table 14: Incremental Change in Depreciation Expense

Description	Date Certain 9/30/2015	1/31/19	Difference
Depreciation Expense	$ 38,359,093	$ 43,394,433	$ 5,035,341

Blue Ridge found that the depreciation expense as of date certain of $38,359,093 ties to the Stipulation, Exhibit 3 amounts.

In Case No. 15-1830-EL-AIR, Staff reviewed the Company's depreciation study and provided recommended depreciation accrual rates in Staff's Report Schedule B-3.2. Staff also recommended that another depreciation study should be performed by the Company in five years.[65] The Stipulation, which was approved by the Commission, agreed to the findings and recommendations in Staff's

[62] DPL response to Blue Ridge Data Request 10.2.
[63] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, page 5.
[64] DPL response to Blue Ridge Data Request 1.19c, Attachment 1.
[65] Case No. 15-1830-EL-AIR et. al, Staff Report, page 11.

Report.[66] Blue Ridge compared the approved depreciation accrual rates to the rates used to calculate depreciation expense in the DIR revenue requirements and found that the rates used agree to the approved rates.[67]

Although the adjustments discussed in other subsections of this report may affect the depreciation expense reflected within the DIR, Blue Ridge found that the depreciation expense calculation is not unreasonable.

Property Tax Expense

The DIR includes incremental property tax expenses from data certain through January 31, 2019, as shown in the following table.

Table 15: Incremental Change in Property Taxes

Description	Date Certain 9/30/2015	1/31/19	Difference
Propety Tax Expense	$ 44,978,513	$ 56,178,110	$ 11,199,597

Blue Ridge found that the property tax expense as of date certain of $44,978,513 ties to the Stipulation, Exhibit 3 amounts.

The Company explained that property taxes are calculated based on the total assessed values for each parcel per the bills issued by each county. After removing the generation-related parcels, the remaining parcels are multiplied by the next tax rate for the total tax due. The total tax due is then divided by the assessed value, and that result is multiplied by 1,000 to derive the "average property tax rate per $1000" valuation.[68]

Blue Ridge reviewed the methodology and supporting documentation used to calculate property tax. The average property tax rate is consistent with the method used in prior distribution rate cases. However, the Company did not update the 2018 average property tax rate and, instead, used the rate effective for 2017. In Case No. 15-1830-EL-AIR, Staff adjusted property tax expense to reflect the latest rates and valuation percentages in effect as of the test year and applied those rates to the plant in service as of date certain,[69] Blue Ridge recommends that the Company use the most recent rates and valuation percentages when calculating property taxes.

Although the adjustments discussed in other subsections of this report may affect the property tax expense reflected within the DIR, Blue Ridge found that the property tax calculation is not unreasonable.

Commercial Activity Tax

Consistent with the Stipulation's Exhibit 3, the DIR revenue requirements includes recovery of Commercial Activity Tax (CAT). The current CAT rate is 0.26 percent for taxable gross receipts above $1 million.[70] The Company's calculation of CAT is not unreasonable.

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[66] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, page 3
[67] WP Rev Req 1-31-19 Blue Ridge DR 01-3-Attachment 5.
[68] DPL response to Blue Ridge Data Request 1.10
[69] Case No. 15-830-ELeAIR, Staff Report, page 14.
[70] Ohio Department of Taxation, Annual Report Fiscal year 2018, page 33.

REVENUE REQUIREMENTS

The Company calculated a DIR revenue requirement of $28,212,082. While, our findings and recommendations discussed throughout this report may affect the calculated revenue requirement, Blue Ridge found that the DIR revenue requirement is consistent with the methodology reflected in the Stipulation, Exhibit 3, and the mathematical calculations are not unreasonable.

ANNUAL CAP

The Stipulation approved by the Commission in Case No.15-1830-EL-AIR included revenue caps for the DIR as follows:

- 2018 $1,200,00 per month effective with DIR commencement
- 2019 $22,000.000
- 2020 $29,000.000
- 2021 $37,000.000
- 2022 $44,000.000
- 2023 $43,000.000 (reflects proration through October 31, 2023)[71]

The following table presents the DIR revenue collected against the caps.[72]

Table 16: Revenue Collected vs. Revenue Cap

Period	Revenue Collected	Revenue Cap	Over/Under
Oct-18	$1,064,201	$1,200,000	$135,799
Nov-18	$1,088,507	$1,200,000	$111,493
Dec-18	$1,211,858	$1,200,000	-$11,858
Total 2018	**$3,364,566**	**$3,600,000**	**$235,434**
2019			
Jan-19	$2,032,797		
Feb-19	$2,074,193		
2019 To Date	**$4,106,990**	**$22,000,000**	**$17,893,010**

As shown in the table, Blue Ridge found that in December 2018, the Company's DIR revenue collected exceeded the 2018 monthly cap of $1,200,000. However, the cumulative over/under recovery for October 2018–January 2018 was within the cumulative cap. Because of the potential of DIR revenue to be over or under the annual caps in a given year, Blue Ridge recommends clarification language on how to address DIR revenue over/under collections to the cap. Suggested language 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 Company's Rider DIR is less than the annual cap allowance, the difference

[71] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, page 7.
[72] WP Rev Req 1-31-19 Blue Ridge DR 01-3-Attacment 5.

> between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap.

Blue Ridge found that the January 31, 2019, filing appropriately limits the DIR revenue collectible to the 2019 revenue cap of $22,000,000. The Percentage of Base Distribution Charge is calculated using the cap instead of the calculated DIR Revenue Requirements of $28,212,082.

The Stipulation also contains the following language. However, this language was not reflected in the Commission's order.

> Should DP&L fail to file a base distribution rate case on or before October 31, 2022, the DIR will sunset, and the DIR rate shall be set to zero, on November 1, 2022. If DP&L files a base distribution rate case on or before October 31, 2022 the DIR will sunset, and the DIR rate shall be set to zero, on November 1, 2023, unless otherwise approved as part of a new standard service offer. Upon approval of a subsequent rate case application, the DIR revenue caps for the remainder of the current SSO period (16-395-EL-SSO) will be re-established on a pro-rated basis, and the collection of revenue under the rider could begin, based upon the outcome of the subsequent rate case.[73]

The DIR sunset is not relevant in the 2018–2019 filings under review; however, Blue Ridge recommends that the sunset provision should be confirmed as relevant for future audits.

As discussed in the Accumulated Deferred Income Tax on Distribution Plant section, the DIR rate base at January 31, 2019, does not reflect the Protected Excess ADIT the Company proposes to credit customers as an offset to the DIR revenue requirement per Case No. 19-0572-EL-UNC. Blue Ridge recommended that the Company clarify whether the impact of the quoted $49.6 million unamortized balance at December 31, 2018, and the corresponding annual amortization of $686,455 would be (1) a dollar-for-dollar offset to the DIR revenue requirement or (2) part of the DIR revenue requirement. If the Company proposes to include the Protected Excess ADIT as part of the DIR revenue requirement, the result would be that customers will receive no credit for the Protected Excess ADIT because the DIR revenue requirement is significantly above the established revenue caps. The Company should clarify its proposal to make the impact on the level of revenues collected from customers transparent.

<u>Percentage of Base Distribution Charges</u>

The rider is collected as a percentage of base distribution revenue. The Company's DIR tariff reflects a DIR charge of 9.0607% of base distribution charges. Case No. 15-1830-EL-AIR approved a base distribution revenue of $242,807,679.[74]

The following table provides the percentage of DIR base distribution revenue included within the Company's DIR Filing.

[73] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, page 7.
[74] Case No. 15-1830-EL-AIR et. al, Stipulation and Recommendation, Exhibit 5, line 47.

Table 17: Percentage of Base Distribution Charges

Description	Amount	% of Base Distribution Revenue
DIR Revenue Requirement	$ 28,212,082	11.6191%
Annual 2019 Revenue Cap	$ 22,000,000	9.0607%
Base Distribution Revenue	$ 242,807,679	

As shown in the table, Blue Ridge found that the 2019 DIR revenue requirement is limited to the 2019 revenue cap of $22,000,000, instead of the calculated DIR Revenue Requirements of $28,212,082. The Company's calculation of Percentage of Base Distribution Charges is not unreasonable.

CONCLUSION

Blue Ridge found that the DIR revenue requirements is consistent with the methodology reflected in the Stipulation, Exhibit 3, and the mathematical calculations are not unreasonable. However, there are several adjustments that should be made to the DIR revenue requirements. These include adjustments to ADIT (1) to reflect the impact of basis adjustments for asset additions after the date certain, (2) correction to the structural deficiencies and user errors in the ADIT financial model, and (3) including the Protected Excess ADIT in rate base and the associated amortization in the DIR tax expense. In addition, the date certain return on rate base should be corrected to tie to the amount within the stipulation.

The Company's calculated DIR revenue requirements was limited to the revenue cap. Blue Ridge recommends that the revenue cap include clarification language on how to address DIR revenue over/under collections to the cap.

Finally, the Protected Excess ADIT is associated with the change in tax rates and, without the DIR, would have been refunded to ratepayers, Blue Ridge recommends that the refund should not be limited by the annual cap but instead refunded as a separate non-DIR-related item either through this proceeding or the tax case referred to by the Company.

OVERALL IMPACT OF FINDINGS ON RIDER DIR REVENUE REQUIREMENTS

Blue Ridge's review of the accounting, accuracy, prudence, and compliance of DP&L with its Commission-approved DIR had findings and recommendations related to some of the components of the DIR revenue requirements that impact the amount that should be recovered through the DIR. These findings and the effect on the DIR Revenue Requirements are summarized below.

Adjustment #1–ADIT, missing basis allocation factor and corrections to multiple data input and processing errors in the life and method differences' financial model:

> Due to the unavailability of tax basis data at a level that would allow specific identification of DIR assets from other distribution plant, the Company applied a 67.68% basis adjustment for assets unitized as of September 30, 2015. The Company did not develop and apply a similar allocation factor to asset additions after October 1, 2015. The Blue Ridge adjustment assumed the same allocation factor as assets installed as of September 30, 2015. In addition, various omissions and errors in the financial model used to compute the life and method differences were corrected. Blue Ridge estimates the impact of the omissions and errors to be an

understatement of the ADIT offset at January 31, 2019, by $(11,589,594). The estimated understatement changes the DIR revenue requirement by $(994,272).

Adjustment #2–Missing Protected Excess ADIT in DIR rate base and tax expense:

The DIR rate base at January 31, 2019, does not reflect the Protected Excess ADIT the Company proposes to credit customers as an offset to the DIR revenue requirement per Case No. 19-0572-EL-UNC. Blue Ridge notes that the application does not make explicit whether the Company proposes to flow the Protected Excess ADIT through the DIR as 1) a dollar for dollar offset to the DIR revenue requirement or 2) part of the DIR revenue requirement. The latter would result in customers receiving no credit for the Protected Excess ADIT because, as the Company explained in Data Request 12-11(a), the DIR revenue requirement is significantly above the established revenue caps. Therefore, incorporating the Protected EDIT into the equation would have no impact on the level of revenues collected. Blue Ridge recommends the issue be presented in a transparent manner. For informational purposes, Blue Ridge is including a proforma adjustment to clarify the impact if the proposal or outcome is a dollar for dollar offset to the DIR revenue requirement. The adjustment is an offset to DIR revenues collected in the amount of $(4,941,641).

Adjustment #3–Misstated return on rate base as of date certain:

The return on rate base as of date certain did not tie to the Stipulation, Exhibit 3 amounts. The Company confirmed that the difference of $5,532 is due to rounding of the pre-tax weighted average cost of capital used in the DIR Filings. Correcting the date certain return on rate base results in a $(5,532) change to the DIR revenue requirement.

The effect of Blue Ridge's recommended adjustments is summarized in the following table:

Table 18: Impact of Blue Ridge's Findings on the DIR Revenue Requirement

Description	DIR Revenue Requirment Impact	DIR Revenue Requirement Offset	Comment
As filed	$ 28,212,082	$ -	
1. ADIT Corrections	(994,072)	-	
2. Protected Excess ADIT	-	(4,941,641)	Outside Cap
3. Misstated Return on Rate Base	(5,532)	-	
Total Adjustment	$ (999,605)	$ (4,941,641)	
Revised Revenue Requirements	$ 27,212,477	$ (4,941,641)	
Annual Revenue Cap 2019	22,000,000	-	
Revenue Requirement Impact	**$ -**	**$ (4,941,641)**	

APPENDICES

Appendix A: Rider DIR Excerpts within Stipulations and Order (and electronic copies on disc of prior audit reports and filings reviewed)

Appendix B: Abbreviations and Acronyms

Appendix C: Data Requests and Information Provided

Appendix D: Work Papers

Appendix A: Rider DIR Excerpts within Order and Combined Stipulation

Excerpts from the following Commission Opinions and Orders specifically related to Rider DIR are provided within this section.

- Case No. 16-395-EL-SSO Opinion and Order dated October 20, 2017
- Case No. 15-1830-EL-AIR Opinion and Order dated June 18, 2018

Case No. 16-395-EL-SSO

Order dated October 20, 2017

A. Summary of the Application [pages 3–4]

{¶ 66} DP&L also proposed several new riders. This included: (1) A Distribution Investment Rider (DIR) that would allow DP&L to recover the costs of specific infrastructure needs; (2) a Reconciliation Rider that would permit DP&L to recover deferred costs from the Ohio Valley Electric Corporation (OVEC); (3) a Distribution Decoupling Rider so that DP&L could account for the decoupling associated with energy efficiency requirements; (4) a Clean Energy Rider to facilitate investment in renewable and advanced technologies; and, finally, (5) a Reliable Electricity Rider (RER), which would permit DP&L to credit or charge customers the annual projected variance between the revenue requirement and revenues expected for its generation assets.

B. Summary of the Amended Stipulation

i. A DIR will be established, set initially at zero, to recover incremental distribution capital investments. Recovery of revenue requirements will be based upon and commence with the resolution of DP&L's distribution rate case or a future distribution rate case. All other matters related to the DIR, including, but not limited to cost allocation, term, rate design, and annual revenue caps, shall be addressed in the pending distribution rate case or a future distribution rate case. [page 7]

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v. v. The Storm Cost Recovery Rider (SCRR) will remain in place as a placeholder tariff. DP&L will file a future application if it seeks any recovery of costs from major storms. This nonbypassable rider will include Operating and Maintenance (O&M) expenses incurred for all storms that are determined to be "Major Events," as defined in Ohio Adm. Code 4901:1-10-01. No level of expenses for major storms will be in base rates, meaning that there will be no baseline for which an amount over would be considered. Therefore, all prudently-incurred expenses that are incremental to base rates would be considered for recovery. This would include, among other things, the amounts over the first forty hours of labor in a given week as well as overtime paid for union and management employees. If any mutual assistance revenue is received for storm repairs done in other markets, the straight-time labor portion of this would be deducted from the Company's storm rider recovery request to avoid potential double-recovery. Any capital assets would be addressed through the DIR. [page 13]

C. Consideration of the Amended Stipulation

1. Is the Settlement a product of serious bargaining among capable, knowledgeable parties?

{¶ 18} OCC is the lone party that argues otherwise. OCC witness Mathew Kahal testified that only 10 of the roughly 30 intervenors support the Amended Stipulation, and of those intervenors, several of them do not explicitly support the DIR or the DMR. Other signatories, according to Kahal, only offer their support in exchange for cash handouts. (OCC Ex. 2 at 13, 16.) OCC witness James Williams further stated that the bulk of DP&L's customer base-the residential customers represented by OCC-do not support the Amended Stipulation. Without the support of the residential customers, who represent 89 percent of DP&L's customers, Williams submits that the Amended Stipulation does not represent a diversity of interests. (OCC Ex. 13 at 7.) [page 17]

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2. Does the settlement, as a package, benefit ratepayers and the public Interest?

p. Whether the DIR violates any important regulatory principles [pages 53–54]

{¶113} OCC first asserts that DP&L failed to comply with the standard filing requirements for infrastructure modernization plans, as outlined in Ohio Adm. Code 4901:1-35-03(C)(9)(g). OCC submits that DP&L's argument that necessary details regarding the DIR could be provided in a future rate case is without merit, as the filing requirements pertain specifically to an ESP proceeding. OCC further states that the DIR is not necessary as there are no pending reliability concerns. According to OCC, despite being the only utility without an infrastructure modernization plan, DP&L has consistently met or exceeded reliability goals while also maintaining high customer satisfaction scores. Accordingly, OCC reasons that there is no alignment between customers' expectations and the need for an accelerated recovery of distribution investments, as required by Ohio Adm. Code 4901:1-35-03(C)(9)(g).

{¶114} DP&L responds that the DIR is lawful. DP&L asserts it is impossible to comply with the standard filing requirements at this time because the costs are still unknown. According to DP&L, the DIR will be set at zero and will not be populated until after the conclusion of the distribution rate case. The Company also disagrees with OCC's assertion that the DIR does not align with customer expectations. DP&L avers residential and commercial customers desire greater reliability, which would be provided by the DIR. The Company submits it would be illogical to wait for reliability to suffer before implementing the DIR.

{¶ 115} The Commission finds that OCC's argument that the DIR is unlawful lacks merit. In approving distribution investment riders for other electric utilities, the Commission has discussed how such riders allow utilities to maintain reliability by reducing regulatory lag. In doing so, the DIR promotes cost causation principles and prevents risking rate shock. See, e.g., In re FirstEnergy, Case No. 14-1297-EL-SSO at 115-116. Moreover, the Amended Stipulation specifically provides that the DIR will initially be set at zero and be used to recover incremental distribution capital investments. All other matters related to the DIR, including cost allocation, term, rate design, and annual revenue caps will be addressed in DP&L's pending distribution rate case, Case No. 15-1830-EL-AIR, or a future distribution rate case. We note that OCC, and any other interested stakeholder, will have a full and fair opportunity to participate in the pending distribution rate case or any future rate cases.

{¶116} Additionally, it was established that maintaining reliability is in alignment with customer expectations (Staff Ex. 1 at 3-7). Thus, because of the benefits associated with the DIR, it is irrelevant whether DP&L is presently meeting reliability standards or not.

<u>Case No. 15-1830-EL-AIR et. al.</u>

Stipulation dated June 18, 2018

III. RIDERS [pages 6–10]

1. The Signatory Parties agree that pursuant to the October 20, 2017 Opinion and Order in Case No. 16-395-EL-SSO, the Commission shall populate DP&L's Distribution Investment Rider ("DIR") in this proceeding, as follows:

    a. The DIR shall commence coincident with the update to DP&L's base rates for electric distribution service approved in this proceeding;

    b. The beginning DIR balance will include the balance of qualifying incremental investments placed in service from October 1, 2015 to the Commission's approval of this Stipulation;

    c. The DIR shall be calculated using the tax rates enacted as part of the TCJA;

    d. The DIR shall be subject to the following revenue caps:

        2018 $1,200,000 per month effective with DIR commencement
        2019 $22,000,000
        2020 $29,000,000
        2021 $37,000,000
        2022 $44,000,000
        2023 $43,000,000 (reflects proration through October 31, 2023).

        Should DP&L fail to file a base distribution rate case on or before October 31, 2022, the DIR will sunset, and the DIR rate shall be set to zero, on November 1, 2022. If DP&L files a base distribution rate case on or before October 31, 2022 the DIR will sunset, and the DIR rate shall be set to zero, on November 1, 2023, unless otherwise approved as part of a new standard service offer. Upon approval of a subsequent rate case application, the DIR revenue caps for the remainder of the current SSO period (16-395-EL-SSO) will be re-established on a pro-rated basis, and the collection of revenue under the rider could begin, based upon the outcome of the subsequent rate case.

    e. DP&L shall file quarterly updates on or about January 1st, April 1st, July 1st and October 1st, with rates effective 60 days after filing unless otherwise suspended by the

Commission. The filings shall be subject to annual Commission review, audit, and reconciliation. Such audit shall include a determination of whether the distribution investments made are used and useful in rendering utility service to customers;

f. DP&L shall include in the DIR tariff language the following provision:

"This Rider is subject to reconciliation or adjustment, including but not limited to, increases or refunds. Such reconciliation or adjustment shall be limited to the 12-month period of expenditures upon which the rates were calculated, if determined to be unlawful, unreasonable, or imprudent by the Commission, or Supreme Court of Ohio in the docket those rates were approved, or the docket where the audit of those rates occurred."

g. DP&L may file an application with the Commission for battery storage projects related to distribution service. Interested parties may submit to DP&L requests to consider battery storage projects related to distribution service. DP&L may install battery storage projects for the purpose of deferring distribution circuit investments or addressing distribution reliability issues, and include those distribution plant investments in the DIR. Prior to including a battery storage investment in the DIR, DP&L agrees to meet with Staff and Signatory Parties prior to filing an application for pre-approval of a battery project. In a battery application, DP&L must demonstrate that the battery (or batteries) will be used for a distribution service and will qualify as distribution equipment under the FERC uniform system of accounts authorized to be included in the DIR (specifically Accounts 360 to 374).

h. The DIR shall be calculated using the same methodology reflected in Exhibit 3 to this Stipulation, which includes the after-tax weighted average cost of capital specified in Part 11.3 above.

i. DP&L shall work with Staff and OCC to develop an annual plan to emphasize proactive distribution maintenance that will focus spending on where it will have the greatest impact on maintaining and improving reliability for customers. The plan shall specifically include identification of those expenditures that will help reduce customers' minutes interrupted. The plan shall be submitted to Staff and OCC annually starting on December 1, 2019. In lieu of the Staff Report recommendation that the DIR revenue caps be set to zero if the Company fails to comply with its Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI") performance standards, the Signatory Parties agree to the following. DP&L's CAIDI and SAIFI performance for 2018 will not be used to determine any penalty for noncompliance with Ohio Adm. Code 4901:1-10-10(E). Beginning with the 2019 CAIDI and SAIFI performance reported on or before March 31, 2020, if either performance standard is not achieved for two consecutive years, DP&L's DIR revenue cap increment will decrease by $2.0 million rather than being assessed a penalty or forfeiture due to a violation of Ohio Adm. Code 4901:1-10-10.

2. DP&L will dedicate up to $1.0 million in total capital investment eligible for DIR recovery, beginning in 2019, to fund distribution grid investments necessary to support installation of electric vehicle ("EV") charging infrastructure in the DP&L service territory. Specifically,

through the DIR the Company may recover costs associated with investments for the meter and equipment in front of meter (i.e., on the Company's side of the meter) to support EV charging stations supported by grants awarded by the Ohio EPA pursuant to its Beneficiary Mitigation Plan for dollars allocated from the Volkswagen Mitigation Trust Fund. DP&L will commit to work with Ohio EPA and charging station host applicants within its service territory to facilitate the installation of DC fast chargers under the Beneficiary Mitigation Plan, including but not limited to siting criteria. In consultation with the Staff and the Signatory Parties, the Company may develop a pilot EV tariff. This provision does not preclude DP&L from spending additional amounts in support of EV deployment and seeking cost recovery for such additional expenditures; however, this Stipulation does not provide any independent right for DP&L to obtain cost-recovery for amounts expended in support of EV deployment. DP&L further agrees to provide, upon reasonable request, information regarding the costs of these investments to any Signatory or Non-Opposing Party.

Exhibit 3 – Revenue Requirements Calculation includes following line item

Description	Stipulated Amounts as of 9/30/2015	March 31, 2018
Distribution Rate Base for DIR	$555,122,225	$620,553,558

Opinion and Order dated September 26, 2018

B. Summary of the Stipulation

III. Riders [pages 25–29]

(1) Pursuant to the October 20, 2017 Opinion and Order in Case No. 16-395-EL-SSO, the Company's Distribution Investment Rider (DIR) shall be populated as follows:

a. The DIR shall commence concurrent with the update to DP&L's base rates for electric distribution service approved in this proceeding;

b. The beginning DIR balance will include the balance of qualifying incremental investments placed in service from October 1, 2015, until the Commission's approval of the Stipulation;

c. The DIR shall be calculated using the tax rates enacted by the TCJA;

d. The DIR shall be subject to the following revenue caps:

2018	$1,200,000 per month effective with DIR commencement
2019	$22,000,000
2020	$29,000,000
2021	$37,000,000
2022	$44,000,000
2023	$43,000,000 (reflects proration through Oct. 31, 2023);

e. DP&L shall file quarterly updates on or about the first day of January, April, July, and October, with rates effective 60 days after filing unless otherwise suspended by the Commission. The filings shall be subject to annual Commission review, audit, and reconciliation;

f. The DIR tariff language shall include a provision specifying that the Rider is subject to reconciliation and adjustment, including increases or refunds;[75]

g. DP&L may file an application for battery storage projects related to distribution service. DP&L may install such projects for the purpose of deferring distribution circuit investments or addressing distribution reliability issues and may include those distribution plant investments in the DIR. Before including any battery storage investment in the DIR, the Company must meet with Staff and Signatory Parties prior to filing an application for pre-approval of a battery project, and, in any battery application, DP&L must demonstrate that the battery(ies) will be used for a distribution service and will qualify as distribution equipment under the FERC uniform system of accounts;

h. The DIR shall be calculated using the same methodology reflected in Exhibit 3 to the Stipulation, which includes the after-tax weighted average cost of capital specified in Part II(3), above;

i. The Company shall work with Staff and OCC to develop an annual plan—to be submitted to Staff and OCC annually starting December 1, 2019—emphasizing proactive distribution maintenance that will focus spending on areas having the greatest impact on maintaining and improving reliability for customers. In lieu of the method recommended in the Staff Report regarding penalties for noncompliance, beginning with the 2019 CAIDI and SAIFI performance reported on or before March 31, 2020, if either performance standard is not achieved for two consecutive years, DP&L's DIR revenue cap increment will decrease by $2 million rather than being assessed a penalty or forfeiture due to a violation of Ohio Adm. Code 4901:1-10-10.

(2) DP&L will dedicate up to $1 million in total capital investment eligible for DIR recovery, beginning in 2019, to fund distribution grid investments necessary to support installation of electric vehicle (EV) charging infrastructure in the DP&L service territory. The Company may recover through the DIR costs associated with investments for the meter and equipment in front of the meter to support EV charging stations supported by grants awarded by the Ohio EPA. In consultation with Staff and the Signatory Parties, DP&L may develop a pilot EV tariff.

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2. The Stipulations, as a package, benefits ratepayers and the public interest. [Page 38]

{¶ 66} The Stipulations contain other reliability sustaining provisions including the recovery of incremental distribution investments through the Company's DIR, which permits DP&L to address known threats to the reliability of its distribution system. Importantly, the provisions related to the DIR also require the Company to work with Staff and OCC to develop an annual plan to improve

[75] The required tariff language is specifically stated in the Stipulation at p. 8.

reliability and ties the Company's performance to its DIR revenue cap. The Stipulations also provide deferral authority for incremental annual expenses for vegetation management, subject to an annual cap of $4.6 million. (DP&L Ex. 1 at 7-8; OCC Ex. 1 at 7-8; Staff Ex. 6 at 5.) And, while not directed toward system reliability, the Stipulations permit DP&L to implement revenue decoupling through the Distribution Decoupling Rider, which will promote energy efficiency efforts, result in the elimination of collection of lost revenues, and provide rate stability to both the Company and its customers (DP&L Ex. 1 at 10; OCC Ex. 1 at 8; Staff Ex. 6 at 5).

V. Order [Page 46]

{¶ 103} It is, therefore.

{¶ 104} ORDERED, That the Stipulations filed June 18, 2018, and June 12, 2018, in this proceeding are approved and adopted by the Commission.

Appendix B: Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report.

ADIT	Accumulated deferred income tax
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Meter Infrastructure
CAT	Commercial Activity Tax
DA	Distribution Automation
DIR	Distribution Investment Rider
DOE	Department of Energy
ESP	Electric Security Plan
FERC	Federal Energy Regulatory Commission
HAN	Home Area Network
IVVC	Integrated Volt-VAR Control
LOSA	Level of Signatory Authority
MRO	Market Rate Offer
PEA	Project Expenditure Authorization
PUCO	Public Utility Commission of Ohio
RFP	Request For Proposal
SOX	Sarbanes-Oxley
SSO	Standard Service Offer
UPIS	Utility Plant In Service
VVO	Volt VAR Optimization
WACC	Weighted average cost of capital

Appendix C: Data Requests and Information Provided

Data Requests Set 1 Submitted 5/1/19

1.1. **Work Orders**: Please provide in Microsoft Excel format a list of all DIR work orders put in service, from October 1, 2015, through January 31, 2019. For each work order, please include the following information:

a) Plant accounts charged (FERC 300 accounts) (Response Received 5/13/19)
b) Project identification numbers (project type, work order and project roll up, if applicable) (Response Received 5/13/19)
c) Project description. Single line description will be acceptable, if descriptive, along with location numbers (Response Received 5/21/19)
d) Project description (e.g., Replacement & Betterment, Growth, Support Services, Information Technology) (Response Received 5/21/19)
e) Work order construction ready for service or completion date (when project became used and useful). (Response Received 5/13/19)
f) Work order accounting in-service date (date charges were moved from FERC 107 to 106) (Response Received 5/13/19)
g) Unitization date (date charges were moved from FERC 106 to FERC 101), if applicable (Response Received 5/13/19)
h) Dollar amount by FERC 300 account number (Response Received 5/13/19)
i) Whether the work was an addition or replacement (Response Received 5/21/19)
j) Whether the work order was a blanket project work order or specific project and associated project identification numbers (Response Received 5/21/19)

1.2. **Work Order Population Reconciliation to DIR Filing**: Please provide a reconciliation of the work order totals provided in the request #1 to the total included in the April 1, 2019, DIR filing (period ending January 31, 2019). (Response Received 5/15/19)

1.3. **DIR Rider Filings:** Please provide, in Microsoft Excel format, each of the DIR Rider filings made to date: (1) period ending June 30, 2018 (replaced on 12/17/18); (2) period ending August 31, 2018 (replaced on 12/17/18); and (3) period ending January 31, 2019 (filed 4/1/19). (Response Received 5/10/19)

1.4. **FERC Form 1 Recon:** For each year, 2015, 2016, 2017, 2018, please provide a rolling forward reconciliation of the Rider DIR plant and reserve balances to the balances in the 2015, 2016, 2017, and 2018 FERC Form 1s. (Response Received 5/13/19 and 6/21/19)

1.5. **Commission Annual Reports:** Please provide the Annual Report for the years ending December 31, 2015, 2016, 2017, and 2018, filed with the Commission. (Response Received 5/10/19)

1.6. **Organization**: Please provide a current organization chart of the Company. (Response Received 5/13/19)

1.7. **Organization**: Please provide the name, title, department, company, and location for the persons responsible for the following functions. Each person should be available for interview and able to perform a walkthrough of his or her activities related to the subject matter.

a) Plant Accounting, including

1. Capitalization
2. Preparation and approval of work orders
3. Recording of CWIP, including the systems that feed the CWIP trial balance;
4. Application of AFUDC
5. Recording and closing of additions, retirements, cost of removal and salvage to plant
6. Unitization process based on the retirement unit catalog
7. Application of depreciation
8. Contributions in Aid of Construction (CIAC)

b) Purchasing/Procurement
c) Accounts Payable/Disbursements
d) Accounting/Journal Entries
e) Payroll (direct charged and allocated)
f) Taxes (Accumulated Deferred Income Tax, Federal, State, and local Income Tax)
g) Insurance recovery
h) Property taxes
i) Allocations
j) Work management system
k) Information Technology (Response Received 5/15/19 – update Received 6/12/19)

1.8. **Policies and Procedures**: During the Audit of Plant in Service in Case No. 15-1830-EL-AIR, Blue Ridge requested policies and procedures for the following activities. Please provide any changes to the policies and procedures made after the Company's May 2017 response.

a) Plant Accounting, including
   i) Capitalization
   ii) Preparation and approval of work orders
   iii) Recording of CWIP, including the systems that feed the CWIP trial balance;
   iv) Application of AFUDC
   v) Recording and closing of additions, retirements, cost of removal and salvage to plant
   vi) Unitization process based on the retirement unit catalog
   vii) Application of depreciation
   viii) Contributions in Aid of Construction (CIAC)
   ix) Damage Claims
b) Purchasing/Procurement
c) Accounts Payable/Disbursements
d) Accounting/Journal Entries
e) Payroll (direct charged and allocated)
f) Insurance recovery
g) Allocations
h) Work Management System
i) Information Technology (Response Received 5/15/19)

1.9. **Policies and Procedures**: Please specifically explain any major changes that have been made to the Company's capitalization policy from September 30, 2015, through January 31, 2019. (Response Received 5/10/19)

1.10. **Rider DIR Preparation:**

a) Please provide a narrative on how the Rider DIR is prepared, including the name, title, and department of each person that provides information for the filing. Each person should be available for interview.
b) Please provide the policies and procedures and/or flow charts for the development of the Rider DIR. Include sources for all components, how components are gathered and entered, and approval requirements (i.e., organizational positions providing approvals, items requiring approval, and timing for when approvals are needed in the process). (Response Received 5/15/19) – tax (Response Received 5/20/19))

1.11. **Policies and Procedures**: Please provide the policies and procedures and/or flow charts for the identification and categorization of projects recovered through the DIR. (Response Received 5/13/19)

1.12. **Vegetation Management**:

a) Please provide the specific guidance and/or instructions, both financial and operational, provided to field personnel enabling them to determine what routine vegetation work is considered capital or expense.
b) When a company or contractor tree-trimming crew finds a tree or limb, outside the right of way, that needs to be removed while performing unrelated work, how does the crew determine the accounting treatment (capital/expense)? (Response Received 5/15/19)

1.13. **Vegetation Management**: For each calendar years 2015, 2016, 2017, 2018, and 2019 please provide these items:

a) Amounts budgeted to expense
b) Amounts budgeted to capital
c) Actual amounts charged to expense
d) Actual amounts charged as capital (Response Received 5/15/19)

1.14. **Pension and OPEB:** ASU 2017-07 amended the accounting for pension and OPEB costs, effective January 1, 2018, to limit the components of net periodic pension and postretirement benefit costs that are eligible for capitalization to only the service costs component. Previously, all components of net periodic pension and postretirement benefit costs (e.g., service cost, interest cost, expected return on plan assets) were eligible to be capitalized. The result of the accounting changes prescribed in ASU 2017-07 is that the portions of the costs that are no longer eligible to be capitalized increase the Company's operating expenses as compared to prior accounting.

a) When did the Company adopt ASU 2017-07?
b) Has the Company modified its policies and procedures to conform to ASU 2017-07? If so, please provide the revised policies and procedures.
c) Has ASU 2017-07 been reflected in the assets put in service during 2018 and 2019?
d) Provide the overhead allocation burdens before and after the adoption of ASU 2017-07. Include the calculations of each. (Response Received 5/10/19)

1.15. **FERC Audits**: Please provide a copy of all FERC audit reports, if any, that were issued during 2015 through 2019. Also provide the Company's response to any findings and the ultimate resolution of those findings. (Response Received 5/10/19)

1.16. **Internal Audits**: Please provide a list of Internal Audits performed from September 30, 2015, through January 31, 2019, or currently in progress. List the name of the audit, scope, objective, and when the audit was performed. (Response Received 5/15/19)

1.17. **SOX Compliance Audits**: Utility Plant in Service (UPIS) is fed from CWIP. Therefore, any system that feeds CWIP, including but not limited to WMS, Payroll, M&S, Overheads, AFUDC, Transportation, and direct contractor charges through purchasing, could have an impact on UPIS and, therefore, the DIR. Please provide any SOX Compliance audits performed from September 30, 2015, through January 31, 2019, on any of those feeder systems that in one form or another feed CWIP, or any other SOX compliance work that impacts the preparation of the DIR. Include whether the controls passed or failed and, if failed, the severity and impact of the failure on the DIR. (Response Received 5/17/19)

1.18. **Riders/Surcharges:** Please provide a comprehensive list of riders and surcharges that were in effect for the Company during October 1, 2015, through January 31, 2019. Of the list of riders, please indicate which, if any, provide for recovery of Distribution Plant. For each of those riders, please show in detail how the Company coordinated cost recovery between them and Rider DIR. Include supporting workpapers. (Response Received 5/13/19)

1.19. **DIR Filings:** Please provide the workpapers and supporting documentation for the information identified with a source "Company Records" used to calculate the following:

a) Plant Related ADIT (pages 4–5) (Response Received 5/15/19)
b) Personal Property Taxes (pages 7–8) (Response Received 6/6/19)
c) Rate of Return Calculation (page 9) (Response Received 5/15/19)
d) Revenue Collected (page 10) (Response Received 5/19/19)

1.20. **DIR Filings:**

a) What is the source of the depreciation rates percentages included in Depreciation Expense by FERC Account (page 6 of filing)?
b) Please provide a copy of the most recent approved depreciation study.
c) If depreciation rates have been changed, please explain for each change when the change was made, what the change was, and whether it was approved by the Commission.
d) Explain any differences between the depreciation rate used in the DIR filing and the rates in the most recent approved depreciation study. (Response Received 5/10/19)

1.21. **Depreciation:** Does the Company use a depreciation rate for any FERC 300 sub account that has not been approved by the Commission? If so, please provide the following for any changes made in 2015 through 2019.

(a) FERC 300 account, sub account
(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 (Response Received 5/10/19)

1.22. **ADIT**: Please provide a narrative of the type of ADIT eligible for inclusion in Rider DIR. (Response Received 5/17/19)

1.23. **ADIT**: Please provide a list of ADIT included within Rider DIR for each year from 2015 through 2019. (Response Received 5/17/19)

1.24. **TCJA**: Please provide a narrative of how the Company has reflected the change in federal income tax rates from the Tax Cuts and Jobs Act of 2017 (TCJA) in the ADIT included within the DIR.

a) Did the Company set up a regulatory liability for excess deferred taxes? Please provide the balance, supporting calculations, and journal entries.
b) When does the Company propose to begin flowing back the excess deferred taxes in customer rates? If the response timing is in connection with a general rate case proceeding, when does the Company anticipate its next filing?
c) Which IRS-sanctioned method will the Company use to flow back the excess deferred taxes in customer rates? For example, will the Company use the average rate assumption method (ARAM) or over the average remaining useful life of the underlying protected assets? (Response Received 5/17/19)

1.25. **Overhead and Indirect Costs**: Please provide a list of all overheads (labor loadings, etc.) and any other indirect items charged to DIR work orders, including descriptions both of the type of charge and how that charged item is applied (e.g., calculation with descriptions of factors used in the calculations). (Response Received 5/15/19)

1.26. **Approval Signatures:** Please provide the Level of Signature Authority (LOSA) document that supports the approval of capital projects put in service from October 1, 2015, through January 31, 2019. Please provide the titles and PRA Role for the employees who were listed as Required Signatures for the Funding and Approval on any of the projects. (Response Received 5/15/19)

1.27. **Variance Analysis**: Please provide a Microsoft Excel spreadsheet in FERC Form 1 format (by FERC 300 account) of the beginning and ending period balances, additions, retirements, transfers, and adjustments for each year ending 2015, 2016, 2017, and 2018. (Response Received 5/21/19)

1.28. **Variance Analysis**: Please provide a Microsoft Excel spreadsheet of the jurisdictional accumulated reserve for depreciation balances by FERC 300 account for each year ending 2015, 2016, 2017, and 2018. (Response Received 6/12/19)

1.29. **Budget:** For each year, please provide the annual capital budgets supporting the plant spend in 2015 through 2019 included in the DIR balances. Also, please include the assumptions supporting the budget/projected data. (Response Received 5/15/19)

1.30. **Capital Dollars Spent:** For each year, please provide the annual total actual capital dollars spent in 2015 through 2019 included in the DIR compared to the approved budget. (Response Received 5/15/19)

1.31. **Variance**: Did the Company maintain any budget-to-actual and/or variance tracking covering the 2015–2019 distribution plant to actual results for 2015–2019?

a) If not, please explain fully why not.
b) If so, please provide the budget-to-actual and/or variance tracking for 2015–2019, including any related Excel files and budget variance explanations. (Response Received 5/15/19)

1.32. **Unitization Backlog**: Please provide information regarding any backlog in the unitization of distribution work orders as of January 31, 2019. Please provide the information by work order <u>number</u> and <u>dollar value</u> of each backlogged work order and the length of time for each in months (e.g., under three months, four to 12 months, and over 12 months). (Response Received 5/10/19)

1.33. **Insurance Recoveries**:

a) Were there any significant events in 2015–2019 that resulted in an insurance claim recovery greater than $50,000 related to Distribution Plant? If so, please provide a list of such events, how each recovery was recorded to the Company's books, and how it was reflected in plant balances.
b) Are there any pending Distribution plant insurance claim recoveries as of January 31, 2019, that are not recorded or accrued that would be charged to capital? If so, please provide the type of recovery, estimated amount, and when receipt is expected. (Response Received 6/21/19 and 6/26/19)

Data Requests Set 2 Submitted 5/17/19

2.1. Follow-up to Data Request response BRDR 1-12—Vegetation Management.
  a. Please explain the accounting for the initial clearing of a right-of-way.
  b. Does the Company have a policy regarding the initial clearing of a right-of-way? If so, please provide that along with any FERC accounting guidance used.
  c. Does the Company have a standard horizontal and vertical distance used for Distribution right-of-ways? If so, please provide that, but if not, how does the Company determine the distance to clear? (Response Received 6/6/19)

2.2. Follow-up to Data Request response BRDR 1-16, attachment 1. For the following internal audits, please provide the summary findings and recommendations. For audits in-progress, please provide the summary findings and recommendations when they[76] become available.
  a. 2016 DPL Third Party Review—Report issued November 28, 2016
  b. DPL Capex (CWIP Distribution)—Report issued November 13, 2017
  c. US Financial Controls-AES Services Transition audit—Report issued August 25, 2018
  d. Procurement Process—Audit report issued February 8, 2019
  e. Cybersecurity and Data Protection—Report issued November 1, 2018
  f. SAP Pre-implementation Audit—Report date unknown
  g. DPL Vegetation Management—Audit in progress (Response Received 5/24/19)

2.3. Follow-up to Data Request BRDR 1-10—Rider DIR Preparation, attachment 1, tab "Recon of plant accounts." Please explain the impact on the depreciation reserve for the inadvertent retirement of $18,463,281 in meters that was not in plant in service for one month. (Response Received 6/6/19)

Data Requests Set 3 Submitted 5/21/19

3.1. **FERC Form 1 Recon:** Reference Company response to Data Request 1.4, attachment 1. Please provide detailed explanation regarding the reasons for the significant additions (in comparison to retirements for the following accounts in the referenced years:
  a. Year 2015
    1. Account 3603—additions: $247,532; retirements: $(0)
    2. Account 3640—additions: $1,441,426; retirements $(70,594)
    3. Account 3670—additions: $2,660,163; retirements: $(325,810)
  b. Year 2016

1. Account 3603—additions: $1,004,177; retirements: $(0)
2. Account 3610—additions: $545,7050; retirements: $(5,957)
3. Account 3620—additions: $7,663,789; retirements: $(995,662)
4. Account 3640—additions: $5,334,698; retirements: $(305,810)
5. Account 3650—additions: $5,212,982; retirements: $(3,335,578)
6. Account 3670—additions: $7,926,100; retirements: $(833,257)
7. Account 3680—additions: $7,869,778; retirements: $(860,620)
8. Account 3691—additions: $1,872,391; retirements: $(35,156)
9. Account 3692—additions: $13,908,245; retirements: $(14,837)
10. Account 3700—additions: $19,855,230; retirements: $(1,219,016)
11. Account 3711—additions: $2,750,783; retirements: $(554,232)

c. Year 2017
   1. Account 3603—additions: $1,118,006; retirements: $(0)
   2. Account 3620—additions: $4,051,331; retirements: $(365,796)
   3. Account 3640—additions: $7,089,777; retirements: $(302,483)
   4. Account 3650—additions: $6,861,202; retirements: $(5,071,584)
   5. Account 3670—additions: $8,844,174; retirements: $(1,274,809)
   6. Account 3680—additions: $15,945,142; retirements: $(988,613)
d. Year 2018
   1. Account 3603—additions: $1,045,858; retirements: $(4,700)
   2. Account 3620—additions: $10,261724; retirements: $(2,252,795)
   3. Account 3640—additions: $19,055,659; retirements: $(678,053)
   4. Account 3670—additions: $12,661,530; retirements: $(1,934,095)
   5. Account 3680—additions: $15,666,380; retirements: $(1,072,004)
   6. Account 3691—additions: $2,745,338; retirements: $(40,359)
   7. Account 3692—additions: $28,876,768; retirements: $(22,723)
   8. Account 3700—additions: $1,757,370; retirements: $(554,212)
   9. Account 3711—additions: $1,216,534; retirements: $(217,204) Response Received 6/17/19)

3.2. **FERC Form 1 Recon:** Reference Company response to Data Request 1.4, attachment 1. Please provide detailed explanation regarding the reasons for the negative additions for the following accounts in the referenced years:

a. Year 2015
   1. Account 3620—additions: $(97,789)
   2. Account 3692—additions: $(6,568)
b. Year 2017
   1. Account 3691—additions: $(5,145)
   2. Account 3692—additions: $(37,586) (Response Received 7/12/19)

3.3. **FERC Form 1 Recon:** Reference Company response to Data Request 1.4, attachment 1. Please provide detailed explanation regarding the reasons for the retirements significantly larger than additions for the following accounts in the referenced years:

a. Year 2015
   1. Account 3700—additions: $2,376,094; retirements: $(19,943,353)
b. Year 2019
   1. Account 3620—additions: $59,018; retirements: $(341,302)

2. Account 3700—additions: $48,739; retirements: $(103,813) (Response Received 6/14/19)

3.4. **FERC Form 1 Recon:** Reference Company response to Data Request 1.4, attachment 1. Please provide detailed explanation regarding the reason for the positive retirements for the following accounts in the referenced years:
   a. Year 2015
      1. Account 3680—retirements: $784,922 (Response Received 6/14/19)

<u>Data Requests Set 4 Submitted 5/23/19</u>

4.1. **FERC Form 1 Recon:** Follow-up to Data Request 1.4. The data request asked for reconciliation of the yearly DIR account balances, by FERC 300 account, to the annual FERC Forms 1. What was provided was the yearly DIR balances by account. Please provide, in FERC Form 1 format (by FERC 300 accounts), reconciliations of the yearly DIR distribution account totals for 2015, 2016, 2017, and 2018 to the associated accounts in the annual FERC Forms 1 for those years. For each account, please provide the variance and the explanation of the variance, including the associated categories and amounts that make up the variance. For example, Account 106 would be one category of difference that would be in the FF1 which is not in the DIR balance for several accounts. Please identify all such categories of differences per account along with their associated balances and explanations.

<u>Data Requests Set 5 Submitted 5/23/19</u>

5.1. Reference Company response to Data Request 1.1. Please refer to the attached work orders selected from the population of work orders provided in response to the referenced data request. Please note that the selection is work order/project based. For each work order/project on the list, please provide the following information in Microsoft Excel spreadsheets:
   a. Detailed description, scope, and objective of the work, including location and any other identifiers
   b. Work order/project justification and approval
   c. Estimated in-service date and actual in-service date
   d. For non-blanket work orders/projects, budget and total cost with any explanation of variances in excess of 20%
   e. Supporting cost detail for each addition to plant (run of charges). The detail should be by charge code (or charge code description) with amounts by year and month (An example of charge code description would include such information as payroll, contractor charges, overheads, other allocations, M&S, transportation, and employee expenses.)
   f. Supporting detail for retirements, cost of removal, and salvage, if applicable, charged or credited to plant (Provide the description, units, amount, and date recorded.)

Notes:

- Please send a sample of the detail that will be provided to make sure it is what we need.

- If you have any questions, please contact Joe Freedman directly at 607-280-3737 or Jfreedman@blueridgecs.com.
- In the interest of time and associated deadlines, please provide the data in batches as they are completed. (Partial Response Received 6/12/19, 7/1/19 – see Control Doc)

<u>Data Requests Set 6 Submitted 6/4/19</u>

6.1. Follow-up to Data Request BRDR 2.2 b. DPL Capex (CWIP Distribution) – Report issued November 13, 2017. T&D Projects Capitalization Process.

a) Please explain what the Company has done to address the following audit report findings: "The required transfer of projects from in-progress to in-service was not performed in a consistent, timely manner for all concluded projects."
Recommendations:
   1. Operational Area should review the close-out process for damage claim projects. . . .
   2. Project Managers should improve the monitoring of ongoing projects. . . .
   3. Projects on hold must be reviewed by the operational area. . . .
   4. Fixed Asset Accounting should improve monitoring controls of projects in progress…
   5. Fixed Asset Accounting should review and correct the projects that were put in service in duplicity. . . .

b) Regarding recommendation v. above, please provide the amount of the projects that were put into service in duplicity and the impact of those projects on the potential overstatement of the DIR. (Response Received 6/13/19)

6.2. Follow-up to Data Request BRDR 2.2 d. Procurement Process—Audit report issued February 8, 2019. Procurement Process. Please explain what the Company has done to address the following audit report findings:
   a) Management should review the procurement policy and procedures. . . .
   b) Management should start to monitor single-source purchases quarterly. . . . (Response Received 6/13/19)

<u>Data Requests Set 7 Submitted 6/7/19</u>

7.1. Follow-up to Company Data Request response BRDR 1-12 – Vegetation Management, c.

<u>Primary Conductor</u>:
The Company response indicated that the easement is assumed to be 10 ft.
   a. Why does the Company use an assumed 10-foot right-of-way and not a standard-width right-of-way?
   b. Does the Company have a standard-width right-of-way footage, and if so, what is it?
   c. Does the Company have a standard-vertical right-of-way footage, and if so, what is it?

The Company response indicated that 12 to 14 feet will be assumed to be minimum clearance at the time of trimming for fast growing trees located within the assumed 10-foot easement.
   d. Is the 12 to 14 feet what is initially cleared? If not, what is the initial clearance?

e. Is anything cleared outside the assumed 10-foot clearance considered outside the right-of-way? If not, why not?
f. Does the Company agree that any tree cleared within the right-of-way not initially cleared is considered expense in accordance with the FERC code of accounts (CFR 18)? If not, why not?

Secondary Conductor:

g. Does the response mean that if the Company cannot obtain a 10-foot right-of-way without removing tree(s), the trees will be removed? If not, please explain. (Response Received 6/13/19)

Data Requests Set 8 Submitted 6/7/19

8.1. Follow-up to Data Request BRDR 3.4 regarding positive retirements for account 3680. The response stated that in 2011, the Company established Transformer Cutouts as separate retirement units. Please respond to the following requests:

c) Please provide the policy for establishing a new retirement unit.
d) Please provide the specific reasons cutouts were established as a separate retirement unit of property, along with the approvals.
e) If the credits were associated with the transformers, and assuming the credits simply reduced the cost of the transformers, why would the credits need to be retired separately? Please fully explain the accounting process.
f) If the credits were retired separately, what happened to the debits that would be the new retirement unit of property?
g) For the audit period, please explain the impact to the reserve and net plant as a result of not retiring the credits timely.
h) Did the Company under accrue depreciation as a result of the delay in retiring the credits? If not, why not?

Data Requests Set 9 Submitted 6/12/19

9.1. Reserve: Reference Blue Ridge DR 01-3 Attachment 5, Tab Plant in Service (also labeled as Page 2 of 11). Provide the source of line 19, FERC 108, Accumulated Reserve (b) ($70,315). We compared the FERC Account balances to Case No. 15-1830-EL-AIR, Staff's Report, Schedule B-3, and could not find the amount. (Response Received 6/14/19)

9.2. Capitalized Incentive Adjustment Factor: Reference Blue Ridge DR 01-3 Attachment 5, Tab Incentive Adj. Provide the support for the Capitalized Incentive Adjustment Factor of 0.7196%.(Response Received 6/14/19)

Data Requests Set 10 Submitted 6/17/19

10.1. **Property Taxes**: Follow-up to DR 1-3, Attachment 5, Tab Tax other than Income. Please provide the source for the True Value of Additions net of Retirements for 2016 Tax, 2017 Tax, and 2018 Tax. (Response Received 6/25/19)

10.2. **Return on Rate Base**: Follow-up to DR 1-3, Attachment 5, Return on Rate Base and Case No. 15-1830-EL-AIR et al., Stipulation and Recommendation, Exhibit 3. Please confirm that the return on rate base of $47,623,955 in the DIR filing as of date certain, September 30, 2019, does not agree with the return on rate base of $47,629,487 in the Stipulation, Exhibit 3, due to rounding of the pre-tax weighted average cost of capital and that the date certain amount should be adjusted to be consistent with the Commission order. Response Received 6/25/19)

10.3. **Capitalized Incentive Adjustment Factor**: Reference Blue Ridge DR 9-2, Attachment 1-Confidential. To determine the factor, capitalized incentives were divided by total capital expense. The capitalized incentives used in the numerator use short-term bonus pay and long-term compensation from February 2018 through July 2018. The source of the total capital expense used in the denominator is labeled "Company Record – Sept-2017 through Aug-2018."

a. Please explain the reason it is appropriate to use different time periods in the numerator and denominator.
b. Please explain how this methodology is consistent with the Staff's adjustment in Case No. 15-1830-EL-AIR and reflected within the approved Stipulation.
c. Please provide any workpapers in Case No. 15-1830-EL-AIR showing how the factor was calculated. Response Received 6/25/19)

10.4. **Approvals**: Follow up to Data Request response BRDR 1-26, attachment 1. Does the LOSA document include approvals for Blanket project/work orders? If not, please provide the approval process specifically for Blanket project/work orders. (Response Received 7/3/19)

Data Requests Set 11 Submitted 6/18/19

11.1. **Transmission Division**: Reference Response to Data Request 5.1 Attachment 5-1(v) – Project 30734525 - Eaker Sub:R/P BK-1. The PEA indicates this work is Transmission work. Please explain why the Company considers this project part of the DIR. Response Received 6/25/19)

11.2. **Approvals**: Reference Response to Data Request 5.1 Attachment 5-1(r) – Project: 30735330 - WEBSTER ST BRIDGE PROJECT - PHASE II - PERMANENTLY RELOCATE AY-1228, AY-1229 INTO BRIDGE – The Budget within the PEA was $276,687. This project did not appear to have the appropriate level of approval based on the LOSA. (Response Received 7/3/19)

11.3. **PEAs**: The following list of Projects are considered "Mandatory" based on the Project Authorization, Scoring and Evaluation Tool provided within the PEA, . Please provide an explanation for why the project is considered Mandatory.

a. Reference Response to Data Request 5.1 Attachment (y) – Project 30734300 - 2015 Cutout Cap Program
b. Reference Response to Data Request 5.1 Attachment (ac) – Project 30734903 - 307-2016 Cutout Replacement Program
c. Reference Response to Data Request 5.1 Attachment (m) – Project 31030572 - R/M poles along levy W/O Keowee to North Bend Blvd. and re-conductor along Stanley Ave. Response Received 6/25/19)

11.4. **In-Service Dates**: Reference Response to Data Request DR 5.1 - The following projects had DPIS dates significantly past the estimated in-service date on the PEA. Please explain the reason(s) for each project delay and if AFUDC was over accrued as a result of the delay. (Response Received 7/3/19)

PEA Location	Project	Project Description	Grand Total	DPIS	Estimated In-Service Date	# Days outside of Estimate
Attachment 5-1(a)	30734131	Vandalia-Install new AZ-1209 Circuit	$(128,733)	2/12/15	9/3/14	162

PEA Location	Project	Project Description	Grand Total	DPIS	Estimated In-Service Date	# Days outside of Estimate
Attachment 5-1(x)	30734191	Indian Lake: I/S BK-1	$2,049,307	3/2/16	10/31/15	123
Attachment 5-1(e)	30734516	Mechanicsburg sub-R/P failed BK-1	$595,301	9/8/15	5/15/15	116
Attachment 5-1(v)	30734525	Eaker Sub:R/P BK-1	$1,098,291	11/16/15	5/1/15	199
Attachment 5-1(f)	30734527	Wilmington Sub: R/P BK-2	$567,756	3/29/16	12/30/15	90
Attachment 5-1(z)	30734743	WEBSTER ST BRIDGE R/P	$435,117	9/30/16	3/1/16	213
Attachment 5-1(ae)	30734968	Treaty Sub: I/S BK-2	$1,840,418	12/1/17	4/1/17	244
Attachment 5-1(ab)	30735090	Spare Transformer	$616,033	5/11/17	11/1/16	191
Attachment 5-1(q)	30735142	JEFFERSONVILLE - R/P JE1204E & JE1202E	$238,927	10/27/17	5/31/17	149
Attachment 5-1(i)	31029343	Keowee St. Rebuild (Helena to Stanley) - Copy of WO:10056375	$361,816	8/9/16	4/30/16	101
Attachment 5-1(j)	31029760	Relocate Utilities for the Village of Ft. Loramie - Copy of WO:10088093	$68,715)	2/16/17	10/31/16	108
Attachment 5-1(k)	31030031	AT1206 -3ph reconductor along Shakertown Rd	$189,206	1/26/17	10/15/16	103
Attachment 5-1(p)	44635314	446-Delco Kettering Sub BK-2 Failure Insurance Claim	$733,508	12/1/17	12/16/16	350

11.5. **Salvage Credits**: Reference Response to Data Request DR 5.1 Attachment 5-1(i) and Attachment 5-2(i) – Project 31029343 - Keowee St. Rebuild (Helena to Stanley) - Copy of WO:10056375. Please explain why the PEA has an estimated Salvage Credit of $0 while the Cost detail has a Salvage Credit of -$3,320. Response Received 6/25/19)

11.6. **Tasks:** Reference Response to Data Request 5.1 Attachments 5-2. What do the following Task Numbers mean?
   a. 1
   b. 11
   c. 70
   d. 8030 Response Received 6/25/19)

11.7. **Tasks**: Reference Response to Data Request 5.1 Attachments 5-2. Please explain and provide the accounting for how Task 90 (cost of removal) charges are recorded including how and when they clear to FERC 108. Response Received 6/25/19)

11.8. **Work Order Testing**: Reference Response to Data Request 5.1 Attachments 5-2 and Data Request 1.1 Attachment 1 (Population). Please explain why the Cost Detail charges were greater than the amounts provided within the population. (Response Received 7/3/19)

Project	Cost Detail Location	Project Description	Population Value DR 1.1	Cost Detail DR 5.1 Att 2	
30734131	Attachment 5-2(a-1)	Vandalia-Install new AZ-1209 Circuit	$(128,733)	$0	PEA 2838 Reimbursed by Buckeye Power
31023954	Attachment 5-2(a-2)	Extend 3ph from BLA6499 to Dog Leg Rd and install Primary Meter	$1,238,799	$(0)	PEA 2838 Reimbursed by Buckeye Power
30734749	Attachment 5-2(c)	AC NETWORK COMMUNICATION PROJECT	$807,869	$817,982	PEA 2863 Booked to Spares
31033377	Attachment 5-2(ak-10)	Removing DP&L facilities	$2,973	$2,985	Blanket No PEA Provided

11.9. **Work Order Testing**: Reference Response to Data Request 5.1 Attachments 5-2 (Cost Detail) and Data Request 1.1 Attachment 1 (Population) - Project 5134314 - 051 Storm 04-02-2016 Capital.

Cost Detail Activity Charges = $1,285,921
(less) Cost Detail Activity Charges for Task 90 (COR/Salvage) = $183,458
(less) Population Activity Charges = $473,586

Difference = $628,877

Please explain the $628,877 difference. Response Received 6/25/19)

11.10. **Cost of Removal**: Reference Response to Data Request 5.1 Attachments 5-1 and 5-2. For the Projects listed please explain why the Task 90 (COR/Salvage) charges exceeded the COR Budget included in the PEA. Response Received 6/25/19)

Project	Project Description	Task 90 - COR/Salvage	PEA Removal Budget
30734453	2015 DAYTON SPOT NETWORK PRIMARY VACUUM SWITCH REPLACEMENT	$ 89,259	$ 81,027
30734515	Huber Hts sub-R/P failed BK-2	$ 35,691	$ 20,000
30734516	Mechanicsburg sub-R/P failed BK-1	$ 73,915	$ 25,000
30734527	Wilmington Sub: R/P BK-2	$ 47,248	$ 23,000
30734903	307-2016 Cutout Replacement Program	$ 336,254	$ 265,500
30735142	JEFFERSONVILLE - R/P JE1204E & JE1202E	$ 34,932	$ 6,000
30735330	WEBSTER ST BRIDGE PROJECT - PHASE II - PERMANENTLY RELOCATE AY-1228, AY-1229 INTO BRIDGE	$ 16,253	$ 4,900
30735338	DIA: AZ-1208 - NEW 1000MCM CABLE TIE - P044	$ 11,667	$ 5,154

30735721	307-Woodstock Substation Replace BK-2	$ 24,160	$ 17,559
36735185	367-Centerville BK-2 Replacement	$ 38,674	$ 20,000
44635312	446-Jeffersonville Sub BK-1 Failure Insurance Claim	$ 93,060	$ 39,705
44635314	446-Delco Kettering Sub BK-2 Failure Insurance Claim	$ 22,308	$ 17,591

11.11. **Revenue Generating**: Reference Response to Data Requests 5.1 Attachments 5-1(m) and 5-2(m) - Project 31030572 - R/M poles along levy W/O Keowee to North Bend Blvd. and re-conductor **along** Stanley Ave. Please explain why the PEA indicates that there will be no Project Benefits while the Cost Detail indicates there has already been $15,000 in “Revenues - NON AP.” Response Received 6/25/19)

11.12. **TRANS Charges**: Reference Response to Data Request 5.1 Attachment 5-2 (Cost Detail). Please explain why the following projects have TRANS related charges included in the DIR. Response Received 6/25/19)

Project		Payroll OH-Benefits - TRANS	S&E - TRANS	A&G Overheads - TRANS	Bonus NonProd-TRANS
30734878	Spare Transformer 2016	$ 1,106	$ 349	$ 213	$ 473
30734968	Treaty Sub: I/S BK-2	$ 178,639	$ 85,074	$ 29,004	$ 64,686
36734187	Southtown sub-I/S for Fuyau glass plant	$ 48,772	$ 20,127	$ 12,461	$ 14,644

11.13. **TRANSMISSION OPERATION Charges**: Reference Response to Data Request 5.1 Attachment 5-2 (Cost Detail). Please explain why the following projects have TRANSMISSION OPERATION related charges included in the DIR. Response Received 6/25/19)

Project		**TRANSMISSION OPERATIONS**
5134314	051 Storm 04-02-2016 Capital	$93,358
30734191	Indian Lake: I/S BK-1	$13,785
30734516	Mechanicsburg sub-R/P failed BK-1	$3,988
30734743	WEBSTER ST BRIDGE R/P	$11,982
30734903	307-2016 Cutout Replacement Program	$693
30734968	Treaty Sub: I/S BK-2	$3,360
30735142	JEFFERSONVILLE - R/P JE1204E & JE1202E	$4,175
30735721	307-Woodstock Substation Replace BK-2	$9,932
31026879	Remove conductors for bridge relacement, OH to UG Con - Copy of WO:10058152	$1,043
31029343	Keowee St. Rebuild (Helena to Stanley) - Copy of WO:10056375	$8,252
31029485	I/S two airbreak switches on AR1204	$462

31030572	R/M poles along levy W/O Keowee to North Bend Blvd. and re-conductor along Stanley Ave.	$3,605
31035405	Relocate Cap Bank on RD1219	$400
36734187	Southtown sub-I/S for Fuyau glass plant	$10,754
36735185	367-Centerville BK-2 Replacement	$8,725
44635312	446-Jeffersonville Sub BK-1 Failure Insurance Claim	$18,466
44635313	446-Jeffersonville Sub BK-3 Failure Insurance Claim	$1,262

11.14. **FIELD VISITS**: As a continuation of the audit process, we have selected certain work orders/projects, for field verification from the work order sample. The purpose of the field verification is to determine that the assets have been installed per the work order scope and description. The work order/project selection criteria were primarily 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.

a. An individual(s) that can coordinate all the field verification with Staff
b. Representatives from FE that can field assist Staff at each field location
c. The Project Manager or a person that was responsible for the work on each project available to answer Staff's questions
d. Schematics/drawings or any other visual diagram that indicates 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 (labor, Material, equipment)

If the Company has questions about the selection, or any other requirement, please contact Joe Freedman via e-mail at jfreedman@blueridgecs.com or by phone at 607-280-3737

Project	Project Description	Total
30734191	Indian Lake: I/S BK-1	$ 2,049,307
30734515	Huber Hts sub-R/P failed BK-2 Insurance claim	$ 797,363
30734516	Mechanicsburg sub-R/P failed BK-1 Insurance claim	$ 595,301
30734525	Eaker Sub:R/P BK-1 insurance claim	$ 1,098,291
30734526	Webster Sub:R/P BK-2 Insurance claim	$ 1,097,370
30734878	Spare Transformer 2016	$ 619,472
30734968	Treaty Sub: I/S BK-2	$ 1,840,418
30735090	Spare Transformer	$ 616,033
36734187	Southtown sub-I/S for Fuyau glass plant	$ 1,708,364
36735185	367-Centerville BK-2 Replacement Insurance claim	$ 910,043
44635312	446-Jeffersonville Sub BK-1 Failure Insurance Claim	$ 1,118,026
44635313	446-Jeffersonville Sub BK-3 Failure Insurance Claim	$ 585,710
44635314	446-Delco Kettering Sub BK-2 Failure Insurance Claim	$ 733,508

<u>Data Requests Set 12 Submitted 6/20/19</u>

12.1. Follow-up to Data Request response 5.1. Work Order 30734525 – Eaker Sub R/P BK 1. -$1,098,291. This work order is for replacement of a failed 69/12 kv transformer, MVA not indicated, and installation of a new foundation and oil plf.

- Estimated cost: $1.3 million (including $80,000 in cost of removal)
- Estimated Insurance reimbursement: $800,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded in UPIS was $598,000 greater than the estimate. (appox 119% over).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not, why not? (Response Received 7/3/19)

12.2. Follow-up to Data Request response 5.1. Work Order 30734516 – Mechanicsburg Sub R/P failed Bk 1.-$595,301. Replace 138/12kv 10/12.5 MVA Bank 1 Transformer.

- Estimated cost: $684,000 (including $25,000 in cost of removal)
- Estimated Insurance reimbursement: $183,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded in UPIS was $95,000 greater than the estimate (approx. 20% over).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not, why not? (Response Received 7/3/19)

12.3. Follow-up to Data Request response 5.1. Work Order 30734515 – Huber Hts Sub R/P failed Bk-2 - $797,362. This work order is for replacement of a failed 69/12 kv, 30MVA transformer and installation of a new foundation and oil pit.

- Estimated cost: $927 thousand (including $20 thousand in Cost of removal)
- Estimated Insurance reimbursement: $427 thousand
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded in UPIS was $297,000 greater than the estimate (approx. 59% over).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.4. Follow-up to Data Request response 5.1. Work Order 30734527 – Wilmington sub R/P failed BK-2 - $567,756. Replace failed 69/12kv. 12/16/20 MVA Transformer.

- Estimated cost: $706 thousand (including $23 thousand of Cost of removal).
- Estimated Insurance reimbursement: $206 thousand
- Estimated net cost of project: $506 thousand.

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. How old was the failed transformer?
d. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.5. Follow-up to Data Request response 5.1. Work Order 30734526 – Webster sub R/P Bk 2 - $1,097,299. Replace failed 69/12 kv transformer, MVA not indicated, and install new foundation and oil pit.

- Estimated cost: $1 million (including $60,000 of cost of removal)
- Estimated Insurance reimbursement: $500,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded to UPIS was $597,000 greater than the estimate (119%).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.6. Follow-up to Data Request response 5.1. Work Order 44635312 – Jeffersonville Sub BK 1- $1.118 million: Replace failed 69/12kv, 7.5/10.5 MVA transformer.

- Estimated cost: $1.381 million (including $35,000 of cost of removal).
- Estimated Insurance reimbursement: $861,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded to UPIS was $618,000 greater than the estimate (123%).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.7. Follow-up to Data Request response 5.1. Work Order 44635313- Jeffersonville Sub BK 3 - $585,000. Replace 69/12 kv 10/12.5 MVA Transformer.

- Estimated cost: $599,000 (including $10,000 of cost of removal)
- Estimated Insurance reimbursement: $99,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.

c. How old was the failed transformer?
d. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.8. Follow-up to Data Request response 5.1. Work Order 44635314 – Delco Kettering Sub BK-2. - $724,000. Replace failed 69/12kv 18/24/30 MVA transformer.

- Estimated cost: $784,000 (including $17,000 of cost of removal)
- Estimated Insurance reimbursement: $284,000
- Estimated net cost of project: $500,000

a. Did the Company receive the insurance reimbursement? If so, when, and what was the amount?
b. If the amount of the insurance reimbursement was less than the estimated amount, please provide the detailed explanation for why it was less.
c. Please explain why the actual project cost recorded to UPIS was $224,000 greater than the estimate (45%).
d. How old was the failed transformer?
e. Was it replaced with a capital spare? If not why? (Response Received 7/3/19)

12.9. Follow-up to Data Request response 5.1.Work Orders 30734878 and 30705090, Purchase 2 69/12kv, 30 MVA transformers - $1.235 million.

a. Has either of the two transformers been used? If so, please provide the details of when and where and for how long. (Response Received 7/3/19)

12.10. Follow-up to Data Request response 5.1. Work Order 3073491 – Indian Lake I/S Bk-1, $2.049 million: Install a 69/12kv, 30 MVA transformer and one 69kv and six 12kv breakers. The original estimated cost of the project was $1.546 million. The total estimated project cost after two supplements was $2.322 million. The supplements represent an increase of 50% over the original estimate.

- A revised estimated cost brought the total estimated project cost to $1.972 million, an increase of $426,000 from the original estimate. The Company explained the increase was due to higher than anticipated external labor costs and the need to install a mobile substation during construction.
  a. Please explain what caused the higher than anticipated external labor costs.
  b. What was the original estimate for external labor and what was the total actual external labor cost?
  c. Why was the use of a mobile substation not considered in the original scope of the project?
- An additional (2nd) revised estimated project cost brought the total estimated project cost to $2.322 million which was an increase of $350 thousand from the first revised cost.
  d. Please explain what caused the higher than anticipated internal labor costs.
  e. What was the original estimate for internal labor and what was the total actual internal labor cost?
  f. Why was it necessary to install a second mobile transformer, and why was that not considered in the original scope of the project? (Response Received 7/3/19)

12.11. Excess Deferred Income Taxes Refer to Paragraph 14 of the Company's Application filed on March 1, 2019, in Case No. 19-572-EL-UNC, to return Excessed ADIT benefits to customers.

> 14. The Protected Excess ADIT is treated, for ratemaking purposes, as a reduction to regulated rate base through a credit made to FERC Uniform System

of Accounts, Accounts 281, 282 and 283, less any debits in FERC Account 190 for ADIT assets (together, the "Deferred Income Tax FERC Accounts"). Beginning January 1, 2018 and continuing until DP&L rates are adjusted to begin crediting Protected Excess ADIT to customers, any amortization of Protected Excess ADIT will continue to increase a regulatory liability in accordance with the Commission COI Entry. As the Protected Excess ADIT relating to future amortization is returned to customers each year, the corresponding amounts will be amortized out of the Deferred Income Tax FERC Accounts. Likewise, as the Protected Excess ADIT that was amortized into a regulatory liability is returned to customers each year, that regulatory liability account will be debited.

a) The quarterly DIR filings to date do not reflect "for ratemaking purposes, a reduction to regulated rate base" for the Protected Excess ADIT. Had the offset been included, what is the impact on DIR revenues for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018?
b) If the Company collected greater revenues than it would have accrued had the Protected Excess ADIT been reflected in rate base in any of the periods, how does the Company propose to handle the overcollection? (Response Received 7/3/19)

Accumulated Deferred Income Taxes

The following questions refer to calculations in DR 01-19a, Attachments 1 through 6. If the Company agrees with any of the issues identified in the questions below, please provide updated workpapers to verify BRCS's computation and expectations of the ADIT balances reflected in the DIR revenue requirement.

12.12. Refer to **DR 01-19a**, worksheet **DIR Page 4 DFIT** in **Attachments 1**, **2**, and **3**. Explain why the book basis in Cell C12 does not rollforward to the total plant, net of retirements, balance on which the tax basis is derived.

January 31, 2019 DIR Filing:

	Book Basis @ 9/30/2015	Retirements	Book Basis @ 1/31/2019
Land	$ 1,882,307	-	$ 1,882,307
Land Rights	23,493,716	-	23,493,716
Depreciable	1,319,861,229	(34,052,115)	1,285,809,114
Total Plant	1,345,237,252		1,311,185,137
	1/ 1,345,230,954		2/ 1,307,011,624
Difference	*6,298*		*4,173,513*

1/ Quarterly DIR Filing, 1/31/19, p. 2 of 11, Line 21, Column D
2/ Blue Ridge DR 01-19a Attachment 1, Worksheet DIR Page 4 DFIT, Cell C12

August 31, 2018 DIR Filing:

	Book Basis @ 9/30/2015	Retirements from 9-30-15 thru 8-31-18	Book Basis @ 8/31/2018
Land	$ 1,882,307	-	$ 1,882,307
Land Rights	23,493,716	-	23,493,716
Depreciable	1,319,861,229	(31,643,127)	1,288,218,101
Total Plant	1,345,237,252		1,313,594,125
	1/ 1,345,230,954		2/ 1,310,309,691
Difference	*6,298*		*3,284,434*

1/ Quarterly DIR Filing, 8/31/18, p. 2 of 11, Line 21, Column D
2/ Blue Ridge DR 01-19a Attachment 2, Worksheet DIR Page 4 DFIT, Cell C12

June 30, 2018 DIR Filing:

	Book Basis @ 9/30/2015	Retirements from 9-30-15 thru 6-30-18	Book Basis @ 6/30/2018
Land	$ 1,882,307	-	$ 1,882,307
Land Rights	23,493,716	-	23,493,716
Depreciable	1,319,861,229	(29,532,897)	1,290,328,332
Total Plant	1,345,237,252		1,315,704,355
	1/ 1,345,230,954		2/ 1,312,942,354
Difference	*6,298*		*2,762,001*

1/ Quarterly DIR Filing, 6/30/18, p. 2 of 10, Line 21, Column D
2/ Blue Ridge DR 01-19a Attachment 3, Worksheet DIR Page 4 DFIT, Cell C12

a) Refer to **DR 01-19a**, worksheet **DIR Page 4 DFIT** in **Attachments 1**, **2**, and **3**. Cell E12 includes the tax basis for land accounts 3601 and 3602 as of September 30, 2015. The reported book basis in the corresponding DIR filings for the same period does not match the tax workpaper. Explain the difference.

Acc	Description	Qtrly DIR Filing p. 2 of 11	DR 01-19a Att 1	Difference
3601	Substation Land - NONE	1,879,925	1,906,570	26,645
3602	Other Land - NONE	2,382	2,382	-
	Total	**1,882,307**	**1,908,952**	**26,645**

b) (Response Received 8/8/19)

12.13. Refer to **DR 01-19a**, worksheet **Land Rights** in **Attachments 1**, **2**, and **3**. Explain the reason for applying a factor of 0.6768 to the book basis to derive the tax basis. What is the source of the numerator ($1,453,260,487) and denominator ($2,147,238,510) used to develop the factor? (Response Received 8/8/19)

12.14. Refer to **DR 01-19a**, worksheet **WP DIR-1 pg 5** in **Attachments 4**, **5**, and **6**. Explain why the 0.6768 factor applied to the book basis to derive the tax basis in **DR 01-19a Attachment 1**, **2**, and **3** does not apply to plant additions after September 30, 2015. (Response Received 8/6/19)

12.15. Refer to **DR 01-19a Attachment 1**, worksheet **Depreciable**. Verify the tax depreciation rate in cell P35 should reference F19, rather than F20.

=ROUND(+O35*SUM('Tax Depreciation Rates'!$B$19:$F$19),0)-(O35***'Tax Depreciation Rates'!F20***11/12) (Response Received 8/6/19)

12.16. Refer to **DR 01-19a Attachment 1**, worksheet **Depreciable**. Verify the Retirements reported under Cell M12 are for the period from 9-30-15 thru 1-31-19 (not 8-31-18). (Response Received 8/6/19)

12.17. Refer to **DR 01-19a Attachment 2**, worksheet **Land Rights**. Verify the input for Cell N12 should reflect the month of August (8), not March (3). (Response Received 8/6/19)

12.18. Refer to **DR 01-19a Attachment 2**, worksheet **Depreciable**. Verify the input for Cells P18 through P35 should apply a factor of 4/12 to derive the prorated tax reserves for August 31, 2018. (Response Received 8/6/19)

Cell P18
=ROUND(+O18*SUM('Tax Depreciation Rates'!$B$19:$V$19),0)-(O18*'Tax Depreciation Rates'!V19***9/12**)

12.19. Refer to **DR 01-19a Attachment 2**, worksheet **Depreciable**. Verify the tax depreciation rate in cell P35 should reference E19, rather than E20. (Response Received 8/6/19)

=ROUND(+O35*SUM('Tax Depreciation Rates'!$B$19:$E$19),0)-(O35***'Tax Depreciation Rates'!E20***9/12)

12.20. Refer to **DR 01-19a Attachment 3**, worksheet **Land Rights**. Verify the input for Cell N12 should reflect the month of June (6), not March (3). (Response Received 8/6/19)

12.21. Refer to **DR 01-19a Attachment 3**, worksheet **Depreciable**. Verify the input for Cells P18 through P35 should apply a factor of 6/12 to derive the prorated tax reserves for June 30, 2018. (Response Received 8/6/19)

Cell P18
=ROUND(+O18*SUM('Tax Depreciation Rates'!$B$19:$V$19),0)-(O18*'Tax Depreciation Rates'!V19***9/12**)

12.22. Refer to **DR 01-19a Attachment 3**, worksheet **Depreciable**. Verify tax depreciation rate in cell P35 should reference E19, rather than E20. (Response Received 8/6/19)

=ROUND(+O35*SUM('Tax Depreciation Rates'!$B$19:$E$19),0)-(O35***'Tax Depreciation Rates'!E20***9/12)

12.23. Refer to **DR 01-19a Attachment 4**, worksheet **WP DIR-1 pg 5**. Explain why the book basis of the plant additions after 9/30/2015 (Cell H58) do not reflect the retirements included in deriving the tax basis (Cell L56) when calculating the DIR revenue requirement in **DR 01-3 - Attachment 1**. (Response Received 8/6/19)

12.24. Refer to **DR 01-19a Attachment 4**, worksheet **WP DIR-1 pg 5**. Cells Q52 through AI52 multiplies cell **$L$51** by the tax depreciation rate. Verify the formula should reference cell **$L$52** instead. (Response Received 8/6/19)

12.25. Refer to **DR 01-19a Attachment 4**, worksheet **WP DIR-1 pg 5**. The formula in Cells Q59 through AI59 includes a summation of plant vintages from 2015 through 2018. Verify the formula should sum plant vintages through 2019. (Response Received 8/6/19)

12.26. Refer to **DR 01-19a Attachment 6**, worksheet **WP DIR-3 pg 5**. Explain the following differences between the reserve balances presented in Cells C10 through C20, compared to cells G10 through G20. (Response Received 8/6/19)

	Original Cost	Accumulated Reserve	Monthly Depreciation
3601	-	-	-
3603	-	-	-
3610	-	(30.83)	-
3620	-	(3,312.96)	-
3640	-	(9,308.32)	-
3650	-	(5,682.67)	-
3660	-	(93.94)	-
3670	-	(4,590.40)	-
3680	-	(58,617.89)	-
3691	-	(9,331.17)	-
3692	-	(89,760.08)	-
3700	(18,463,261.20)	1,504,755.79	(50,158.53)
3711	-	(1,135.16)	-
	(18,463,261.20)	1,322,892.35	(50,158.53)

12.27. Refer to **DR 01-3 - Attachment 2**, worksheets **Acumulated DFIT** and **Plant in Service**. Explain the discrepancy between the sum of the book reserves (Cells G16, G44) as of June 30, 2018, compared to the total accumulated reserve reported under Plant in Service (Cell I68). (Response Received 8/6/19)

	DIR Model Worksheet	Amount as of June 30, 2018	Amount as of August 31, 2018	Amount as of January 31, 2019
Book Reserve for Surviving Assets Unitized as of 9/30/2015	Acumulated DFIT	$ 706,273,132	$ 712,185,836	$ 722,258,332
Book Reserve (Capital Additions After 9/30/2015)	Acumulated DFIT	15,356,992	13,745,348	16,514,949
		$ 721,630,124	$ 725,931,184	$ 738,773,281
Accumulated Reserve	Plant In Service	$ 721,571,512	$ 725,931,184	$ 738,773,281
	Difference	*58,612*	*0*	*(0)*

Data Requests Set 13 Submitted 6/24/19

13-1. Follow-up to Data Request response Set 1.33a. The Company response indicated that the Insurance reimbursements received were credited to FERC account 924 (Property Insurance). A jurisdictional allocation factor of 24.54% was applied to the account in the Company's most recent Distribution base rate case.

a. Please explain how the Insurance Reimbursements reduced the applicable capital work orders for the replacement of the assets that were closed to UPIS and included in the DIR.
b. Why would any of the Insurance reimbursements related to a capital activity be charged against FERC 924 (Property Insurance)?
c. Does the Company agree that the cost to replace the damaged assets represents a capital activity and that the cost that should be included in the DIR is the total cost of the projects, including deductible, less any Insurance reimbursements? If not, why not? (Response Received 7/3/19)

Data Requests Set 14 Submitted 7/15/19

14-1. Follow-up to Data Request response BRDR 13-1, parts a and b. The Company response stated in part that the jurisdictional share of the insurance reimbursements is treated as a cost of service credit in the Company's most recent distribution rate case. The insurance recoveries are treated as a reduction of property insurance expense, and there is no impact on DPL Inc.

a. Please provide the rate case number and specific language within the rate case that allows the Company to treat insurance reimbursements as a cost of service credit.
b. Please explain how MVIC and DP&L, both being subsidiaries of DPL, relates to how insurance recoveries are treated for accounting purposes.
c. What are the FERC guidelines (18 CFR) applicable to the accounting for Insurance Reimbursements related to the replacement of capital assets? (Response Received 8/6/19)

14-2. Follow-up to Data Request response BRDR 1-33. The Company response indicates that each of the insurance recoveries was credited to account 924 (Property Insurance) and an allocation factor of 24.54% was applied to that account in the Company's most recent rate case.

a. Please provide the rate case number and specific language within the rate case that allows the Company to apply an allocation factor of 24.54%.
b. What does the 24.54% allocation factor represent and how is it calculated?
c. Has the allocation factor been changed since the last rate case? If yes, please provide all changes in the rates. If not, why not?
d. Does the Company agree that the insurance recoveries relate to 100% Distribution assets owned by DP&L? If not, why not?
e. How was the cost of removal of the damaged or destroyed assets accounted for?
f. How was any salvage accounted for?
g. How were the insurance deductibles accounted for?
h. How does the customer recover the return on and of the capital investments in the assets that were prematurely retired before reaching their Average Service lives?
i. How do the retirements of damaged assets impact the Accumulated Reserve for Depreciation and ultimately the accrual rates? (Response Received 8/6/19)

Data Requests Set 15 Submitted 7/17/19

15-1. Follow up to Data Request response BRDR 12-4, d. The Company response indicates that the failed Transformer was removed, repaired, and re-installed.

a) What was the accounting for the removal, repair, and re-installation of the failed Transformer?
b) Was the repair considered a Capital activity? If so why? If not why not?
c) If the repair and re-installation was considered capital what was the average service life of the old Transformer and the average service life of the repaired Transformer?
d) If the repaired Transformer was not replaced with a Spare how did the Substation continue to operate?
e) If the Substation did not operate how long was it off line? (Response Received 8/6/19)

Data Requests Set 16 Submitted 8/5/19

16-1. Please refer to the Company's response to Blue Ridge DR 12-11(a), wherein the reply states, "Per the Company's Application filed in Case No. 19-572-EL-UNC, DP&L proposes to credit the Protected Excess ADIT as an offset to the DIR revenue requirement. Per DP&L's filing, the amount of Protected Excess ADIT amortized on the Company's books for 2018 was $686,455. Since DP&L's DIR revenue requirement has remained significantly above the established revenue caps, reducing the DIR revenue requirement by $686,455 would not impact the revenue levels collected for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018."

a) The response addresses the impact of the EDIT amortization only. Wouldn't inclusion of the EDIT balance in DIR rate base also impact the revenue requirement before factoring in the cap?

b) Provide the following balances and calculations (in electronic format with formulas intact) for the periods ended January 31, 2019, August 31, 2018, and June 30, 2018:

i) Proforma EDIT balance in DIR rate base;
ii) Proforma EDIT amortization flowing through DIR tax expense; and

c) Proforma impact on DIR revenue requirement before cap. Response Received 8/22/19)

Data Requests Set 17 Submitted 8/7/19

17-1. Follow-up to Data Request BRDR 8.1, part b. Blue Ridge requested approvals regarding the establishment of Transformer Cutouts as separate retirement unit of property. The Company's response did not mention the approvals.

d) What Financial and Engineering approvals are necessary to establish a new retirement unit of property either as part of an existing larger retirement unit of property or an entirely new retirement unit of property?
e) Does the Company have a written policy regarding how new retirement units of property can be established and added to the retirement unit catalog? (Response Received 8/8/19)

Data Requests Set 18 Submitted 8/28/19

18-1. Reference DPL Response to Data Request 5.1 Attachment 2 and 3. Please explain why the following projects had retirements recorded but no Cost of Removal. (Response Received 8/29/19)

Project	Project Description	ADDITION	Retirement Unit
15210301	ELE METERS & DEVICES-DIV	$8,600,673	0416-0
30710081	Service Upgrades	$46,959,100	0412-0
30710281	DISTRIBUTION LINE TRANSFORMERS, REGULATORS & DEVICES	$43,537,692	0406-2500
31028287	GF1204 - BL# D6648-Extend two more phases into Sandy Run	$83,665	0330-41
31031754	NON RES UPGRADE 3PH SECONDARY TO PRIMARY VOLTAGE	-$41,426	0330-41
31033377	Removing DP&L facilities	$2,923	0372-0
46110389	Land Purchase and retire	$26,645	0925-0

APPENDIX D: WORK PAPERS

Blue Ridge's workpapers are available on a USB thumb drive and were delivered to the PUCO Staff per the RFP requirements. Workpapers that support Blue Ridge's analysis are listed below.

- ASU_2016-02_Section_A.pdf
- ASU_2017-07.pdf
- Ohio Department of Taxation 2018 Annual Report.pdf
- PUCO 17 DP&L Distribution Tariffs.pdf
- WP 15-1830-EL-AIR Approved Depreciation Rates.pdf
- WP 18-1468-EL-RDR DPL DIR Reconciliation, Sensitivity, Sample Size and PULLING Sample.xlsx
- WP Blue Ridge DR 09-02 Attachment 1 - CONFIDENTIAL.xlsx
- WP DPL DIR Audit Work Order Testing Matrix FINAL.xlsx
- WP DR 1.4 Gross Plant Balances.xlsx
- WP Effective Tax Rates Blue Ridge DR 01 - 19c Attachment 1.xlsx
- WP Impact of Adjustments Blue Ridge DR 01-3 - Attachment 5_013119 08-28-19.xlsx
- WP Rev Req 1-31-19 Blue Ridge DR 01-3 - Attachment 5.xlsx
- WP 15-1830-EL-AIR Staff Report Sch B-2.1 Gross Plant.pdf
- WP 15-1830-EL-AIR Staff Report Sch B-3 Reserve.pdf
- WP 15-1830-EL-AIR Staff Report Sch B-3.2 Depreciation Rates.pdf
- WP 15-1830-EL-AIR Stipulation Base Distribution Revenues.pdf
- WP 15-1830-EL-AIR Stipulation Exhibit 3 DIR Rev Req Format.pdf
- WP Effective Tax Rate Blue Ridge DR 01 - 19c Attachment 1.xlsx
- WP Other Riders Review for Plant Recovery.xlsx
- WP Var Analysis Blue Ridge DR 01-4 Attachment 1.xlsx

Case No. 15-1830-EL-AIR Data Responses

- Blue Ridge 1.8 CONFIDENTIAL
- Blue Ridge 1.9

Interview Notes

- Case No. 15-1830-EL-AIR
    - DPL Interview - FERC 7 Factor test (DR 11 Response)(R1) Approved 6-21-Final.docx
    - DPL Interview - History of property accounting Approved 6-21-Final.docx
    - DPL Interview - Time line (DR 6 response) Approved 6-21- Final.docx
- Case No. 19-0439-EL-RDR
    - DPL Interview - Reconciliation REVIEWED AND APPROVED by Company.docx

Field Visit Photos and Observation Notes