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PUBLIC VERSION

REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDIT OF THE FUEL ADJUSTMENT CLAUSE AND THE ALTERNATIVE ENERGY RIDER OF THE DAYTON POWER AND LIGHT COMPANY

Case No. 16-0224-EL-FAC

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1 EXECUTIVE SUMMARY

The Dayton Power and Light Company (DP&L) is a public utility as defined in Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of the Public Utilities Commission of Ohio (PUCO). Under an approved stipulation, DP&L's rates were set pursuant to a rate stabilization plan (RSP) from January 1, 2006 through December 31, 2008 (RSP Stipulation). Under the RSP, DP&L's fuel rate was fixed and included in the base retail generation rates.

On October 10, 2008, DP&L filed an application for a standard service offer (SSO) in the form of an electric security plan (ESP), pursuant to Section 4928.143, Revised Code. A stipulation (the ESP Stipulation), approved by the PUCO (the ESP Order), extended the DP&L rate plan through December 31, 2012 (subsequently extended by a year) and allowed DP&L among other things to implement a by-passable fuel recovery rider to recover jurisdictional fuel and purchased power costs consistent with the provisions of Senate Bill 221. DP&L is required to make quarterly filings related to its fuel and purchased power costs and have its costs subject to an annual audit by an independent third-party or PUCO Staff.

A second ESP (ESP2) for DP&L was approved on September 4, 2013 in Case No. 12-426-EL-SSO et al for the period beginning January 1, 2014 and ending May 31, 2017. The order established a schedule under which DP&L would conduct auctions to procure power to serve its standard service offer customers, which transitioned to 100 percent by the end of the ESP period. As described below, the schedule was subsequently accelerated. At the end of the ESP, the company is expected to have divested all of its generation assets. DP&L will establish a service stability rider (SSR) in order for it to provide a stable standard service offer as it divests its generation assets during the term of the ESP. The SSR will collect $330 million from Jan. 1, 2014, through Dec. 31, 2016. DP&L will have the option to seek future approval from the PUCO for a five month extension not to exceed $45.8 million.

Several parties filed for rehearing and on March 19, 2014 the PUCO determined that DP&L's phase-in to full competitive pricing for SSO generation requirements should be accelerated. The PUCO based its ruling upon DP&L's February 25, 2014 supplemental filing in a separate proceeding (Case No 13-2420-EL-UNC) that addressed the company's proposal to transfer or sell its generating assets. In that supplemental filing, DP&L indicated that the company and "its indirect parent, The AES Corporation (AES), have recently begun to evaluate the transfer of DP&L's generation assets to an unaffiliated third party through a potential sale. A sale to a third party could occur as early as 2014." The PUCO, therefore, determined that the competitive bid process (CBP) should account for 60 percent of load beginning January 1, 2015 (up from 40 percent); and, 100 percent of load beginning January 1, 2016 (up from 70 percent). Also, the PUCO determined on rehearing that the deadline for the company to divest its generation should be no later than January 1, 2016. In June, the PUCO further modified its orders and established December 31, 2016, as the date by which DP&L will complete the sale or transfer of its generation assets.

In July 2014, AES announced that it planned to retain DP&L's generating assets and it would do so by transferring them to an affiliate by January 1, 2017, consistent with one of the allowed options in the latest approved DP&L Electric Security Plan (ESP). AES indicated this strategy was preferable because it allowed the ultimate sale value to benefit from a recovery of power prices.

In September 2014, the PUCO approved DP&L's plan to sell most of its generation to an affiliate. The PUCO indicated that DP&L needs to at least try to market its stake in the coal-fired Ohio Valley Electric Cooperative (OVEC), despite numerous challenges associated therewith.

With respect to the fuel cost recovery, the current ESP provides for both a Fuel Adjustment Clause (FAC) and Alternative Energy Rider (AER) through the term of the second ESP. The FAC Rider is based upon a least cost stacking methodology for jurisdictional customers consistent with the prior ESP with the exception that the DPL Energy Resources, Inc. (DPLER), DP&L's competitive retail electric supplier, load is now excluded. DP&L continues to be required to make quarterly filings related to its fuel and purchase power costs and have its costs subject to an annual audit by an independent third-party or PUCO Staff.[1]

The PUCO solicited proposals for the performance of the FAC Rider and AER audits of the years 2015. Energy Ventures Analysis, Inc. (EVA) and its subcontractor, Larkin & Associates PLLC (Larkin) (collectively, the EVA Team) were selected by the PUCO to perform the desired management/performance and financial audits. EVA and Larkin had previously performed the audits of 2010, 2011, 2012, 2013, and 2014.

A Stipulation and Recommendation (2014 FUEL Rider Stipulation) was entered into by the parties relative to issues raised regarding DP&L's FUEL Rider for the audit period January 1, 2014 through December 31, 2014 on May 10, 2016. A hearing on the 2014 FUEL Rider Stipulation was held on June 27, 2016. The Commission approved the Stipulation on August 3 ,2016.

The 2014 FUEL Rider Stipulation states the following:

1. Upon approval of this Stipulation by PUCO order, DP&L will credit $16,042 for 2014 to SSO customers relating to the proceeds DP&L received on 2014 related to the process of refined coal at Stuart. Additionally, DPL (sic) will credit 100% of the jurisdictional share of any proceed DP&L received related to the process of refined coal at Stuart in any given year until the FAC mechanism ends. The 2015 credit will be determined after an audit and verified by an outside auditor in the 2015 FAC case.
2. DP&L will continue test burns of higher quality coal at Stuart and will evaluate effects on forced outage rates.

[1] DPLER was sold to IGS Energy in early 2016.

3. DP&L's internal audit group will continue to monitor and periodically assess whether there are any large deviations between book and physical inventories (defined as an eight percent variance bas upon book inventory and a two percent variance based upon burn and the variance must be greater than 5,000 tons). When there are large deviations, DP&L shall undertake an analysis to identify root causes and, to the extent appropriate, develop an action plan.
4. DP&L will conduct a full review and include consideration of prudence issues if buy-down costs associated with Conesville #4 contract are passed through to customers.
5. DP&L will evaluate whether any changes can reasonably be made to its Master Agreement template or Transaction Confirmation template as it relates to coal supply agreements. DP&L will evaluate its credit policy with regard to coal procurement. The evaluation will consider and update the amount of coal consumed by DP&L operated plant, the financial condition of each counterparty, and all other factors deemed relevant. DP&L agrees that the scope of the next audit includes a review of whether procurements in 2015 were in compliance with the credit policy.
6. DP&L will credit $17,625 to the Fuel Rider relating to the Patriot payment received in 2015 based upon the dates when the money was due, not received. This amount represents the amounts received by DP&L allocated on plant ownership share and retail jurisdictional share.

Due to the timing of the Stipulation approval, a number of the items were not completed during the audit period.

FUEL Rider Background

DP&L's fuel adjustment clause, the FUEL Rider, is the mechanism that is being used to recover DP&L's prudently incurred fuel and purchased power. The FERC accounts included in the FUEL Rider are as follows:

- Accounts 411.8 and 411.9 (Gains and Losses from Disposition of Allowance) – the gains or losses from the sale of allowances.
- Account 421 – Miscellaneous Non-Operating Income.
- Account 426 – the realized loss on purchased power.
- Account 456 – for gains and losses on coal sales and heating oil derivatives.
- Account 501 (Fuel) – the cost of fuel and transportation for generating electricity.
- Account 509 (Allowances) – the cost of emission allowances related to emissions of sulfur dioxide (SO_2) and nitrous oxide (NOx).
- Account 547 (Non-Steam Fuel) – the cost of fuel used in non-steam applications such as simple cycle gas peaking plants.
- Account 555 (Purchased Power) – the cost of purchased electricity including both energy and demand or capacity charges.

- Account 565 – transmission costs associated with certain purchased power. (No fuel-related charges were made from this account in calendar year 2015.)

Audit of the FUEL Rider

The audit direction was to follow the general guidance provided for this work in former Appendix D and Appendix E to Chapter 4901:1-11, Ohio Administrative Code (O.A.C.). The audit period includes the actual cost for the Rider FAC for the months January 1, 2015 through December 31, 2015. The audits should follow the guidelines in Section L of Appendix D and Section M of Appendix E to former Chapter 4901:1-11, O.A.C.

Audit Approach

EVA and Larkin conducted this audit through a combination of document review, interrogatories, site visits, and interviews. The EVA Team visited the Killen power plant on June 27, 2016. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-1 on June 28th and 29th. DP&L regulatory staff and PUCO Staff also attended interviews.

Exhibit 1-1. Interviews Conducted

Topic	Department	Participants
Generation & Plant Operations	Generation	[redacted]
Settlements/Accounting	Settlements	
Internal Audit	Internal Audit	
Fuel Procurement	Commercial Operations & Fuel Procurement	
Merchant Portfolio Strategy	Commercial Strategies	
Commodity Risk Management	Treasury	
Risk Management	Risk Management	
Forecast Data	Portfolio Analytics	
Regulatory Operations	Regulatory Operations	
Accounting for Fuel Rider and AER	Accounting	

Major Management Audit Findings

1. In 2015, DP&L purchased 5.8 million tons of coal at an average delivered price of $2.19 per MMBtu. This volume is about 1.1 million tons lower than the volume purchased in 2014. On a dollars per MMBtu basis, the price is about the same.

2. In 2015, generation year on year declined by 6.6 percent overall and 4.3 percent for DP&L operated plants. With the exception of Miami Fort, all of the coal plants in which DP&L either operates or is a non-operating partial owner had lower generation in 2015 compared to 2014.

3. The Stuart power plant operations continue to be challenged. The capacity factor in 2015 fell below [redacted] for which data were readily available and perhaps longer. Among other things, DP&L looked to [redacted] A number of test burns were conducted throughout the year.

4. DP&L's 2015 coal purchase costs as reported to the Energy Information Administration (EIA) on Form 923 are competitive with other Ohio and nearby utilities for which data are available.

5. The average delivered prices of coal to the Killen and Stuart Stations in 2015 are competitive with the average delivered cost to nine utility plants which receive coal by barge that are equipped with scrubbers, burn high sulfur coals, and that are proximate to Killen and Stuart.

6. In 2015, a Director of Commercial Operations was named. The DP&L fuel procurement organization reports to this Director.

7. DP&L conducted one formal Request for Proposal (RFP) in 2015. This RFP, conducted in August 2015, DP&L did not indicate in the RFP package its [redacted]. Nor did DP&L indicate in the RFP its intention to [redacted]. This may have limited the quality of the bid response. The level of responses was inconsistent with the amount of coal available in the market.

8. DP&L made four purchases from the August 2015 RFP. It purchased Central Appalachia coal from [redacted] [redacted] and [redacted] tons from [redacted] for Killen.

9. DP&L also made two spot purchases in 2015, neither of which was from a solicitation and neither of which was documented with a justification.

10. DP&L reduced volumes under two [redacted] contracts (one for lower quality coal and one for higher quality coal) and entered into [redacted].

11. DP&L was [redacted]. When DP&L entered into the agreement for this coal [redacted] While this provision is not standard for contracts for coal [redacted] DP&L sold the balance of the commitment [redacted] at a price that was [redacted] per ton below the contract price.

12. No changes were made in the credit policy in 2015 with respect to coal supplier concentration.

13. DP&L purchased [redacted] percent of its 2015 supply from a single producer. Two other producers accounted for almost [redacted] percent of its 2015 supply.

14. The inventory levels ranged between [redacted] days at Stuart and [redacted] days at Killen of maximum burn during the audit period. Inventory levels were higher than target inventory levels throughout the audit period but consistent with industry levels due to the low coal burn experienced in 2015.

15. Physical inventories were conducted in 2015 at Killen and Stuart. The difference between book inventory and physical inventory at Stuart were within the tolerances. The difference between book inventory and physical inventory at Killen was not within tolerance with respect to percent of Book but was in tolerance with respect to percent of Burn. As a result, a root cause analysis was not required..

16. In 2013, DP&L finalized four agreements with [redacted]. DP&L indicated that virtually all of the coal consumed at Stuart in 2015 [redacted]. In the 2014 Fuel Rider Stipulation, DP&L agreed to flow the jurisdictional revenues through the 2015 Fuel Rider.

17. DP&L started 2015 with a considerable inventory of Non-Solar RECs due to lower than anticipated requirements. DP&L took delivery of [redacted] non-solar RECs from the market, took delivery of [redacted] solar RECs from the market and obtained [redacted] RECS from Yankee. DP&L has commitments for a small share of its expected requirement for RECs going forward.

Management Audit Recommendations

1. DP&L should be required to submit documentation to the PUCO of DP&L's compliance with all elements of the Stipulation from Case No. 15-42-EL-FAC.

2. The jurisdictional share of the incremental cost of the [redacted] coal associated with the [redacted] should not be recoverable through the Fuel Rider. Based upon the information provided on quality, [redacted]

3. The jurisdictional share of the losses associated with the sale of the [redacted] coal should not be recoverable through the Fuel Rider. [redacted]

4. DP&L should develop and implement a REC procurement strategy. At a minimum, this strategy should consider the following:

    - Expected REC requirements (solar and non-solar) by Ohio utilities
    - Impact of future actual and potential Federal/state RPS requirements on REC availability
    - Expected REC supply from qualifying sources
    - Opportunities to develop a portfolio risk management strategy wherein commitments for future REC requirements can be layered in
    - Cost of and opportunity for long-term commitments for RECs

Financial Audit Findings

Fuel Rider

1. DP&L's Fuel Rider deferral (i.e., the 2015 undercollection) has been impacted by customer supplier switching that has occurred. Larkin reviewed a schedule provided in response to LA-2015-83 that reflected statistical data for the 2015 review period. This schedule indicated that over the course of 2015 that (1) DP&L gained [redacted] customers primarily in the residential and residential heat customer classes, (2) [redacted] customers, and (3) other suppliers' customer bases increased by [redacted] customers.
2. DPLER is no longer an affiliate of DP&L and was sold on January 1, 2016.
3. In preparing its Fuel Rider sales forecasts for its quarterly Fuel Rider filings affecting 2015, DP&L reflected the impact of known customer supplier switching.
4. Pursuant to Additional Commitment B in the Stipulation and Recommendation dated December 5, 2012, DP&L created and used a trend line analysis for forecasting and validating its sales forecasts, including the impact of customer switching. DP&L stated that due to seasonality and other factors, monthly forecasts will vary and as such, a simple trend line analysis will not be reflective of a seasonal quarter
5. DP&L incorporated customer switching into its forecast by observing the known level of switching at the time the forecast is created then projects incremental switching to be consistent with the rate observed in recent months.
6. In its Opinion and Order dated September 4, 2013 in Case No. 12-426-EL-SSO, et al, the Commission directed that the Reconciliation Rider be divided into a by-passable ("RR-B") and a non-bypassable ("RR-N") rider.
7. DP&L's deferred fuel in account shows an undercollection of [redacted] as of December 31, 2015.
8. DP&L has reasonable procedures in place to account for and collect plant fuel burn related information.
9. Based on the results of physical inventories, DP&L made adjustments to its coal inventory balances at the Stuart and Killen Stations during 2015. The adjustment related to Stuart increased coal inventory (and reduced Fuel expense) by [redacted] which reflects DP&L's ownership share. The adjustment to Killen increased coal inventory (and reduced Fuel expense) by [redacted], which reflected DP&L's ownership share.
10. DP&L did not conduct any investigations as to the reasons for the coal inventory variances at Stuart and Killen in 2015. The Company stated that, [redacted] These conditions were not exceeded with respect to either the Stuart or Killen 2015 coal inventory variances. As a result, DP&L has no plans to conduct any investigations into the reasons for the coal inventory variances at Stuart or Killen.

11. During 2015, DP&L made six transfers of coal from Stuart to Killen. There were two transfers in January and one transfer each in the months of August, October, November, and December. These transfers resulted in: [redacted]. Larkin traced all the gains and losses from these coal transfers to the general ledger. Due to the stacking of costs in the months in which these coal transfers occurred, according to the monthly workbooks, an average of approximately 99.5% of these gains and losses were allocated to wholesale sales and thus were not flowed through the Fuel Rider.

12. The joint owners' share of the gains and losses associated with the coal transfers were billed to them, so there was no impact of the joint owners' share of the gains and losses on the Fuel Rider.

13. DP&L is appropriately accounting for the cost of demurrage as part of the transportation cost of delivering coal to the generating plants. For 2015, DP&L had demurrage costs of [redacted], which was substantially higher than in both 2013 and 2014. DP&L explained that the reasons for the substantial increase in demurrage costs is that the 2015 demurrage charges were adversely affected by lower than forecasted dispatch of the Stuart units (including effects of market dispatch, unplanned outages, and derates), unloader availability, accumulating barges to unload test coals directly to the units and the disruptive effect to unloading generally of giving unloading priority to certain coals during tests.

14. As described in the response to LA-2015-44, DP&L had taken various actions in 2015 throughout the year to manage demurrage costs.

15. In conforming to Item No. 9 from the Stipulation and Recommendation dated October 5, 2011 from the 2011 review, DP&L prepared explanations for differences between forecast and actual Fuel Rider revenues and between forecast and actual Fuel Rider costs in 2015.

16. Larkin reviewed DP&L's audit trail for Fuel Rider includable costs, focusing on the test month of July 2015 and also selectively verified actual cost contained in DP&L's Reconciliation Adjustments (RAs) to supporting documentation. We conclude that DP&L has maintained adequate audit trail documentation for 2015 and for its Reconciliation Adjustments.

17. The Company reflected a loss on the sale of Fuel oil in the amount of [redacted] in March 2015 that related to the Beckjord plant. The Beckjord plant was operated by Duke and was closed in September 2014. DP&L had allocated 100% of that loss to DP&L retail customers, thus the entire loss flowed through the Fuel Rider. DP&L subsequently stated that it be would more appropriate to allocate this loss based on the historical split between retail and wholesale.

18. Larkin calculated a retail allocation of [redacted] for the March 2015 Beckjord fuel oil sales loss, which was derived by taking the monthly retail and wholesale allocation percentages from 2012, 2013 and 2014 and calculating a three-year average for the retail

portion. DPLER was included in the 2012 and 2013 retail amounts. Larkin removed the 2012 and 2013 retail portions attributable to DPLER. Allocating [redacted] of the [redacted] to non-DP&L retail would reduce 2015 Fuel Rider includable costs by [redacted].

19. The monthly Excel workbooks include a tab titled ".19 GL on Purchased Power". For the months of January through June as well as November 2015, the Company included net derivative losses totaling [redacted]. Of this amount, [redacted] was allocated to DP&L retail and $1,348 was allocated to wholesale sales. However, in response to LA-2015-2-6, DP&L stated that these transactions should have been allocated 100% to wholesale sales. An adjustment to reduce 2015 retail fuel costs by [redacted] is needed to reflect the proper allocation to wholesale of these derivative losses.

20. Pursuant to Section J of the Optimization Provisions from the Stipulation and Recommendation dated December 5, 2012, DP&L agreed to cease charging back 75% of any fuel optimization transactions to the Fuel Rider. DP&L confirmed that there were no costs related to Optimizations included in DP&L's Fuel Rider for any months of 2015.

21. DP&L made five adjustments to Fuel Rider costs during the months of February, March, June, and July 2015 in the amounts of ($14,692), ($5,544,543), [redacted], ($1,719,204) and [redacted], respectively. These adjustments related to(1) a disallowance discussed in the PUCO Order from the 2013 Fuel Rider audit, (2 and 4) reclassifications of the Fuel deferral balance which exceeds the 10% threshold pursuant to the RR-N that was approved by the PUCO in its Order and Opinion dated September 4, 2013 in Case No. 12-0426-EL-SSO et al, (3) a revision to purchased power MWh and dollars in April 2015, and 5a carrying cost correction related to the previous adjustment. The Commission approved these specific adjustments in its Finding and Orders dated May 28, 2014, August 20, 2014, and November 20, 2014.

22. During the interviews on June 29, 2016, the manager of Internal Audit discussed the auditing and sampling procedures used in conducting an internal audit of the Fuel Rider. The Company stated that it used a random sampling "tool" to select the samples related to the Fuel Cost recovery audit and the sampling parameters are automatically input into the system.

23. Larkin reviewed a sampling of customer billing information to test whether DP&L had accurately applied the Fuel Rider rates. No exceptions were noted. The Company's internal audit group performed similar testing in its internal audit of the Fuel Rider.

24. LA-2015-47 asked the Company to provide the following information: "For purchases of power recorded in July 2015 that are included in the Fuel Rider, please provide the related invoices, and paid cash voucher or cash payment receipt." The Company provided copies of PJM Settlement statements, and a spreadsheet titled "Fuel Clause Purchase Sale Summary – July 2015 – PJM Summary", which DP&L referred to as the "PJM Reconciliation". DP&L provided further support for its purchased power costs with a reconciliation schedule for its PJM settlements. From this additional documentation, Larkin was able to tie out the July 2015 power purchases from PJM to the amounts included in the July 2015 Excel workbook and thus through the Fuel Rider. Other than some immaterial variances, no exceptions were noted.

[redacted] On February 18, 2013, DP&L entered into four separate contract agreements with [redacted] (" [redacted] "), including a [redacted]

26. Pursuant to the investment by [redacted] transferred ownership of its plant to a new wholly-owned subsidiary called [redacted].

27. DP&L provided documentation related to the sale of coal to [redacted], as well as the 2015 accruals and accounting analysis reflecting all postings to FERC Account 456099.

28. Pursuant to the Stipulation and Recommendation dated May 10, 2016, which relates to the 2014 audit, DP&L agreed that upon approval of the Stipulation by the Commission, it will credit $16,042 (the 2014 [redacted]) to the Fuel Rider. In addition, DP&L agreed to credit the Fuel Rider related to [redacted] in any given year until the FAC mechanism ends. The Stipulation was approved in the Commission's Opinion and Order dated August 3, 2016. DP&L stated that the amount of the 2015 credit will be determined after being audited and verified in the 2015 audit. The [redacted] were not included by DP&L in the Fuel Rider during 2015.

29. DP&L provided a schedule with the responses to EVA-2015-1-39 and LA-2015-17, which provided by month, a breakout of the [redacted] and [redacted] during 2015. The DP&L [redacted], after apportioning Duke/Dynegy's and AEP's share, totaled [redacted]. DP&L [redacted], after apportioning Duke/Dynegy's and AEP's share, totaled [redacted]. After allocating to retail, reflecting the [redacted] would reduce DP&L's Fuel Rider includable costs by [redacted] and [redacted], respectively.

30. Included in the 2015 [redacted] data provided in EVA-2015-1-39 and LA-2015-17, the Company had added four additional columns for [redacted]. Under the Cash Receipts Tax column, DP&L included [redacted] in September 2015, which related to reimbursements from [redacted] paid by DP&L and the joint owners. After accounting for the Duke/Dynegy and AEP ownership shares, the DP&L portion of this amount is allocated over 100% to wholesale based on the allocation factors in the monthly workbook for September 2015. However, the documentation provided in the response to LA-2015-18 indicates that the [redacted] was broken out over the first six months of 2015, all of 2014 and certain months of 2013. After accounting for the Dynegy and AEP ownership portions, the DP&L portion of the reimbursement for the [redacted] is a credit amount of [redacted]. Using the documentation provided in LA-2015-18 for this item, Larkin applied the applicable retail and wholesale allocation factors for each month in 2013, 2014 and 2015 which apply to the [redacted]. The result is a DP&L retail amount of [redacted].

31. As part of its Application for an ESP in Case No. 12-426-EL-SSO, et al, DP&L proposed a non-bypassable Reconciliation Rider ("RR"), which would recover (1) the costs of administering the competitive bidding process ("CBP"), (2) the costs of implementing competitive retail enhancements, and (3) any remaining over or under-collection associated with particular riders. With respect to the third item, the Company proposed

that it be allowed to recover through the RR, any deferred balance that exceeds 10% of the base amount of riders Fuel, RPM, AER and CBT on a quarterly basis. DP&L's premise for its proposal was that recovery of the deferred balance amounts through the RR was necessary to avoid a situation where there were too few remaining SSO customers as a result of customer switching to cover the cost of the deferral balance.

32. Larkin reviewed the Reconciliation Rider filings that DP&L filed with the Commission in January and April 2015. As it relates to the Fuel Rider deferrals of $5,544,543 (March - May 2015) and $1,719,204 (June - August 2015) Larkin examined the monthly Excel workbook for December 2015 and verified that the Company removed these amounts from the Fuel Rider. Specifically, the tab titled ".2 Account Reconciliation" reflects the removal of the $5,544,543 in March 2015 and the removal of the $1,719,204 in May 2015.

33. DP&L posted a journal entry in March 2016, which reflects the transfer of the remaining balances of the Fuel Rider, Reconciliation Rider, RPM Rider, and TCRR Rider into the Competitive Bid True-up Rider. Larkin reviewed the journal entries and related support and is satisfied that these transactions were recorded properly.

34. Larkin reviewed DP&L's quarterly AER filings, which covered the forecasted periods encompassing calendar 2015. Our review also included DP&L's calculations of the Reconciliation Adjustment (RA) components included within those quarterly AER filings. Larkin's review of DP&L's RA information included verification to actual recorded results on a test basis for the months of January through December 2015

35. Pursuant to meeting compliance requirements, DP&L calculated the baseline using the kWh consumed in the 2015 compliance year.

36. REC costs are forecasted by taking the forecasted sales (100% SSO) and multiplying them by the requirements in ORC 4928.64 for both solar and non-solar and then multiplying those requirements by the weighted average cost of inventory for RECs.

37. Starting in September 2014, the Company's costs included the monthly amount of $121,882 related to the recovery of historical costs associated with the Yankee Street solar photovoltaic facility ("Yankee"). Specifically, in its second ESP, DP&L had requested a nonbypassable charge, or an Alternative Energy Rider - Nonbypassable ("AER-N") in order to recover the costs of Yankee. Historically, the Company had assigned a cost of $0 to the Yankee solar renewable energy credits ("SRECs") based on the expectation that it would recover the Yankee costs through the AER-N. However, the Commission denied DP&L's request for the AER-N and instead directed the Company to "consult with Staff to determine an appropriate methodology to recover through the AER the cost of past renewable energy resources used to serve its SSO customers."

38. In its July 18, 2014 AER filing, using Charles River Associates ("CRA") estimated fair market value estimations, DP&L identified historical costs for Yankee SRECs which totaled approximately $1.4 million, which it proposed to recover over four quarters beginning on September 1, 2014. Pursuant to this approach, the Company proposed that $365,647 be included in the AER rate going into effect on September 1, 2014.

39. The historical Yankee SREC costs were fully recovered by DP&L as of August 2015. As a result, DP&L removed Schedule 4 from its quarterly AER filings. Larkin confirmed that the historical Yankee costs were not reflected in the Company's quarterly AER filings after August 2015.

40. For 2015, DP&L reported total REC expense of $307,233 and compliance administrative expense in the amount of $8,553 on Schedule 2 in (1) DP&L's September 1, 2015 filing in Case No. 15-0045-EL-RDR, which reflected actual costs from January through November 2015; and (2) DP&L's March 1, 2016 filing in Case No. 16-0035-EL-RDR, which reflected actual 2015 costs from March through December 2015. Compared with 2015 AER revenue of $957,909, DP&L had an under recovery of $332,935.

41. For 2015, DP&L calculated AER carrying costs totaling a credit amount of $26,229, using a cost of debt of 4.943%, which had been approved by the Commission in Case No. 12-426-EL-SSO. Larkin's recalculations of DP&L's AER carrying charges for 2015 were without exception.

42. DPL's compliance costs are limited to 3% of the cost of the non-renewable energy that is supplied to SSO customers, with a sales baseline matching that for the REC obligation. For 2015, the 3% cost cap totaled $7,347,781. The REC costs totaling [redacted] for the 2015 compliance year were well below the cost cap. Exhibit 6-27 reflects total 2015 REC expense in the amount of $307,233, or a difference of [redacted]. The response to LA-2015-113, which provided the support for the amounts in the quarterly AER filings for the 2015 review period, included a workpaper which summarized REC expense for each month of 2015. The total of these REC expenses total the [redacted] noted above. This workpaper also reflects a correction that was booked in March 2015 that relates to a downward revision of the Company's 2014 REC compliance quantities. Specifically, this correction was a credit amount of [redacted] which related to 2014 solar compliance quantities and [redacted] related to non-solar quantities. The sum of these two corrections totaled the [redacted] difference noted above.

43. DP&L provided its confidential Annual Compliance Plan Status Reports for 2015 as well as its related Annual Alternative Energy Portfolio Status Report that was filed with the Commission on April 15, 2016 in Case No. 16-0752-EL-ACP. The Company's 2015 compliance report stated that DP&L achieved compliance by meeting the 2015 benchmark for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables.

44. REC purchases for DP&L's 2015 compliance requirements were primarily made in 2012. Some REC purchases were made by DP&L in 2015 to satisfy its requirement. DP&L indicated that it also purchases RECs for the next year's requirements.

45. DP&L's January 1, 2015 REC inventory consisted of [redacted] non-solar RECs at a cost of [redacted] and [redacted] solar RECs at a cost of [redacted]. After accounting for the solar and non-solar retirements to meet compliance requirements, the Company's December 31, 2015 REC inventory had [redacted] non-solar RECs at a cost of [redacted] and [redacted] solar RECs at a cost of [redacted].

46. Pursuant to the passage of Senate Bill 310 in May 2014, which in part eliminated the requirement that at least one-half of the renewable energy resources implemented to meet the benchmarks must be met through facilities located in Ohio, DP&L maintains appropriate REC inventories, at weighted average cost, which is updated monthly, for each type of REC.

    (1) Non-Solar RECs,

    (2) Solar RECs,

47. Larkin's review of the Company's weighted average cost of inventory workpapers, noted two purchases from [redacted]. for [redacted] and [redacted] solar RECs in September and December 2015, respectively. DP&L purchased these solar RECs at a unit price of [redacted]. Larkin requested that DP&L provide documentation related to the evaluation and ultimate decision to purchase these solar RECs at that price. [redacted].

48. DP&L's compliance requirement for solar RECs totaled 4,714 for 2015 and the Company retired these RECs using a [redacted] for a cost of [redacted].

49. DP&L's compliance requirement for non-solar RECs totaled 93,501 for 2015 and the Company retired these RECs [redacted] for a cost of [redacted].

50. DP&L posted a journal entry in March 2016, which reflects the amounts for the cost of RECs retired to meet its 2015 compliance requirements for solar and non-solar RECs. Using information that DP&L provided, Larkin tied the amounts from the March 2016 journal entry and related support to the Company's Annual Alternative Energy Portfolio Status Report for calendar year 2015 as well as to the solar and non-solar REC expense data that was provided in response to LA-2015-113.

Financial Audit Recommendations

1. Pursuant to the loss on the sale of Fuel oil in the amount of [redacted] that related to the Beckjord plant in March 2015, Larkin recommends that [redacted], or [redacted] of this amount flow through the Fuel Rider, which would result in an adjustment to decrease the amount flowing through the Fuel Rider by [redacted].

2. Pursuant to LA-2015-2-6, Larkin recommends that the Fuel Rider be decreased by $8,028 to reflect the reclassification of derivative gains and losses on purchased power to 100% wholesale sales.

3. Pursuant to the Stipulation from the 2014 audit that was approved by the Commission on August 3, 2016, Larkin recommends that the revenues associated with the sales of coal to [redacted] and related lease payments, which totaled [redacted] and [redacted], respectively, on a DP&L retail basis, flow through the Fuel Rider.

4. Pursuant to Stipulation that was approved by the Commission on August 3, 2016, as it relates to the sales of coal to [redacted], Larkin recommends that the DP&L retail portion of the economic benefit provided by the reimbursement for the [redacted] paid in the amount of [redacted] flow through the Fuel Rider as an offset to includable expense.

Audit Review

A draft of the audit report was provided to the Company for review. The auditors appreciated the Company's efforts and every issue raised by the Company was addressed. The Company in its comments noted that it did not verify every number in the report and reserved its rights regarding any future process with respect to the report. If additional issues concerning the report that have not been identified to date are subsequently raised by the Company, the auditors reserve the opportunity to respond.

Audit Outline

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

- Section 2 DP&L Background
- Section 3 Fuel Procurement Audit
- Section 4 Plant Performance
- Section 5 Financial Audit
- Section 6 AER Audit

2 DP&L BACKGROUND

Overview

In November 2011, the AES Corporation completed its purchase of DPL Inc., owner of DP&L. AES is a global power company which was incorporated in Delaware in 1981. As of the end of 2015, AES owns and/or operates a diversified generation portfolio of approximately 35,876 MW world-wide.[2] As a percentage of installed capacity, coal and natural gas account for 34 percent and 33 percent, respectively; renewables 28 percent; and oil, diesel and petroleum coke five percent.

AES operates two integrated utilities in North America, Indianapolis Power and Light (IPL), which it owns through IPALCO Enterprises, Inc. (IPALCO), the parent holding company of IPL and The Dayton Power and Light Company (DP&L), which it owns through DPL Inc. (DPL), the parent company of DP&L. In 2015, La Caisse de depot et placement du Quebec (CDPQ) announced its plans to invest in IPALCO. In March 2016, CDPQ completed its investment commitments. Following this investment, CDPQ owns 17.65 percent of IPALCO and AES owns the balance.[3]

IPL generates, transmits, distributes and sells electricity to approximately 480,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. DP&L transmits and distributes electricity to 515,000 customers in a 6,000 square mile area of West Central Ohio. DP&L procures power to supply SSO service to customers that have not chosen a generation supplier, some of which is treated as sourced from DP&L-owned generation facilities.

DP&L owns all or part of 13 power generating facilities. DP&L's share of total capacity is 2,504 megawatts of which 2,071 MW or 82 percent is coal. Exhibit 2-1 lists the facilities; Exhibit 2-2 displays their locations.

DP&L's coal capacity declined in 2015 with the retirement of Hutchings in 2015 and the sale of DP&L's share of East Bend to Duke Energy Kentucky which was completed in January 2015.

As part of an Electric Security Plan (ESP) approved in September 2013, DP&L is required to separate its generation assets by 2017. DP&L has stated the book value of its generating assets as approximately [redacted]. As of mid-2014, after marketing these assets, AES announced that rather than sell the generating assets to an unaffiliated third party, it will instead transfer the

[2] 2015 10-K

[3] 2016 Q1 10-Q

majority of the fleet to an affiliate of DPL by January 1, 2017 in order to comply with the ESP. AES noted in its press release that "(i)n light of the potential recovery of power prices, as well as PJM capacity prices, AES believes that this business has additional value that can be captured by continuing to own and operate these generating assets."

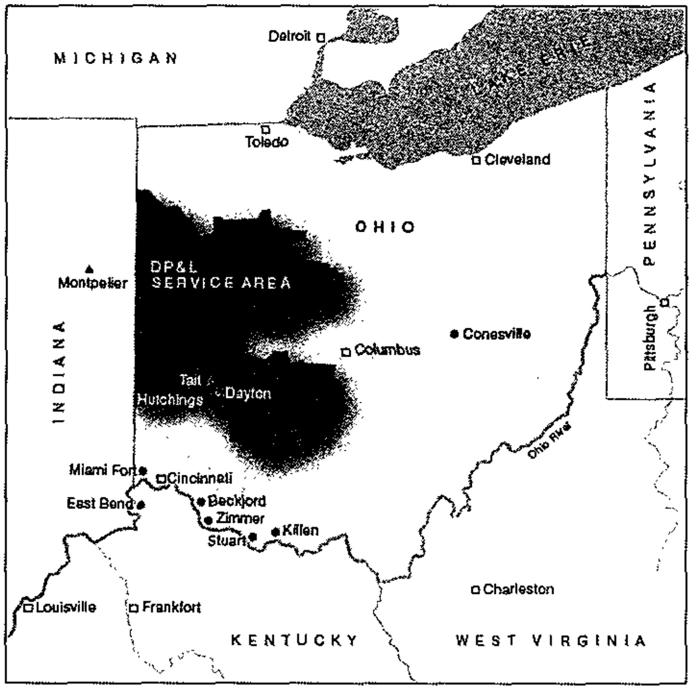
Exhibit 2-1. DP&L Ownership in Fossil Generation Facilities as of December 31, 2015

Utility	Plant Name	Units	Location	Ownership %	Capacity (MW) Total	Capacity (MW) DP&L Share	Fuel Type
COAL GENERATING ASSETS							
Dayton P&L	O.H. Hutchings	1-6	Miamisburg, OH	100%	365	365	Coal
Dayton P&L	J.M. Stuart	1-4	Aberdeen, OH	35%	2,308	808	Coal
Dayton P&L	Killen	2	Wrightsville, OH	67%	600	402	Coal
AEP Ohio	Conesville	4	Conesville, OH	17%	780	129	Coal
Duke Energy Kentucky	East Bend	2	Rabbit Hash, KY	31%	600	186	Coal
Duke Energy Ohio	Miami Fort	7,8	North Bend, OH	36%	1,018	366	Coal
Duke Energy Ohio	Zimmer	1	Moscow, OH	28%	1301	366	Coal
OTHER GENERATING ASSETS							
Dayton P&L	O.H. Hutchings CT	7	Miamisburg, OH	100%	23	23	NG
Dayton P&L	JM Stuart IC	1-4	Aberdeen, OH	35%	8.8	3	DFO
Dayton P&L	Killen IC	1	Manchester, OH	67%	18	12	DFO
Dayton P&L	Frank M Tait GT	1-3	Moraine, OH	100%	256	256	NG
Dayton P&L	Frank M Tait IC	1-4	Moraine, OH	100%	10	10	DFO
Dayton P&L	Monument IC	1-5	Dayton, OH	100%	12	12	DFO
Dayton P&L	Sidney IC	1-5	Sidney, OH	100%	12	12	DFO
Dayton P&L	Yankee Street GT	1-7	Centerville, OH	100%	94	94	NG

***Notes:* Hutchings stopped generating in 2012 but was not officially retired until 2015; DPL's interest was sold to Duke in early 2015**

DP&L belongs to the regional transmission organization PJM Interconnection (PJM) which is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Among the primary purposes of PJM are to dispatch electric generating plants on a lowest cost basis, thereby reducing the electric costs for all members of the pool, to coordinate regional planning to ensure reliability to the region in which it operates, and to operate markets for capacity, energy, demand response products and ancillary services. Exhibit 2-3 provides a map of PJM.

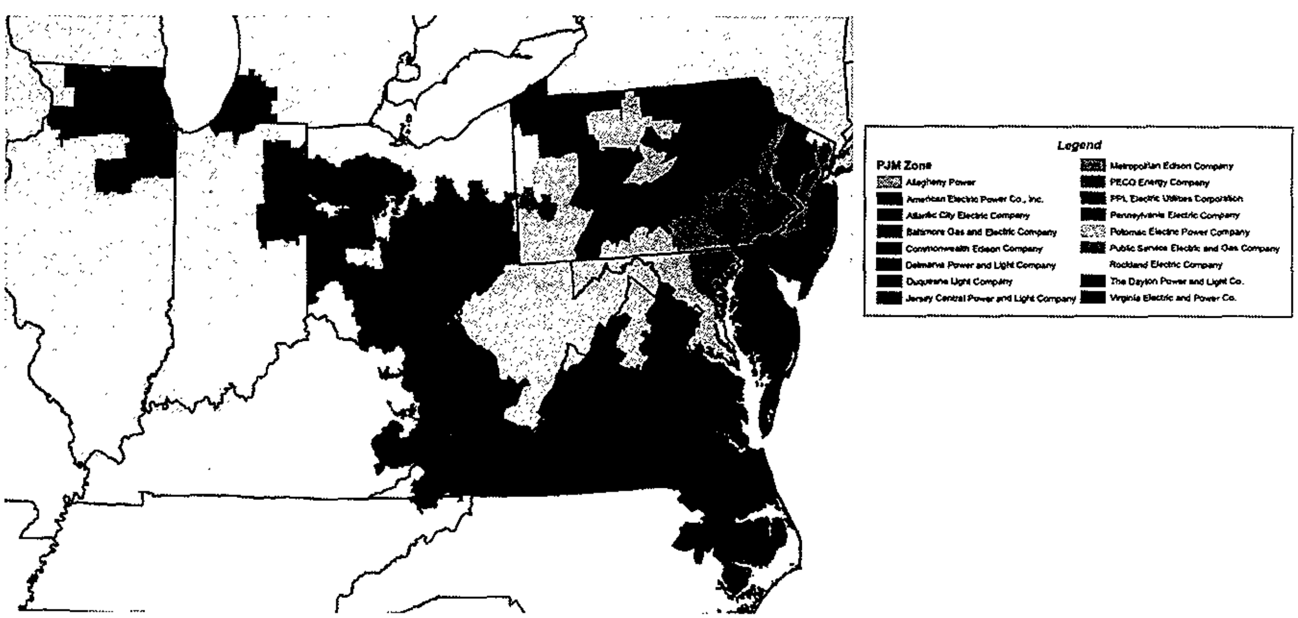
Exhibit 2-2. Location of DP&L Power Generation Facilities[12]



▲ *Natural Gas Peaking Generation Units*

● *Wholly & Commonly Owned Coal-Fired Generating Plants*

Exhibit 2-3. PJM Interconnection Zones



DP&L's share of generation by plant in 2015 is summarized in Exhibit 2-4. Coal accounted for 99.6 percent of DP&L generation. About 56 percent of its coal-fired generation came from the two DP&L-operated plants.

Exhibit 2-4. DP&L 2015 Generation by Plant (GWH)

Plant Name	Coal	Gas	Oil	Total 2015	2014	Change
Conesville 4	490,564			490,564	689,240	-28.8%
Frank M. Tait CT 1-3		46,345		46,345	13,559	241.8%
Frank M. Tait IC			49	49	53	-7.5%
J.M Stuart	3,572,547			3,572,547	3,627,530	-1.5%
J.M Stuart IC			343	343	237	44.7%
Killen CT		80		80	564	-85.8%
Killen 2	2,334,976			2,334,976	2,546,858	-8.3%
Miami Fort 7/8	2,417,829			2,417,829	2,402,350	0.6%
Monument IC			43	43	104	-58.7%
O.H. Hutchings CT		33		33	1	3200.0%
Sidney IC			78	78	113	-31.0%
W.H. Zimmer	1,757,655			1,757,655	2,089,270	-15.9%
Yankee CT		230		230	273	-15.8%
Total	**10,573,571**	**46,688**	**513**	**10,620,772**	**11,370,152**	**-6.6%**

Source: FERC Form 1

Generation year on year declined by 6.6 percent overall and 4.3 percent for DP&L operated plants. With the exception of Miami Fort, all of the coal plants in which DP&L either operates or is a non-operating partial owner had lower generation in 2015 compared to 2014.

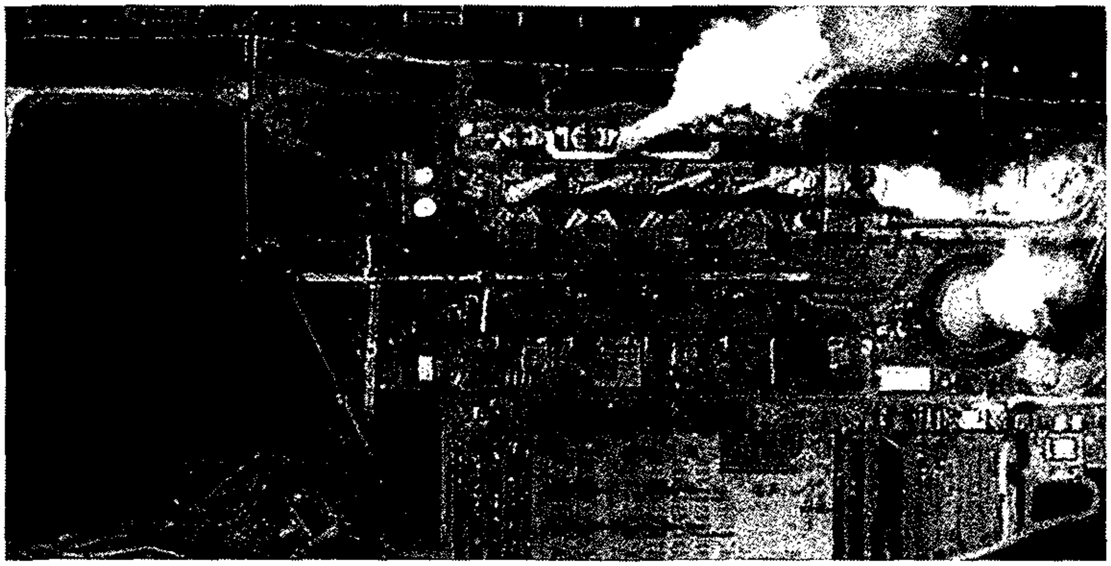
Coal Plants

This section provides background information on the two coal plants operated by DP&L in 2015. These are the only coal plants for which DP&L has responsibility for coal procurement.

J. M. Stuart

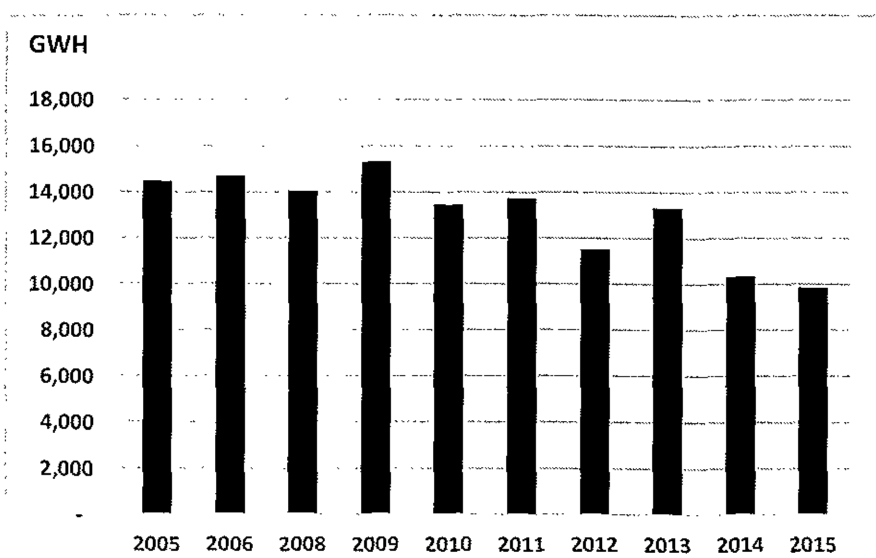
The Stuart Station consists of four units with a total generating capacity of 2,308 MW. The retrofits of flue gas desulfurization units on all four units were completed in 2008. As can be seen in Exhibit 2-5, the four units now share a common stack. All coal to this station is delivered by barge.

Exhibit 2-5. Aerial View of Stuart Plant



Generation in 2015 was the lowest generation in the 17-year period for which data are available as shown in Exhibit 2-6.

Exhibit 2-6. Stuart Annual Generation (GWH)



The lower generation reflected itself in coal burn and capacity factor as shown in Exhibit 2-7.

Exhibit 2-7. J.M. Stuart Operating Statistics

Plant	Units	Location	Ownership %	Total MW	Utility Share
JM Stuart	1-4	Adams, OH	35	2,308	808
	2015	2014	2013	2012	2011
Generation (MWh)	9,798,935	10,336,967	13,314,057	11,509,341	13,739,923
Consumption					
Coal (tons)	4,459,169	4,643,164	5,780,295	7,139,309	7,386,506
Oil (barrels)	92,057	65,434	59,039	78,049	82,765
Capacity Factor	48.5%	50.9%	65.9%	56.9%	68.0%
Heat Rate (Btu/kWh)	10,302	9,999	9,927	9,906	9,942

Prior to the retrofitting of the scrubbers, the Stuart Station burned low sulfur coal in order to meet its 3.16 pound of SO_2 per MMBtu SIP limit. The coal originated primarily in Central Appalachia. The retrofit of the scrubbers has allowed higher sulfur coal. The scrubbers are designed for coals with an SO_2 content up to 7.22 pounds per MMBtu. However, given the design of the boilers, DP&L did not assume a complete switch to higher sulfur coals because of concerns over slagging and fouling. DP&L ultimately switched all four units to burn 100 percent high sulfur coal which has a lower ash fusion temperature.

After the conversion, DP&L has struggled with slagging issues at Stuart. DP&L installed a magnesium oxide injection system but found it expensive to use and not particularly effective. In 2014, DP&L indicated it started to dispatch Stuart [redacted]. A [redacted]. In 2015, DP&L retained the [redacted].

Significant operating problems in 2014 caused DP&L to make a number of management and organizational changes. In addition, DP&L committed to a full evaluation of fuel options. A number of test burns were performed in 2015 as part of this effort.

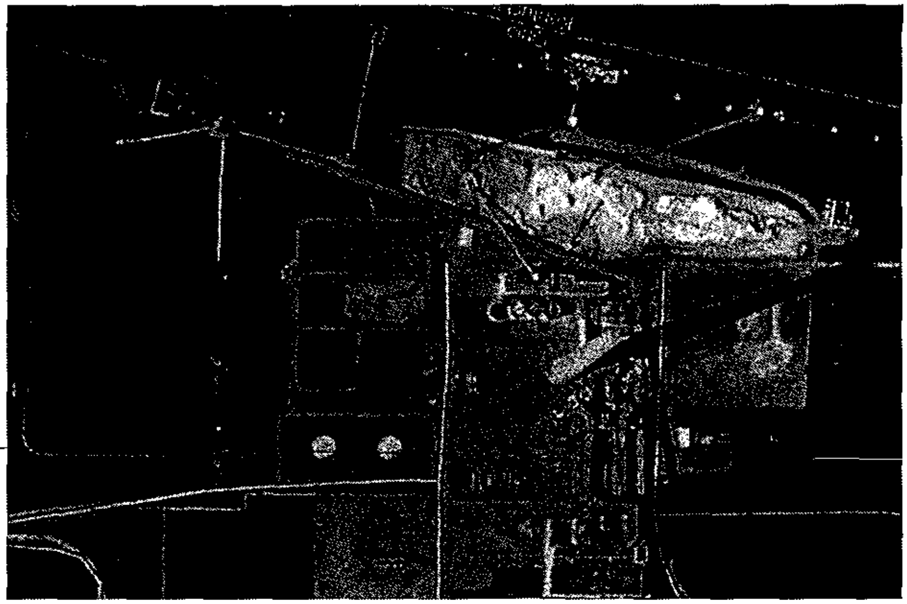
DP&L entered into multiple agreements with [redacted] ([redacted]) during 2013 related to the installation of [redacted] at Stuart. The interest in [redacted] is related to [redacted]. [redacted]. In order to qualify for the [redacted] must be purchased from an unrelated party. As a result, in order for [redacted] to qualify for [redacted], DP&L sells the coal to [redacted]. The [redacted] EVA notes that DP&L remains convinced the [redacted] is not contributing to operating problems.

Killen

The Killen Station consists of one 600 MW coal-fired power plant. The station was designed for two units, but only one unit (Killen 2) was built. The unit was subject to the original New Source Performance Standard of 1.2 pounds SO_2 per MMBtu which the utility chose to comply with through the use of low sulfur compliance coal. A scrubber was retrofit on the Killen Station in 2007. An aerial view of the plant is provided in Exhibit 2-8. All of the coal consumed by Killen is delivered by barge. Killen has converted almost completely to high sulfur coal. Due to its size, Killen's boiler is capable of accommodating the higher sulfur and lower-fusion Illinois Basin coals with fewer operational challenges than Stuart. After significant testing, the plant thought it could accept lower quality coals for up to 33 percent of its supply.

Killen retains a small amount low sulfur Central Appalachian coal, which allows the plant a larger degree of flexibility during start-up after maintenance outages. The low sulfur coal has two applications, both related to the scrubber operations. After an extended maintenance outage, the chemical reaction in the jet bubbling reactor (JBR) must be initiated before it reaches a level sufficient to remove SO_2 from high sulfur coal. Killen has a short (one hour) air permit, requiring the plant to meet a lower level of emissions during start-up which is more difficult with high sulfur coal. DP&L believes the plant start-up with the low sulfur coal is a better strategy for enabling the JBR reaction to reach the level needed to effectively scrub the higher sulfur coal to comply with the air permit.

Exhibit 2-8. Aerial View of Killen Plant



The second use of low sulfur coal is when issues arise with the scrubber which may compromise its operation, but are not sufficiently problematic to require complete shut-down. During this time the plant may burn low sulfur coal in order to slow the chemical reaction in the JBR down and make repairs, while the unit remains in service.

Recent plant operating statistics are provided in Exhibit 2-9. The plant operated at a 65.5 percent capacity factor in 2015 and burned approximately 1.6 million tons.

Exhibit 2-9. Killen Operating Statistics

Plant	Units	Location	Ownership %	Total MW	Utility Share
Killen	2	Adams, OH	67	600	402
	2015	2014	2013	2012	2011
Generation (MWh)	3,440,952	3,820,619	3,442,966	3,605,364	3,872,867
Consumption					
Coal (tons)	1,605,479	1,799,987	1,578,242	1,610,257	1,740,912
Oil (barrels)	18,345	20,155	23,286	21,985	18,838
Capacity Factor	65.5%	72.5%	65.5%	68.6%	73.7%
Heat Rate (Btu/kWh)	10,540	10,322	10,214	10,489	10,296

O.H. Hutchings

The last of DP&L's Hutchings coal-fired units was retired in 2015 although it had not generated power since 2012. The remaining coal inventory was sold. Hutchings Unit 7, a natural gas-fired peaking unit, remains in operation.

3 FUEL PROCUREMENT AUDIT

Overview

In 2015, DP&L purchased 5.8 million tons of coal at an average delivered price of $51.54 per ton or $2.19 per MMBtu. (Exhibit 3-1) According to DP&L's classification, 63 percent of purchases were on a spot basis. Total tons were down by about 1.1 million tons in 2015 versus 2014. The average price on a dollars per MMBtu basis was approximately the same in 2015 as it was in 2014.

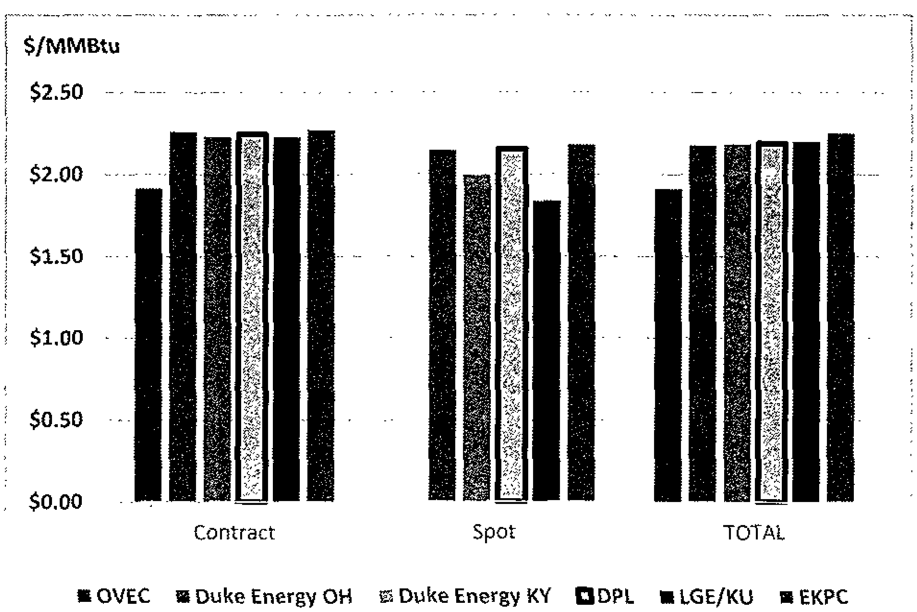
Exhibit 3-1. DP&L Coal Purchases, 2015

	Contract					Spot					TOTAL				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
Stuart	1,396,385	11,708	2.66	52.38	2.237	2,813,312	11,831	2.70	51.20	2.164	4,209,697	11,790	2.68	51.59	2.188
Killen	754,293	11,692	2.71	52.98	2.266	833,487	11,769	2.61	49.98	2.123	1,587,780	11,732	2.66	51.41	2.191
TOTAL	2,150,678	11,702	2.68	52.59	2.247	3,646,799	11,817	2.68	50.92	2.155	5,797,477	11,774	2.68	51.54	2.189

Source: Form 923.

DP&L's delivered coal costs on a dollars per MMBtu basis are compared to the other Ohio and nearby utilities for which data are publicly available in Exhibit 3-2. DP&L is in the middle of the pack of the eight utilities included in this comparison. Exhibit 3-3 provides some additional details about each utility's purchases. Some of the differences are explained by location, legacy contracts, the average quality of the purchases, and the contract/spot mix.

Exhibit 3-2. Ohio and Nearby Utility Coal Purchase Costs, 2015 ($/MMBtu)



Source: Form 923.

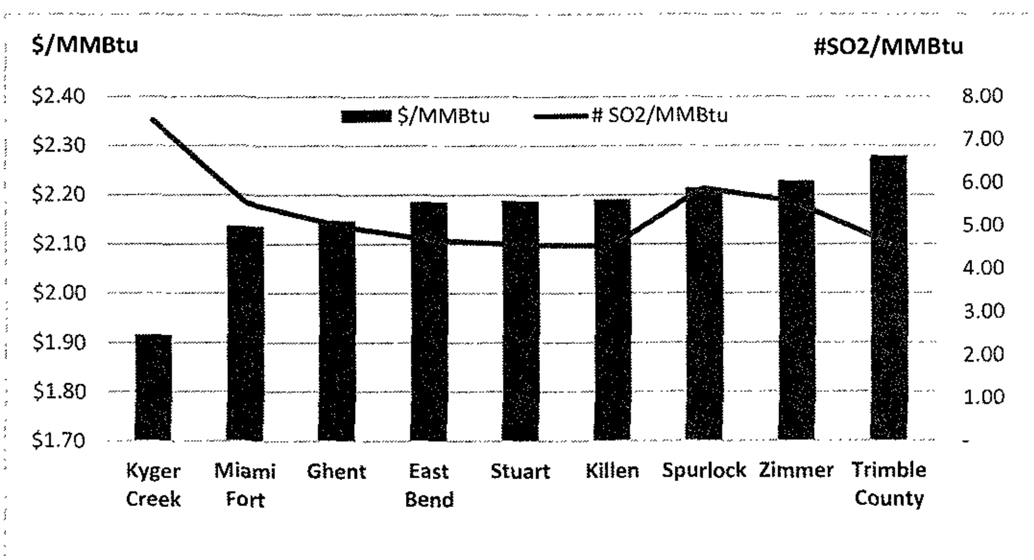
Exhibit 3-3. Coal Purchase Details for Other Ohio and Nearby Utilities, 2015

	Contract					Spot					TOTAL				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
OVEC	2,129,413	12,420	4.63	47.61	1.916						2,129,413	12,420	4.63	47.61	1.916
DEO	1,422,410	12,238	3.43	55.35	2.262	3,899,908	11,949	3.30	51.30	2.147	5,322,318	12,026	3.33	52.38	2.178
DEK	1,513,290	11,731	2.92	52.28	2.228	316,899	12,392	2.03	49.45	1.995	1,830,189	11,846	2.77	51.79	2.186
DP&L	2,150,678	11,702	2.68	52.59	2.247	3,646,799	11,817	2.68	50.92	2.155	5,797,477	11,774	2.68	51.54	2.189
LGE_KU	8,893,413	11,175	2.72	49.77	2.227	596,727	10,974	2.27	40.35	1.839	9,490,140	11,162	2.69	49.18	2.203
EKPC	2,559,010	11,294	3.32	51.31	2.272	681,883	11,811	2.68	51.54	2.182	3,240,893	11,402	3.18	51.36	2.252

Source: Form 923.

Another relevant metric for DP&L is how the delivered prices to Stuart and Killen compare to the delivered prices to other plants located nearby on the river which are equipped with scrubbers and/or burn high sulfur coal. Of the nine plants shown in Exhibit 3-4, Killen and Stuart are the fifth and sixth lowest cost plants. Also provided on the exhibit is the average sulfur dioxide (SO_2) content of the coal purchases at each plant. All of the plants burn high sulfur coal. While the lowest cost plant purchases the highest sulfur coal, the correlation between SO_2 and price is not strong. Other factors influencing average cost are contract vintages, spot/contract mix and plant locations.

Exhibit 3-4. Delivered Prices to Proximate River Plants, 2015



Background on DP&L's Coal Supply

The retrofitting of scrubbers on Killen and Stuart continues to dramatically change the type of coal purchased by the utility. In 2007, DP&L purchased almost exclusively Central Appalachia coal. In 2015, less than one percent of purchases originated in Central Appalachia. DP&L indicated it maintains a small stockpile of Central Appalachian coal at Killen for use in bringing unit on line after extended outages.

The current coal specifications which are contained in DP&L's standard operating procedure (SOP) for coal procurement are shown in Exhibit 3-5 for Killen and Stuart. The specifications, which DP&L sometimes refers to as its boxed specifications, were not revised in 2015. DP&L indicated it no longer restricts bids to these limits. DP&L verbally indicated it had raised the minimum Btu specifications.

Exhibit 3-5. Killen and Stuart Coal Specifications

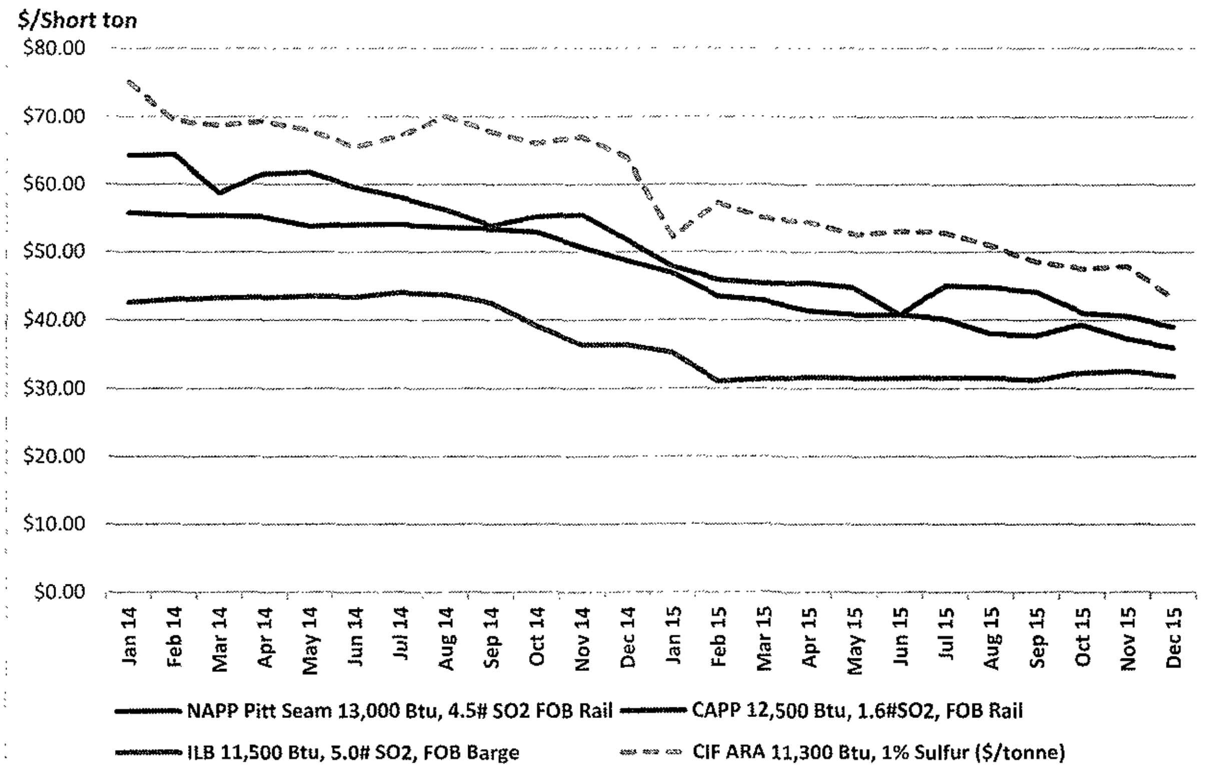
[redacted]

State of the Coal Market

Given DP&L's reliance on coal, continued changes in the coal market in 2015 are relevant to the management/performance audit. Power sector demand for coal contracted again during 2015 as the price for natural gas fell in order for natural gas-fired combined cycles to displace coal generation.[4] As the power sector is the largest source of demand for U.S. coals, the loss of that market had a significant impact on the overall market. This is similar to what occurred in 2012 with one major exception. In 2015, a strong U.S. dollar caused the global coal price to fall making U.S. coal uncompetitive in the global market. The net result was a large drop in domestic coal prices. The decline which started in 2014, as shown in Exhibit 3-6, worsened in 2015.

[4] A significant increase in shale gas resulted in a supply overhang. The only immediate market for natural gas is the power sector which has under-utilized combined cycle capacity.

Exhibit 3-6. Market Prices for Key Supply Regions and International Coal



There are a number of negative consequences related to the price decline offsetting the obvious benefit of lower cost fuel. The most important is the impact on the financial health of the coal industry. By the end of 2015, the number of coal producers which had filed for bankruptcy significantly increased. Over 10 percent of 2015 U.S. production was from companies in bankruptcy or recently emerged from bankruptcy. In January 2016, Arch Coal filed and then in May 2016, Peabody Coal filed bringing the share of U.S. production associated with bankrupt companies to over 40 percent. The concern about counter-party credit has increased with the increased financial fragility of the industry. While most of the bankruptcies are being done under Chapter 11 of the Bankruptcy Code (indicating an expectation of a reorganization) that may not continue to be the case if the market deteriorates further.

Another consequence of the softness in the market is the mismatch between purchases and requirements. Higher inventory levels are a challenge. Also a challenge is the reduced ratability of the demand as a consequence of variable operations of the coal plants.

Management and Organization

In 2013, there were a number of organizational changes within DP&L as a result of AES incorporating DP&L into its U.S. Strategic Business Unit. As a result, some of the changes related to the transfer of certain functions to Indianapolis. In addition, AES centralized U.S. coal procurement (excluding Indianapolis Power and Light (IPL) procurement) in Dayton. Some additional organizational changes were made in 2014 related to plant operations. In 2015, a new position, Director of Commercial Operations, was created and filled. The Fuels group now reports through this director.

The current SBU organization is shown in Exhibit 3-7. The organization of the fuel procurement team is provided in Exhibit 3-8. The fuel procurement team is responsible for procurement of commodities and transportation services for the fossil fuel generating stations operated by the Company. The functions performed by this group encompass the following:

- planning and budgeting functions,
- solicitation and evaluation of proposals for fuel and transportation contracts,
- selection and qualification of suppliers and shippers,
- contract negotiation,
- administration and enforcement, and
- operations support.

Exhibit 3-7. U.S. Strategic Business Unit Organization Chart

[redacted]

Exhibit 3-8. Fuel Procurement Team

[redacted]

The fuel team has a stated goal of creating value for DP&L's customers and shareholders by contracting and delivering commodities that are compatible with the company's equipment and achieving the reliability of supply at the most economical value per megawatt hour generated.

DP&L personnel are now responsible for the procurement of fuel for other AES North American assets excluding IPL.

Policies and Procedures

DP&L has documented its fuel procurement policies and procedures in what it referred to as its Standard Operating Procedures or SOPs. There are seven separate SOPs related to fuel. These SOPs, listed below, are very detailed.

- Coal and Limestone Procurement
- Coal, Limestone, Fuel Oil, Gypsum Scheduling

- Coal Quality Control
- Coal Supply Chain Disruption
- Coal Inventory
- Fuel Oil Inventory and Quality Control
- Fuel Consumption Estimate and Position Management

Coal and Limestone Procurement SOP

DP&L revised its Coal and Limestone Procurement SOP most recently in January 2013. In May 2013, DP&L changed its credit policy with respect to coal suppliers. Before the change, there was a 35 percent cap on how much coal an individual company could supply. There is now a fairly complicated evaluation process to determine what amount (tons and percent) of coal an individual party can supply based upon their qualified production not the share of supply purchased by DP&L. As noted in the prior management/performance audit, the revision appears to have been motivated by DP&L's desire to purchase additional tons from [redacted] for both 2014 and 2015 following the April 2013 RFP which would have exceeded the 35 percent limit.

The new policy focuses on the share of a supplier's qualified production it can ship not on the single producer. It is industry standard risk management to have a diversified supplier base where possible. This revision which appears to have been motivated by a desire not to be in violation of its own credit policy does not appear to have any analytical justification. Despite the findings as well as several additional concerns noted with DP&L's methodology, DP&L made no changes in its credit policy in 2015. Nor did DP&L incorporate explicit consideration of supplier concentration in its recommendation memorandum. As discussed below, the concern about concentration of supply will increase going forward due to several industry consolidations. DP&L's current practices do not reflect leading industry practices and DP&L could be exposed if its primary supplier goes into bankruptcy.

In 2015, DP&L issued one formal coal RFP. The RFP issued in August requested offers for up to 250,000 tons in Q4 2015 and up to 250,000 tons per quarter for all of 2016. No quality limits were listed despite DP&L's desire to increase the minimum Btu content of its coal. DP&L requested bids based upon plus or minus 25 percent volume optionality and Btu, SO_2, and ash quality adjustments. DP&L received 14 offers although a number of them were disqualified because they did not meet the minimum quality standards.

The purchases made from this RFP are summarized in Exhibit 3-9. [redacted] coals were purchased for [redacted] at Stuart. In order to accommodate the test, [redacted] tons purchased for Stuart will be moved to Killen. In addition, DP&L also purchased [redacted] tons of [redacted] coal from [redacted] for Killen. The [redacted] purchase provides attractive volume optionality. The [redacted] offer also provides some volume optionality.

Exhibit 3-9. Purchases from August 2015 RFP

[redacted]

DP&L prepared a justification memorandum that explained the rationale for the purchases. There was nothing in the Justification Memorandum that provided an analysis of the additional commitment to [redacted] in light of its already high concentration of supply with this supplier.

DP&L made two spot coal purchases in 2015 without formal solicitations. DP&L purchased [redacted] tons of coal from [redacted], to be delivered during the summer. The coal was priced at [redacted] per ton for an 11,500 Btu/lb product. DP&L also purchased [redacted] tons from [redacted] for delivery in the fourth quarter. The [redacted] purchase is described below in the section on [redacted] contracts. DP&L did not provide justifications for either purchase.

RFP Practices

DP&L's RFP process generally remained the same in 2015. With respect to the amount of coal to purchase, DP&L ties purchases to hedging power sales (longer-term) and anticipated market dispatch (shorter-term). DP&L uses its Portfolio Optimization Model (POP) to develop the dispatch simulations that are the basis for the coal purchases. POP uses the PowerSimm model, a 24/7 dispatch model, to forecast dispatch. POP performs 200 simulations to establish a range of outcomes. While purchases are based upon the mean results, low and high probability outcomes are also considered.

A complete RFP package is sent to a large list of prospective suppliers. RFP announcements are also sent to the coal periodicals.

The RFP package contains a description of the procurement, the bid form, and a draft contract for the potential suppliers to comment upon.

Coals are evaluated using the Coal Evaluation Model. The Coal Evaluation Model is designed to value the cost characteristics of each coal on a $/MMBtu basis. The model also considers the delivered coal price and associated operating costs for the specific coal quality. For coals outside the standard quality specifications, there is a separate evaluation by the plant if the economics of the coal merit further consideration.

As part of each procurement, DP&L prepares a procurement summary consistent with other AES procurement.

Coal Inventory SOP

The Coal Inventory SOP explains the responsibilities for inventory management, the basis for the establishment of inventory minimums, the inventory minimums, and the tons constituting the base inventory levels. DP&L has established a "normal minimum" of 30 days at each station. The days are based upon the operating inventory (i.e., the inventory on the ground and in transit exclusive of the base) divided by the full burn rate. DP&L does not include a target inventory level for each station in its SOP.

An inventory of coal is maintained to manage fluctuations in fuel consumption and delivery. Common causes of fluctuations in inventory are:

- Seasonal Variation in burn
- Planned/Unplanned maintenance
- Delivery schedule based on seasonal and supplier variation
- Lock and unloader outages
- Overall supply conditions in the market

Two groups oversee inventory decisions; one group establishes inventory goals while the other approves them. The membership of each group is as follows:

Establish Inventory Goals

- Managing Dir., Commercial Operations
- Plant Mangers
- CD/CCD co-owners (if applicable)

Approve Inventory Goal

- Vice President, Commercial Operations
- Sr. Vice President of Generation & Marketing

Stuart Coal Inventory

Stuart is a base-load plant that historically has run at high capacity factors throughout the year. That was not the case in 2015.

Inventory performance (as measured by end-of-month inventory) in 2015 is provided on Exhibit 3-10. The Stuart inventory trended downward through 2015 but still remained well above its stated target.

Exhibit 3-10. Monthly Coal Inventory for J.M. Stuart (DP&L Share)

[redacted]

Stuart's inventory days based upon maximum burn[5] are displayed in Exhibit 3-11. Inventory was typically around [redacted] (plus or minus). With a target of [redacted], the magnitude of the variance from target is substantial.

Exhibit 3-11. Stuart Days of Inventory Based on Maximum Burn

[redacted]

Much of the U.S. coal power industry is struggling with high inventories. Power companies purchased coal based upon historical burn levels which did not materialize. As a result, purchases for many exceeded demand and inventories ballooned.

Stuart's days of inventory compared to actual stockpile days of Illinois Basin coal are shown in Exhibit 3-12. Until the end of the year, Stuart days of inventory were similar to the inventory average. By year end, Stuart's days of inventory fell below the industry average. This is to DP&L's credit that it was able to limit the impact of lower burns.

[5] Maximum average monthly over the years 2013-2015.

Exhibit 3-12. Days of Inventory Versus Industry Average[6]

[redacted]

Killen Coal Inventory

Killen, like Stuart, is a base-load plant that historically runs at very high capacity factors. Killen unlike Stuart, has greater ability to cycle which means the burn forecasts for it are more sensitive to slight changes in the market.

Inventory performance for 2015 is displayed on Exhibit 3-13.

Exhibit 3-13. Monthly Coal Inventory for Killen (DP&L Share)

[redacted]

[6] Industry average is from EVA Stockpile Report for plants burning Illinois Basin coal based upon three-year max burn.

The days of inventory based upon maximum burn is displayed on Exhibit 3-14. Killen inventory levels were more volatile than Stuart's. After almost achieving target levels in August and September, Killen inventories ballooned by year-end. Killen had slightly better inventory performance than Stuart compared to the industry overall.

Exhibit 3-14. Killen Days of Burn in Inventory Based on Maximum Burn

[redacted]

Killen's days of inventory compared to average stockpile days of Illinois Basin coal based upon three-year max burn is shown in Exhibit 3-12 above. Like Stuart, Killen days are well below industry averages but not by the same degree.

Hutchings Coal Inventory

Hutchings was not operated in 2015. The remaining inventory at Hutchings was sold.

Physical Inventory Adjustments

DP&L's procedures are documented in DP&L Business Practice Generation – 001 Coal Pile Inventory. There is also a procedure related to Internal Audit's role in the physical inventory process. (DP&L Business Practice 741) Neither procedure establishes a threshold amount which would trigger an investigation of the results. Per the 2010 FUEL Rider Stipulation, DP&L established thresholds that would trigger an investigation. The thresholds are eight percent of book and two percent of burn with a minimum of 5,000 tons.

The specific addition to the Business Practice was as follows:

> *5.6.1 If the physical coal inventory difference is greater than both +/-8% of the coal tonnage during the physical inventory month and +/-2% of the coal tonnage consumed during the prior 12-month* (sic) *(excluding prior year's adjustment), an /additional review will be completed. We will not perform this additional review if the tonnage difference is less than 5,000 tons.*

The results from the physical inventory surveys of Stuart and Killen conducted in 2015 are summarized in Exhibit 3-15.

Exhibit 3-15. Physical Inventory Results, 2015

[redacted]

The results from the surveys did not trigger the requirements for additional investigation at Killen or Stuart. The large deviation at Killen between the Physical Inventory and the Book Inventory is a cause for concern.

Coal Procurement

In 2015, DP&L primarily bought high sulfur coal on both a contract and spot basis. Small amounts of low sulfur coal were purchased for a test burn at Stuart.

Master Agreements

DP&L uses Master Agreements as the primary contractual document with suppliers. As provided for in the Master Agreement, the details of each transaction are then documented in a Confirmation. The Confirmation also contains any deviations to the Master that apply for the particular transaction. The Master Agreements appear to work well for DP&L by significantly reducing the time and resources required to negotiate each purchase agreement.

Long-Term Contracts

As noted above, it is DP&L's practice to enter into master agreements with counter-parties and then use Confirmations for specific transactions. In 2015, DP&L received coal under [redacted] confirmations. The confirmations are listed in Exhibit 3-16 with the contract identification, the 2015 obligation, the adjusted 2015 obligation, and the supply region.

Exhibit 3-16. DP&L Contracts

[redacted]

A summary of shipments by supply region and supplier are provided respectively in Exhibits 3-17 and 3-18. The reliance on Illinois Basin coal declined somewhat in 2015 with a corresponding increase in Northern Appalachia.

Exhibit 3-17. 2015 Purchases by Supply Region

	CAPP	ILB	NAPP	TOTAL
[redacted]				

[redacted] (through [redacted] and [redacted] Coal) supplied [redacted] percent of DP&L's purchases in 2015. [redacted] and [redacted] were [redacted] percent, respectively.

Exhibit 3-18. 2015 Purchases by Supplier

[redacted]

The longer-term commitments are reviewed below with each company.

[redacted]

In 2015, DP&L received coal under two contracts with [redacted]. One contract was entered into in 2013 for coal from the [redacted] mine. The second contract was a spot purchase for coal from the [redacted] mine. The basic terms of the agreements are provided in Exhibit 3-19.

Exhibit 3-19. [redacted] Coal Contracts

[redacted]

The [redacted] agreement provides some volume optionality as well as two quality adjustments. The Btu adjustment is pro rata. The SO_2 adjustment provides a [redacted] per ton penalty per [redacted] pounds of SO_2/MMBtu per ton greater than the SO_2 specification. The SO_2 specification is [redacted] pounds for Confirm [redacted]. The [redacted] agreement only has a Btu quality adjustment.

Tonnage shipped by contract and plant under the [redacted] Agreements are provided in Exhibit 3-20. During the audit period, DP&L exercised its option to decrease volumes under Confirm [redacted]. DP&L's compared the contract price to the market index to make its decision. EVA does not believe that the market index is a substitute for bids and that DP&L use actual bids when making these decisions.

Exhibit 3-20. Shipments under the [redacted] Agreement, 2015

[redacted]

Quality of shipments under the [redacted] agreement [redacted] is summarized in Exhibits 3-21. [redacted] was slightly out of compliance with its guaranteed Btu specifications during six of the months.

Exhibit 3-21. Quality of Shipments under the [redacted] Agreements

[redacted]

[redacted]

In 2015, DP&L received coal under three contracts with [redacted]. Two of the contracts were entered into in 2014; one contract was entered into in 2015. The [redacted] coal had been the original source of coal when the plants were initially retrofitted with scrubbers. This coal is of increasing interest at Stuart because of its quality.

The basic terms of the three agreements are provided in Exhibit 3-22.

Exhibit 3-22. [redacted] Coal Contracts

[redacted]

Tonnage shipped under the [redacted] Agreements is summarized in Exhibit 3-23. Confirmations [redacted] was amended in 2015 to provide for the shortfall of shipments to be made in 2016.

Exhibit 3-23. 2015 Shipments under the [redacted] Agreements

[redacted]

Quality of shipments under the [redacted] agreements is summarized in Exhibits 3-24. The actual Btu content was below the Btu specifications in most months.

Exhibit 3-24. Quality of Shipments under the [redacted] Contracts

[redacted]

[redacted]

In 2015, DP&L received coal under three contracts with [redacted]. The basic provisions of these contracts are summarized in Exhibit 3-25.

Exhibit 3-25. [redacted] Contracts

[redacted]

Confirm [redacted] was amended two times in 2015. In September 2015, Amendment 4 added the [redacted] as a delivery point for the same price. Given the [redacted], the amendment provided DP&L with some value. Amendment 5 added the [redacted]

[redacted] mines as possible sources. Confirm [redacted] was amended in January 2016 to provide for the shortfall in 2015 deliveries in 2016.

Tonnage shipped under this agreement in 2015 is summarized in Exhibit 3-26. In December 2014, DP&L elected to make neither the upward nor downward quarterly quantity adjustments for Q1 of 2015. Given the costs to exercise these options, DP&L determined the options were uneconomic compared to the market indices. EVA does not believe that the market index is a substitute for bids and that DP&L should use actual bids when making these decisions. In February 2016, June 2016, and September 2016, DP&L elected to make the downward volume adjustments. In all three quarters, the replacement tons were purchased from [redacted]. The Q2 replacement was through Confirm [redacted]. The Q3 replacement was through [redacted] Confirm [redacted]. The Q4 replacement was part of DP&L's purchases from the August RFP. DP&L designated the replacement to be part of [redacted] Confirm [redacted].[7]

Exhibit 3-26. 2015 Shipments Under [redacted] Coal Contracts

[redacted]

The quality of shipments under the [redacted] agreements is summarized in Exhibits 3-27. [redacted] was slightly out of compliance with its guaranteed Btu specifications during six of the months under Confirm [redacted].

[7] The replacement should actually be considered the highest cost coal purchased at that time which was the spot coal purchased from [redacted]. The [redacted] purchased was still economic compared to the [redacted] contract tons.

Exhibit 3-27. Quality of Shipments under the [redacted] Contract [redacted]

[redacted]

[redacted]

In February 2013, DP&L entered into four agreements with [redacted] ([redacted]) that collectively provide the basis for the installation of [redacted] at Stuart. The interest in [redacted] must be purchased from an unrelated party. As a result, in order to qualify for [redacted], DP&L must [redacted]. The agreements all expire December 13, 2021 unless they have been terminated early.

The four agreements are the [redacted], and [redacted].

Under the [redacted] at the [redacted] for the month of purchase.

Under the [redacted], DP&L provides or coordinates the following services: [redacted] per ton for providing these services on the first [redacted] tons and [redacted] ton for tons above [redacted].

Under the [redacted], DP&L agrees to [redacted] per ton to represent what the parties call the "[redacted]" and the number of delivered tons.

Under the [redacted], [redacted] pays [redacted] per month starting with the Commercial Operating Date for the use of the "real estate" at the site.

DP&L did not flow any of the revenue received from [redacted] through the FUEL Rider. EVA believes that jurisdictional customers are due their share of the proceeds. The only reason a [redacted] is located at Stuart is that Stuart burns substantial quantities of coal. To the extent this coal was purchased for jurisdictional customers, jurisdictional customers should get the benefit created by this procurement. In other words, the asset (i.e., the jurisdictional customer share of coal) during the audit period effectively belonged to them. Therefore, the fees received are inextricably tied to DP&L's ability to lever this asset into a [redacted]. While not suggesting customers are due a residual payment over the life of the project, EVA is recommending that during the remaining term of the FAC the jurisdictional share of proceeds should flow through the FUEL Rider.

The parties to the agreement have considerable discretion as to how they structured the payments other than the obligation to buy the [redacted]. For example, the agreements could have been structured to purchase [redacted].

In 2013, there was a stipulation among the parties to flow 50 percent of the 2013 revenue received from the owner of the facility excluding the amounts received under the ground lease. The stipulation did not apply to 2014 and beyond. In the stipulation for the 2014 FUEL Rider DP&L, the parties agreed as follows:

> Upon approval of this Stipulation by PUCO order, DP&L will credit $16,042 for 2014 to SSO customers relating to the proceeds DP&L received on 2014 related to the process of refined coal at Stuart. Additionally, DPL (sic) will credit 100% of the jurisdictional share of any proceed DP&L received related to the process of refined coal at Stuart in any given year until the FAC mechanism ends. The 2015 credit will be determined after an audit and verified by an outside auditor in the 2015 FAC case.

DP&L indicated that [redacted]. As discussed in Section 5, Larkin confirmed that the jurisdictional share of [redacted] proceeds flowed through the FUEL Rider.

[redacted]

In 2015, DP&L received coal under nine contracts with [redacted]. [redacted] is *the operator for the* [redacted] *mines including* [redacted]. *For all intents and purposes,* [redacted] and [redacted] are the same company but are discussed separately in this section due to prior practice. The nine contracts are listed in Exhibit 3-28.

Exhibit 3-28. [redacted] Contracts With Deliveries During 2015

[redacted]

A number of these contracts were entered into (and subsequently amended) to undo the *obligations under Confirms* [redacted] *and* [redacted] *reflecting DP&L's finding that* [redacted].

Confirms [redacted] and [redacted] were entered into as a package.

A summary of the volume changes under Confirms [redacted] and [redacted] are compared to the new commitments under Confirms [redacted], [redacted], [redacted], [redacted], and [redacted] in Exhibit 3-29.

Exhibit 3-29. Volume Changes and Commitments Related to [redacted] and [redacted]

[redacted]

The prices in the new Confirms are basically the weighted average of the prices under Confirms [redacted] and [redacted], i.e., [redacted] and [redacted] respectively. The same methodology was used to calculate the Btu specification. A difference between the new Confirms and the Confirm [redacted] and [redacted] is the loss of [redacted] which was included in the initial Confirms but was not replicated in the new Confirms. As shown below, *this had significant cost implications.*

Also DP&L was [redacted] tons of coal under Confirm [redacted]. As a result, DP&L sold the coal into the market. It was purchased at an [redacted], which DP&L determined to be its highest value option.

Shipments by Confirm are shown below. (Exhibit 3-30) The shipments under Confirm [redacted] are actually purchases by DP&L with a coincident sale to [redacted]

Exhibit 3-30. Shipments of [redacted] Contract Coal in 2015

[redacted]

The quality of shipments under the [redacted] agreements is summarized in Exhibits 3-31. The guarantee specifications were not met in many months under most of the Confirms.

Exhibit 3-31. Quality of Shipments under the [redacted] Agreements

[redacted]

EVA has two problems with DP&L's performance with respect to Confirms [redacted] and [redacted]. The first problem relates to their initial construction. While the Confirms were under the Master Agreement that DP&L had entered into with [redacted] in 2007, DP&L agreed to [redacted]. It was included in the Master Agreement because the agreement with [redacted] was for significant volumes of coal from a new mine which did not have a track record in the DP&L units. Confirm [redacted] was similar, i.e., a multi-year contract for a coal from a new mine with limited experience in DP&L's plants. Through its actions, i.e. the Confirm with the removal of [redacted] DP&L did not exercise its prior good judgement with respect to a new supply source that provided protection in the event of problems. DP&L did not provide an adequate basis for the removal of this section.

[redacted]

As a result, DP&L was required to use a variety of methods [redacted] its coal commitment. As shown above, DP&L negotiated five new Confirms which provided for delivery of a coal meeting higher quality standards. The tons and quality were based upon reductions under both Confirms [redacted] and [redacted]. However, by reducing the tons under Confirms [redacted] and [redacted] and entering into five new confirms, DP&L did not retain [redacted] provisions included in Confirms [redacted] and [redacted]

The omission of [redacted] in the replacement Confirms is problematic. As shown in Exhibit 3-32, [redacted]

Exhibit 3-32. [redacted]

[redacted]

The second concern relates to the fact that DP&L was [redacted] under Confirm [redacted] through the renegotiations. [redacted] Given DP&L's failure to protect itself in the event [redacted], it is hard to support retail customers paying for the recovery of these losses which are [redacted]

[redacted]

A result of the October 2014 RFP was a contract with [redacted]. [redacted]. A summary of the new contract is provided in Exhibit 3-33. The contract was amended twice in 2015 to extend the delivery period, ultimately through August 2015.

[8] Actual shipments of [redacted]

Exhibit 3-33. Summary of [redacted] Contract

[redacted]

[redacted] offered [redacted] coal and the pricing assumes delivery is FOB barge [redacted], suggesting either [redacted] or [redacted] is the source of the coal. The agreement also allowed for [redacted] to deliver at the [redacted].

Tonnage shipped under the [redacted] agreement in 2015 is summarized in Exhibit 3-34. As noted above, the shipments went through August.

Exhibit 3-34. 2015 Shipments Under the [redacted] Contract

[redacted] narized in Exhibit 3- [redacted]

[redacted]

In 2015, DP&L received coal under two contracts with [redacted][9]. In 2012, DP&L entered into a contract [redacted] for 2014 tonnage with [redacted] from the [redacted] Mine #1. [redacted], the final delivery of tons under [redacted] were delayed until 2015. From the October 2014 RFP, DP&L entered into an agreement [redacted] for deliveries in 2015 and 2016. The contracts with [redacted] are summarized in Exhibit 3-36.

Exhibit 3-36. Contracts with [redacted] LLC

[redacted]

Deliveries in 2015 are summarized on Exhibit 3-37. Confirm [redacted] was extended through January 2015 to allow for deliveries to be completed. DP&L did not exercise its right in [redacted] to reduce tonnages by 10 percent in each quarter in 2015.

Exhibit 3-37. 2015 Shipments under [redacted] Agreements

[redacted]

The quality of the 2015 shipments by purchase order are summarized in Exhibit 3-38. Under both agreements, the SO_2 content of the coal delivered was significantly better than the contract specifications. With one exception, all guaranteed quality specifications were achieved.

[redacted]

Exhibit 3-38. Quality of Shipments under [redacted] Agreements

[redacted]

[redacted]

DP&L received coal under one long-term contract with [redacted]. This contract, the terms of which are summarized in Exhibit 3-39, represents DP& [redacted].

Exhibit 3-39. Overview of [redacted] Long-Term Contract

[redacted]

[redacted].

The quantity of the shipments under the [redacted] contract is summarized in Exhibits 3-40. Some of the [redacted].

Exhibit 3-40. 2015 Shipments Under the [redacted] Contract

[redacted]

The quantity of the shipments under the [redacted] contract is summarized in Exhibits 3-41

Exhibit 3-41. Quality of Shipments Under the [redacted] Contract, 2015

[redacted]

Shipments in every month were non-compliant with the monthly guaranteed SO_2 specifications. Shipments in half the months were non-compliant with either the Btu and moisture specifications. The SO_2 is particularly problematic because there is no SO_2 penalty in the contract.

Fuel Costs in Jointly-Owned Plants Not Operated by DP&L

As noted in Section 2, in 2015 DP&L owned shares of Conesville #4, Zimmer, and Miami Fort #7 & #8. Conesville #4 which was initially owned and operated by Columbus Southern Power is now owned and operated by AEP Generation Resources. Zimmer and Miami Fort were built by Cincinnati Gas & Electric, became part of Duke Energy Ohio and as of April 2015 are owned and operated by Dynegy.

The joint ownership came about as the plants were being constructed in an effort to minimize risk. The joint ownership has limited the input from the other owners in operating and fuel procurement decisions. The costs paid by DP&L to its partners and the payments by its partners to DP&L are proscribed in the Fuel Communication and Allocation of Fuel Gains and Losses Agreement (GLA) dated August 11, 2011.

Transportation

Coal and limestone are delivered by barge to Killen and Stuart. The coal and limestone barge agreements are described below. No information was provided on whether the agreements were being extended or replaced after the 2016 expirations.

[redacted]

DP&L is a party to a [redacted]

[redacted]

The [redacted] agreement was not amended during the audit period.

During the audit period, an increase in the Inland Waterways User Tax went into effect. This tax is charged to towboat operators for the purpose of generating funds to support infrastructure projects along the river system. The increase was from $0.20 to $0.29 per gallon for the diesel consumed.

Also during the audit period, a loaded [redacted]. DP&L filed a claim. In February 2016, the parties executed a Receipt and Release in which [redacted] agreed to pay the claim [redacted] and DP&L agreed to release [redacted] from any liability.

[redacted]

DP&L also is a party to a [redacted] for the [redacted] transportation. DP&L is obligated to ship at least 95 percent of [redacted]. There are no minimum tonnage requirements. The [redacted] agreement was not amended during the audit period.

Natural Gas Procurement

Overview

For DP&L, natural gas represents a very small portion of its fuel purchases – both in terms of volume and dollar cost. With less than five percent of total fuel dollars spent on natural gas, it serves one primary use within the DP&L generating portfolio: meeting peak system load by generating from the Tait Gas Turbine facility.

Despite the small amount of gas used within the system, it is critical for DP&L to have a strong awareness of the U.S. natural gas market, as recent developments continue to push rapid change within the industry that will affect both the physical gas delivery system as well how gas is priced in the future.

Industry Background

Over the last decade, the natural gas industry in the United States has changed dramatically. Rapid growth in unconventional gas development – primarily through the harnessing of shale gas– has greatly changed the landscape for both producers and consumers of natural gas. The critical nature of these changes demand action from primary stakeholders to ensure the appropriate allocation of capital for fuel procurement.

When looking at the shifts in natural gas over the last several years, there are three primary focus areas that will be critical to DP&L going forward:

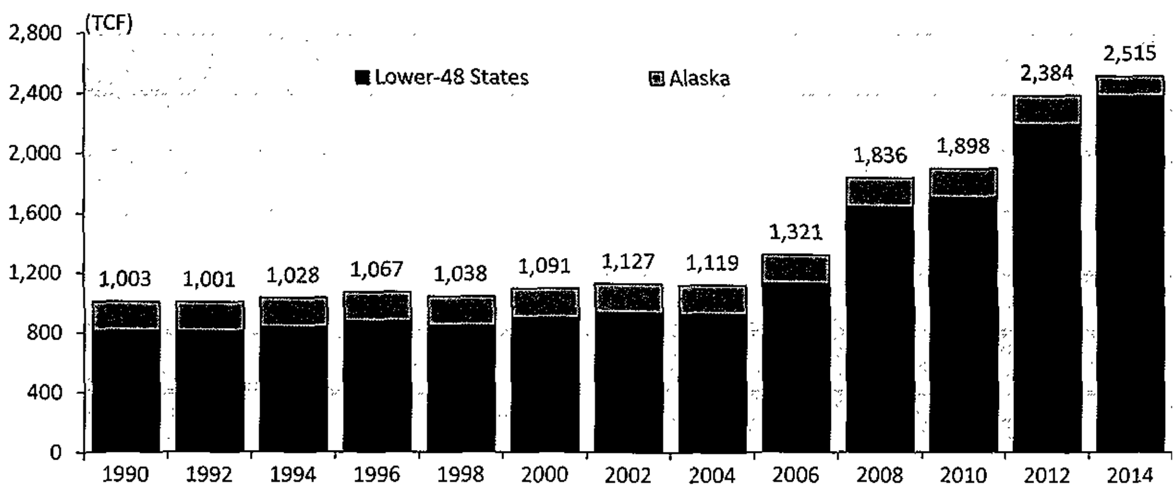
- Discovery and rapid development of new natural gas supply sources, such as the Marcellus Shale
- Alteration of and additions to existing natural gas pipeline infrastructure to accommodate shifting supply base

- Impact of new supplies and infrastructure on natural gas prices and basis differentials

Natural Gas Supply

Every two years, the Potential Gas Committee – a gathering of industry experts, geologists and other stakeholders – release its estimates of how much natural gas exists in the reserve base of the United States. While the Committee does not comment on the economic viability of the development of these natural gas reserves, it does discuss the location and characteristics of how much gas is believed to be in the ground nationwide. Exhibit 3-42 shows the rapid change in this resource base over the last eight years.

Exhibit 3-42. Potential Gas Committee Natural Gas Reserve Base Estimates



Source: Potential Gas Committee. Note: Mean values.

Exhibit 3-43 shows the rapid growth in Lower 48 Natural Gas production since 2004. Exhibit 3-44 shows the location of the shale plays accounting for this incremental production.

Exhibit 3-43. Lower 48 States Natural Gas Production (BCFD)

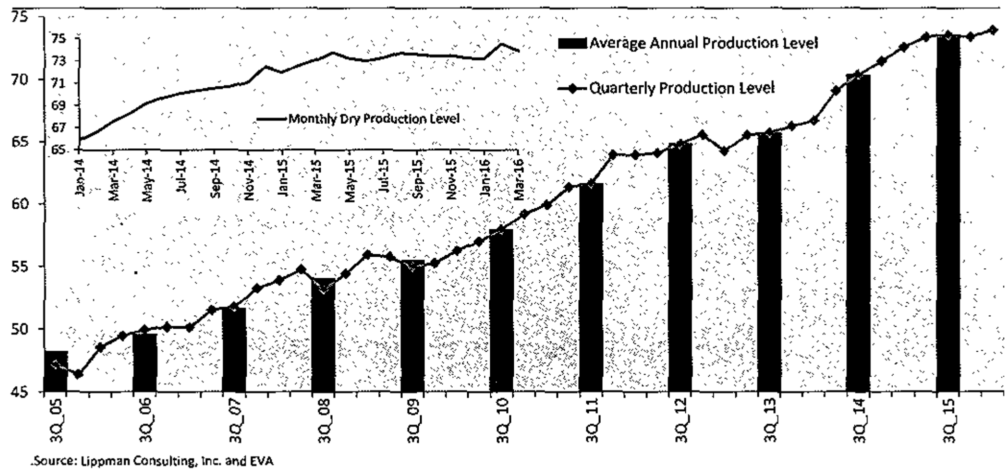
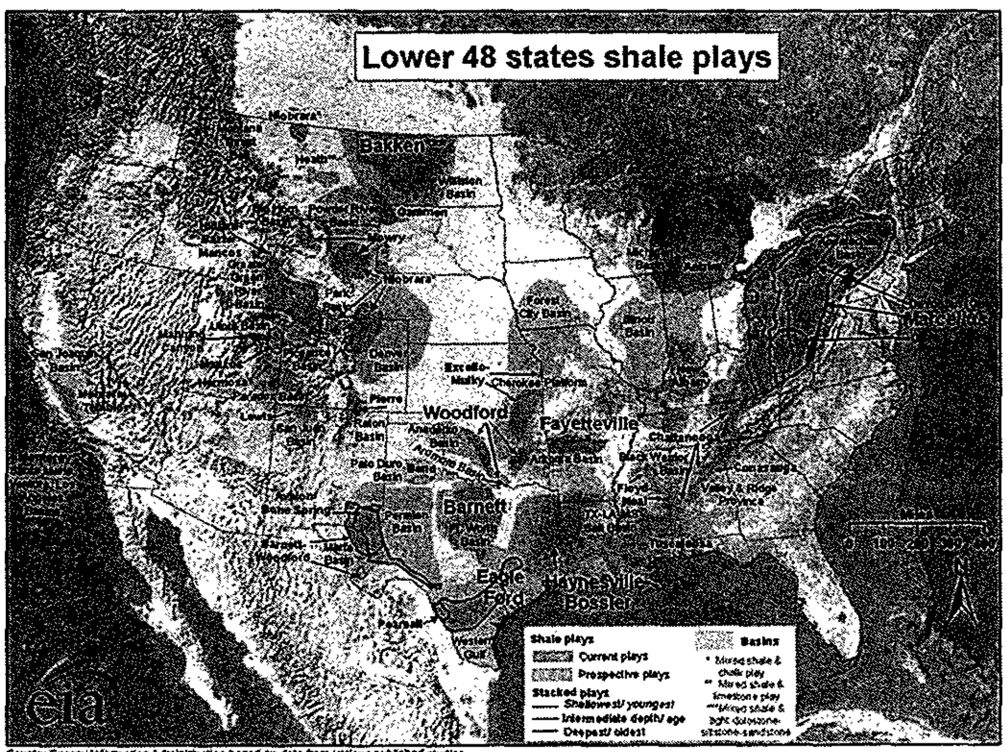


Exhibit 3-44. Shale Gas Reserve Map from EIA

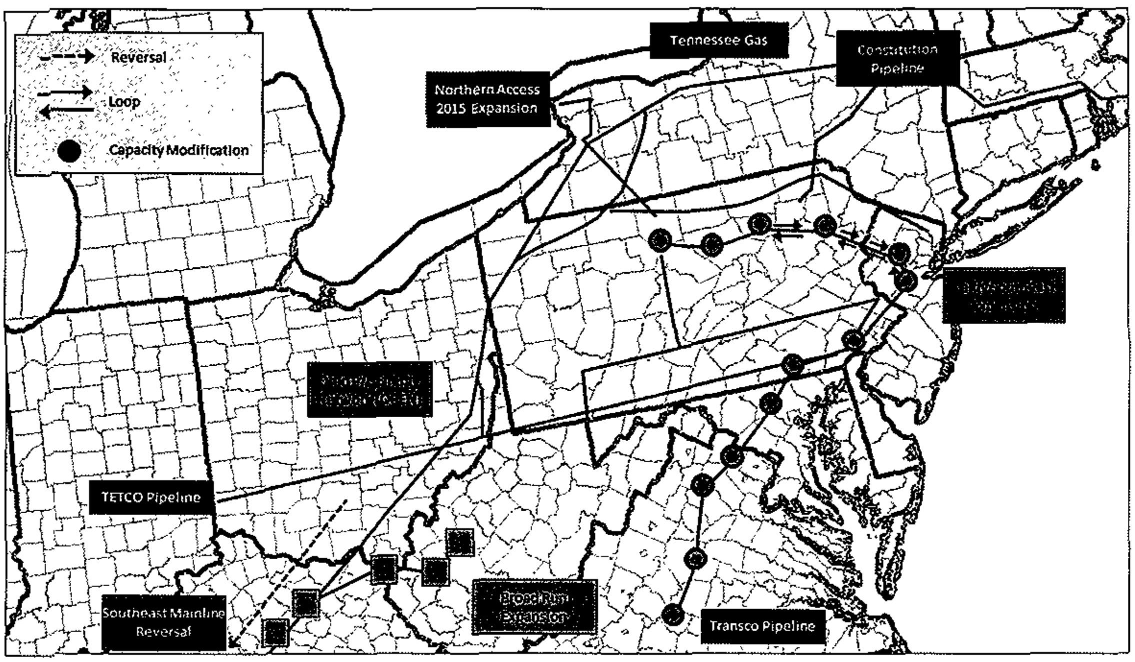


The importance of the shale revolution to DP&L is twofold: first is the impact on natural gas pricing (which is discussed below). The second is the locational dynamics of this new supply. With much of the new supply coming online in the northeastern US (i.e., Pennsylvania, West Virginia and Ohio), DP&L has increased proximity to an enormous volume of new shale gas reserves, greatly increasing its buying power within the region. This fact should permeate its pricing strategy as well as how it negotiates contracts with those pipelines that are able to service its facilities.

Natural Gas Infrastructure

In order to accommodate the recent shift in natural gas supply from the south/Gulf region to the Northeast, there are more than 60 completed or pending pipeline projects tasked with relieving the supply glut facing the core production areas of the Marcellus shale. Exhibit 3-45 shows an example of some of the larger projects that have taken place over the past several years.

Exhibit 3-45. Major Northeast Pipeline Expansion Projects



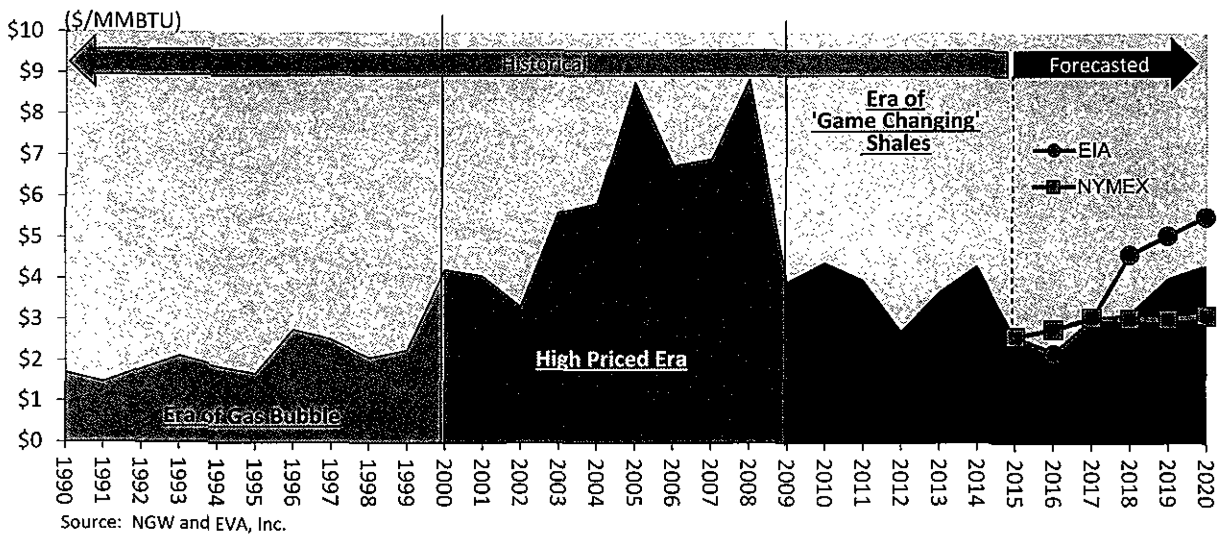
The implications of this new infrastructure are numerous and must be a critical input to any procurement strategy at DP&L. Some examples include:

- The creation of new pricing points and hubs – especially in the northeast. These include TETCO M2, Millennium South and the Leidy Hub. This provides greater trading liquidity in the region and offers greater pricing transparency
- Compression of basis differentials. The price differences between assorted regional pricing points will be reduced, thus reducing the delivered price of gas.
- Redirection and/or re-tasking of existing pipelines. Pipelines (such as the Rockies Express and Columbia Gulf) are looking to reverse direction to service Marcellus production.

Natural Gas Pricing

The net result of these large structural changes to the natural gas market has been a rapid decline in natural gas prices as shown in Exhibit 3-46. In 2012, prices hit lows not seen in close to a decade, dropping below $2.00/MMBtu in March/April, as a surplus of natural gas resulted in prices falling to the levels necessary to displace coal generation. After a brief recovery, prices fell again in 2015 and 2016 for the same reasons. There are different views of prices going forward with EIA expected some firming and NYMEX reflecting a relatively flat price outlook. (EVA's price outlook falls in between.) Regardless this "new era" of prices is a consideration to DP&L's natural gas procurement practices and, even more critically, its long term review of reliability and generation issues.

Exhibit 3-46. Henry Hub Natural Gas Price History



2015 Gas Purchase Review

In 2015, DP&L Energy purchased [redacted] million cubic feet (Mcf) of natural gas with a total cost of [redacted] million. Natural gas volumes and charges by month are shown in Exhibit 3-47.[10]

[10] Includes regulated and un-regulated purchases.

Exhibit 3-47. DP&L Natural Gas Purchases

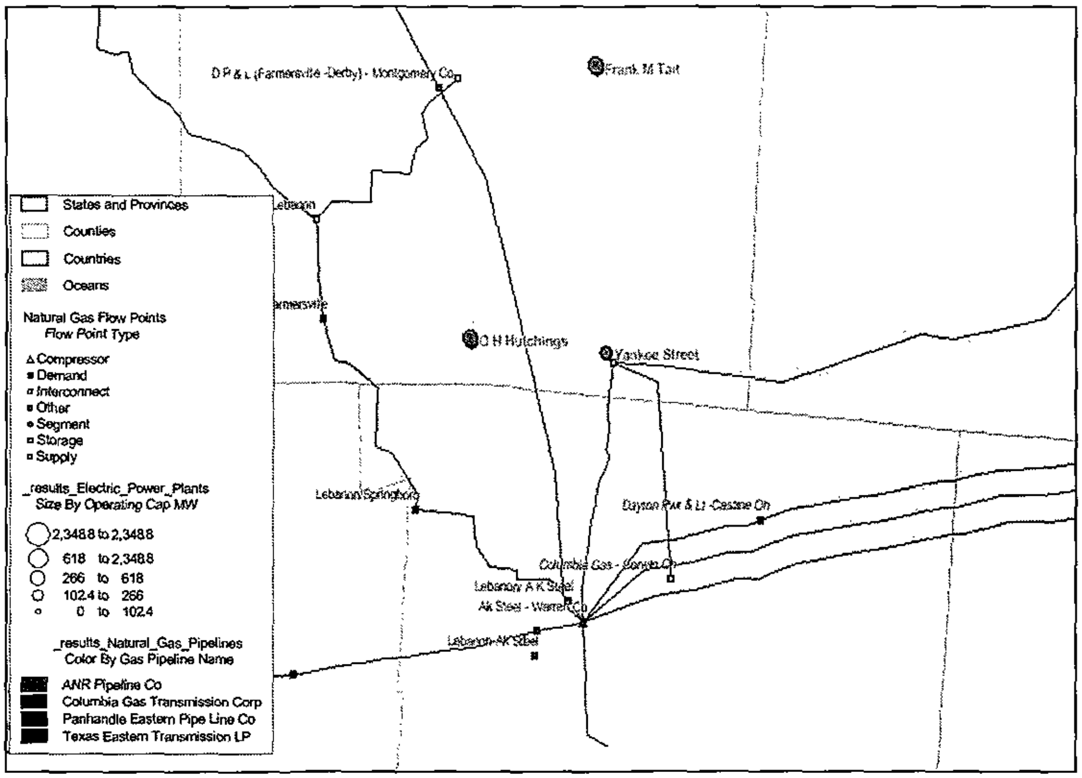
[redacted]

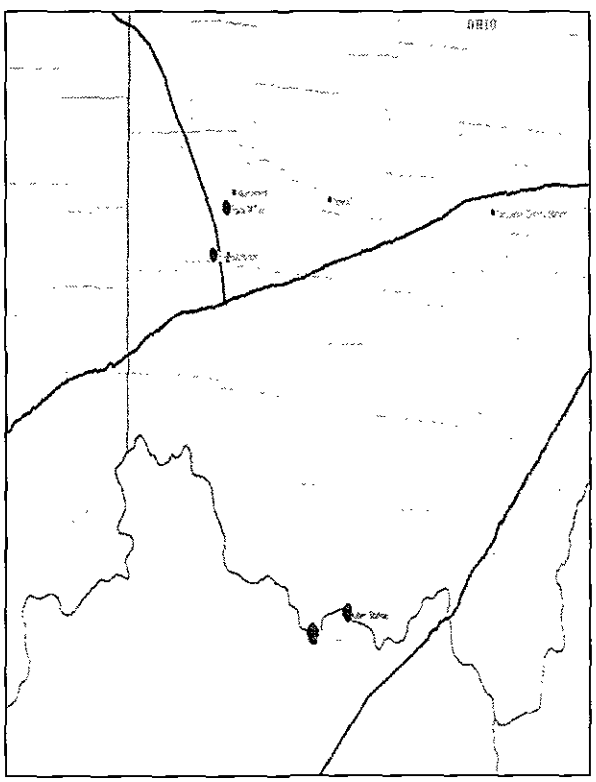
Upon review of the gas purchases, all prices paid and volumes purchased appeared to be prudent. Additionally, DP&L only conducted trades with counterparties with whom it has up-to-date master agreements.

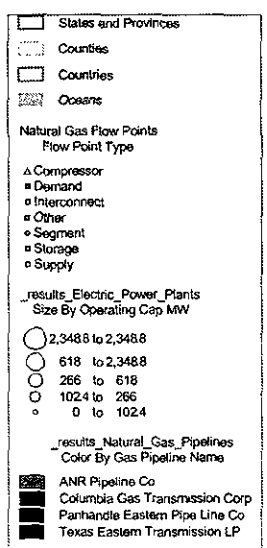
Upon review of DP&L's pipeline charges, they also appeared prudent. DP&L holds pipeline contracts with four major interstate pipeline systems: [redacted] The most heavily used path for natural gas flow has been through [redacted].

Exhibit 3-48 shows a map of DP&L's key gas generating assets as well as the pipelines at that service them. The location of Tait, Yankee and Hutchings provides gas supply volume diversification options as well as direct paths from core supply sources to DP&L facilities.

Exhibit 3-48. Key Gathering Assets and Pipelines







4 PLANT PERFORMANCE

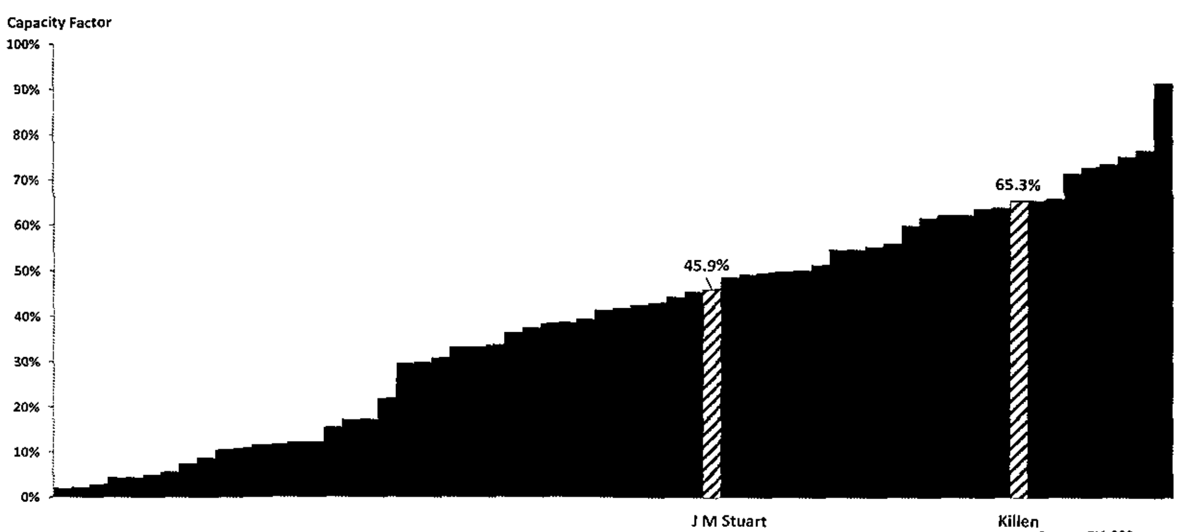
Benchmarking

The performance of the DP&L-operated coal plants can be measured against other coal-fired plants in the PJM Interconnection to determine how competitive these plants are at providing electricity to the power pool. This same comparison can be made to coal plants in Ohio and Kentucky which have similar fuel costs.

Two measures used to demonstrate plant performance are capacity factor and heat rate. Heat rate is the amount of energy used to generate one unit of electricity expressed in BTUs per kilowatt- hour. Capacity factor is the utilization rate of the plant or how many megawatt-hours were generated verses its potential generation. Capacity factor generally ties to the competitiveness of the plant.

The capacity factors of the two DP&L-operated plants compared to the other coal-fired plants in the PJM Interconnection are presented in Exhibit 4-1. Overall, Killen's and Stuart's performance declined in 2015. Killen's capacity factor declined from 72.5 percent in 2014 to 65.3 percent in 2015. Stuart's capacity factor declined from 50.9 percent in 2014 to 45.9 percent in 2015.

Exhibit 4-1. PJM Coal-Fired Power Capacity Factors in 2015



Killen's and Stuart's heat rates are in the lower half of the PJM curve (Exhibit 4-2). A lower heat rate conveys that a plant will use less fuel to produce a unit of electricity, therefore the plants marginal cost to produce electricity is lower and able to sell electricity at a more competitive rate into the power pool. Both Killen and Stuart had poorer heat rates in 2015 than in 2014. This is not surprising given the correlation between capacity factor and heat rate.

Exhibit 4-2. PJM Coal-Fired Power Plant Heat Rates in 2015

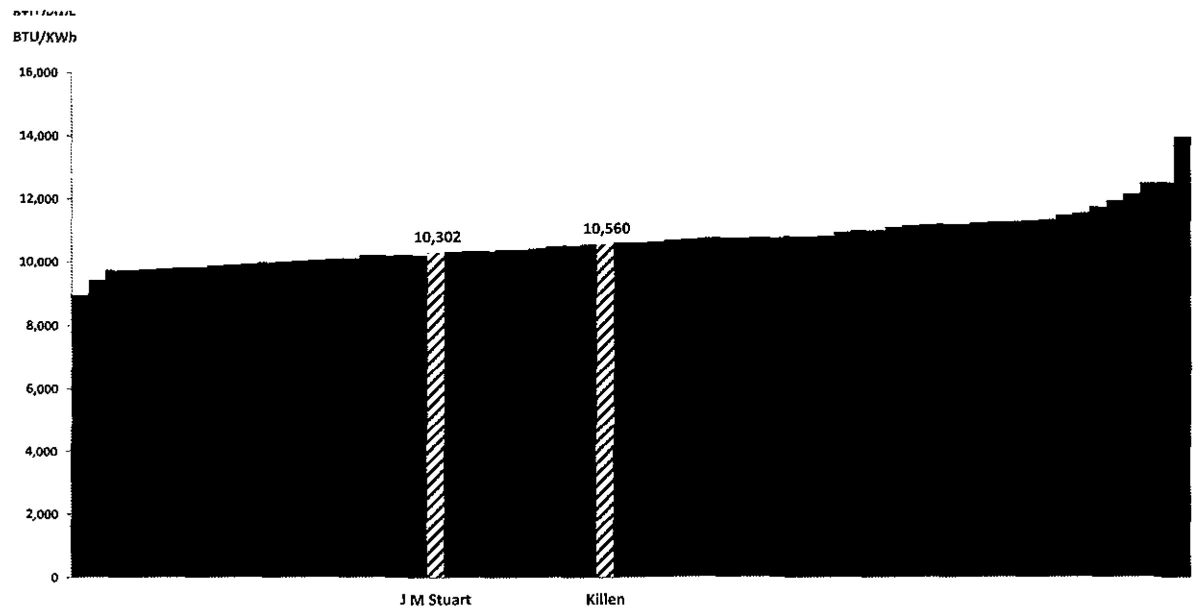
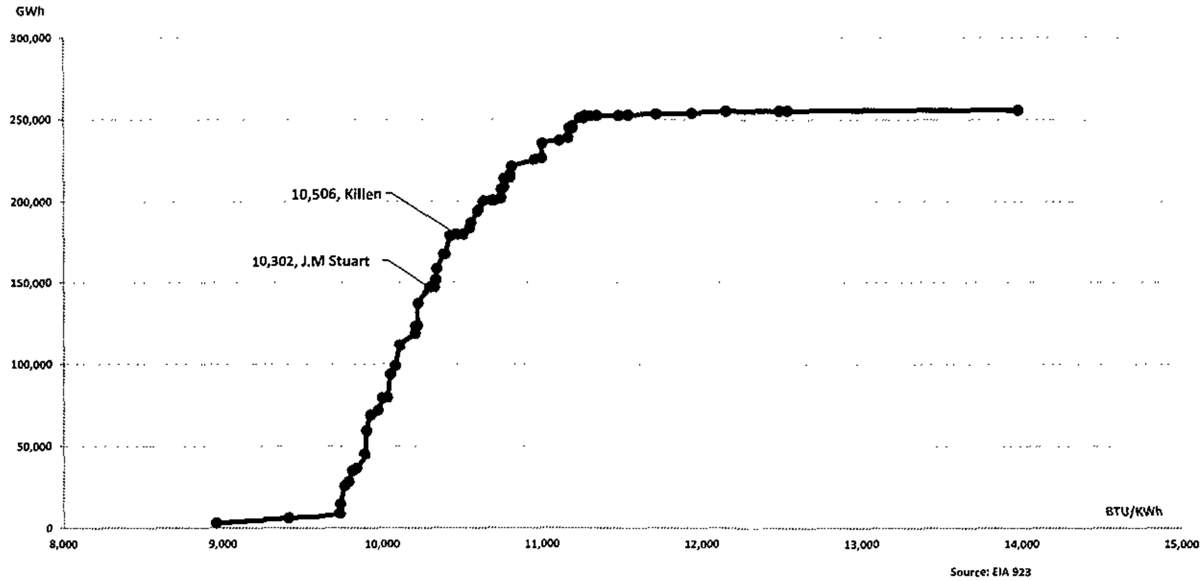


Exhibit 4-3 displays the cumulative 2015 generation of PJM coal-fired plants by heat rate. Both Stuart's and Killen's heat rate puts then on the top half of the dispatch curve.

Exhibit 4-3. PJM Coal-Fired Facilities Annual Cumulative Generation by Heat Rate, 2015



The comparisons with capacity factor and heat rate are provided with Kentucky and Ohio coal-fired plants respectively in Exhibits 4-4 and 4-5. Not surprisingly, the results are similar with the PJM population.

Exhibit 4-4. Ohio and Kentucky Coal-Fired Power Capacity Factors in 2015

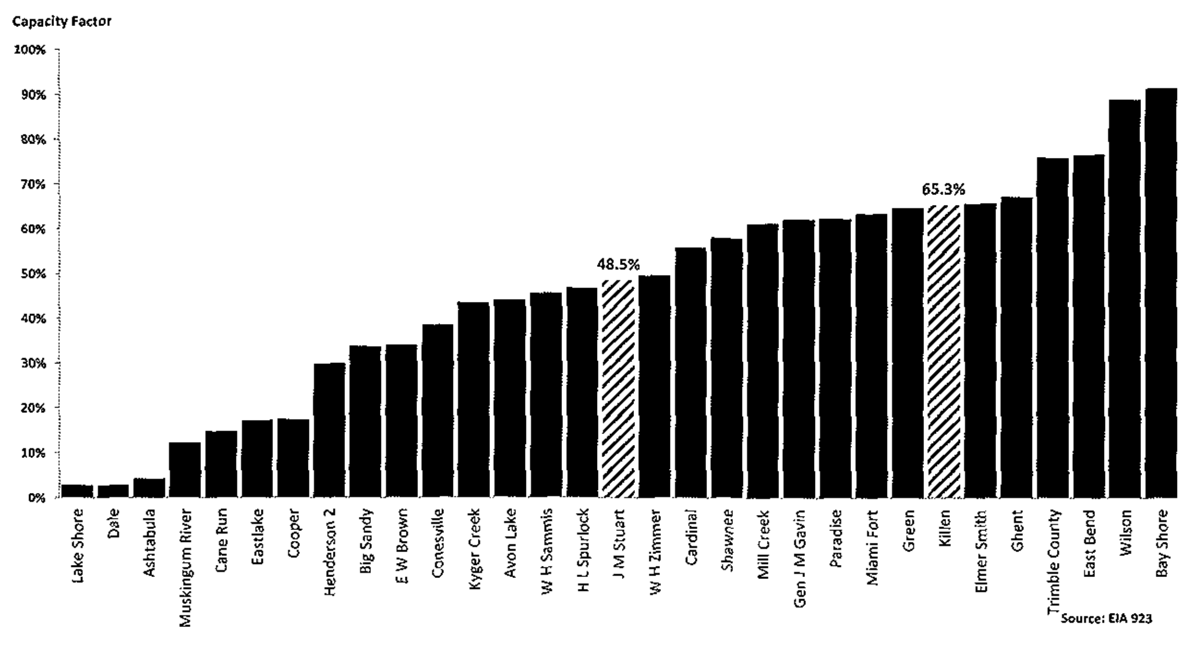
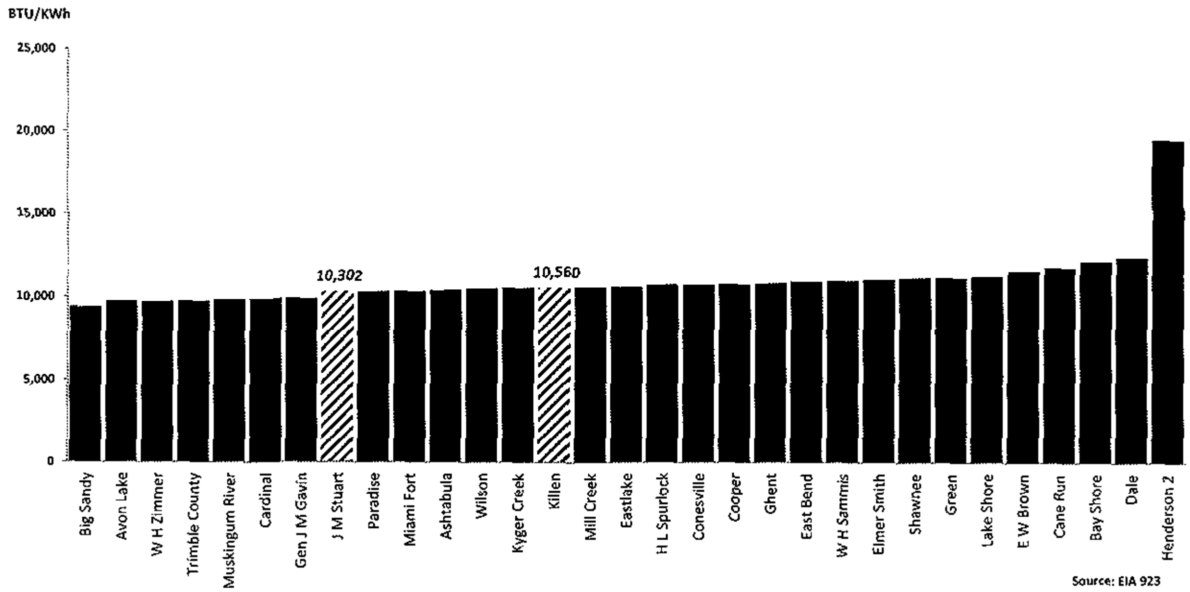


Exhibit 4-5. Ohio and Kentucky Coal-Fired Power Plant Heat Rates in 2015



5 FINANCIAL AUDIT OF THE FUEL ADJUSTMENT CLAUSE RIDER (FUEL RIDER) COMPONENT

Organization

The section of the report concerning the Fuel Rider filings audit is organized into the following sections:

- Background
- Stipulation from Case No. 08-1094-EL-SSO
- Certificate of Accountability of Independent Auditors
- Accounts Included in DP&L's FUEL Rider
- Quarterly FUEL Rider Filings
- Variances Between Forecasted and Actual Fuel Rider Revenues and Costs
- Potential for a Terminal Undercollected Balance
- Minimum Review Requirements
- Jointly Owned Generation
- Review Related to Coal Order Processing
- Fuel Ledger
- BTU Adjustments
- Freight and Barge Vouchers
- Fuel Analysis Reports
- Retroactive Escalations
- Review Related to Station Visitation and Coal Processing Procedure
- Review Related to Coal Transfers Between Generating Stations
- Review Related to Fuel Supplies Owned or Controlled by the Company
- Review Related to Purchased Power
- Demurrage
- Review Related to Service Interruptions and Unscheduled Outages
- Audit Trail for FUEL Rider Filings, Supporting Workpapers and Documentation

- Reconciliation Adjustments Audit Trail
- System Optimization
- Accounting for Emission Allowances
- Application of FUEL Rider Rates to Customer Bills
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- General Ledger Detail and Audit Trail
- Loss on Sale of Fuel Oil and Beckjord
- Customer Switching
- Internal Audits
- Section 45 Plant
- Reconciliation Rider
- Competitive Bid True-Up Rider
- Memorandum of Findings and Recommendations

Background

On September 3, 2003, the Commission approved a stipulation extending DP&L's market development period to December 31, 2005, and provided for a rate stabilization plan ("RSP") from January 1, 2006 through December 31, 2008. Under the RSP, DP&L's Fuel rate was fixed and included in the base retail generation rates. DP&L filed an application with the Commission on October 10, 2008 for a standard service offer ("SSO") in the form of an electric security plan ("ESP") as Case No. 08-1094-EL-SSO et al. The application was supplemented on December 5, 2008. A Stipulation was subsequently filed with the Commission on February 24, 2009. (See discussion below) In the Commission's Opinion and Order dated June 24, 2009, the Commission authorized DP&L to implement a bypassable Fuel recovery rider ("FUEL Rider") to become effective January 1, 2010. The Commission also determined that the Stipulation would freeze distribution rates through December 31, 2012; would ensure rate certainty through December 31, 2012, with limited, specific exceptions; and requires DP&L to implement energy efficiency and peak demand reduction programs in consultation with an energy efficiency collaborative. The ESP also established an Alternative Energy Rider to recover alternative energy costs. On September 4, 2013, the Commission approved a second ESP for DP&L in Case No. 12-426-EL-SSO, et al, which covers the period January 1, 2014 through May 31, 2017.

Stipulation From Case No. 08-1094-EL-SSO

Certain provisions of the FUEL Rider were addressed in a stipulation reached in Case No. 08-1094-EL-SSO et al.

Certificate Of Accountability Of Independent Auditors

To: The Dayton Power & Light Company

We have examined the quarterly FUEL Rider filings of The Dayton Power & Light Company ("DP&L") for the year ended December 31, 2015, which support the calculations of the Fuel Rider rates for the 12-month period January through December 2015. In addition, we have examined the quarterly Alternative Energy Rider ("AER") filings, which support the calculations of the Alternative Energy Rider for the 2015 period. In conducting our review, we were aware of and considered the guidance set forth in former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component".

Our examination for this purpose was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining on a test basis, the accounting records and such other procedures as we considered necessary in the circumstances. We did not make a detailed examination as would be required to determine that each transaction was recorded in accordance with the financial procedural aspects of former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code. Our examination does not provide a legal determination of DP&L's compliance with specific requirements.

The FUEL Rider and AER filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to DP&L's fair determination of the FUEL Rider rates for January through December 2015 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period January through December 2015 that were reflected by DP&L through the Company's quarterly FUEL Rider filings, and to express an opinion as to DP&L's fair determination of the Rider AER rates for January through December 2015, that were reflected by DP&L through the Company's quarterly AER filings. We believe that our examination provides a reasonable basis for our opinion.

In our opinion, except for the recommended adjustments that are discussed in the Management Audit section of this report, DP&L has determined, in all material respects, the FUEL Rider rates for the 12-month period January through December 2015, including the Reconciliation Adjustments for the period January through December 2015 in accordance with its proposed procedures and its interpretation of what should be includable in the FUEL Rider rates.

In our opinion, except for the concerns noted in this report, DP&L has determined, in all material respects, the AER rates for January through December 2015 in accordance with its proposed procedure, and its interpretation of what should be includable in the AER rates.

This report is intended solely for use in Case No. 16-0224-EL-FAC at the Public Utilities Commission of Ohio ("PUCO").

Larkin & Associates PLLC

Larkin & Associates PLLC
Livonia, Michigan

The following passages are from the Stipulation and Recommendation in Case No. 08-1094-EL-SSO et al., dated February 24, 2009 at paragraphs 1 and 2:

> To assist in maintaining rate certainty, the parties agree to extend DP&L's current rate plan through December 31, 2012, except as expressly modified herein.
>
> DP&L will implement a bypassable Fuel recovery rider to recover retail Fuel and purchased power costs, based on least cost Fuel and purchased power being allocated to retail customers. To calculate the rider, jurisdictional emission allowance proceeds and twenty-five percent of jurisdictional coal sales gains will be netted against the Fuel and purchased power costs. Retail customers for the purpose of this calculation include DP&L as well as DPL Energy Resource customers. The rider will initially be established at 1.97¢ per kWh, which amount will be subtracted from DP&L's residual generation rates. No later than November 1, 2009, DP&L will make a filing at the Commission to establish the Fuel rider to become effective January 1, 2010. Thereafter, the Company shall file quarterly adjustments for recovery of the cost of Fuel and purchased power. The Company's annual filing will be submitted during the first quarter of each year, beginning in 2011, and will be subject to due process, including audits and hearings (unless no signatory party objects to foregoing the hearing) for the twelve-month periods ending December 31, 2010 and 2011. The Company's annual filing shall include but not be limited to details substantiating all costs included in the Fuel recovery rider during the prior calendar year so that Staff and interested parties can evaluate the methodology, account balances, forecasts, and substantiating support. Such audit shall be conducted by an independent third party auditor or Staff, at the Commission's discretion. If conducted by a third party: (a) the third party will be engaged by and report to staff; and (b) DP&L will fund the audit and may seek cost recovery through the Fuel recovery rider. DP&L will withdraw its request for deferral of Fuel costs for 2009-2010.

Accounts Included In DP&L's FUEL Rider

As stated in the Company's Application to Establish a FUEL Rider, DP&L has interpreted the Stipulation and Order in Case No. 08-1094-EL-SSO et al to allow for the inclusion of costs from the following FERC accounts and types of costs in its quarterly FUEL Rider filings:

> **Fuel Costs.** FERC Accounts 501 and 547 include the costs of Fuel and transportation of Fuel used for the generation of electricity. The majority of Fuel handling costs at the plants are also recorded in Account 501. Gains and losses on Fuel sales that are recorded into Account 456 and cleared through Account 501 were separately estimated as discussed below. The costs for disposal of fly ash are also recorded in FERC Account 501, but were excluded from the projected costs used to establish initial FUEL rates. The portion of the recorded costs for biomass and similar Fuels that is higher than the equivalent cost of coal will be excluded from Fuel calculations and recovered through the Alternative Energy

Rider; the portion of these costs up to the equivalent cost of coal will be included in the Fuel calculations for recovery through the FUEL rates.

Purchased Power Costs and Related Transmission Not Otherwise Recovered. FERC Account 555 includes the cost of purchased power. FERC Account 565 includes electric transmission costs, including costs of transmission of power external to PJM to bring it to PJM (if any).

Emissions Allowances. FERC Account 509 records the costs of emission allowances. Currently this account includes sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emission allowance costs. Future legislation may add other types of allowance costs that would also be recorded in this account for recovery.

Emission Fees. FERC Account 506 records the costs of emission fees, which are from the Ohio EPA. The Fuel Rider contains two separate components of emission fees, including (1) state emission fees related to DP&L withdrawing its application in Case No. 93-1000-EFR pursuant to paragraph 15 from the Stipulation and Recommendation dated October 5, 2011; and (2) ongoing monthly emission fees to date.

Gains and Losses. Gains and losses on purchased power are recorded in FERC Accounts 421 and 426. Gains and losses on the sale of coal and on the sale of heating oil futures used as a price hedge are recorded in FERC Account 456. Gains and losses on the sale of emission allowances are recorded in FERC Accounts 411.8 and 411.9. The net proceeds of optimization transactions, where there is a sale of coal or power and a replacement purchase, are based on the price of coal or power sold, net of the cost of the replacement coal or power.

Reconciliation Adjustment Initially Set to Zero. Within future Fuel Rider quarterly filings, the amounts under-recovered or over-recovered will be assessed or returned to customers over time through a reconciliation adjustment, which will also include a component to reflect carrying costs or benefits at DP&L's weighted average debt rate as last set in Case No. 08-1094-EL-SSO.

Quarterly FUEL Rider Filings

For the period 2015, DP&L made the following quarterly FUEL Rider filings:

Exhibit 5-1. Quarterly FUEL Rider Filings

Date Filed	Forecast Period Covered	Reconciliation Adjustment (Actual Period Covered)
October 17, 2014	December 2014 - February 2015	January - September 2014
January 15, 2015	March - May 2015	October - December 2014
April 17, 2015	June - August 2015	October 2014 - March 2015
July 17, 2015	September - November 2015	January - June 2015
October 16, 2015	December 2015	January - September 2015
	December 2015 - May 2016	January - November 2015

Larkin's review of DP&L's quarterly FUEL Rider filings covers the forecast periods encompassing calendar 2015. Our review also covers DP&L's calculations of the Reconciliation Adjustment (RA) components included within those quarterly FUEL Rider filings for the months of 2015. Larkin's review of DP&L's RA information included verification to actual recorded results on a test basis for the months of January through December 2015.

The following sections discuss DP&L's 2015 quarterly Fuel Rider filings[11] by reproducing Schedules 1 and 2 as well as Workpaper 1 as Exhibits 5-2 through 5-24.

Quarterly FUEL Rider Filing – December 2014 through February 2015

Exhibit 5-2. Forecasted Quarterly Rate Summary, December 2014 through February 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Dec-14	(C) Jan-15	(D) Feb-15	(E) Total Jan & Feb	(F) Total	(G) Source
1	Forecasted FUEL Costs	$9,371,261	$4,249,403	$3,127,839	$7,377,242	$16,748,503	Workpaper 1, Line 13
2	*Forecasted Generation Level Sales*	*388,765,293*	*396,894,272*	*208,533,176*	*605,427,448*	*994,192,741*	*Workpaper 1, Line 14*
3	FUEL Rate before Reconciliation Adjustment $/kWh	$0.0241052			$0.0121852		Line 1 / Line 2
4	Reconciliation Adjustment $/kWh	$0.0016947			$0.0016947		Schedule 2, Line 22
5	Forecasted Retail FUEL Rate $/kWh	$0.0257999			$0.0138799		Line 3 + Line 4
	FUEL Rates at Distribution Level:			High Voltage & Substation	Primary	Secondary & Residential	
6	Distribution Line Loss Factors			1.00583	1.01732	1.04687	Line Loss Study 2009
7	***December FUEL Rates $/kWh***			***$0.0259503***	***$0.0262468***	***$0.0270091***	*Line 5, Column B * Line 6*
8	**January & February FUEL Rates $/kWh**			**$0.0139608**	**$0.0141203**	**$0.0145305**	Line 5, Column E * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to incur during the period December 2014 through February 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted Fuel costs for December 2014 through February 2015, which totaled $16.749 million (column F). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 994.193 million kWh for the period December 2014 through February 2015. For December 2014, the Company calculated its retail Fuel rate before Reconciliation Adjustment of $0.0241052 per kWh by dividing the forecasted December Fuel costs of $9.371 million by the forecasted Generation Level Retail Sales for December of 388.765 million. For January and February 2015, the Company calculated its retail Fuel rate before Reconciliation Adjustment of $0.0121852 per kWh by dividing the forecasted January and February 2015 Fuel costs of $7.377 million by the forecasted Generation Level Retail Sales for January and February 2015 of 605.427 million. The

[11] DP&L provided the Excel versions of its quarterly Fuel Rider filings in response to LA-2014-52.

Company reflected a Reconciliation Adjustment for the period January 2014 through February 2015 (see Schedule 2 discussion below) of $0.0016947 per kWh on line 4. For December 2014, DP&L added its Reconciliation Adjustment to the $0.0241052 per kWh noted above to derive its forecasted retail Fuel rate of $0.0257999 per kWh as shown on line 5 of Schedule 1. For January and February 2015, DP&L added its Reconciliation Adjustment to the $0.00121852 per kWh noted above to derive its forecasted retail Fuel rate of $0.0138799 per kWh. After applying the line loss factors of 1.00583, 1.01732, and 1.04687 cents per kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0259503, $0.0262468, and $0.0270091 cents per kWh as shown on line 7 for December 2014. Using the same line loss factors, the Company calculated Fuel rates at the distribution level of $0.0139608, $0.0141203, and $0.0145305 cents per kWh as shown on line 8 for January and February 2015.

Exhibit 5-3. Reconciliation Adjustment – January 2014 through February 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Description	Actual Fuel Costs	Actual Revenue Recovery	(Over)/Under Recovery (D) = (B) + (C)	Carrying Costs	Total (F) = (D) + (E)	YTD[1]	Source
1	Prior Period					$195,730	$195,730	Accounting Records
2	January-14	$13,619,865	($11,057,984)	$2,561,880	$6,083	$2,567,963	$2,763,693	Accounting Records
3	February-14	$11,497,955	($10,927,437)	$570,518	$12,559	$583,077	$3,346,770	Accounting Records
4	March-14	$11,486,139	($9,037,325)	$2,448,815	$18,829	$2,467,644	$5,814,414	Accounting Records
5	April-14	$9,020,601	($7,457,280)	$1,563,321	$27,170	$1,590,491	$7,404,906	Accounting Records
6	May-14	$10,545,612	($6,172,374)	$4,373,238	$39,509	$4,412,747	$11,817,652	Accounting Records
7	June-14	$10,373,979	($7,970,104)	($2,251,670) [2]	$44,041	($2,207,629)	$9,610,023	Accounting Records
8	July-14	$9,631,909	($9,182,015)	$449,893	$40,512	$490,405	$10,100,428	Accounting Records
9	August-14	$10,580,843	($8,649,533)	$1,931,310	$45,583	$1,976,893	$12,077,321	Accounting Records
10	September-14	$8,202,510	($9,263,662)	($7,798,897) [2]	$33,686	($7,765,211)	$4,312,110	Accounting Records
11	October-14	$5,581,179	($6,160,857)	($579,678)	$16,568	($563,110)	$3,749,000	Corporate Forecast
12	November-14	$5,360,984	($5,822,048)	($461,064)	$14,493	($446,571)	$3,302,429	Corporate Forecast
13	December-14	$9,371,261	($9,371,261)	$0	$8,894	$8,894	$3,311,324	Corporate Forecast
14	January-15	$4,249,403	($4,249,403)	$0	$1,628	$1,628	$3,312,951	Corporate Forecast
15	February-15	$3,127,839	($3,127,839)	$0	($479)	($479)	$3,312,473	Corporate Forecast
16	(Over)/Under Recovery						$3,312,473	Line 15
17	(Over)/Under Recovery Through November 2014						$3,302,429	Line 12
18	10% Quarterly Threshold						$1,674,850	(Sum of Column B, Lines 13 - 15) * 10%
19	Amount Exceeding Threshold						$1,627,579	Line 17 - Line 18
20	Total (Over)/Under Recovery						$1,684,894	Line 16 - Line 19
				Dec-14	Jan-15	Feb-15		
21	Forecasted Generation Level Sales			388,765,293	396,894,272	208,533,176	994,192,741	
22	Forecasted RA Rate $/kWh						$0.0016947	Line 20 / Line 21

[1] YTD = current month Total + previous month YTD total

[2] (Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period January through September 2014, and (2) DP&L's estimated Fuel costs for the period October through February 2015 for total actual and forecasted Fuel costs of $122.650 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($108.449) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $2.808

million, as shown in column D. Column E reflects the carrying costs for the period of January 2014 through February 2015, which totaled $309,078. The under-recovery for the period of January 2014 through February 2015 and the addition of the carrying costs for the same period resulted in a YTD under-recovery of $3.312 million (column G, line 16). Line 17 reflects the under-recovery of $3.302 million for the period of January through November 2014. The amount on Line 18 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted Fuel costs for the period December 2014 through February 2015 by 10% which totals $1.675 million. This calculation relates to the implementation of the Company's Reconciliation Rider. [12] This amount was then subtracted from the under-recovery through November 2014 to calculate the Amount Exceeding Threshold of $1.628 million, as shown on line 19. The result is a total under-recovery of $1.685 million, which is derived by subtracting the amount exceeding the threshold from the under recovery through November 2014, as shown on line 20. Line 21 of Schedule 2 reflects DP&L's forecasted generation level sales for the period December 2014 through February 2015, which totals 994.193 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of ($0.0016947) per kWh by dividing the total under-recovery of $1.685 million by its forecasted sales for the period December 2014 through February 2015.

[12] The Reconciliation Rider is discussed in further detail in a later section of this report.

Exhibit 5-4. Forecasted Quarterly Rate – Workpaper 1, December 2014 through February 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Dec-14	(C) Jan-15	(D) Feb-15	(E) Total Jan & Feb	(F) Total
	Forecasted Costs ($)[1]					
1	Steam Plant Generation (501)	$6,556,281	$2,057,179	$1,229,063	$3,286,242	$9,842,524
2	Steam Plant Fuel Oil Consumed (501)	$215,767	$51,031	$27,193	$78,224	$293,991
3	Steam Plant Fuel Handling (501)	$196,688	$61,715	$36,872	$98,587	$295,276
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	$34	$0	($6)	($6)	$28
7	Allowances Consumed (509)	$0	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$0	$0	$0
9	Purchased Power (555)	$2,390,343	$2,075,738	$1,832,012	$3,907,750	$6,298,093
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0	$0
12	Emission Fees (506)	$12,147	$3,739	$2,705	$6,445	$18,592
13	Total Costs	$9,371,261	$4,249,403	$3,127,839	$7,377,242	$16,748,503
14	Total Forecasted Generation Level Sales	388,765,293	396,894,272	208,533,176	605,427,448	994,192,741
15	Retail FUEL Rate $/kWh	$0.0241052			$0.0121852	
	Reconciliation Adjustment					
16	Under (Over) Recovery					$1,684,894
17	Forecasted RA Rate $/kWh					$0.0016947

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level December	Rate at Distribution Level January & February
18	High Voltage & Substation	1.00583	$0.0259503	$0.0139608
19	Primary	1.01732	$0.0262468	$0.0141203
20	Secondary & Residential	1.04687	$0.0270091	$0.0145305

Fall FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Dec-14	Jan-15	Feb-15	Total
21	High Voltage & Substation	32,378,548	29,013,372	29,610,451	91,002,371
22	Primary	7,318,878	5,732,963	8,640,008	21,691,849
23	Secondary & Residential	333,138,152	345,677,585	162,351,050	841,166,786
24	Total	372,835,578	380,423,920	200,601,509	953,861,007
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$840,233	$405,050	$413,386	$1,658,669
26	Primary	$192,097	$80,951	$122,000	$395,048
27	Secondary & Residential	$8,997,762	$5,022,868	$2,359,042	$16,379,672
28	Total	$10,030,092	$5,508,869	$2,894,427	$18,433,388

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period December 2014 through February 2015. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for December 2014 through February 2015 which totals the $16.749 million shown on Schedule 1. Lines 14 and 15 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales and retail Fuel rate. Lines 16 and 17 reflect the under-recovery of $1.685 million and the forecasted RA rate of ($0.0016947) per kWh. Lines 18 through 20 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 6 and 7, respectively and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 21 through 28 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Columns B through D reflect forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels by month for the December 2014 through February 2015 period. For this three-month period, the forecasted kWh for each voltage level totals 91.002 million kWh, 21.692 million kWh, and 841.167 million kWh for the High Voltage & Substation, Primary, and Secondary & Residential, respectively. The Company's forecast totals 953.861 million kWh as shown on line 24. Column E of Workpaper 1 reflects the Company's forecasted standard offer revenue for each voltage level by month for the December 2014 through February 2015 period, which was calculated by multiplying the kWh associated with each of the monthly voltage levels referenced above by the forecasted Fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $18.433 million as shown on line 28.

Exhibit 5-5. Calculation of Carrying Costs – Workpaper 2, January 2014 through February 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								CARRYING COST CALCULATION	
Line No.	Period	First of Month Balance	New FUEL Rider Costs	Amount Exceeding Threshold	Amount Collected FUEL Rider (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost[1]	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (COD% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$195,730	$0	$0
2	Jan-14	$195,730	$13,619,865	$0	($11,057,984)	$2,561,880	$2,757,611	$6,083	$2,763,693	($1,280,940)	$1,476,671
3	Feb-14	$2,763,693	$11,497,955	$0	($10,927,437)	$570,518	$3,334,211	$12,559	$3,346,770	($285,259)	$3,048,952
4	Mar-14	$3,346,770	$11,486,139	$0	($9,037,325)	$2,448,815	$5,795,585	$18,829	$5,814,414	($1,224,407)	$4,571,178
5	Apr-14	$5,814,414	$9,020,601	$0	($7,457,280)	$1,563,321	$7,377,735	$27,170	$7,404,906	($781,660)	$6,596,075
6	May-14	$7,404,906	$10,545,612	$0	($6,172,374)	$4,373,238	$11,778,143	$39,509	$11,817,652	($2,186,619)	$9,591,524
7	Jun-14	$11,817,652	$10,373,979	($4,655,545)	($7,970,104)	($2,251,670)	$9,565,982	$44,041	$9,610,023	$1,125,835	$10,691,817
8	Jul-14	$9,610,023	$9,631,909	$0	($9,182,015)	$449,893	$10,059,917	$40,512	$10,100,428	($224,947)	$9,834,970
9	Aug-14	$10,100,428	$10,580,843	$0	($8,649,533)	$1,931,310	$12,031,738	$45,583	$12,077,321	($965,655)	$11,066,083
10	Sep-14	$12,077,321	$8,202,510	($6,737,745)	($9,263,662)	($7,798,897)	$4,278,424	$33,686	$4,312,110	$3,899,448	$8,177,873
11	Oct-14	$4,312,110	$5,581,179	$0	($6,160,857)	($579,678)	$3,732,432	$16,568	$3,749,000	$289,839	$4,022,271
12	Nov-14	$3,749,000	$5,360,984	$0	($5,822,048)	($461,064)	$3,287,936	$14,493	$3,302,429	$230,532	$3,518,468
13	Dec-14	$3,302,429	$9,371,261	($1,627,579)	($10,030,092)	($2,286,410)	$1,016,020	$8,894	$1,024,914	$1,143,205	$2,159,225
14	Jan-15	$1,024,914	$4,249,403	$0	($5,508,869)	($1,259,466)	($234,552)	$1,628	($232,924)	$629,733	$395,181
15	Feb-15	($232,924)	$3,127,839	$0	($2,894,427)	$233,412	$488	($479)	$9	($116,706)	($116,218)

[1] The Opinion and Order in Case No. 12-426-EL-SSO updated the cost of debt (COD) from 5.86% to 4.943% starting in January 2014.

Workpaper 2: Workpaper 2 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period January 2014 through February 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0016947). First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate. Workpaper 2 also included a column showing the amounts that exceeded the 10% threshold in prior quarterly Fuel Rider filings. Specifically, this column reflects the $4.656 million, $6.738 million and $1.628 million that DP&L allocated to the RR-N in June, September, and December 2014, respectively, and thus, these amounts did not flow through the Fuel Rider. These adjustments are discussed in more detail in a later section of this report.

Quarterly FUEL Rider Filing – March through May 2015

Exhibit 5-6. Forecasted Quarterly Rate Summary, March through May 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Mar-15	(C) Apr-15	(D) May-15	(E) Total	(F) Source
1	Forecasted FUEL Costs	$3,288,436	$2,520,662	$2,576,571	$8,385,669	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	301,641,052	225,350,238	230,708,930	757,700,220	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh				$0.0110673	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh				$0.0011278	Schedule 2, Line 16
5	Forecasted Retail FUEL Rate $/kWh				$0.0121951	Line 3 + Line 4

	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	
6	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
7	**FUEL Rates $/kWh**	**$0.0122662**	**$0.0124063**	**$0.0127667**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to incur during the period March through May 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted Fuel costs for March through May 2015, which totaled $8.386 million (column E). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 757.700 million kWh for the March through May 2015 period. The Company calculated its retail Fuel rate before Reconciliation Adjustment of $0.0110673 per kWh by dividing the forecasted Fuel costs of $8.386 million by the forecasted Generation Level Retail Sales of 757.700 million. The Company then reflected a Reconciliation Adjustment for the period October 2014 through May 2015 (see Schedule 2 discussion below) of $0.0011278 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0.0110673 per kWh noted above to derive its forecasted retail Fuel rate of $0.0121951 per kWh as shown on line 5 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732, and 1.04687 cents per kWh for the High Voltage & Substation, Primary, and Secondary

& Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0122662, $0.0124063, and $0.0127667 cents per kWh as shown on line 7.

Exhibit 5-7. Reconciliation Adjustment – October 2014 through May 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under Recovery (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$3,988,464	$3,988,464	Accounting Records
2	October-14	$8,815,316	($7,107,687)	$1,707,629	$19,946	$1,727,575	$5,716,039	Accounting Records
3	November-14	$8,979,166	($7,587,500)	$1,391,665	$26,412	$1,418,077	$7,134,116	Accounting Records
4	December-14	$11,077,123	($9,257,690)	$191,854 [2]	$29,782	$221,636	$7,355,752	Accounting Records
5	January-15	$4,249,403	($5,508,869)	($1,259,466)	$27,706	($1,231,760)	$6,123,992	Corporate Forecast
6	February-15	$3,127,839	($2,894,427)	$233,412	$25,706	$259,118	$6,383,110	Corporate Forecast
7	March-15	$3,288,436	($3,288,436)	$0	$14,070	$14,070	$6,397,180	Corporate Forecast
8	April-15	$2,520,662	($2,520,662)	$0	$1,437	$1,437	$6,398,617	Corporate Forecast
9	May-15	$2,576,571	($2,576,571)	$0	$486	$486	$6,399,103	Corporate Forecast
10	(Over)/Under Recovery						$6,399,103	Line 9
11	(Over)/Under Recovery Through February 2015						$6,383,110	Line 6
12	10% Quarterly Threshold						$838,567	(Sum of Column B, Lines 7 - 9) * 10%
13	Amount Exceeding Threshold						$5,544,543	Line 11 - Line 12
14	Total (Over)/Under Recovery						$854,560	Line 10 - Line 13
				Mar-15	Apr-15	May-15		
15	Forecasted Generation Level Sales			301,641,052	225,350,238	230,708,930	757,700,220	Workpaper 1, Line 14
16	**Forecasted RA Rate $/kWh**						$0.0011278	Line 14 / Line 15

[1] YTD = current month Total + previous month YTD total

[2] (Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period October through December 2014, and (2) DP&L's estimated Fuel costs for the period January through May 2015 for total actual and forecasted Fuel costs of $44.635 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($40.742) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $2.265 million, as shown in column D. Column E reflects the carrying costs for the period of January 2014 through February 2015, which totaled $145,544. The under-recovery for the period of October 2014 through May 2015 and the addition of the carrying costs for the same period resulted in a YTD under-recovery of $6.399 million (column G, line 10). Line 11 reflects the under-recovery of $6.383 million for the period of October 2014 through February 2015. The amount on Line 12 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted Fuel costs for the period March through May 2015 by 10% which totals $838,567. This amount was then subtracted from the under-recovery through February 2015 to calculate the Amount Exceeding Threshold of $5.545 million, as shown on line 13. The result is a total under-recovery of $854,560, which is derived by subtracting the amount exceeding the threshold from the under recovery through February 2015, as shown on line 14. Line 15 of Schedule 2 reflects DP&L's forecasted generation level sales for the period March through May 2015, which totals 757.700 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of ($0.0011278) per kWh by dividing the total under-recovery of $854,560 by its forecasted sales for the period March through May 2015.

Exhibit 5-8. Forecasted Quarterly Rate – Workpaper 1, March through May 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Mar-15	(C) Apr-15	(D) May-15	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$1,366,878	$1,071,652	$1,219,762	$3,658,292
2	Steam Plant Fuel Oil Consumed (501)	$6,243	$13,998	$21,549	$41,789
3	Steam Plant Fuel Handling (501)	$41,006	$32,150	$36,593	$109,749
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	($620)	($677)	($64)	($1,361)
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$0	$0
9	Purchased Power (555)	$1,873,280	$1,402,060	$1,297,070	$4,572,409
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$1,650	$1,479	$1,661	$4,790
13	Total Costs	$3,288,436	$2,520,662	$2,576,571	$8,385,669
14	Total Forecasted Generation Level Sales	301,641,052	225,350,238	230,708,930	757,700,220
15	Retail FUEL Rate $/kWh				$0.0110673
	Reconciliation Adjustment				
16	Under (Over) Recovery				$854,560
17	Forecasted RA Rate $/kWh				$0.0011278

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
18	High Voltage & Substation	1.00583	$0.0122662
19	Primary	1.01732	$0.0124063
20	Secondary & Residential	1.04687	$0.0127667

Spring FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Mar-15	Apr-15	May-15	Total
21	High Voltage & Substation	33,454,006	32,919,852	38,174,095	104,547,952
22	Primary	7,223,908	6,918,102	7,824,543	21,966,553
23	Secondary & Residential	248,973,591	176,908,824	176,098,481	601,980,895
24	Total	289,651,505	216,746,778	222,097,118	728,495,400
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$410,354	$403,801	$468,251	$1,282,406
26	Primary	$89,622	$85,828	$97,074	$272,524
27	Secondary & Residential	$3,178,571	$2,258,542	$2,248,196	$7,685,309
28	Total	$3,678,547	$2,748,171	$2,813,521	$9,240,239

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2009 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period March through May 2015. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for March through May 2015 which totals the $8.386 million shown on Schedule 1. Lines 14 and 15 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales and retail Fuel rate. Lines 16 and 17 reflect the under-recovery of $854,560 and the forecasted RA rate of ($0.0011278) per kWh. Lines 18 through 20 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 6 and 7, respectively and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 21 through 28 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Columns B through D reflect forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels by month for the March through May 2015 period. For this three-month period, the forecasted kWh for each voltage level totals 104.548 million kWh, 21.967 million kWh, and 601.981 million kWh for the High Voltage & Substation, Primary, and Secondary & Residential, respectively. The Company's forecast totals 728.495 million kWh as shown on line 24. Column E of Workpaper 1 reflects the Company's forecasted standard offer revenue for each voltage level by month for the March through May 2015 period, which was calculated by multiplying the kWh associated with each of the monthly voltage levels referenced above by the forecasted Fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $9.240 million as shown on line 28.

Exhibit 5-9. Calculation of Carrying Costs – Workpaper 2, October 2014 through May 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								CARRYING COST CALCULATION	
Line No. (A)	Period (B)	*First of* Month Balance (C)	*New* FUEL Rider Costs (D)	*Amount* Exceeding Threshold (E)	Amount *Collected* FUEL Rider (CR) (F)	NET AMOUNT (G)	*End of Month* before Carrying Cost (H)	Carrying Cost (I)	*End of* Month Balance (J)	*Less:* One-half Monthly Amount (K)	*Total* Applicable to Carrying Cost (L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$3,988,464	$0	$0
2	Oct-14	$3,988,464	$8,815,316	$0	($7,107,687)	$1,707,629	$5,696,093	$19,946	$5,716,039	($853,814)	$4,842,279
3	Nov-14	$5,716,039	$8,979,166	$0	($7,587,500)	$1,391,665	$7,107,705	$26,412	$7,134,116	($695,833)	$6,411,872
4	Dec-14	$7,134,116	$11,077,123	($1,627,579)	($9,257,690)	$191,854	$7,325,970	$29,782	$7,355,752	($95,927)	$7,230,043
5	Jan-15	$7,355,752	$4,249,403	$0	($5,508,869)	($1,259,466)	$6,096,286	$27,706	$6,123,992	$629,733	$6,726,019
6	Feb-15	$6,123,992	$3,127,839	$0	($2,894,427)	$233,412	$6,357,404	$25,706	$6,383,110	($116,706)	$6,240,698
7	Mar-15	$6,383,110	$3,288,436	($5,544,543)	($3,678,547)	($5,934,654)	$448,456	$14,070	$462,526	$2,967,327	$3,415,783
8	Apr-15	$462,526	$2,520,662	$0	($2,748,171)	($227,510)	$235,017	$1,437	$236,453	$113,755	$348,771
9	May-15	$236,453	$2,576,571	$0	($2,813,521)	($236,950)	($497)	$486	($11)	$118,475	$117,978

Workpaper 2: Workpaper 2 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period October 2014 through May 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0011278). First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are

applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly FUEL Rider Filing – June through August 2015

Exhibit 5-10. Forecasted Quarterly Rate Summary, June through August 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Jun-15	(C) Jul-15	(D) Aug-15	(E) Total	(F) Source
1	Forecasted FUEL Costs	$2,884,486	$3,615,980	$3,421,287	$9,921,753	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	278,865,929	350,362,168	334,463,859	963,691,956	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh				$0.0102956	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh				$0.0010400	Schedule 2, Line 19
5	Forecasted Retail FUEL Rate $/kWh				$0.0113356	Line 3 + Line 4

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
6	Distribution Line Loss Factors	1.00613	1.01701	1.04461	Line Loss Study 2015
7	**FUEL Rates $/kWh**	**$0.0114051**	**$0.0115284**	**$0.0118413**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to incur during the period June through August 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted Fuel costs for June through August 2015, which totaled $9.922 million (column E). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 963.692 million kWh for the June through August 2015 period. The Company calculated its retail Fuel rate before Reconciliation Adjustment of $0.0102956 per kWh by dividing the forecasted Fuel costs of $9.922 million by the forecasted Generation Level Retail Sales of 963.692 million. The Company then reflected a Reconciliation Adjustment for the period October 2014 through August 2015 (see Schedule 2 discussion below) of $0.0010400 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0.0102956 per kWh noted above to derive its forecasted retail Fuel rate of $0.0113356 per kWh as shown on line 5 of Schedule 1. After applying the line loss factors of 1.00583, 1.01732, and 1.04687 cents per kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0114051, $0.0115284, and $0.0118413 cents per kWh as shown on line 7.

Exhibit 5-11. Reconciliation Adjustment – October 2014 through August 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under Recovery (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$3,988,464	$3,988,464	Accounting Records
2	October-14	$8,815,316	($7,107,687)	$1,707,629	$19,946	$1,727,575	$5,716,039	Accounting Records
3	November-14	$8,979,166	($7,587,500)	$1,391,665	$26,412	$1,418,077	$7,134,116	Accounting Records
4	December-14	$10,258,238	($9,257,690)	($627,031) [2]	$28,095	($598,936)	$6,535,180	Accounting Records
5	January-15	$6,514,382	($6,138,316)	$376,066	$27,694	$403,760	$6,938,940	Accounting Records
6	*February-15*	*$6,551,119*	*($5,901,203)*	*$649,916*	*$29,921*	*$679,837*	*$7,618,777*	*Accounting Records*
7	March-15	$6,086,429	($5,031,083)	($4,489,198) [2]	$22,137	($4,467,061)	$3,151,716	Accounting Records
8	April-15	$2,520,662	($2,748,171)	($227,510)	$12,514	($214,996)	$2,936,721	Corporate Forecast
9	May-15	$2,576,571	($2,813,521)	($236,950)	$11,609	($225,341)	$2,711,379	Corporate Forecast
10	June-15	$2,884,486	($2,884,486)	$0	$7,058	$7,058	$2,718,437	Corporate Forecast
11	July-15	$3,615,980	($3,615,980)	$0	$2,244	$2,244	$2,720,681	Corporate Forecast
12	August-15	$3,421,287	($3,421,287)	$0	$759	$759	$2,721,440	Corporate Forecast
13	(Over)/Under Recovery						$2,721,440	Line 12
14	(Over)/Under Recovery Through May 2015						$2,711,379	Line 9
15	10% Quarterly Threshold						$992,175	(Sum of Column B, Lines 10 - 12) * 10%
16	*Amount Exceeding Threshold*						*$1,719,204*	*Line 14 - Line 15*
17	Total (Over)/Under Recovery						$1,002,236	Line 13 - Line 16
				Jun-15	Jul-15	Aug-15		
18	Forecasted Generation Level Sales			278,865,929	350,362,168	334,463,859	963,691,956	Workpaper 1, Line 14
19	**Forecasted RA Rate $/kWh**						$0.0010400	Line 17 / Line 18

[1] YTD = current month Total + previous month YTD total

[2] (Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period October 2014 through March 2015, and (2) DP&L's estimated Fuel costs for the period April through August 2015 for total actual and forecasted Fuel costs of $62.224 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($56.507) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $1.455 million, as shown in column D. Column E reflects the carrying costs for the period of October 2014 through August 2015, which totaled $188,389. The under-recovery for the period of October 2014 through August 2015 and the addition of the carrying costs for the same period resulted in a YTD under-recovery of $2.721 million (column G, line 13). Line 14 reflects the under-recovery of $2.711 million for the period of October 2014 through May 2015. The amount on Line 15 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted Fuel costs for the period June through August 2015 by 10% which totals $992,175. This amount was then subtracted from the under-recovery through May 2015 to calculate the Amount Exceeding Threshold of $1.719 million, as shown on line 16. The result is a total under-recovery of $1 million, which is derived by subtracting the amount exceeding the threshold from the under recovery through May 2015, as shown on line 17. Line 18 of Schedule 2 reflects DP&L's forecasted generation level sales for the period June through August 2015, which totals 963.692 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of ($0.0010400) per kWh by dividing the total under-recovery of $1 million by its forecasted sales for the period June through August 2015.

Exhibit 5-12. Forecasted Quarterly Rate – Workpaper 1, June through August 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Jun-15	(C) Jul-15	(D) Aug-15	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$1,492,910	$1,931,742	$1,808,271	$5,232,923
2	Steam Plant Fuel Oil Consumed (501)	$20,363	$31,724	$27,122	$79,209
3	Steam Plant Fuel Handling (501)	$44,787	$57,952	$54,248	$156,988
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	($266)	($1,042)	$667	($641)
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0	$0	$0
9	Purchased Power (555)	$1,324,559	$1,592,971	$1,528,328	$4,445,857
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$2,133	$2,633	$2,650	$7,417
13	Total Costs	$2,884,486	$3,615,980	$3,421,287	$9,921,753
14	Total Forecasted Generation Level Sales	278,865,929	350,362,168	334,463,859	963,691,956
15	Retail FUEL Rate $/kWh				$0.0102956
	Reconciliation Adjustment				
16	Under (Over) Recovery				$1,002,236
17	Forecasted RA Rate $/kWh				$0.0010400

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
18	High Voltage & Substation	1.00613	$0.0114051
19	Primary	1.01701	$0.0115284
20	Secondary & Residential	1.04461	$0.0118413

Spring FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Jun-15	Jul-15	Aug-15	Total
21	High Voltage & Substation	43,171,760	43,766,882	46,129,253	133,067,895
22	Primary	13,269,783	12,474,380	10,192,420	35,936,583
23	Secondary & Residential	212,456,347	281,100,530	265,827,476	759,384,354
24	Total	268,897,890	337,341,793	322,149,150	928,388,832
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$492,378	$499,166	$526,109	$1,517,653
26	Primary	$152,979	$143,810	$117,502	$414,291
27	Secondary & Residential	$2,515,759	$3,328,596	$3,147,743	$8,992,098
28	Total	$3,161,117	$3,971,571	$3,791,354	$10,924,042

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2015 Line Loss Study

Workpaper 1: Column A *of this workpaper (lines 1-13) reflects a breakout of the categories of* the forecasted costs that the Company has included in its Fuel Rider for the period June through August 2015. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for June through August 2015 which totals the $9.922 million shown on Schedule 1. Lines 14 and 15 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales and retail Fuel rate. Lines 16 and 17 reflect the under-recovery of $1 million and the forecasted RA rate of ($0.0010400) per kWh. Lines 18 through 20 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 6 and 7, respectively and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 21 through 28 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Columns B through D reflect forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels by month for the June through August 2015 period. For this three-month period, the forecasted kWh for each voltage level totals 133.068 million kWh, 35.937 million kWh, and 759.384 million kWh for the High Voltage & Substation, Primary, and Secondary & Residential, respectively. The Company's forecast totals 928.389 million kWh as shown on line 24. Column E of Workpaper 1 reflects the Company's forecasted standard offer revenue for each voltage level by month for the June through August 2015 period, which was calculated by multiplying the kWh associated with each of the monthly voltage levels referenced above by the forecasted Fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $10.924 million as shown on line 28.

Exhibit 5-13. Calculation of Carrying Costs – Workpaper 2, October 2014 through August 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								CARRYING COST CALCULATION	
Line No. (A)	Period (B)	First of Month Balance (C)	New FUEL Rider Costs (D)	Amount Exceeding Threshold (E)	Amount Collected FUEL Rider (CR) (F)	NET AMOUNT (G) (G) = (D) + (E) + (F)	End of Month before Carrying Cost (H) (H) = (C) + (G)	Carrying Cost (I) (I) = (L) * (4.943% / 12)	End of Month Balance (J) (J) = (H) + (I)	Less: One-half Monthly Amount (K) (K) = - (G) * 0.5	Total Applicable to Carrying Cost (L) (L) = (H) + (K)
1	*Prior Period*								*$3,988,464*	*$0*	*$0*
2	Oct-14	$3,988,464	$8,815,316	$0	($7,107,687)	$1,707,629	$5,696,093	$19,946	$5,716,039	($853,814)	$4,842,279
3	Nov-14	$5,716,039	$8,979,166	$0	($7,587,500)	$1,391,665	$7,107,705	$26,412	$7,134,116	($695,833)	$6,411,872
4	*Dec-14*	*$7,134,116*	*$10,258,238*	*($1,627,579)*	*($9,257,690)*	*($627,031)*	*$6,507,085*	*$28,095*	*$6,535,180*	*$313,516*	*$6,820,601*
5	Jan-15	$6,535,180	$6,514,382	$0	($6,138,316)	$376,066	$6,911,246	$27,694	$6,938,940	($188,033)	$6,723,213
6	Feb-15	$6,938,940	$6,551,119	$0	($5,901,203)	$649,916	$7,588,856	$29,921	$7,618,777	($324,958)	$7,263,898
7	Mar-15	$7,618,777	$6,086,429	($5,544,543)	($5,031,083)	($4,489,198)	$3,129,579	$22,137	$3,151,716	$2,244,599	$5,374,178
8	Apr-15	$3,151,716	$2,520,662	$0	($2,748,171)	($227,510)	$2,924,207	$12,514	$2,936,721	$113,755	$3,037,962
9	May-15	$2,936,721	$2,576,571	$0	($2,813,521)	($236,950)	$2,699,770	$11,609	$2,711,379	$118,475	$2,818,246
10	Jun-15	$2,711,379	$2,884,486	($1,719,204)	($3,161,117)	($1,995,835)	$715,545	$7,058	$722,603	$997,917	$1,713,462
11	Jul-15	$722,603	$3,615,980	$0	($3,971,571)	($355,591)	$367,012	$2,244	$369,256	$177,795	$544,807
12	Aug-15	$369,256	$3,421,287	$0	($3,791,354)	($370,067)	($811)	$759	($52)	$185,034	$184,222

Workpaper 2: Workpaper 2 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period October 2014 through August 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0010400). First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted from the end of the month balance before carrying costs (beginning of the month

balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly FUEL Rider Filing – September through November 2015

Exhibit 5-14. Forecasted Quarterly Rate Summary, September through November 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Sep-15	(C) Oct-15	(D) Nov-15	(E) Total	(F) Source
1	Forecasted FUEL Costs	$2,532,733	$2,289,087	$2,673,056	$7,494,876	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	254,641,094	218,221,376	256,049,714	728,912,184	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh				$0.0102823	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh				$0.0010444	Schedule 2, Line 19
5	Forecasted Retail FUEL Rate $/kWh				$0.0113267	Line 3 + Line 4

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	
6	Distribution Line Loss Factors	1.00613	1.01701	1.04461	Line Loss Study 2015
7	**FUEL Rates $/kWh**	**$0.0113961**	**$0.0115194**	**$0.0118320**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to incur during the period September through November 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted Fuel costs for September through November 2015, which totaled $7.495 million (column E). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 728.912 billion kWh for the period September through November 2015. The Company then calculated its retail Fuel rate before Reconciliation Adjustment of $0.0102823 per kWh by dividing the forecasted Fuel costs of $7.495 million by the forecasted Generation Level Retail Sales as shown on line 3. The Company reflected a Reconciliation Adjustment for the period January through November 2015 (see Schedule 2 discussion below) of $0.0010444 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0.0102823 per kWh noted above to derive its forecasted retail Fuel rate of $0.0113267 per kWh as shown on line 5 of Schedule 1. After applying the line loss factors of 1.00613, 1.01701, and 1.04461 cents per kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels, the Company calculated Fuel rates at the distribution level of $010113961, $0.0115194, and $0.0118320 cents per kWh, as shown on line 7.

Exhibit 5-15. Reconciliation Adjustment – January through November 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under Recovery (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$6,535,180	$6,535,180	Accounting Records
2	January-15	$6,514,382	($6,138,316)	$376,066	$27,694	$403,760	$6,938,940	Accounting Records
3	February-15	$6,551,119	($5,901,203)	$649,916	$29,921	$679,837	$7,618,777	Accounting Records
4	March-15	$5,710,681	($5,031,083)	($4,864,946) [2]	$21,363	($4,843,583)	$2,775,194	Accounting Records
5	April-15	$5,388,840	($3,774,416)	$1,614,424	$14,757	$1,629,181	$4,404,375	Accounting Records
6	May-15	$3,764,513	($3,180,204)	$584,309	$19,346	$603,655	$5,008,030	Accounting Records
7	June-15	$5,375,112	($3,523,712)	$132,196 [2]	$20,901	$153,098	$5,161,128	Accounting Records
8	July-15	$3,615,980	($3,971,571)	($355,591)	$20,527	($335,064)	$4,826,064	Corporate Forecast
9	August-15	$3,421,287	($3,791,354)	($370,067)	$19,117	($350,950)	$4,475,114	Corporate Forecast
10	September-15	$2,532,733	($2,532,733)	$0	$10,037	$10,037	$4,485,151	Corporate Forecast
11	October-15	$2,289,087	($2,289,087)	$0	$1,305	$1,305	$4,486,455	Corporate Forecast
12	November-15	$2,673,056	($2,673,056)	$0	$466	$466	$4,486,921	Corporate Forecast
13	(Over)/Under Recovery						$4,486,921	Line 12
14	(Over)/Under Recovery Through August 2015						$4,475,114	Line 9
15	10% Quarterly Threshold						$749,488	*(Sum of Column B, Lines 10 - 12) * 10%*
16	Amount Exceeding Threshold						$3,725,626	Line 14 - Line 15
17	Total (Over)/Under Recovery						$761,294	Line 13 - Line 16
				Sep-15	Oct-15	Nov-15		
18	Forecasted Generation Level Sales			254,641,094	218,221,376	256,049,714	728,912,184	Workpaper 1, Line 14
19	**Forecasted RA Rate $/kWh**						$0.0010444	Line 17 / Line 18

[1] YTD = current month Total + previous month YTD total

[2] (Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period January through June 2015, and (2) DP&L's estimated Fuel costs for the period July through November 2015 for total actual and forecasted Fuel costs of $47.836 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($42.807) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an over-recovery in the amount of ($2.234) million, as shown in column D. Column E reflects the carrying costs for the period of January through November 2015, which totaled $185,433. The under-recovery for the period of January through August 2015 and the addition of the carrying costs for the January through November 2015 period resulted in a YTD under-recovery of $4.487 million (column G, line 13). Line 14 reflects the under-recovery of $4.475 million for the period of January through August 2015. The amount on Line 15 is referred to as the "10% Quarterly Threshold", and is calculated by multiplying the forecasted Fuel costs for the period September through November 2015 by 10% which totals $749,488. The 10% quarterly threshold was then subtracted from the under-recovery through August 2015 to calculate the "Amount Exceeding Threshold" of $3.726 million, as shown on line 16. The result is a total under-recovery of $761,294, which is derived by subtracting the amount exceeding the threshold from the under recovery through November 2015, as shown on line 17. Line 18 of Schedule 2 reflects DP&L's forecasted generation level sales for the period September through November 2015, which totals 728.912 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of $0.0010444 per kWh by dividing the total under-recovery of $761,294 by its forecasted sales for the period September through November 2015.

Exhibit 5-16. Forecasted Quarterly Rate – Workpaper 1, September through November 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Sep-15	(C) Oct-15	(D) Nov-15	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$1,114,631	$876,614	$1,273,265	$3,264,510
2	Steam Plant Fuel Oil Consumed (501)	$3,856	$2,603	$4,101	$10,559
3	Steam Plant Fuel Handling (501)	$33,439	$26,298	$38,198	$97,935
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	$599	$618	$1,123	$2,340
7	Allowances Consumed (509)	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$13,830	$9,307	$0	$23,137
9	Purchased Power (555)	$1,362,488	$1,370,600	$1,351,889	$4,084,977
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0
12	Emission Fees (506)	$3,891	$3,047	$4,480	$11,418
13	Total Costs	$2,532,733	$2,289,087	$2,673,056	$7,494,876
14	Total Forecasted Generation Level Sales	254,641,094	218,221,376	256,049,714	728,912,184
15	Retail FUEL Rate $/kWh				$0.0102823
	Reconciliation Adjustment				
16	Under (Over) Recovery				$761,294
17	Forecasted RA Rate $/kWh				$0.0010444

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
18	High Voltage & Substation	1.00613	$0.0113961
19	Primary	1.01701	$0.0115194
20	Secondary & Residential	1.04461	$0.0118320

Spring FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Sep-15	Oct-15	Nov-15	Total
21	High Voltage & Substation	36,149,020	33,776,903	33,435,653	103,361,575
22	Primary	3,920,640	2,839,283	4,181,300	10,941,223
23	Secondary & Residential	205,132,203	173,605,310	208,840,311	587,577,823
24	Total	245,201,863	210,221,495	246,457,263	701,880,621
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$411,958	$384,925	$381,036	$1,177,919
26	Primary	$45,163	$32,707	$48,166	$126,036
27	Secondary & Residential	$2,427,124	$2,054,098	$2,470,999	$6,952,221
28	Total	$2,884,246	$2,471,730	$2,900,201	$8,256,176

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2015 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for the period September through November 2015. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for September through November 2015 which totals the $7.495 million shown on Schedule 1. Lines 14 and 15 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales and retail Fuel rate. Lines 16 and 17 reflect the under-recovery of $761,294 and the forecasted RA rate of $0.0102823 per kWh. Lines 18 through 20 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 6 and 7, respectively and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 21 through 28 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Columns B through D reflect forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels by month for the September through November 2015 period. For this three-month period, the forecasted kWh for each voltage level totals 103.362 million kWh, 10.941 million kWh, and 587.578 million kWh for the High Voltage & Substation, Primary, and Secondary & Residential, respectively. The Company's forecast totals 701.881 million kWh as shown on line 24. Column E of Workpaper 1 reflects the Company's forecasted standard offer revenue for each voltage level by month for the September through November 2015 period, which was calculated by multiplying the kWh associated with each of the monthly voltage levels referenced above by the forecasted Fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $8.256 million as shown on line 28.

Exhibit 5-17. Calculation of Carrying Costs – Workpaper 2, January through November 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								CARRYING COST CALCULATION	
Line No. (A)	Period (B)	First of Month Balance (C)	New FUEL Rider Costs (D)	Amount Exceeding Threshold (E)	Amount Collected FUEL Rider (CR) (F)	NET AMOUNT (G)	End of Month before Carrying Cost (H)	Carrying Cost (I)	End of Month Balance (J)	Less: One-half Monthly Amount (K)	Total Applicable to Carrying Cost (L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$6,535,180	$0	$0
2	Jan-15	$6,535,180	$6,514,382	$0	($6,138,316)	$376,066	$6,911,246	$27,694	$6,938,940	($188,033)	$6,723,213
3	Feb-15	$6,938,940	$6,551,119	$0	($5,901,203)	$649,916	$7,588,856	$29,921	$7,618,777	($324,958)	$7,263,898
4	Mar-15	$7,618,777	$5,710,681	($5,544,543)	($5,031,083)	($4,864,946)	$2,753,831	$21,363	$2,775,194	$2,432,473	$5,186,304
5	Apr-15	$2,775,194	$5,388,840	$0	($3.774,416)	$1,614,424	$4,389,619	$14,757	$4,404,375	($807,212)	$3,582,407
6	*May-15*	*$4,404,375*	*$3,764,513*	*$0*	*($3,180,204)*	*$584,309*	*$4,988,684*	*$19,346*	*$5,008,030*	*($292,155)*	*$4,696,530*
7	Jun-15	$5,008,030	$5,375,112	($1,719,204)	($3,523,712)	$132,196	$5,140,227	$20,901	$5,161,128	($66,098)	$5,074,128
8	Jul-15	$5,161,128	$3,615,980	$0	($3,971,571)	($355,591)	$4,805,537	$20,527	$4,826,064	$177,795	$4,983,332
9	Aug-15	$4,826,064	$3,421,287	$0	($3,791,354)	($370,067)	$4,455,997	$19,117	$4,475,114	$185,034	$4,641,031
10	Sep-15	$4,475,114	$2,532,733	($3,725,626)	($2,884,246)	($4,077,139)	$397,976	$10,037	$408,012	$2,038,569	$2,436,545
11	Oct-15	$408,012	$2,289,087	$0	($2,471,730)	($182,643)	$225,369	$1,305	$226,673	$91,322	$316,690
12	Nov-15	$226,673	$2,673,056	$0	($2,900,201)	($227,145)	($472)	$466	($6)	$113,573	$113,101

Workpaper 2: Workpaper 2 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period January through November 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of $00010444. First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted

from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly FUEL Rider Filing – December 2015

Exhibit 5-18. Forecasted Quarterly Rate Summary, December 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Dec-15	(C)	(D) Total	(E) Source
1	Forecasted FUEL Costs	$3,915,689		$3,915,689	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	369,620,920		369,620,920	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh			$0.0105938	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh			$0.0011145	Schedule 2, Line 20
5	Forecasted Retail FUEL Rate $/kWh			$0.0117083	Line 3 + Line 4
	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	
6	Distribution Line Loss Factors	1.00613	1.01701	1.04461	Line Loss Study 2015
7	**FUEL Rates $/kWh**	**$0.0117801**	**$0.0119075**	**$0.0122306**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to be incurred during December 2015. As shown on line 1, DP&L's forecasted Fuel costs for the period December 2015 totaled $3.916 million (column D). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 369.621 million kWh for December 2015. On line 3, the Company calculated its retail Fuel Rate before Reconciliation Adjustment, which totaled $0.0105938 per kWh, by dividing the forecasted Fuel costs of $3.916 million by the 369.621 million kWh of forecasted Generation Level Retail Sales. The Company reflected a forecasted Reconciliation Adjustment rate for December 2015 (see Schedule 2 discussion below) of $0.0011145 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0.0105938 per kWh noted above to derive its forecasted retail Fuel rate of $0.0117083 per kWh as shown on line 5 of Schedule 1. After applying the line loss factors of 1.00613, 1.01701, and 1.04461 cents per kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0117801, $0.0119075, and $010122306 cents per kWh as shown on line 7.

Exhibit 5-19. Reconciliation Adjustment – January through December 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Description	Actual Fuel Costs	Actual Revenue Recovery	(Over)/Under Recovery (D) = (B) + (C)	Carrying Costs	Total (F) = (D) + (E)	YTD[1]	Source
1	Prior Period					$6,535,180	$6,535,180	Accounting Records
2	January-15	$6,514,382	($6,138,316)	$376,066	$27,694	$403,760	$6,938,940	Accounting Records
3	February-15	$6,551,119	($5,901,203)	$649,916	$29,921	$679,837	$7,618,777	Accounting Records
4	March-15	$5,710,681	($5,031,083)	($4,864,946) [2]	$21,363	($4,843,583)	$2,775,194	Accounting Records
5	April-15	$5,388,840	($3,774,416)	$1,614,424	$14,757	$1,629,181	$4,404,375	Accounting Records
6	May-15	$3,764,513	($3,180,204)	$584,309	$19,346	$603,655	$5,008,030	Accounting Records
7	June-15	$5,737,221	($3,523,712)	$494,305 [2]	$21,647	$515,952	$5,523,982	Accounting Records
8	July-15	$6,026,012	($4,029,370)	$1,996,641	$26,866	$2,023,508	$7,547,490	Accounting Records
9	August-15	$5,778,259	($4,284,814)	$1,493,445	$34,165	$1,527,611	$9,075,100	Accounting Records
10	September-15	$4,960,081	($3,839,481)	$1,120,600	$39,690	$1,160,290	$10,235,390	Accounting Records
11	October-15	$2,289,087	($2,471,730)	($182,643)	$41,785	($140,858)	$10,094,532	Corporate Forecast
12	November-15	$2,673,056	($2,900,201)	($227,145)	$41,113	($186,032)	$9,908,500	Corporate Forecast
13	December-15	$3,915,689	($3,915,689)	$0	$20,365	$20,365	$9,928,866	Corporate Forecast
14	(Over)/Under Recovery						$9,928,866	Line 13
15	(Over)/Under Recovery Through November 2015						$9,908,500	Line 12
16	10% Quarterly Threshold						$391,569	Column B Line 13 * 10%
17	Amount Exceeding Threshold						$9,516,932	Line 15 - Line 16
18	*Total (Over)/Under Recovery*						*$411,934*	*Line 14 - Line 17*
19	*Forecasted Generation Level Sales*					Dec-15 *369,620,920*	*369,620,920*	*Workpaper 1, Line 14*
20	**Forecasted RA Rate $/kWh**						$0.0011145	Line 18 / Line 19

[1] YTD = current month Total + previous month YTD total

[2] (Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period January September 2015, and (2) DP&L's estimated Fuel costs for the period October through December 2015 for total actual and forecasted Fuel costs of $59.309 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($48.990) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $3.055 million, as shown in column D. Column E reflects the carrying costs for the period of January through December 2015, which totaled $338,713. The under-recovery for the period of January through December 2015 and the addition of the carrying costs for the same period resulted in a YTD under-recovery of $9.929 million (column G, line 14). Line 15 reflects the under-recovery of $9.909 million for the period of January 2013 through November 2015. The amount on Line 16 is referred to as the "10% Quarterly Threshold", and is calculated by multiplying the forecasted Fuel cost for December 2015 by 10% which totals $391,569. The 10% quarterly threshold was then subtracted from the under-recovery through November 2015 to calculate the "Amount Exceeding Threshold" of $9.517 million, as shown on line 17. The result is a total under-recovery of $411,934, which is derived by subtracting the amount exceeding the threshold from the under recovery through December 2015, as shown on line 18. Line 19 of Schedule 2 reflects DP&L's forecasted generation level sales for December 2015, which totals 369.621 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of $0.0011145 per kWh by dividing the total under-recovery of $411,934 by its forecasted sales for December 2015.

Exhibit 5-20. Forecasted Quarterly Rate – Workpaper 1, December 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider

Line No.	(A) Description	(B) Dec-15	(C) Total
	Forecasted Costs ($)[1]		
1	Steam Plant Generation (501)	$1,917,232	$1,917,232
2	Steam Plant Fuel Oil Consumed (501)	$4,246	$4,246
3	Steam Plant Fuel Handling (501)	$57,517	$57,517
4	Steam Plant Gas Consumed (501)	$0	$0
5	Coal Sales (456)	$0	$0
6	Heating Oil Realized Gains or Losses (456)	$1,946	$1,946
7	Allowances Consumed (509)	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$0	$0
9	Purchased Power (555)	$1,928,489	$1,928,489
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0
12	Emission Fees (506)	$6,259	$6,259
13	Total Costs	$3,915,689	$3,915,689
14	Total Forecasted Generation Level Sales	369,620,920	369,620,920
15	Retail FUEL Rate $/kWh		$0.0105938
	Reconciliation Adjustment		
16	Under (Over) Recovery		$411,934
17	Forecasted RA Rate $/kWh		$0.0011145
	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
18	High Voltage & Substation	1.00613	$0.0117801
19	Primary	1.01701	$0.0119075
20	Secondary & Residential	1.04461	$0.0122306
	Winter FUEL Rider		
	Standard Offer Metered Level Sales (kWh)	Dec-15	Total
21	High Voltage & Substation	33,627,760	33,627,760
22	Primary	3,243,858	3,243,858
23	Secondary & Residential	318,289,109	318,289,109
24	Total	355,160,727	355,160,727
	Standard Offer Revenue ($)		
25	High Voltage & Substation	$396,138	$396,138
26	Primary	$38,626	$38,626
27	Secondary & Residential	$3,892,867	$3,892,867
28	Total	$4,327,631	$4,327,631

Notes: [1] Data from Corporate Model
[2] Distribution Loss Factors from 2015 Line Loss Study

Workpaper 1: Column A of this workpaper (lines 1-13) reflects a breakout of the categories of the forecasted costs that the Company has included in its Fuel Rider for December 2015. Column B provides a breakout of the forecasted amounts associated with each expense category for December 2015 which totals the $3.916 million shown on Schedule 1. Lines 14 and 15 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales and retail Fuel rate. Lines 16 and 17 reflect the under-recovery of $411,934 and the forecasted RA rate of $0.0011145 per kWh. Lines 18 through 20 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 6 and 7, respectively and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 21 through 28 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Column B reflects forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels for December 2015 period. For this one-month period, the forecasted kWh for each voltage level totals 33.628 million kWh, 3.244 million kWh, and 318.289 million kWh for the High Voltage & Substation, Primary, and Secondary & Residential, respectively. The Company's forecast totals 355.161 million kWh as shown on line 24. Column E of Workpaper 1 reflects the Company's forecasted standard offer revenue for each voltage level for December 2015 period, which was calculated by multiplying the kWh associated with the monthly voltage levels referenced above by the forecasted Fuel rates at the distribution level. The Company's forecasted Fuel Rider totals $4.328 million as shown on line 28.

Exhibit 5-21. Calculation of Carrying Costs – Workpaper 2, January through August 2014

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY							CARRYING COST CALCULATION	
Line No. (A)	Period (B)	First of Month Balance (C)	New FUEL Rider Costs (D)	Amount Collected FUEL Rider (CR) (E)	NET AMOUNT (F)	End of Month before Carrying Cost (G)	Carrying Cost @ 4.943% (H)	End of Month Balance (I)	Less: One-half Monthly Amount (J)	Total Applicable to Carrying Cost (K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (L) * (4.943% / 12)	(I) = (G) + (H)	(J) = - (F) * 0.5	(K) = (G) + (J)
1	Prior Period							$182,608	$0	$0
2	Jan-14	$182,608	$13,619,865	($11,057,984)	$2,561,880	$2,744,489	$6,029	$2,750,518	($1,280,940)	$1,463,549
3	Feb-14	$2,750,518	$11,497,955	($10,927,437)	$570,518	$3,321,035	$12,505	$3,333,540	($285,259)	$3,035,776
4	Mar-14	$3,333,540	$11,983,424	($9,037,325)	$2,946,100	$6,279,640	$19,799	$6,299,439	($1,473,050)	$4,806,590
5	Apr-14	$6,299,439	$4,762,891	($4,480,526)	$282,365	$6,581,804	$26,530	$6,608,334	($141,183)	$6,440,621
6	May-14	$6,608,334	$4,661,643	($4,303,605)	$358,038	$6,966,372	$27,958	$6,994,330	($179,019)	$6,787,353
7	Jun-14	$2,367,668	$7,454,474	($8,085,925)	($631,451)	$1,736,216	$8,452	$1,744,669	$315,726	$2,051,942
8	Jul-14	$1,744,669	$8,218,560	($9,132,906)	($914,346)	$830,322	$5,303	$835,626	$457,173	$1,287,495
9	Aug-14	$835,626	$7,848,761	($8,678,742)	($829,981)	$5,645	$1,733	$7,378	$414,990	$420,635

Workpaper 2: Workpaper 2 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period January through December 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of $0.0011145. First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are applicable to

carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly FUEL Rider Filing – January 2016

Exhibit 5-22. Forecasted Quarterly Rate Summary, Final reconciliation

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B)	(C)	(D) Total	(E) Source
1	Forecasted Retail FUEL Rate $/kWh			$0.0112579	Schedule 2, Line 19
	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	
2	Distribution Line Loss Factors	1.00613	1.01701	1.04461	Line Loss Study 2015
3	**FUEL Rates $/kWh**	**$0.0113269**	**$0.0114494**	**$0.0117601**	Line 1 * Line 2

Schedule 1: This schedule reflects DP&L's estimates of past unrecovered Fuel costs it expected to be recovered during the period. As shown on line 1, DP&L's forecasted retail Fuel rate is $0.0112579 per kWh. After applying the line loss factors of 1.00613, 1.01701, and 1.04461 cents per kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0113269 $0.0114494, and $0.0117601 cents per kWh as shown on line 3.

Exhibit 5-23. Reconciliation Adjustment – January 2015 through May 2016

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Reconciliation Adjustment (RA)

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under Recovery (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$6,535,180	$6,535,180	Accounting Records
2	January-15	$6,514,382	($6,138,316)	$376,066	$27,694	$403,760	$6,938,940	Accounting Records
3	February-15	$6,551,119	($5,901,203)	$649,916	$29,921	$679,837	$7,618,777	Accounting Records
4	March-15	$5,710,681	($5,031,083)	($4,864,946) [2]	$21,363	($4,843,583)	$2,775,194	Accounting Records
5	April-15	$5,388,840	($3,774,416)	$1,614,424	$14,757	$1,629,181	$4,404,375	Accounting Records
6	May-15	$3,764,513	($3,180,204)	$584,309	$19,346	$603,655	$5,008,030	Accounting Records
7	June-15	$5,737,221	($5,523,712)	$494,305 [2]	$21,647	$515,952	$5,523,982	Accounting Records
8	July-15	$6,026,012	($4,029,370)	$1,996,641	$26,866	$2,023,508	$7,547,490	Accounting Records
9	August-15	$5,778,259	($4,284,814)	$1,493,445	$34,165	$1,527,611	$9,075,100	Accounting Records
10	September-15	$5,114,374	($3,839,481)	$1,274,894	$40,008	$1,314,901	$10,390,001	Accounting Records
11	October-15	$3,442,844	($3,142,640)	$300,204	$43,416	$343,621	$10,733,622	Accounting Records
12	November-15	$4,390,572	($2,949,548)	$1,441,025	$47,181	$1,488,206	$12,221,829	Accounting Records
13	December-15	$3,915,689	($3,915,689)	$0	$30,743	$30,743	$12,252,571	Corporate Forecast
14	*January-16*				*$23,857*	*$23,857*	*$12,276,428*	*Corporate Forecast*
14	February-16				$31,082	$31,082	$12,307,510	Corporate Forecast
15	March-16				$20,236	$20,236	$12,327,746	Corporate Forecast
15	April-16				$11,126	$11,126	$12,338,872	Corporate Forecast
16	May-16				$3,737	$3,737	$12,342,609	Corporate Forecast
17	Total (Over)/Under Recovery						$12,342,609	Line 16
		Jan-15	Feb-15	Mar-15	Apr-15	May-15		
18	Forecasted Generation Level Sales	302,432,780	235,574,247	237,703,816	158,808,443	161,829,099	1,096,348,385	Corporate Forecast
19	***Forecasted RA Rate $/kWh***						*$0.0112579*	*Line 17 / Line 18*

[1] YTD = current month Total + previous month YTD total

[2] *(Over)/Under Recovery is equal to the current (over)/under recovery minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.*

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period January through November 2015, and (2) DP&L's estimated Fuel costs for the period December 2015 for total actual and forecasted Fuel costs of $62.335 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($49.710) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $5.630 million, as shown in column D. Column E reflects the carrying costs for the period of January 2015 through May 2016, which totaled $447,145. The under-recovery for the period of January through November 2015 and the addition of the carrying costs for January 2015 through May 2016 resulted in a total under-recovery of $12.343 million (column G, line 17). Line 18 of Schedule 2 reflects DP&L's forecasted generation level sales for the period January through May 2015, which totals 1.096 billion kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of $.0112579 per kWh by dividing the total under-recovery of $12.343 million by its forecasted sales for the period January 2015 through May 2016.

Exhibit 5-24. Calculation of Carrying Costs – Workpaper 1, January 2015 through May 2016

THE DAYTON POWER AND LIGHT COMPANY
Case No. 15-0042-EL-FAC
FUEL Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								CARRYING COST CALCULATION	
Line No. (A)	Period (B)	First of Month Balance (C)	New FUEL Rider Costs (D)	Amount Exceeding Threshold (E)	Amount Collected FUEL Rider (CR) (F)	NET AMOUNT (G)	End of Month before Carrying Cost (H)	Carrying Cost (I)	End of Month Balance (J)	Less: One-half Monthly Amount (K)	Total Applicable to Carrying Cost (L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$6,535,180	$0	$0
2	Jan-15	$6,535,180	$6,514,382	$0	($6,138,316)	$376,066	$6,911,246	$27,694	$6,938,940	($188,033)	$6,723,213
3	Feb-15	$6,938,940	$6,551,119	$0	($5,901,203)	$649,916	$7,588,856	$29,921	$7,618,777	($324,958)	$7,263,898
4	Mar-15	$7,618,777	$5,710,681	($5,544,543)	($5,031,083)	($4,864,946)	$2,753,831	$21,363	$2,775,194	$2,432,473	$5,186,304
5	Apr-15	$2,775,194	$5,388,840	$0	($3,774,416)	$1,614,424	$4,389,619	$14,757	$4,404,375	($807,212)	$3,582,407
6	May-15	$4,404,375	$3,764,513	$0	($3,180,204)	$584,309	$4,988,684	$19,346	$5,008,030	($292,155)	$4,696,530
7	Jun-15	$5,008,030	$5,737,221	($1,719,204)	($3,523,712)	$494,305	$5,502,335	$21,647	$5,523,982	($247,152)	$5,255,183
8	Jul-15	$5,523,982	$6,026,012	$0	($4,029,370)	$1,996,641	$7,520,623	$26,866	$7,547,490	($998,321)	$6,522,303
9	Aug-15	$7,547,490	$5,778,259	$0	($4,284,814)	$1,493,445	$9,040,935	$34,165	$9,075,100	($746,723)	$8,294,212
10	Sep-15	$9,075,100	$5,114,374	$0	($3,839,481)	$1,274,894	$10,349,994	$40,008	$10,390,001	($637,447)	$9,712,547
11	Oct-15	$10,390,001	$3,442,844	$0	($3,142,640)	$300,204	$10,690,206	$43,416	$10,733,622	($150,102)	$10,540,104
12	Nov-15	$10,733,622	$4,390,572	$0	($2,949,548)	$1,441,025	$12,174,647	$47,181	$12,221,829	($720,512)	$11,454,135
13	Dec-15	$12,221,829	$3,915,689	($9,516,932)	($3,915,689)	($9,516,932)	$2,704,897	$30,743	$2,735,639	$4,758,466	$7,463,363
14	Jan-16	$2,735,639	$9,516,932	$0	($3,404,758)	$6,112,174	$8,847,813	$23,857	$8,871,670	($3,056,087)	$5,791,726
15	Feb-16	$8,871,670	$0	$0	($2,652,071)	($2,652,071)	$6,219,599	$31,082	$6,250,681	$1,326,036	$7,545,635
16	Mar-16	$6,250,681	$0	$0	($2,676,046)	($2,676,046)	$3,574,635	$20,236	$3,594,871	$1,338,023	$4,912,658
17	Apr-16	$3,594,871	$0	$0	($1,787,850)	($1,787,850)	$1,807,022	$11,126	$1,818,147	$893,925	$2,700,946
18	May-16	$1,818,147	$0	$0	($1,821,856)	($1,821,856)	($3,709)	$3,737	$28	$910,928	$907,219

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period January 2015 through May 2016, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0112579). First, 50% of the net amount of FUEL Rider costs (the new monthly FUEL Rider cost minus the amount collected by the FUEL Rider) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of Fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate FUEL Rider Deferrals

In its Opinion and Order dated June 24, 2009 regarding DP&L's October 10, 2008 application for a Electric Security Plan ("ESP"), in Case No. 08-1094-EL-SSO, the Commission approved an ESP and FUEL Rider for DP&L for a three-year period January 1, 2010 through December 31, 2012. In an Entry dated December 19, 2012, states:[13]

> Section 4928.141, Revised Code, provides that the rate plan of an electric distribution utility shall continue until a standard service offer is first authorized under Section 4928.142 or Section 4928.143, Revised Code. Similarly, Section 4928.143(C)(2)(b), Revised Code, directs that if a utility terminates an application for an ESP, the Commission will issue an order to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in Fuel costs, until a subsequent offer is authorized.

[13] Entry in Case No. 08-1094-EL-SSO, dated December 19, 2012, page 3.

On December 12, 2012, DP&L filed a revised application for an SSO pursuant to Section 4928.141 of the Revised Code, and which was for approval of a revised ESP in accordance with Section 4928.143 of the Revised Code[14]. In its Opinion and Order dated September 4, 2013 in Case No. 12-426-EL-SSO, the Commission approved DP&L's application for a second ESP for the period January 1, 2014 through May 31, 2017. In accordance with the referenced Opinion and Order as well as the Opinion and Order issued in Case No. 08-1094-EL-SSO, the Commission ordered two audits of the Fuel Rider and AER, with the first audit covering the period 2013 and the second audit covering 2014.

DP&L records its Fuel deferrals in Account 1823000/2543000.

It should be noted that in the prior review periods 2010, 2011 and 2012, DP&L had filed an Annual Fuel Filing pursuant to the 2009 ESP Stipulation, which, as noted above, expired on December 31, 2012. During the review period for 2013, DP&L had advised that the 2013 ESP Opinion and Order, which superseded the 2009 ESP Stipulation, contained no requirement for an Annual Fuel Filing. Therefore, DP&L has not made such a filing for the 2015 review period.

The Company's responses to data requests LA-2015-1-52and LA-2015-1-53 produced DP&L's Excel files and supporting workpapers for the FUEL Rider filings and RA adjustments.

Variances Between Forecasted and Actual Fuel Rider Revenues and Costs

During Larkin's review of DP&L's forecasted Fuel Rider revenues and expenses for the 2010 review period, Larkin had concluded that understanding the reason(s) for why variances occur between forecasted and actual Fuel Rider revenues and expenses could lead to improvements in the accuracy of such future forecasts. As a result of that conclusion, Larkin had made a recommendation which was incorporated into the Stipulation and Recommendation dated October 5, 2011. Specifically, Item No. 9 from the Stipulation states:

> The Parties agree that DP&L will "prepare explanations of differences between forecast and actual Fuel Rider revenues, and between forecast and actual Fuel Rider costs" in time for the review by the auditor for the 2011 Audit, and will provide these explanations to the Parties.
>
> (Footnote omitted)

Pursuant to confirming that DP&L was in compliance with this item from the 2011 Stipulation and Recommendation, Larkin asked the Company to provide a narrative which explains the variances between the forecasted and actual Fuel Rider revenues and expenses. In response to LA-2015-64, DP&L provided a summary of variances between forecasted and actual 2015 Fuel Rider revenues and expenses, which is replicated in Exhibit 5-25 below.

[14] DP&L's revised application was filed to correct errors discovered in its initial ESP application, which was filed on October 5, 2012.

Exhibit 5-25. Summary of Variances Between Forecast And Actual FUEL Rider Revenues and Costs during 2015

[redacted]

Over the last several years, DP&L has experienced a trend whereby many of its customers have switched to alternative providers[15], including DP&L's affiliate, DPLER. However, during 2015 DP&L actually gained 5,018 customers.[16] Because the Fuel Rider rate is bypassable, once customers switch to an alternative provider, they are no longer subject to paying rates established pursuant to the Fuel Rider. Consequently, customers who were DP&L retail jurisdictional customers during a period where an undercollection of Fuel costs occurred, but who have selected an alternative provider, avoid the obligation to make future payments for the Fuel Rider deferral (undercollection) that had occurred in periods when the customers had been DP&L retail jurisdictional customers subject to the Fuel Rider. Paying for the Fuel Rider undercollection thus becomes the responsibility of only the remaining DP&L retail jurisdictional customers who have not switched providers. As discussed in a later section of this report, DP&L has attempted to mitigate the impacts of customer switching on the deferral balance with the implementation of its Reconciliation Rider[17], which was approved by the Commission in its Order and Opinion dated September 4, 2013 in Case No. 12-426-EL-SSO, el al. Customer switching is discussed in more detail in a later section of this report.

Potential for a Terminal Undercollected Balance

Data request LA-2015-62 asked the Company to provide the most current estimates and projections of the deferred Fuel Rider costs currently through to the end of the ESP term. This

[15] Customers can opt to obtain transmission and generation services from a Certified Retail Electric Service (CRES) provider. CRES providers operating in DP&L's service territory include DP&L's affiliate DPLER and other non-affiliated providers.
[16] See the response to LA-2015-83.
[17] See discussion of the Reconciliation Rider in a later section of this report.

request also asked the Company to indicate DP&L's estimate of the collection period necessary to completely recover the deferred Fuel Rider costs after the ESP terms ends and to provide an estimate of the prospective surcharge and rate impact. In response, DP&L stated that it transferred the Fuel Rider deferred balance of $1,075,667 to the Competitive Bid True-Up Rider at the end of March 2016.[18]

Minimum Review Requirements

As noted above, Larkin referred to the objectives and procedures outlined in Appendix E of former Chapter 4901:1-11 of the Ohio Administrative Code as guidance for the review requirements of this project. The purpose of the Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component is to provide uniform standards and specifications as guidelines for an independent auditing firm which conducts an EFC "financial audit"[19] pursuant to former section 4905.66(B)(2) of the Revised Code and former rule 4901:1-11-09 of the Administrative Code. The EFC "financial audit" program is only a guide for the auditor and should not be used to the exclusion of the auditor's initiative, imagination, and thoroughness.

Section E of those Standards provides for the following Minimum Review Requirements:

> The auditor's review shall include, but not be limited to, a review of:
>
> Purchasing procedures for Fuel procurement not under long-term contracts;
>
> Procedures for accounting for Fuel receipts, testing, and payments;
>
> Procedures for weighing, testing and reporting coal burned;
>
> Procedures for amortizing nuclear Fuel costs corresponding to nuclear generated energy;
>
> Procedures for recording purchases and interchanges;
>
> Procedures for accounting treatment of emission allowances; and
>
> Procedures for calculating the EFC rate, including an evaluation of the company's compliance with the financial procedural aspects of former Chapter 4901:1-11 of the Administrative Code, and its application to customer bills.

Larkin reviewed DP&L's response to data request LA-2015-1 for the Company's procedures for accounting for Fuel receipts, testing of samples to ensure quality, and payments to vendors. DP&L provided several narratives from its Accounting Policies and Procedures Manual which discussed the various aspects of the Company's procedures with respect to Fuel receipts, testing and payments to vendors. Each of these areas is discussed below.

<u>Accounting for Coal Purchases, Consumption and Inventory</u>

[18] See discussion of the Competitive Bid True-Up Rider in a later section of this report.

[19] As noted above, the review of DP&L's quarterly FUEL Rider filings were conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants.

The Corporate Accounting Department oversees DP&L's coal accounting process. Information obtained from DP&L's two operated generation stations, the Risk Management/Commodity Settlement Department and Fuel bills from Cincinnati Gas & Electric ("Duke")/Dynegy and Columbus Southern Power ("AEP") is used to account for the Company's coal purchases. As it is responsible for covering the settlement of coal transactions, the Risk Management/Commodity Settlements Department forwards monthly coal transaction[20] data from the three generating stations to the Corporate Accounting Department. The Company records Fuel inventory in FERC Account 151 by using a moving weighted average and expenses it based on monthly coal usage. Specific procedures are as follows:

[redacted]

Accounting for Gas Purchases, Consumption and Inventory

Corporate Accounting oversees DP&L's gas accounting process and information is obtained from the O.H. Hutchings generation station, the Risk Management/Commodity Settlements Department and monthly Vectren Fuel bills. The Risk Management/Commodity Settlements Department addresses the settlement of peaker gas transactions, which consist of purchases, transportation, consumption, transfers, and other relevant information related to peaker gas on a monthly basis. Corporate Accounting is also tasked with the accounting associated with all peaker gas and O.H. Hutchings monthly gas usage. The peaker gas usage, including

[20] DP&L's coal transaction activity consists of coal purchases (recorded in FERC Acct 151), consumption (recorded in FERC Acct 501) as well as transfers or other relevant coal related information on a monthly basis.

[redacted]

transportation demand fees, is charged to FERC Account 547 and O.H. Hutchings gas usage, including transportation demand fees, is charged to FERC Account 501. Specific procedures are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Accounting for Fuel Oil Purchases, Consumption and Inventory

Corporate Accounting oversees DP&L's Fuel oil accounting process using information obtained from the generating stations, Risk Management/Commodity Settlements' FMS system, DP&L's Oracle system, copies of oil cash vouchers, as well as Fuel bills from Duke/Dynegy and AEP. Risk Management addresses the settlement of Fuel oil purchases and Corporate Accounting accounts for all monthly Fuel oil transactions, as well as the verifying, compiling and billing to DP&L's CCD/CD partners. The Company accounts for Fuel inventory by using a moving weighted average and Fuel oil is expensed on a monthly basis as it is consumed. Specific procedures are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Accounting for Coal Sales

Corporate Accounting oversees DP&L's coal sales accounting process by using information obtained from Risk Management/Commodity Settlements' FMS system as well as Fuel bills from Duke/Dynegy and AEP. Risk Management/Commodity Settlements addresses the settlement of coal sale transactions and forwards monthly Coal Sales Period Sales Profit/Loss Reports for DP&L operated generating stations to Corporate Accounting, which allocates the CCD/CD partners' share accordingly. Corporate Accounting is also tasked with compiling, billing and the accounting of coal sales gains or losses to and from the CCD/CD partners on a monthly basis. The Company records coal sales gains and losses by comparing the sales price to the cost of the coal sold and gains and losses are recorded when each transaction has been finalized and realized. Specific procedures are as follows:

[redacted]

Coal Pile Inventory

A physical coal pile inventory is taken annually on July 31. Central Services meets with each Station Manager and appoints a Station Inventory Representative. The One Project Coordinator[24] is chosen by the Vice President (or his designate) of Central Services from the field of Station Inventory Representatives.

Station Inventory Representatives are responsible for ensuring that all activities performed by the personnel and contractors are completed correctly and on time. Pursuant to this meeting these

[24] The Project Coordinator is responsible for contacting and selecting contractors to determine density and volumetric values and producing the final coal inventory report.

objectives, the Station Inventory Representative initiates a kick-off meeting, the purpose of which is to review the roles and responsibilities of all of the parties involved in the coal pile inventory process. The topics of this kick-off meeting include (1) contractor requested measurement locations; (2) additional grooming requests; (3) equipment needed to secure measurements in difficult to access locations; and (4) daily communication requirements. Once the aforementioned activities have been finalized, the Project Coordinator informs Internal Audit and Corporate Accounting of the schedule of activities at least ten work days prior to any on-site work.

The contractor submits the inventory report to each Station Inventory Representative. Once the report has been completed and reviewed and any necessary corrections made, it is then forwarded to the Station Manager for approval, and is then submitted to other areas of the Company. Specific procedures are as follows:

[redacted]

[redacted]

Each Station Inventory Representative is responsible for the inventory report at his/her respective station. Each of these reports must be developed under the following guidelines:

[redacted]

The Station Inventory Representative issues the original draft of the contractor's report to Internal Audit and Corporate Accounting within two weeks after receiving all relevant information.

[redacted]

[25] Density is valid if it is within the boundaries of the pile, above the base elevation of the pile, and below the theoretical maximum density from the sample's specific gravity.

[redacted]

All documentation related to the flyover, density and material balance is retained for a minimum of three years.

<u>Coal Sales Billing</u>

[redacted]

When payment is received from the Counterparty:

[redacted]

[redacted]

Fuel Oil Payment

[redacted]

When Settlements receives invoices in the Fuel oil mailbox:

[redacted]

In the event the invoice data does match the manually entered data from the FMS into the EFOS and/or the pricing information:

[redacted]

Coal and Limestone Payment

[redacted]

[redacted]

Larkin also reviewed the Company's procedures for weighing, testing, and reporting coal burned per data request LA-2015-2. The specific information provided, which pertained to the Killen and Stuart generation stations, included the following:

[redacted]

[redacted]

DP&L does not have nuclear generation, so the provisions of E (4) do not apply.

[redacted]

[redacted]

[redacted]

Jointly Owned Generation

According to the response to LA-2015-4, DP&L participates in seven jointly owned power plants, including (1) J.M. Stuart; (2) Killen; (3) Conesville #4; (4) Beckjord #6; (5) Zimmer; (6) East Bend; and (7) Miami Fort #7&8. However, AES Corporation's 2015 Form 10-K states that DP&L has undivided ownership interests in five jointly owned coal generation facilities, which are provided in Exhibit 5-26.

Exhibit 5-26. DP&L's Ownership Percentage of Jointly Owned Power Plants[28]

Plant	Co-owners	Operating Company	DP&L Ownership Percentage
J.M. Stuart	Duke/Dynegy; Columbus Southern Power ("CSP")	DP&L	35%
Conesville #4	Duke/Dynegy; CSP	CSP	17%
Zimmer	Duke/Dynegy; CSP	Duke/Dynegy	28%
Killen	Duke/Dynegy	DP&L	67%
Miami Fort #7&8	Duke/Dynegy	Duke/Dynegy	36%

As noted in Exhibit 1-22, Beckjord Unit #6 and East Bend are not listed despite LA-2015-4 stating that the Company participates in seven jointly owned power plants (including Beckjord Unit #6 and East Bend as noted above). Beckjord Unit #6 was retired on September 19, 2014 and the write-down for the disposal of the Fuel reserves was booked to Account No. 4210021, which had no impact on the Fuel Rider in 2015.

DP&L sold its interest in East Bend to Duke Energy Kentucky in December 2014. As part of the 2014 audit, the Company had provided all of the accounting detail and other relevant documentation related to the coal inventory and Fuel cost impacts from the sale of East Bend. In addition, Larkin had requested during the 2014 audit that the Company explain whether any cost or financial impacts related to the sale of East Bend affected the Fuel Rider to which DP&L stated that there were no costs or other financial impacts on the Fuel Rider resulting from the sale of East Bend.

The Corporate Accounting Department oversees DP&L's CCD/CD Fuel billing process. The Company obtains information from its operated generating stations, the Risk Management/Commodity Settlements Department as well as Fuel bills received from Duke/Dynegy and AEP.

DP&L accounts for Fuel at jointly owned generation plants as follows. The same accounting methodology is used at all seven jointly owned power plants:

[28] The information shown in the table is correct as rounded. We note that the precise ownership of Zimmer is 28.1% and Conesville is 16.5%.

[redacted]

Larkin asked DP&L to identify any Fuel amounts being deferred which affect the review period and to identify any such amounts by account and explain the reason for the deferral. In response to LA-2015-5, the Company provided a brief narrative on each of the FERC accounts that are included in the Fuel Rider and for which Larkin summarized in the section of this report titled: "Accounts Included in DP&L's Fuel Rider" in Chapter 5 on pages 4-5. The response to LA-2015-5 also included a summary of the Company's deferral amounts (by FERC account) as of December 31, 2015. This summary, which is reproduced in Exhibit 5-27, used the overall deferred balance as of December 31, 2014 as the starting point.

Exhibit 5-27. DP&L's Deferral Amounts by FERC Account as of December 31, 2015

[redacted]

Review Related to Coal Order Processing

According to the response to EVA-2015-1-3, DP&L does not use purchase requisitions or purchase orders for coal, natural gas or oil. Instead, an executed coal contract is used as authorization for DP&L to accept and pay for shipments of coal that meet the requirements of the contract until the contract obligations have been fulfilled. DP&L's response to data request EVA-2015-1-1 included copies of the coal contracts, which were reviewed by EVA. In addition, the Company purchases physical natural gas and oil for delivery to its generating stations at the prevailing market price. As part of this process, DP&L confirms that supplier invoices equal the market price and verifies that the quantity delivered is accurate.

To review the Company's processing of Fuel invoices, Larkin obtained copies of cash vouchers and payment documentation for Fuel purchases recorded in July 2015. This documentation was provided in the response to data request LA-2015-9.

The information provided in LA-2015-9 included a summary of payment vouchers and invoices for the period July 2015. For each invoice listed on the invoice detail summary pages, Larkin was able to trace the amount listed on the summary to the actual invoice. In addition, Larkin traced all of the invoices to general ledger account 151. Other than some minor rounding differences, no exceptions were noted.

Fuel Ledger

Data request LA-2015-10 requested DP&L's Fuel ledgers for the period January through December 2015. In response, DP&L referred to the response to LA-2015-71, which requested that DP&L provide detailed general ledger pages for each of the following accounts: 151, 182.4, 254, 501, 456, 506, 509, 547, 555, 421, 426, 411.8, and 411.9 (see additional discussion below) as well as each account that was used in 2015 to record 2015 [redacted] revenue and related cash receipts.[29]

BTU Adjustments

Data request LA-2015-11 asked DP&L to provide documentation for Btu adjustments for Fuel purchases recorded in July 2015. [redacted]

[redacted]

Pursuant to the narrative above, the responses to LA-2015-15 and LA-2015-27 refer to the response to LA-2015-11.

Freight And Barge Vouchers

Data request LA-2015-12 asked DP&L to provide freight cash vouchers for two days of coal receipts in July 2015 as well as copies of the portions of the corresponding coal received reports. In response, DP&L stated that it did not receive any coal via rail during any month in 2015.

In data request LA-2015-13, Larkin requested that DP&L provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2015 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. DP&L's barging

---

[redacted]

[30] Larkin modified the narrative to reference data requests related to the 2015 review period.

services are provided by [redacted]. In its confidential response, DP&L provided copies of invoices from [redacted], cash vouchers as well as Invoice Detail sheets, which included data related to coal shipments received at the Killen and Stuart plants during July 2015 and which tied out to the [redacted] invoices. Upon reviewing and comparing the data listed on the documents provided, Larkin was able to trace the coal shipments detailed on the Barge Unloading Report to each of the cash vouchers and [redacted] invoices. Other than some minor rounding differences, no exceptions were noted.

Fuel Analysis Reports

Data request LA-2015-14 asked DP&L to provide the Company's procedures for preparing monthly Fuel analysis reports. In its confidential response, the Company stated:

[redacted]

DP&L has appropriate procedures in place for monitoring the quality of coal received.

Retroactive Escalations

Data request LA-2015-16 asked that DP&L identify all pending or approved retroactive escalations that affect Fuel cost for the period January through December 2015 [redacted] EVA-2015-1-15 [redacted] EVA-2015-1-15 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Review Related To Station Visitation And Coal Processing Procedure

EVA conducted an onsite field visit at DP&L's Killen Generation station on June 27, 2016.[31] However, data requests LA-2015-19 through LA-2015-45 relate to fulfilling the objectives of the station visit and the review of the Company's coal processing procedure from the receipt of coal to the disposition of fly ash.

A description of the Company's coal receiving procedures and controls for shortages, overages, and other discrepancies was provided in DP&L's confidential response to LA-2015-19, and is as follows:

[redacted]

---

[31] Due to scheduling conflicts, Larkin was unable to attend the Killen Station plant tour for the 2015 review period.

[redacted]

According to LA-2015-20, DP&L weighs the coal as received in the following manner:

For the Stuart and Killen plants:

[redacted]

Larkin requested a description of how the Company resolves freight bill and car number discrepancies. In prior year's audits, DP&L listed a number of procedures related to this subject, but for the 2015 review, the response to LA-2015-21 states:

> *There were mechanisms in place specific to railcar discrepancies, but DP&L has not received rail deliveries since 2011 and does not expect to receive any in the future.*

LA-2015-36 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. Such discrepancies are handled in the following manner:

[redacted]

In response to data request LA-2015-37, DP&L described how damaged barges are checked and who instigates claims for shortages:

[redacted]

[redacted]

[redacted]

DP&L's response to LA-2015-23 described the Company's month-end cut-off procedures for coal deliveries and coal burn:

[redacted]

[redacted]

[redacted]

A description of the Company's coal sampling procedures was provided in response to data request LA-2015-24, which are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

Scale calibration logs for the period January through July 2015 were requested in LA-2015-25. In response, DP&L provided conveyor calibration and feeder calibration records for the Killen and Stuart plants for the entire year. In the event coal scales are inoperable, the following procedures are performed:

[redacted]

[redacted]

[redacted]

DP&L's procedures for handling coal from the stockpile to the firebox or boiler were requested with data request LA-2015-28. In response, DP&L provided two separate sets of documentation titled "DPL Business Practice" for the Killen and Stuart stations. Each of these sets of documents outlined a number of coal handling procedures that are performed by personnel at each of the referenced stations. The procedures are specific and detailed for each plant, and include references and helpful diagrams, such as the following diagram (from the Killen station coal handling procedures):

Exhibit 5-28. Diagram of Coal Barge Configuration and Coal Loading Specifications at Killen Station

[redacted]

DP&L's procedures for taking physical inventories of coal are described in the response to LA-2015-29. DP&L's procedures for coal pile inventory are detailed and specific.

DP&L's coal handling and coal pile physical inventory procedure manuals are among the most detailed we have seen.

In addition to the working coal inventory, DP&L maintains a permanent or "base" coal inventory, which is recorded in a plant account and amortized.

In response to data request LA-2015-31, which requested accounting documentation for physical inventory and any related inventory adjustments recorded for the review period, including the general ledger, and Fuel stock and consumption records, DP&L provided:

- Physical inventory worksheets for coal, oil and limestone
- Stuart and Killen Coal Consumed Monthly Summaries
- BFMS Period Posting Summary Reports
- Letters from Mikon Corporation (consulting engineers who conducted the inventory)
- Summaries of coal and oil inventory transactions
- General Ledgers for Accounts 151 (Fuel Inventory) and 501 (Fuel Consumption)

Larkin reviewed DP&L's records and was able to trace the amounts from the BFMS Period Posting Summary Reports to the general ledger (Account 501 - Fuel Inventory). With respect to Fuel oil, Larkin was able to trace the amounts from the workpapers and journal voucher to the general ledger (Account 501 – Fuel Consumption).

During Larkin's review of the aforementioned documents, it was noted that DP&L made two coal related physical inventory adjustments during the review period. One such adjustment related to the Stuart generation station while the other adjustment related to the Killen generation station. With respect to the inventory adjustment at Stuart, DP&L determined that the adjusted coal inventory totaled [redacted] tons versus a book coal inventory totaling [redacted] tons, which resulted in a total physical inventory adjustment of [redacted] tons ([redacted]) with DP&L's portion totaling [redacted] tons. A review of DP&L's inventory adjustment workpapers indicated that the Company allocated the [redacted] tons among Stuart Units 1 through 4 as summarized in Exhibit 5-29 below.

Exhibit 5-29. Summary of Physical Coal Inventory Adjustment at Stuart

[redacted]

As reflected in the Exhibit 5-29, Stuart's physical inventory exceeded its book value by [redacted] after applying DP&L's ownership percentage). As for the inventory adjustment related to Killen, DP&L determined that the adjusted coal inventory totaled [redacted]

[redacted]. The dollar impact of the Killen inventory adjustment is summarized in Exhibit 5-30 below.

Exhibit 5-30. Summary of Physical Coal Inventory Adjustment at Killen

[redacted]

As reflected in the Exhibit 5-30, Killen's physical inventory [redacted] after applying DP&L's ownership percentage).

As noted above, DP&L made a substantial adjustment to increase coal inventory at Stuart Station by [redacted]. The Company also had made a substantial adjustment to increase coal inventory at Stuart in 2014 as discussed in the audit report in Case No. 15-042-EL-FAC. In the 2014 audit report, both Larkin and EVA had recommended that the Company conduct a root cause analysis in order to determine the reason(s) for the substantial physical inventory variance which occurred at Stuart. A settlement in the 2014 was ultimately reached and the foregoing recommendation was incorporated into the Stipulation and Recommendation ("Stipulation") that was filed with the Commission on May 10, 2016 pursuant to the settlement. Specifically, finding number 3 on page 6 the Stipulation states:

> DP&L's internal audit group will continue to monitor and periodically assess whether there are any large deviations between book and physical inventories (defined as an eight percent variance based upon book inventory and a two percent variance based upon burn and the variance must be greater than 5,000 tons). When there are large deviations, DP&L shall undertake an analysis to identify root causes and, to the extent appropriate, develop an action plan.

As shown in the exhibits above, both the Stuart and Killen inventory adjustments were in excess of 5,000 tons. Upon Larkin's inquiry as to whether an investigation was conducted in 2015 as to the cause of the coal inventory variances, in response to LA-2015-121 DP&L stated that is did not conducted any investigations in 2015 or subsequently as to the reason for the variances between the physical and book coal inventories at Stuart and Killen. The Company cited its Accounting Policy FA-40.A01 - Fuel Inventories: Accounting for Coal Purchases, Consumption and Inventory, specifically Section 5.6.1 which states:

[redacted]

The Company stated that for Stuart, both percentages were under the requirements specified in the passage above. For Killen, the physical coal inventory difference was [redacted].

The percentages for both generating stations are summarized in the exhibit below.

Exhibit 5-31. Summary of Physical Coal Inventory Percentage Variances at Stuart and Killen

[redacted]

With regard to the Killen physical coal inventory variance being [redacted] the Company stated:

[redacted]

In a related matter, Larkin also requested that DP&L explain how it has complied with the root cause analysis provisions of the 2014 Fuel Rider Settlement and whether it has developed an action plan to comply with such provisions. In addition, Larkin requested that the Company explain when and how it would comply with these provisions and how such compliance can be verified. In response to LA-2015-2-2 DP&L stated:

[redacted]

The Company's response to LA-2015-32 describes the levels of review applicable to DP&L's plant operating statistics. The power plants develop Monthly Station Operating Reports, which are sent by each station's Engineering Department to various other departments for crosschecking and reporting purposes. In addition, the reports are also sent to the Middle Office, Fuels Department, and Accounting to verify the data used for accounting purposes.

Larkin requested copies of the generating station reports for the review period January through December 2015 that were sent to the Company's general office for incorporation into company statistics and workpapers sufficient to trace the reports to the statistics. DP&L's response to LA-2015-35 provided copies of generating station reports for Hutchings, Killen and Stuart for the period January through December 2015. Attachments to LA-2015-35 reflected the service hours, net heat rate, gross generation, net generation, and startups for each generating unit at the two plants. The attachments also reflect detailed daily and month-to-date information for each generating unit. For example, the monthly information for the Killen generating station includes details on the following datasets.

Exhibit 5-32. Generating Unit Datasets Used In Killen Station Monthly Operating Reports for 2015

Gross Generation, MWh
Net Generation, MWh
Coal Burned, KLB
Heating Value of Coal, BTU/LB
Heat in Coal, mil BTU
Total Boiler Oil, GAL
Heat in Boiler Oil, mil BTU
Unit Ignition Oil, GAL
Heating Value of Oil, BTU/GAL
Service Oil, GAL
Start Up Oil, GAL
Aux Boiler Oil, GAL
Oil Received to Main Tanks
Oil Trans Main Tanks, GAL
Emer. Diesel Gen. Oil, GAL
Diesel Fire Pump Oil, GAL
Oil on Hand in Main Tanks, GAL
Gas Turbine, GAL
Gas Turbine Gen, MWh

DP&L has reasonable procedures in place to account for and collect plant Fuel burn related information.

Data Request LA-2015-38 asked for the base coal inventory amounts at Stuart and Killen Stations for both total plant and DP&L's share for 2015 and 2016 that shows any adjustments. In response, the Company provided the amounts shown in Exhibits 5-33 and 1-34 and stated that for Stuart, [redacted] of the DP&L figure is depreciated, leaving an undepreciated balance of [redacted]. For Killen, [redacted] of the DP&L figure is depreciated, leaving an undepreciated balance of [redacted].

Exhibit 5-33. Base Coal Inventory at Stuart Station for 2015 and 2016

[redacted]

Exhibit 5-34. Base Coal Inventory at Killen Station for 2015 and 2016

[redacted]

Review Related to Coal Transfers Between Generating Stations

Documentation related to the treatment of coal transfers between power plants was requested in LA-2015-40. DP&L's response to LA-2015-40 referred to the response to LA-2015-88, Attachment 11. The documentation provided in that attachment related to six coal transfers from Stuart to Killen during 2015. Two of the transfers occurred in January 2015 and the remaining four transfers occurred in August, October, November and December 2015. The specifics of each of the six coal transfers are discussed below.

First Coal Transfer - January 2015

According to the documentation provided in the response to LA-2015-88, the first coal transfer in January 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components that relate to this transfer are summarized in Exhibit 5-35 below.

Exhibit 5-35. Summary of First Coal Transfer from Stuart to Killen in January 2015

[redacted]

As shown in Exhibit 5-35, this transfer resulted in a [redacted] to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in February 2015.

Second Coal Transfer - January 2015

According to the documentation provided in the response to LA-2015-88, the second coal transfer in January 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components related to this transfer are summarized in Exhibit 5-36 below.

Exhibit 5-36. Summary of Second Coal Transfer from Stuart to Killen in January 2015

[redacted]

This transfer resulted in a [redacted] Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in February 2015.

<u>Third Coal Transfer - August 2015</u>
According to the documentation provided in the response to LA-2015-88, the coal transfer in August 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components related to these transfers are summarized in Exhibit 5-387 below.

Exhibit 5-37. Summary of Third Coal Transfer from Stuart to Killen in August 2015

[redacted]

This transfer resulted in a [redacted] to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in September 2015.

<u>Fourth Coal Transfer - October 2015</u>

According to the documentation provided in the response to LA-2015-88, the coal transfer in October 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components related to these transfers are summarized in Exhibits 5-378 below.

Exhibit 5-38. Summary of Fourth Coal Transfer from Stuart to Killen in October 2015

[redacted]

This transfer resulted in a [redacted] to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in November 2015.

<u>Fifth Coal Transfer - November 2015</u>

According to the documentation provided in the response to LA-2015-88, the coal transfer in October 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components related to these transfers are summarized in Exhibits 5-379 below:

Exhibit 5-39. Summary of Fifth Coal Transfer from Stuart to Killen in November 2015

[redacted]

This transfer resulted in a [redacted] to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in November 2015.

Sixth Coal Transfer - December 2015

According to the documentation provided in the response to LA-2015-88, the coal transfer in October 2015 involved the transfer of [redacted] tons of coal from Stuart to Killen. This coal had a contract price of [redacted] per ton and a transfer price of [redacted] per ton. The components related to these transfers are summarized in Exhibits 5-3740 below.

Exhibit 5-40. Summary of Sixth Coal Transfer from Stuart to Killen in December 2015

[redacted]

This transfer resulted in a [redacted] gain to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2015-71 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in December 2015.

It was unclear whether the gains and losses from the six transfers of coal from Stuart to Killen that occurred during 2015 flowed through the Fuel Rider. Upon Larkin's follow-up inquiry, DP&L confirmed that the gains and losses on the coal transfers discussed above were embedded in the gains and losses for Stuart that are reflected in the Excel workbooks provided in LA-2015-53 in the same months that the gains and losses were posted to the general ledger.

Larkin reviewed the monthly Excel workbooks and noted that, due to the stacking of costs in the months in which the coal transfers were reflected (i.e., February, September, November and December) that approximately [redacted] (on average) of these gains and losses were allocated to wholesale sales and not flowed through the Fuel Rider.

Review Related To Fuel Supplies Owned Or Controlled By The Company

DP&L's confidential response to data request LA-2015-46 stated that neither the [redacted]

Review Related To Purchased Power

DP&L's response to LA-2015-47 provided documentation relating to the review of purchased power. Specifically, LA-2015-47 asked "For DPL, for purchases of power recorded in July 2015 that are included in the Fuel Rider, please provide the related invoices, and paid cash voucher or cash payment receipt". In its confidential response, the Company provided [redacted]

[redacted] In response to Larkin's inquiry, the Company provided the following narrative:

> [redacted]

Through reviewing the July 2015 PJM Reconciliation, Larkin was able to tie out the July 2015 power purchases from PJM to the amounts included in the FUEL Rider. Other than some immaterial variances, no exceptions were noted.

<u>Derivative Gains and Losses on Purchased Power</u>

The monthly Excel workbooks include a tab titled ".19 GL on Purchased Power". For the months of January through June as well as November 2015, the Company included derivative gains and losses totaling $9,376. Of this amount, $8,028 was allocated to DP&L retail and $1,348 was allocated to wholesale sales. Larkin requested that for each month of 2015 in which a derivative gain or loss of purchased power was reflected in the Excel workbook, that the Company provide documentation in support of such gains or losses and to explain why they were included in the Fuel Rider. In response to LA-2015-2-6, DP&L stated that these transactions should have been allocated 100% to wholesale sales and not allocated between retail and wholesale. Therefore, Larkin recommends that the Fuel Rider be decreased by $8,028 to reflect the reclassification of derivative gains and losses on purchased power to 100% wholesale sales.

With respect to system dispatch, Data Request LA-2015-48 inquired as to whether the dispatch related to the Company's generating units were under the control of PJM during the January through December 2015 review period. In its confidential response, DP&L [redacted]

[redacted]

LA-2015-49 asked: "During the review period were any of the Company's generating units designated by PJM as "must run" for reliability or voltage control purposes? If so, please identify the units, hours, and cost/Mwh for each "must run" situation at the Company's generating units during this period." In its confidential response, [redacted] are reflected in Exhibits 5-41 through 5-42 below.

Exhibit 5-41. "Must Run" Generating Units For Tait CT 3 for Transmission Constraint - June and September 2015

[redacted]

Exhibit 5-42. "Must Run" Generating Units For Stuart Diesel for Voltage Support - October 2015

[redacted]

Exhibit 5-43. "Must Run" Generating Units For Stuart Diesel for Transmission Constraint - December 2015

[redacted]

[redacted]

[redacted]

[redacted]

Demurrage

Demurrage, in general, relates to the delaying of a ship, barge, railway wagon, etc., caused by the charterer's failure to load, unload, etc., before the time of scheduled departure and to the extra charge required as compensation for such delay. DP&L incurs demurrage charges related to the barging of coal and other materials primarily to the Stuart and Killen plants it operates, which are located on the Ohio River within a few miles of each other and are served by barge delivery, when delays occur in the unloading of such barges. The Company stated in response to LA-2015-1-42 that [redacted]

Managing barge deliveries to minimize demurrage charges is one aspect of the overall least-cost management of Fuel procurement. DP&L records demurrage charges as part of its cost for the transportation of coal. Demurrage costs are recorded into the coal inventory account (Account 151) and become part of the Fuel cost for coal (Account 501) when the coal is burned.

According to the confidential response to LA-2015-41, during the 2015 review period, [redacted]

As noted above, during 2015, [redacted], which is substantially higher than 2014 and 2013 levels as summarized in the following exhibit:

Exhibit 5-44. Net Demurrage Charges For Years 2013 through 2015

[redacted]

Larkin inquired as to why the demurrage charges were [redacted] and in response DP&L stated:

[redacted]

It should be noted that the schedules provided in LA-2015-41 and LA-2015-43 (from which the amounts in Exhibit 5-444 were taken) represent total plant amounts and not solely DP&L's share.

DP&L provided additional explanations of how it weighs and evaluates the cost of incurring demurrage with other factors in managing its coal inventory and plant coal burn in its response to LA-2015-44:

[redacted]

[redacted]

Review Related to Service Interruptions and Unscheduled Outages

Documentation relating to the review of Service Interruptions and Unscheduled Outages includes DP&L's responses to data requests LA-2015-50 and LA-2015-1-51.

Exhibit 1-45 illustrates a few examples of the longest forced outages at DP&L's generating units during 2015 from DP&L's response to part 1 of LA-2015-51:

Exhibit 5-45. Examples of Longest Forced Outages

[redacted]

Data request LA-2015-50 asked about customer power supply interruptions during the review period January through December 2015. In response, DP&L stated that none of its customers experienced an interruption as a result of a lack of power supply during the January through December 2015 review period. DP&L also stated that some of its customers have agreements with a Certified Retail Electric Service (CRES) provider or through a PJM-administered program for Curtailment Service Providers in which supply interruptions are permitted under the terms and conditions set forth in the related contracts and/or PJM procedures.

LA-2015-51 requested DP&L to identify instances during the review period in which the Company's generating units experienced unscheduled outages and to provide documentation concerning the following:

1. The cause(s) of the outage.
2. Steps taken by the Company to minimize the impacts of the unscheduled outage.
3. Efforts made to secure replacement power, if applicable.
4. The methodology employed to price the replacement power, if applicable.
5. The cost impacts resulting from the periods during which the unscheduled outage occurred.

In response to item 1, DP&L provided an Excel file titled "LA-2015-51 Part 1", which listed information relating to unscheduled outages at DP&L's generating units during the review period, including the unit name, event type, starting and ending dates of the outage, category name, code, and a brief description of what caused the unscheduled outages. An example of this file was presented as Exhibit 5-45 above.

With respect to items 1 through 3, DP&L explained that the following three points need to be made before discussing the steps taken by the Company to minimize the impacts of the outages: (1) DP&L's stipulation provides jurisdictional customers with the least cost generation units, meaning that each day, jurisdictional customers receive the cost of DP&L's generating units to meet their needs beginning with the lowest cost unit; (2) DP&L is part of the PJM RTO and as such participates in the PJM energy market, which uses PJM's Security Constrained Economic Dispatch Model ("SCED") in order to dispatch and ensure that the least cost unit will be dispatched system wide to meet the next MW of load needed; and (3) DP&L's position is managed on a portfolio basis so that all available resources are considered when determining the impact of the unscheduled outages. The result of these three points is that the Company's jurisdictional customers receive least cost supply stacking from the Company's generating units coupled with an efficient market for energy through participating in the PJM market.

The Company further explained that in order to minimize the impacts of an unscheduled outage, [redacted]

With respect to item 4, which requested the methodology employed to price the replacement power (if applicable), the Company stated:

[redacted]

With respect to item 5, the cost impacts resulting from the periods during which the unscheduled outage occurred, DP&L stated that the cost impact to customers of each unscheduled outage depends on the retail position at the time of the outage and where the unit is in the supply stack. If the generator was not serving retail load on the day of the outage, there would be no cost impact to the retail customers. If the generator was serving retail load, the energy would be replaced by the most economical method available (i.e. either the next available resource in the supply stack or power purchases). On the day after the generator initially went offline, the remaining available resources would be stacked and the customers will use the least cost resources from DP&L's portfolio for that day.

Audit Trail for FUEL Rider Filings, Supporting Workpapers, and Documentation

DP&L provided documentation relating to the audit trail for its Fuel Rider filings in its responses to data requests LA-2015-52 as well as LA-2015-53 through LA-2015-56.

Data request LA-2015-52 asked DP&L to provide electronically in Excel, all of the Company's quarterly Fuel Rider filings, which pertained to costs incurred or revenues recorded in the January through December 2015 review period. In response, DP&L provided Fuel Cost forecasts for January-May, June-August, September-November, and December 2015. DP&L also provided the related revenue class to tariff class conversions.

LA-2015-53 asked for a complete set of supporting workpapers for all calculations in the FUEL Rider filings for the review period January through December 2015 and/or which pertained to costs incurred or revenues recorded in the review period. In response, DP&L provided monthly Excel workbooks which consisted of the following:

- The 2015 monthly actual Fuel Recovery calculations supporting the recorded journal entry
- Summary calculation for Fuel Recovery Derivative Gain Loss Adjustment
- Summary calculations for Fuel cost adjustments from the Fuel Application
- Supporting workpapers for the summary sheets
- Monthly revenue to each tariff class

Each of the monthly Excel workbooks are comprised of Tabs .1 through .23. This overview included the following components:

Input Tabs – These tabs are linked to the various Calculation and Allocation tabs in order to generate the Fuel Rider Over/Under Recovery (Deferral or Liability).

Account Reconciliation Tab – The reconciliation tabs reconcile the Total Calculated Deferral from within this spreadsheet to the recorded Fuel Deferral in the General Ledger.

Allocation and Output Tabs – Tab .5 is where the retail costs and revenues are allocated between retail, billed, unbilled and carrying costs. Tab .6 reflects the calculation of the carrying costs for the over or under recovery of the Fuel deferral.

Summary Tabs – These tabs serve as the summaries of the dollars and MWhs in the Fuel Deferral. They summarize the information in Tabs .9 through .23 and are summarized by type of cost and plant as well as reflecting the retail/wholesale split.

Calculation Tabs – These tabs serve as the primary calculation tabs for the various expenses included in the Fuel Rider recovery calculation. Specifically, these tabs calculate the amount of expense to be allocated between retail and wholesale costs for each unit within each plant.

In terms of the expense and revenue amounts that are reflected in the RA portion of DP&L's quarterly Fuel Rider filings (i.e. Schedule 2 from such filings), the primary tabs from the Excel file associated with these amounts are Tabs .5 through .7. Tab .7, which is titled "Summary $ Sheet", summarizes the total expenses that DP&L has included in its Fuel Rider after allocating such expenses between retail and wholesale. The calculations from Tabs .9 through .20 flow through to Tab .7. The FERC accounts below (from Tab .7) represent the costs that DP&L has included in its Fuel Rider. The following list shows which tab from the Excel file relates to the FERC accounts listed below:

501 – Steam Plant Generation (Tab .9)

501 – Steam Plant Fuel Oil Consumed (Tab .10)

501 – Steam Plant Fuel Handling (Tab .11)

506 – Emission Fees (Tab .12)

456 – Coal Sales (Tab .14)

456 – Heating Oil Realized Gains or Losses (Tab .15)

509 – Allowances Consumed (Tab .16)

547 – Gas and Diesel Peakers of DP&L (Tab .17)

555 & 565 - Purchased Power (Tab .18)

421 – Purchased Power Realized Gain (Tab .19)

426 – Purchased Power Realized Losses (Tab .19)

411.8 & 411.9 – Allowance Sales (Tab .20)

In addition, Tabs .21, .22, and .23 represent Fuel cost MWhs, gas and diesel peaker MWhs, and purchased power MWhs, respectively.

From there, the DP&L retail costs then flow through to Tab .5, which is titled "JE Spreadsheet". It is from this tab that the over/under recovery deferral is calculated by taking the difference between the DP&L retail costs and the billed monthly FUEL Rider revenues. The over/under recovery is then allocated between a billed and an unbilled deferral which is based on the ratio of DP&L's billed and unbilled monthly revenues and the billed deferral is flowed through to the Company's quarterly FUEL Rider filings. In addition, Tab .5 includes a column titled "Deferral Entry Amount for Carrying Costs" in which these deferral amounts are calculated by multiplying the carrying costs calculated on Tab .6 by the ratio of the DP&L retail costs among the FERC accounts listed above.

DP&L also included additional supporting documentation in the form of a PDF file, which contains reproductions of journal entries and other support used in calculating the RAs. The pages of the PDF are DP&L's support for the amounts reflected on the various tabs within the Excel file. These documents are labeled as Worksheets S-1 through S-17. Of these documents, the primary support is from Worksheet S-12, which is titled "Fuel Recovery Oracle Report" and represents amounts recorded in the general ledger.

Larkin had selected July 2015 as its test month in terms of verifying the Fuel related revenues and expenses that the Company included in the FUEL Rider. Specifically, data requests LA-2015-72, LA-2015-73, and LA-2015-76 requested that DP&L provide a complete audit trail from its quarterly Fuel Rider filings to the FUEL Rider workpapers and relevant general ledger accounts (and sub-accounts) for July 2015 actual RA Fuel costs and revenues. In response, the Company provided detailed support from its internal accounting systems for the July 2015 revenues and expenses included in the Fuel Rider. Larkin was able to tie the amounts from this detail to the monthly Excel workbook for July 2015 (provided in LA-2015-53), which in turn was traced to the RA adjustment in the quarterly Fuel Rider filing dated December 1, 2015 as well as the general ledger. Larkin also performed similar selective procedures for other months in the review period as well. As a result of the procedures described above, Larkin concluded that DP&L maintained adequate audit trail documentation for 2015.

LA-2015-54 asked whether DP&L engaged in "active management" of its Fuel, purchased power, or emission allowance positions during the January through December 2015 review period, and if so, to identify, quantify and provide the related accounting documentation for each such "active management" transaction. In its confidential response, the Company stated:

[redacted]

Reconciliation Adjustments Audit Trail

As discussed previously, Larkin requested that DP&L provide a complete audit trail for all amounts in the RA portions in each of the Company's quarterly FUEL Rider filings. Specifically, the information requested by Larkin included the following:

<u>LA-2015-55 (Pertains to Reconciliation Adjustments)</u>

- The accounting records and other documentation needed to trace each dollar amount in the RAs from the FUEL Rider filings to the Fuel ledger, from the Fuel ledger to the general ledger, and from the Fuel ledger to the purchase orders and invoices.
- The complete documentation to trace the energy and system loss quantities in the Fuel Rider filings to the source documents.
- All journal entries, journal entry supporting documentation, and workpapers related to recording RA adjustments in the Company's accounting records.
- Provide all calculations and supporting documentation related to computing RA adjustments in the Company's FUEL Rider workpapers.

<u>LA-2015-56 (Pertains to Subaccounts for Purchased Power)</u>

- The accounting records and other documentation needed to trace each dollar amount in the RAs through the FUEL Rider filings to the general ledger, and from the general ledger to the purchase orders and invoices.
- The complete documentation to trace the purchased power costs in the FUEL Rider filings to the source documents.
- All journal entries, journal entry supporting documentation and workpapers related to recording purchased power costs in RA adjustments in the Company's accounting records.
- Provide all calculations and supporting documentation related to computing purchased power costs in RA adjustments in the Company's FUEL Rider workpapers.

The data requested in LA-2015-55 and LA-2015-56 was provided in LA-2015-53. In its responses to LA-2015-55 and LA-2015-56 (which were combined into a single response), DP&L discussed five adjustments that it made during the review period and which are summarized in Exhibit 5-466 below.

Exhibit 5-46. 2015 Adjustments to Fuel Rider

[redacted]

The Company provided documentation which showed how each of the five adjustments was derived. The first adjustment listed in the exhibit of $14,692 relates to a recommendation to disallow this amount that was proposed in the 2013 Fuel audit and agreed to by DP&L in the Stipulation from that prior audit, and which was addressed in the PUCO's Order and Opinion dated February 11, 2015 in Case No. 14-117-EL-FAC. Adjustment No. 3 relates to a revision made to purchased power MWhs and dollars in June 2015, but which relates to April 2015 and which also caused carrying charges to increase by [redacted]. Adjustment No. 5 related to a [redacted] adjustment to carrying costs in July 2015, which resulted from the carrying costs that were reflected in the May 2015 Excel workbook (provided in LA-2015-53) whereby the May Excel workbook did not reflect the correct ending balance for April 2015 pursuant to Adjustment No. 3 discussed above.

Adjustment Nos. 2 and 4 related to reclassifying the Fuel deferral balance which exceeds the 10% threshold pertain to the RR-N that was approved by the PUCO in its Order and Opinion dated September 4, 2013 in Case No. 12-0426-EL-SSO et al and discussed in an earlier section of this report. Pursuant to the Commission's directive in the September 4, 2013, Order and Opinion as it relates to the Reconciliation Rider (see additional discussion later in this chapter), DP&L filed two separate applications in Case No. 15-43-EL-RDR to include rider amounts above the 10% threshold, which the Commission approved in its Finding and Orders dated February 25, 2015 and May 20, 2015. Larkin noted that DP&L reflected these adjustments in the relevant monthly Excel workbooks that were provided in LA-2015-53 as well as the quarterly Fuel Rider filings.

As noted previously, Larkin selected July 2015 as its test month for the 2015 review of the Fuel Rider. As such, data requests LA-2015-72 and LA-2015-73 requested the Company to provide the following data:

LA-2015-72
A complete audit trail from (1) the Company's quarterly Fuel Rider filings to (2) the FUEL Rider workpapers, to (3) the general ledger balances for each of the general ledger accounts in which FUEL Rider includable costs are recorded as well as any other accounts used by DP&L for the July 2015 actual RA Fuel costs.

LA-2015-73
A complete audit trail from (1) the Company's quarterly Fuel Rider filings to (2) the FUEL Rider workpapers, to (3) the general ledger balances and accounting records used by DP&L for the July 2015 actual RA Fuel revenue.

As noted above, in the combined response to LA-2015-72 and LA-2015-73, DP&L provided detailed support for the amounts reflected in the monthly Excel workbook for July 2015 (provided in LA-2015-53)[32].

System Optimization

In prior years dating back to the 2010 review period, and continuing through the 2013 review period, the Company has "optimized" its coal position in order to reduce the cost of Fuel and obtain "sharing" profits from the optimization trades. A 75/25 DP&L/customer sharing ratio was provided for in the February 24, 2009 Stipulation in Case No. 08-1094-EL-SSO.

[32] Data requests LA-2015-74 and LA-2015-75 requested similar actual Fuel revenue and expense data for January 2015.

As part of the ESP Stipulation dated February 24, 2009 in Case No. 08-1094-EL-SSO and subsequently approved by the Commission in its Opinion and Order dated June 24, 2009, DP&L has implemented coal and coal/power optimizations which the Company states systematically lowers the Fuel and purchased power costs and thus, results in reduced rates to its customers. Section 2 of the Stipulation (pages 3 and 4) states in part:

> DP&L will implement a bypassable Fuel recovery rider to recover retail Fuel and purchased power costs, based on least cost Fuel and purchased power being allocated to retail customers. To calculate the rider, jurisdictional emission allowance proceeds and twenty-five percent of jurisdictional coal sales gains will be netted against the Fuel and purchased power costs.

Pursuant to the ESP Stipulation, during the 2010, 2011 and 2012 review periods, DP&L had flowed the 75% charge-back associated with its optimization transactions through the Fuel Rider. Throughout the course of the Fuel audits conducted by EVA and Larkin during the 2010, 2011 and 2012 review periods, system optimization has been a contentious issue. This contention culminated with the Stipulation and Recommendation dated December 5, 2012 where, at Paragraph J (pages 9 and 10), it states:

> Beginning January 1, 2013, and continuing until such time as the Commission issues an order approving a rate plan in Case No. 12-426-EL-SSO and continuing thereafter unless such approved rate plan specifies otherwise, DP&L will cease the charge-back of 75% of any Fuel optimization transaction. It is recognized that DP&L may, in its business judgment, continue to engage in transactions that would be considered optimizations, but the jurisdictional share of any accounting gains and losses and changes in Fuel cost would be reflected in rates without any optimization charge-back to customers.

Pursuant to the forgoing provision of the Stipulation and Recommendation dated December 5, 2012, Larkin asked DP&L to confirm that there are no costs related to system optimizations in the Fuel Rider in any months of 2015. In response to LA-2015-81, the Company stated:

> There were no costs related to optimizations included in DP&L's Fuel Rider for any months of 2015.

In a related question, Larkin asked DP&L whether there were any adjustments, costs or credits to recorded Fuel costs during 2015 that pertained to any prior year(s) Optimizations, and if so, to identify, quantify and explain each such adjustment and to provide the related journal entries. In its response to LA-2015-82, DP&L stated in part:

> There were no optimization adjustments, costs, or credits to Fuel cost recorded in 2015 related to any prior years.

Upon reviewing the monthly Excel workbooks that were provided in LA-2015-53, Larkin confirmed that no system optimization transactions flowed through the Fuel Rider during 2015.

Accounting for Emission Allowances

DP&L provided documentation related to accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in the responses to LA-2015-59 through LA-2015-61.

Data request LA-2015-59 asked the Company to provide the detailed general ledger pages for each account that contains costs and/or revenues included in the Fuel Rider filings. In response, DP&L referred to its responses to data requests LA-2015-5 and LA-2015-71.

Data request LA-2015-60 requested detailed general ledger pages for all purchases and sales of emission allowances ("EA") and for gains or losses realized on such purchases and sales of EAs. In response, the Company referred to the response to LA-2015-71.

As it relates to the ratios used to determine emission allowance sales proceeds, Item No. 11 from the Stipulation and Recommendation dated October 6, 2011 stated:

> No later than December 31, 2011, DP&L will propose a method for periodically updating the ratio used to determine the jurisdictional share of emission allowance sales proceeds, and make its methodology available for review by the auditor, and DP&L will make this methodology available to the Parties.

Pursuant to this component of the 2011 Stipulation, data request LA-2015-69 asked the Company to provide the annual generation data which supports the allocation factors for emission allowance sales. In response, DP&L referred to allocation schedules that were provided as an attachment in the response to LA-2015-69. The Company stated that these schedules are also used for the Transmission Cost Recovery Rider ("TCRR") allocation calculation. In addition, the monthly allowance percentages are determined by the percentage of MWh sales from the 12 month period ended for DP&L's and DPLER's SSO customers as well as wholesale customers. Larkin compared the monthly allocation schedules provided in LA-2015-69 to the monthly Excel workbooks provided in LA-2015-1-53 and confirmed that the allocation factors tied out between the two sets of schedules. No exceptions were noted.

In terms of emission allowance purchases, sales and gains and losses flowing through the Fuel Rider, the monthly Excel workbooks provided in LA-2015-53 reflected activity in Accounts 411.8 and 411.9 during February, April, July and August of 2015 with the remaining months reflecting zero activity. In a related data request which addresses the Company's emission allowance strategy, the Company's response to EVA-2015-1-30 stated:

[redacted]

Data request LA-2015-61 asked DP&L to provide its monthly emission allowance inventory (quantity of allowances and cost) and to show how it was allocated between native and non-native customers. In response, DP&L stated that the allocations between retail and wholesale customers are reflected on Tab .16 from the monthly Excel workbooks provided in LA-2015-53.

In addition, DP&L's response to LA-2015-61 included an attachment which reflected DP&L's monthly EA inventory balances. The exhibit below summarizes for DP&L the monthly EA inventory balances for each month of the January through December 2015 review period.

Exhibit 5-47. DP&L Emission Allowance Inventory

[redacted]

Larkin requested that DP&L provide documentation related to the purchase of annual NOx allowances in 2016 to meet the 2015 requirement including quantity, price, transaction dates, associated accounting (journal entries) and related invoices. In its response to LA-2015-70, the Company [redacted]

Application of FUEL Rider Rates to Customer Bills

In order to verify that DP&L has included the correct FUEL Rider rates on its electric bills, Larkin reviewed a sample selection of monthly bills from the period July 2015, which were provided in the confidential response to data request LA-2015-78. This sample included nine customer billing statements with each reflecting a different billing rate. Larkin recalculated the

Fuel Rider charges by multiplying the Fuel rates for each rate type included in the sample by the meter usage indicated on each of the customer billing statements and then compared the results to each sampled customer's billing statement by the line item "Fuel Rider". No exceptions were noted as reflected in Exhibit 1-48 below. Larkin then compared the results of its analysis to a summary sheet that was provided in LA-2015-78, and which contained calculations similar to those performed by Larkin. Again, no exceptions were noted.

Exhibit 5-48. Summary of Customer Bill Analysis

Tariff Class	Rate	Page	Fuel Rate	Usage	Calculated Total	Bill Amount	Difference
Residential	111	1, 2	0.0118413	2,547	$ 30.16	$ 30.16	$ -
Residential Heat	141	3, 4	0.0118413	1,118	$ 13.24	$ 13.24	$ -
Secondary	117	5, 6	0.0118413	342	$ 4.05	$ 4.05	$ -
Primary	532	7, 8	0.0115284	835,332	$ 9,630.04	$ 9,630.04	$ -
Primary Substation					No SSO Customers		
High Voltage	531	9, 10	0.0114051	40,571,855	$ 462,726.06	$ 462,726.06	$ -
Private Outdoor Lighting	25	11, 12	0.0118413	75	$ 0.89	$ 0.89	$ -
School	162	13, 14	0.0118413	40	$ 0.47	$ 0.47	$ -
Street Light	65	15, 16, 17	0.0118413	3,957	$ 46.86	$ 46.86	$ -
Source: LA-2015-78							

Changes To Fuel, Purchased Power Procurement, And Emission Allowance Procurement

Documentation related to the review of changes to Fuel, purchased power procurement and emission allowance procurement during the period January through December 2015 includes DP&L's responses to LA-2015-65 through LA-2015-68.

Data request LA-2015-65 asked the Company to list and describe all organizational changes to the Company's Fuel, Purchased Power Procurement, and Emission Allowance Procurement during the review period. In response, DP&L listed four employees who joined the Company[33] and two who left the Company during 2015. The six employees in question had worked in Commercial Operations, Competitive Market Services or Competitive Generation.

Data request LA-2015-66 requested information similar to LA-2015-65 although from a procedural versus organizational standpoint. In response, DP&L stated that were no procedural, policy or accounting changes to the Company's Fuel, Purchased Power Procurement, or Emission Allowance Procurement during the 2015 review period. In addition, DP&L provided two attachments with this response. The first of these attachments was related to the Company's accounting procedures for emission allowances, which included the sale of emission allowances. This document indicated an issue date of August 27, 2009 and the "approval signatures" reflect various dates in September 2009. The second attachment was related to AES's accounting practices as it relates to derivative assets and liabilities. This document indicated an effective date of July 1, 2012 and approved date of August 29, 2012.

[33] The response to LA-2015-65 indicates that one such employee, who joined AES in June 2015, subsequently left the Company in October 2015.

General Ledger Detail and Audit Trail

Data request LA-2015-71 requested general ledgers pages for the various FERC accounts which the Company has included in the Fuel Rider. In response, DP&L provided the requested general ledger account sheets for January through December 2015.

As discussed above, data requests LA-2015-72 and LA-2015-73 asked DP&L to provide a complete audit trail from the Company's quarterly Fuel Rider filings to the Fuel Rider workpapers and to the general ledger balances for each of the accounts included in DP&L's Fuel Rider and any other accounts used by DP&L for July 2015 actual RA Fuel costs and revenues. In its confidential response, DP&L provided the detailed support for July 2015, which agreed to the monthly data provided in the response to LA-2015-53 as well as the related general ledger FERC accounts.

Data requests LA-2015-74 and LA-2015-75 asked DP&L to provide the audit trail from the Company's quarterly Fuel Rider filings to the Fuel Rider workpapers to the general ledger balances for each of the accounts requested in LA-2015-71 and any other accounts used by DP&L for January 2015 actual RA Fuel costs and revenues. In its confidential response, DP&L provided the detailed support for January 2015, which agreed to the monthly data provided in response to LA-2015-53 as well as the related general ledger accounts.

Data request LA-2015-76 asked the Company to provide the complete audit trail from the general ledgers for each account listed in LA-2015-71 to the invoices, journal entries and other documentation that supports the costs recorded in the general ledgers for each Fuel Rider includable account and sub-account. In response, DP&L referred to the same data that was provided in response to LA-2015-72 and LA-2015-73 (previously discussed above) as well as LA-2015-53 for the requested supporting documentation.

Loss on Sale of Fuel Oil at Beckjord

Larkin had requested that DP&L provide invoices and any other documentation which supports any gains or losses recorded for each of the Company's generating station, which DP&L provided in response to LA-2015-88. Included with this documentation was an Excel spreadsheet titled "All & Net Coal Sales Transactions". Larkin noted a portion of this spreadsheet included data which was from Duke's monthly fuel invoices for each month of 2015. The generating stations included on the Duke monthly invoices are Beckjord[34], Miami Fort 7&8 and Zimmer. [redacted] According to the response to LA-2015-2-4, the quantity of the fuel oil on DP&L books was [redacted] gallons at a value totaling [redacted]. The fuel oil was transferred to Miami Fort pursuant to the fuel agreement between DP&L and the other CCD co-owners. The sale price for the oil per the ownership agreement was [redacted] per gallon so the revenue recorded by DP&L for the transfer to Miami Fort was $[redacted], which generated the [redacted]. During the interviews conducted on June 29, 2016, DP&L stated that Miami Fort benefitted from the transfer of the fuel oil.

[34] The Beckjord generating station closed in September 2014.

Upon reviewing the monthly Excel workbook (provided in LA-2015-53) for March 2015, Larkin noted that [redacted] was indicated for Beckjord and allocated [redacted] to DP&L retail, thus the entire amount was flowed through the Fuel Rider, which DP&L confirmed in the response to LA-2015-2-4. However, [redacted] was reflected for Miami Fort in the March 2015 monthly workbook. Upon Larkin's inquiry as to why there was no entry for Miami Fort related to the fuel oil transfer, DP&L stated that the oil was taken in as a purchase which reduced the weighted average cost of the oil on hand which is then consumed. Larkin also asked the Company to (1) provide *documentation which supports the Company's statement that Miami Fort* [redacted] *from the* transfer of the Beckjord fuel oil and, (2) to quantify and state the month in 2015 in which the claimed [redacted] flowed through the Fuel Rider. In response the Company stated:

1) Miami Fort's average cost of oil was [redacted] the fuel expense in future months. Oil owned by DPL at Miami Fort prior to transfer WACI [redacted] Receipts in Jan including transfers [redacted] WACI to [redacted] at end of January.

2) Any oil transferred would be included in that plant's oil inventory balance. The price it was transferred at would be factored into the weighted average cost of inventory ("WACI"). Anything that reduced the WACI would reduce the total oil cost in future months where the oil was consumed.

Larkin had requested that the Company justify allocating [redacted] loss on the sale of the Beckjord fuel oil to DP&L retail. In response to LA-2015-2-4, [redacted]

DP&L provided the generation (in MWh) applicable to the DP&L ownership portion of Beckjord in each of the five years prior to the plant's retirement, which included how the Company allocated its share between retail and wholesale. Using the information provided, Larkin calculated revised retail and wholesale allocation factors, which were based on a three-year historical average using the 2012, 2013 and 2014 data. Larkin's calculation of the revised retail and wholesale allocation factors is reflected in the exhibit below.

Exhibit 5-49. Re-allocation of Loss on Sale of Beckjord Fuel Oil

[redacted]

As shown in the exhibit above, Larkin calculated a revised retail allocation factor of [redacted] which was based on a three-year average. Applying the [redacted] retail factor to the [redacted] results in [redacted] being allocated to DP&L retail customers. Therefore, Larkin recommends that the amount flowing through the Fuel Rider be [redacted].

It should be noted that, as shown in columns D-H, for 2012 and 2013 it was necessary for Larkin to remove the Beckjord related generation that was applicable to DPLER, which Larkin did using the monthly workbooks from the 2012 and 2013 fuel audits.[35] It was not necessary to remove the DPLER piece from the 2014 data since, as was discussed in the 2014 audit report, at the beginning of 2014, DP&L's Risk Management Group provided Accounting with the Standard Service Offer ("SSO") retail MWh exclusively, which negated the need to allocate the retail costs between DP&L and DPLER in the monthly Excel workbooks.

Customer Switching

Since the 2010 review period, DP&L's retail load has been shifting to alternative suppliers, primarily [redacted]. As a result of this "customer switching," customers who have switched to alternative suppliers have potentially avoided paying for any under-collections that have accumulated in the Fuel Rider during the time in which these customers were DP&L retail customers.

In order to mitigate the potential for this cost avoidance, Item No. 8 from the Stipulation and Recommendation dated October 6, 2011 stated in part:

> The Parties agree that DP&L will "incorporate its best estimate of the impacts of ongoing customer supplier switching into its Fuel Rider kWh sales forecasts."

In data request LA-2015-84, Larkin asked the Company to explain fully and in detail how DP&L has incorporated this requirement from the October 6, 2011 Stipulation and Recommendation. In its confidential response, DP&L stated:

> DP&L incorporates customer switching into its forecast by first observing the known level of switching at the point in time that the forecast is created and then projecting incremental switching to be generally consistent with the rate observed in recent months. Any additional information known regarding electric aggregation is considered.

Data request LA-2015-83 asked DP&L provide statistics on 2015 customer switching by month and by tariff of those customers that switched from DP&L's jurisdictional service territory to another service provider including those customers that switched to DPLER. In its confidential response, DP&L provided statistical data by consumption and number of customers of customers that switched suppliers during 2015. Exhibit 5-50 provides a summary by month of those DP&L customers who switched to either DPLER or another alternative supplier during 2015.

[35] EVA and Larkin conducted the Management/Performance and Financial Audit of DP&L's Fuel Rider for the 2012 and 2013 review periods in Case Nos. 12-2881-EL-FAC and 14-0117-EL-FAC. Consequently, the 2012 and 2013 data was included in Larkin's workpapers from those prior engagements.

Exhibit 5-50. Number of Customers who Switched to an Alternative Supplier in 2015

[redacted]

As shown in the exhibit above, during 2015, DP&L reflected [redacted]

During the 2011 review period, Larkin had made the recommendation that DP&L (1) improve the accuracy of its forecast Fuel Rider rates; and (2) minimize the build-up of undercollections related to residential customer switching, use historical data to provide its own trend line analysis for residential customer switching when developing its Fuel Rider kWh sales forecasts.[36] In LA-2015-85, Larkin requested that DP&L provide the trend line analysis for residential customer switching pursuant to its recommendation. In response, the Company provided the requested trend analysis, which is replicated in Exhibit 5-51 below.

[36] This recommendation was adopted as Additional Commitment B at page 11 of the Stipulation and Recommendation dated December 5, 2012.

Exhibit 5-51. Trend Line Analysis Related to Residential Customer Switching (Actual Sales Billed per Month)

[redacted]

DP&L stated that it uses the trend line analysis to forecast and validate its sales forecasts, but that because of seasonality and the factors noted in LA-2015-83 (as discussed above), monthly forecasts necessarily vary based on the season. As a result, a simple trend line analysis is not reflective of a seasonal quarter.

As discussed in a previous section of this report, DP&L made two adjustments to decrease the amount flowing through the Fuel Rider which relates to the RR-N that became effective in January 2014 pursuant to the PUCO's Order and Opinion dated September 4, 2013 in Case No. 12-0426-EL-SSO et al.

Findings:

1. In preparing its Fuel Rider sales forecasts for its quarterly Fuel Rider filings affecting 2015, DP&L reflected the impact of known customer supplier switching.
2. DP&L's Fuel Rider deferral (i.e., the 2015 undercollection) has been impacted by customer supplier switching that has occurred.
3. DP&L incorporates customer switching into its forecast by observing the known level of switching at the time the forecast is created then projects incremental switching to be consistent with the rate observed in recent months.
4. DP&L created and used a trend line analysis for forecasting and validating its sales forecasts, but due to seasonality and other factors, monthly forecasts will vary and as such, a simple trend line analysis will not be reflective of a seasonal quarter.
5. The RR-N that became effective in January 2014 pursuant to the Commission's Opinion and Order dated September 4, 2013 in Case No. 12-426-EL-SSO, et al, was implemented in part to help mitigate the impacts that customer switching has had on the Fuel Rider deferral.

Internal Audits

Data request LA-2015-79 asked the Company to provide a listing of and copies of any and all internal audit reports related to Fuel procurement, synfuel, coal trading, fuel inventory management, purchased power, emission allowances, accounting for Fuel Rider-includable costs, portfolio optimization, energy sales, PJM charges and revenues, Fuel and purchased power invoices, PJM invoices, allocation of PJM revenues and costs to Ohio retail load customers, allocation of other Fuel Rider includable costs and revenues to Ohio retail load customers, and/or other Fuel Rider related subject matter for the review period. In addition, LA-2015-80 inquired as to whether DP&L conducted an internal audit of its Fuel Rider processes and calculations during 2015 and if so, to provide the related internal audit report.[37] In response to both of these data requests, DP&L referred to the confidential response to EVA-2015-1-43, which had requested any internal audits of fuel and purchased power that DP&L had conducted during

[37] Pursuant to the Stipulation and Recommendation dated October 6, 2011, the parties agreed that DP&L would conduct an internal audit of the Fuel Rider on a biennial basis commencing in 2011. The next internal audit of the Fuel Rider was scheduled for the 2015 review period.

2015. The response to EVA-2015-1-43 was comprised of a one page internal audit report and cover page titled "DPL Fuel Cost Recovery Audit" which is dated September 23, 2015.[38] In a section titled "Audit Overview - As of June 30, 2015", this report states that, at the request of DP&L management, the internal audit group conducted an audit of the operational effectiveness of the Fuel Cost Recovery process for the period January 1, 2014 through June 2015. The stated scope of this internal audit was to:

- Review processes and calculations that support the PUCO rate filings;
- Evaluate the effectiveness of the process for recording deferral and recovery of costs in the general ledger; and
- Confirm the accuracy of customer bills

Under the heading "Basis for Conclusion", the internal audit report presented the following conclusion:

> Based upon the results from our limited procedures, we found the process and controls to mitigate risks related to DP&L Fuel Cost Recovery process to be adequate and operating effectively to achieve the intended process objectives for the period under review.

At only one page long, the internal audit report covering the Fuel Rider for the 18 month period January 2014 through June 2015 lacked sufficient detail which led Larkin to question whether the audit testing performed with respect to the Fuel Rider processes and calculations was sufficient. During the interviews at the Company's offices on June 29, 2016, Larkin spoke to the Company's manager of internal audit in an effort to get clarification on the procedures performed pursuant to the internal audit of the Fuel Rider.

With regard to the internal audit of the Fuel Rider, the manager of the Internal Audit department stated that the results of the audit, which was conducted by an outside consulting firm, was that no exceptions were noted from the limited procedures that were performed, sampling used and the supporting documentation that was reviewed. The audit procedures performed were outlined in audit program materials that the Internal Audit manager brought to the interview and which were subsequently provided in response to LA-2015-2-8. Specifically, the audit program for the Fuel Rider focused on the following four objectives:

Objective No. 1 - Verify all policies and procedures are up to date, properly approved, and stored in a location accessible to individuals needing to follow the guidance

[redacted]

[redacted]

[38] The response to EVA-2015-1-43 also included Coal and Limestone Inventory reports dated November 2, 2015, for the Stuart and Killen generating stations. These reports, which were prepared by Mikon Corporation, are not internal audit reports.

[redacted]

Objective No. 2 - Verify all PUCO rate filings are calculated correctly, adequately supported, and submitted in a timely manner

[redacted]

Objective No. 3 - Verify journal entries are accurate, adequately supported, and recorded in the appropriate period in a timely manner

[redacted]

Objective No. 4 - Verify customer bills are accurate according to the newly effective rates

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Exhibit 5-52. Controls Testing Requirements Per AES Corporation SOX Sampling Guidelines

[redacted]

[redacted]

[redacted]

On February 18, 2013, DP&L entered into four separate contract agreements with [redacted] all of which relate to the installation of a [redacted]. Specifically, DP&L The four contracts include [redacted] A brief summary of each contract agreement is as follows[39]:

[redacted]

[redacted]

[redacted]

[redacted]

A "Letter Agreement" to DP&L from [redacted] dated June 12, 2013, which referenced [redacted]. The [redacted] remained in full force and effect during the suspension, thus [redacted] continued to pay DP&L rent in accordance with the terms of the Lease Agreement.

In another Letter Agreement from [redacted] to DP&L dated August 27, 2013, [redacted] The Letter Agreement set forth the understanding

[39] These contracts are discussed in further detail in the EVA section of this report.
[40] Exhibit A-2 of the [redacted]

between DP&L and [redacted] with regard to certain matters relating to the contract agreements. Specific to those matters was the following assignment:

[redacted]

DP&L's response to LA-2015-17 provided documentation relating to the sales of coal to [redacted]. Specifically, LA-2015-17 asked

> "Please provide the accounting entries in 2015, by plant, for [redacted]. Show the amounts recorded in each account for each month of 2015 for [redacted].
>
> a. Please show the total amounts for each month, and also show the details of allocations between (1) joint owners, (2) DP&L Wholesale and Retail and (3) DP&L Fuel Rider and DPLER."

In its response to LA-2015-17, the Company provided documentation related to the [redacted], as well as the 2015 accruals and accounting analysis reflecting all postings to FERC Account 456099 and 4560025. DP&L stated that [redacted] were not included in the Fuel Rider during 2015 (see additional discussion below).

The aforementioned documentation consisted of a schedule which summarized the 2015 monthly activity associated with [redacted] revenue as well as the relevant pages from the Company's general ledger ("G/L") that relates to the [redacted] revenue. Each of the G/L pages provided included the following four footnotes: (1) Accrual; (2) Reversal of Prior Month Accrual; (3) Receipt of Actual Revenue from Prior Month; and (4) Duke/Dynegy & AEP Share of Revenue.

Conclusion:

In the 2014 audit report, both Larkin and EVA had recommended that DP&L's jurisdictional share of the revenues [redacted]. As previously discussed, a settlement in the 2014 was ultimately reached and in that settlement, DP&L agreed to Larkin's and EVA's recommendation. The foregoing recommendation was incorporated into the Stipulation that was filed with and approved by the Commission in its Opinion and Order dated August 3, 2016 pursuant to the settlement. Specifically, finding number 1 on page 5 the Stipulation states:

> Upon approval of this Stipulation by PUCO order, DP&L will credit $16,042 for 2014 to SSO customers relating to the proceeds DP&L received in 2014 related to the process of refined coal at Stuart. Additionally, DP&L will credit 100% of the jurisdictional share of any proceed DP&L received related to the process of refined coal at Stuart in any given year until the FAC mechanism ends. The 2015 credit will be determined after an audit and verified by an outside auditor in the 2015 FAC case.

As noted above, DP&L did not include the [redacted] related revenues in the Fuel Rider during 2015. Pursuant to the provision in the Stipulation that the 2015 [redacted] be audited/verified prior to DP&L flowing these credits through the Fuel Rider, Larkin traced the amounts for [redacted] that were provided in the response to LA-2015-17 to the general ledger. Larkin modified the schedule that DP&L provided in the response to LA-2015-17 in a manner similar to the schedule provided in response to EVA-2015-1-39, which included the wholesale and retail allocation factors in order to derive the net DP&L retail share of the [redacted]. Upon reviewing the wholesale allocation related data in the monthly Excel workbooks provided in LA-2015-53, Larkin noted that the wholesale allocation percentages for Stuart Station for May, August, September and October 2015 were greater than 100%. The exhibits below reflect the DP&L retail share of the [redacted] by (1) capping the May, August, September and October 2015 wholesale allocation percentages for Stuart at 100%; and (2) allocating the wholesale portion of the May, August, September and October 2015 [redacted] revenue using the wholesale allocation percentages, which are greater than 100%, that are reflected for Stuart in the monthly Excel workbooks.

Exhibit 5-53. DP&L Share of [redacted] With Wholesale Allocators for May, August, September & October 2015 capped at [redacted]%

[redacted]

Exhibit 5-54. DP&L Share of [redacted] With Wholesale Allocators for May, August, September & October 2015 greater than [redacted]%

[redacted]

As shown in Exhibit 5-53, with the wholesale allocators for May, August, September, and October 2015 capped at [redacted], the DP&L retail portion of the [redacted] totaled [redacted]. As shown in Exhibit 5-54, with the wholesale allocators for May, August, September, and October 2015 at greater than [redacted], the DP&L retail portion of the [redacted] coal spray revenue totaled [redacted][41], or a difference of [redacted].

The Company had included a credit amount of [redacted] in September 2015, which the Company stated related to reimbursements from [redacted] for [redacted] paid by DP&L and the joint owners. After accounting for the Duke/Dynegy and AEP ownership shares, the DP&L portion of this amount is allocated [redacted] to wholesale based on the allocation factors in the monthly workbook for September 2015. However, the documentation provided in the response to LA-2015-18 indicates that the [redacted] was broken out over the first six months of 2015, all of 2014 and certain months of 2013. Based on that breakout, in Larkin's view, allocating the DP&L portion of the [redacted] [redacted]. Therefore, Larkin removed this amount from the exhibits above and is recommending a separate adjustment as shown in the exhibit below.

[41] This amount corresponds to what is reflected in the response to EVA-2015-1-39.

Exhibit 5-55. Reallocation of Reimbursement from [redacted] for CAT Tax Paid to DP&L Retail

[redacted]

As shown in the exhibit above, after accounting for the Duke/Dynegy and AEP ownership portions, the DP&L portion of the reimbursement for the [redacted] paid is a credit amount of [redacted]. Using the documentation provided in LA-2015-18 for this item, Larkin applied the applicable retail and wholesale allocation factors for each month in 2013, 2014 and 2015 which apply to the reimbursement from [redacted] for the paid [redacted]. The result is a DP&L retail amount of [redacted]. Pursuant to the Stipulation approved by the Commission on August 3, 2016, Larkin recommends that the economic benefit resulting from the [redacted] flow through the Fuel Rider as an offset to includable expense.

Exhibit 5-56. DP&L Share of [redacted] Revenue With Wholesale Allocators for May, August, September & October 2015 capped at [redacted]

[redacted]

Exhibit 5-57. DP&L Share of [redacted]e Revenue With Wholesale Allocators for May, August, September & October 2015 greater than [redacted]

[redacted]

As shown in Exhibit 5-54, with the wholesale allocators for Stuart for May, August, September and October 2015 capped at [redacted], the DP&L retail portion of the [redacted] revenue totaled

$14. As shown in Exhibit 5-55, with the wholesale allocators for May, August, September and October 2015 at greater than [redacted], the DP&L retail portion of the [redacted] revenue totaled [redacted], or a difference of [redacted].

Upon reviewing other costs throughout different accounts in the monthly Excel workbooks, Larkin noted several instances where the wholesale allocators exceeded [redacted], thus the DP&L retail portion of certain expenses were flowed through the Fuel Rider at less than [redacted] of such costs.

To summarize, as shown in the foregoing exhibits, after applying the monthly wholesale allocation factors, including the May, August, September and October factors that exceeded 100%, the DP&L retail portion of the [redacted] revenue that should flow through the Fuel Rider for 2015 totaled [redacted] and the [redacted] revenue that should flow through the Fuel Rider totaled [redacted] for 2015. As it relates to the reimbursement from [redacted] for the [redacted] paid by DP&L, Duke/Dynegy and AEP, as discussed above, the DP&L retail amount of [redacted] that was calculated in the exhibit above should also be flowed through the Fuel Rider for 2015.

Reconciliation Rider

On September 4, 2013, in Case No. 12-426-EL-SSO, et al, the Commission issued an Opinion and Order which authorized DP&L's proposed ESP. As part of its Application, DP&L proposed a non-bypassable Reconciliation Rider ("RR"). The rider as proposed would recover (1) the costs of administering the competitive bidding process ("CBP"), (2) the costs of implementing competitive retail enhancements, and (3) any remaining over or under-collection associated with particular riders. With respect to the third item, the Company proposed that it be allowed to recover through the RR, any deferred balance that exceeds 10% of the base amount of riders Fuel, RPM, AER and CBT on a quarterly basis. DP&L's premise for its proposal was that recovery of the deferred balance amounts through the RR was necessary to avoid a situation where there were too few remaining SSO customers as a result of customer switching to cover the cost of the deferral balance. In its Opinion and Order dated September 4, 2013, the Commission directed that the RR be divided into a by-passable ("RR-B") and a non-bypassable ("RR-N") rider. As it relates to the RR-N, the Commission stated in part:

> *The RR-N should recover any deferred balance that exceeds 10 percent of the base amount of riders FUEL, RPM, AER, and CBT, as proposed by DP&L. However, DP&L must file an application with the Commission, in a separate proceeding, seeking specific approval to defer for future recovery any amounts exceeding the 10 percent threshold for each individual rider.*

DP&L filed separate applications in which it sought to update the RR-N consistent with the Commission's Opinion and Order in Case No. 12-426-EL-SSO, et al.

Larkin requested that DP&L provide its RR-N filings from January and April 2015 that were approved by the Commission in Case No. 15-43-EL-RDR, which the Company provided in response to LA-2015-2-10. The following sections discuss DP&L's two 2015 RR-N filings by reproducing Schedules A and B as well as Workpapers WPA-1, WPA-2 and WPA-3 in the exhibits below.

January 2015 Reconciliation Rider Filing

The Dayton Power and Light Company				
Case No. 15-0043-EL-RDR				
Reconciliation Rider Nonbypassable - Rate Development				
March 2015 - May 2015				
Data: Forecasted				
Type of Filing: Original				Schedule A
Work Paper Reference No(s).: WPA-1, WPB-1				Page 1 of 1
			Estimated	
Line	**Description**		**Balance**	**Source**
(A)	(B)		(C)	(D)
1	Fuel Deferral Balance exceeding 10% Threshold	$	5,544,543	Schedule B, Line 4
2	AER Deferral Balance exceeding 10% Threshold	$	-	Placeholder
3	RPM Deferral Balance exceeding 10% Threshold	$	-	Placeholder
4	CBT Deferral Balance exceeding 10% Threshold	$	-	Placeholder
5	Prior Period Reconciliation	$	179,678	WPA-1, Col (I), Line 9
6				
7	**Total**	$	**5,724,221**	Sum (Line 1 thru 5)
8				
9	Carrying Costs	$	23,141	WPA-1, Col (H)
10				
11	Total	$	5,747,361	Line 7 + Line 9
12	Gross Revenue Conversion Factor		1.0072	Case No. 12-0426-EL-SSO
13	**Total to be Recovered**	$	**5,788,742**	Line 11 * Line 12
14				
15	kWh Sales		3,134,764,994	WPB-1, Line 5
16				
17	**RR-N Rate ($/kWh)**	$	**0.0018466**	Line 13 / Line 15

Schedule A: Lines 1-5 of this schedule reflect DP&L's estimated balances for the (1) Fuel Rider deferral balance exceeding the 10% threshold, (2) AER deferral balance exceeding the 10% threshold, (3) RPM deferral balance exceeding the 10% threshold, (4) CBT deferral balance exceeding the 10% threshold, and (5) prior period reconciliation. As shown above, the only amounts for this period relate to the Fuel Rider ($5,544,543) and prior period reconciliation ($179,678) for a total of $5,724,221. Line 9 reflects that carrying costs totaling $23,141 (calculated on WPA-1 below), which are added to the overall estimated deferral balance. As shown on Line 12, the total amount is multiplied by a Gross Revenue Conversion Factor ("GRCF") of 1.0072, which was approved in Case No. 12-0426-EL-SSO. The grossed-up total amount to be recovered is $5,788,742. This amount is then divided by the forecasted kWh sales for March, April and May 2015, which totaled 3,134,764,994 (calculated on WPB-1 below) as shown on Line 15. Finally, the $5,788,742 is divided by the forecasted kWh sales to derive an RR-N ($/kWh) rate of $0.0018466.

The Dayton Power and Light Company			
Case No. 15-0043-EL-RDR			
Reconciliation Rider Nonbypassable - Deferral Balance Calculation			
March 2015 - May 2015			
Data: Forecasted			
Type of Filing: Original			Schedule B
Work Paper Reference No(s).: None			Page 1 of 1
Line	**Description**	**Amount**	**Source**
(A)	(B)	(C)	(D)
	FUEL Rider		
1	Forecasted FUEL Costs March 2015 - May 2015	$ 8,385,669	Case No. 15-0042-EL-FAC
2	FUEL Deferral Balance February 28, 2015	$ 6,383,110	Case No. 15-0042-EL-FAC
3	10% Threshold	$ 838,567	Line 1 * 10%
4	**Amount Exceeding Threshold**	**$ 5,544,543**	Line 2 - Line 3

Schedule B: This schedule reflects the calculation of the amount of the Fuel Rider deferral balance that exceeds the 10% threshold. Specifically, the amount exceeding the threshold was calculated by multiplying the forecasted fuel costs for the period March through May 2015 by 10% and then subtracting the result from the Fuel Rider deferred balance as of February 28, 2015. The result is the $5,544,543 ($6,383,110 - $838,567) that is reflected on Line 1 of Schedule A.

The Dayton Power and Light Company										
Case No. 15-0043-EL-RDR										
Reconciliation Rider Nonbypassable - Calculation of Carrying Costs										
June 2014 - May 2015										
Data: Actual and Forecasted										
Type of Filing: Original										WPA-1
Work Paper Reference No(s).: None										Page 1 of 1
		MONTHLY ACTIVITY							CARRYING COST CALCULATION	
		First of Month	Reconciliation Rider -N	Amount Collected	NET	End of Month before	Carrying Cost @	End of Month	Less: One-half Monthly	Total Applicable to
Line	Period	Balance	Costs	(CR)	AMOUNT	Carrying Cost	4.943%	Balance	Amount	Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (4.943% / 12)	(I) = (G) + (H)	(J) = - (F) * 0.5	(K) = (J) + (G)
1	Jun-14	$ -	$ 5,111,592	$ (1,581,277)	$ 3,530,315	$ 3,530,315	$ 7,271	$ 3,537,586	$ (1,765,158)	$ 1,765,158
2	Jul-14	$ 3,537,586	$ -	$ (1,728,036)	$ (1,728,036)	$ 1,809,550	$ 11,013	$ 1,820,563	$ 864,018	$ 2,673,568
3	Aug-14	$ 1,820,563	$ -	$ (1,680,318)	$ (1,680,318)	$ 140,246	$ 4,038	$ 144,284	$ 840,159	$ 980,405
4	Sep-14	$ 144,284	$ 6,885,252	$ (2,681,408)	$ 4,203,845	$ 4,348,129	$ 9,252	$ 4,357,381	$ (2,101,922)	$ 2,246,207
5	Oct-14	$ 4,357,381	$ -	$ (2,247,860)	$ (2,247,860)	$ 2,109,521	$ 13,319	$ 2,122,840	$ 1,123,930	$ 3,233,451
6	Nov-14	$ 2,122,840	$ -	$ (2,279,268)	$ (2,279,268)	$ (156,428)	$ 4,050	$ (152,378)	$ 1,139,634	$ 983,206
7	Dec-14	$ (152,378)	$ 1,627,579	$ (416,709)	$ 1,210,870	$ 1,058,493	$ 1,866	$ 1,060,359	$ (605,435)	$ 453,058
8	Jan-15	$ 1,060,359	$ -	$ (472,862)	$ (472,862)	$ 587,497	$ 3,394	$ 590,891	$ 236,431	$ 823,928
9	Feb-15	$ 590,891	$ -	$ (412,797)	$ (412,797)	$ 178,094	$ 1,584	$ 179,678	$ 206,399	$ 384,492
10	Mar-15	$ 179,678	$ 5,544,543	$ (2,041,612)	$ 3,502,931	$ 3,682,608	$ 7,955	$ 3,690,563	$ (1,751,465)	$ 1,931,143
11	Apr-15	$ 3,690,563	$ -	$ (1,853,044)	$ (1,853,044)	$ 1,837,519	$ 11,386	$ 1,848,905	$ 926,522	$ 2,764,041
12	May-15	$ 1,848,905	$ -	$ (1,852,620)	$ (1,852,620)	$ (3,716)	$ 3,800	$ 85	$ 926,310	$ 922,594
13										
14						Total Carrying Cost March - May:	$ 23,141			

WPA-1: *This workpaper presents the calculation of the carrying costs that are applied to the amounts exceeding the 10% threshold as shown on Schedule A (discussed above) for the period March through May 2015. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amount are then flowed through to Schedule A and included in the calculation of the RR-N rate.*

The Dayton Power and Light Company		
Case No. 15-0043-EL-RDR		
Reconciliation Rider Nonbypassable - Forecasted Sales		
March 2015 - May 2015		
Data: Forecasted		
Type of Filing: Original		WPB-1
Work Paper Reference No(s).: None		Page 1 of 1
Line	**Description**	**Sales Forecast (kWh)**
(A)	(B)	(C)
1	**Distribution Sales Forecast (kWh)**	
2	March 2015	1,113,566,581
3	April 2015	1,010,714,756
4	May 2015	1,010,483,657
5	**Total Distribution Sales Forecast (kWh)**	**3,134,764,994**
Source: Company's monthly forecast consistent with 2014 LTFR Case No. 14-536-EL-FOR		

WPB-1: This workpaper reflects the forecasted distribution sales for the period March through May 2015, which totals the 3,134,764,994 kWh that are reflected on Line 15 of Schedule A.

The Dayton Power and Light Company				
Case No. 15-0043-EL-RDR				
Reconciliation Rider Nonbypassable - Calculation of Private Outdoor Lighting Charges				
Data: Forecasted				
Type of Filing: Original				WPC-1
Work Paper Reference No(s).: None				Page 1 of 1
Line	**Description**	**kWh / Fixture**	**RR-N Rate**	**Source**
(A)	(B)	(C)	(D)	(E)
1	**Private Outdoor Lighting Rate ($/kWh)**		$0.0018466	Schedule A, Line 17
2				
3	**Private Outdoor Lighting Charge ($/Fixture/Month)**			
4	9500 Lumens High Pressure Sodium	39	$0.0720174	Line 1 * Col (C), Line 4
5	28000 Lumens High Pressure Sodium	96	$0.1772736	Line 1 * Col (C), Line 5
6	7000 Lumens Mercury	75	$0.1384950	Line 1 * Col (C), Line 6
7	21000 Lumens Mercury	154	$0.2843764	Line 1 * Col (C), Line 7
8	2500 Lumens Incandescent	64	$0.1181824	Line 1 * Col (C), Line 8
9	7000 Lumens Fluorescent	66	$0.1218756	Line 1 * Col (C), Line 9
10	4000 Lumens PT Mercury	43	$0.0794038	Line 1 * Col (C), Line 10

WPC-1: As shown on Line 1, this workpaper reflects for the Private Outdoor Lighting Rate, the RR-N ($/kWh) rate of $0.0018466 that was calculated on Line 17 of Schedule A.

April 2015 Reconciliation Rider Filing

The Dayton Power and Light Company			
Case No. 15-0043-EL-RDR			
Reconciliation Rider Nonbypassable - Rate Development			
June 2015 - August 2015			
Data: Forecasted			
Type of Filing: Original			Schedule A
Work Paper Reference No(s).: WPA-1, WPB-1			Page 1 of 1
		Estimated	
Line	**Description**	**Balance**	**Source**
(A)	(B)	(C)	(D)
1	Fuel Deferral Balance exceeding 10% Threshold	$ 1,719,204	Schedule B, Line 4
2	AER Deferral Balance exceeding 10% Threshold	$ -	Placeholder
3	RPM Deferral Balance exceeding 10% Threshold	$ -	Placeholder
4	CBT Deferral Balance exceeding 10% Threshold	$ -	Schedule B, Line 10
5	Prior Period Reconciliation	$ (316,503)	WPA-1, Col (I), Line 12
6			
7	**Total**	**$ 1,402,701**	Sum (Line 1 thru 5)
8			
9	Carrying Costs	$ 23,386	WPA-1, Col (H)
10			
11	Total	$ 1,426,087	Line 7 + Line 9
12	Gross Revenue Conversion Factor	1.0072	Case No. 12-0426-EL-SSO
13	**Total to be Recovered**	**$ 1,436,355**	Line 11 * Line 12
14			
15	kWh Sales	3,673,680,697	WPB-1, Line 5
16			
17	**RR-N Rate ($/kWh)**	**$ 0.0003910**	Line 13 / Line 15

Schedule A: Lines 1-5 of this schedule reflect DP&L's estimated balances for the (1) Fuel Rider deferral balance exceeding the 10% threshold, (2) AER deferral balance exceeding the 10% threshold, (3) RPM deferral balance exceeding the 10% threshold, (4) CBT deferral balance exceeding the 10% threshold, and (5) prior period reconciliation. As shown above, the only amounts for this period relate to the Fuel Rider ($1,719,204) and prior period reconciliation (a credit of $316,503) for a total of $1,402,701. Line 9 reflects that carrying costs totaling $23,386 (see additional discussion below), which are added to the overall estimated deferral balance. As shown on Line 12, the total amount is multiplied by the previously discussed GRCF of 1.0072. The grossed-up total amount to be recovered is $1,436,355. This amount is then divided by the forecasted kWh sales for June, July and August 2015, which totaled 3,673,680,697 (calculated on WPB-1 below) as shown on Line 15. Finally, the $5,788,742 is divided by the forecasted kWh sales to derive an RR-N ($/kWh) rate of $0.0003910.

The Dayton Power and Light Company				
Case No. 15-0043-EL-RDR				
Reconciliation Rider Nonbypassable - Deferral Balance Calculation				
June 2015 - August 2015				
Data: Forecasted				
Type of Filing: Original				Schedule B
Work Paper Reference No(s).: None				Page 1 of 1
Line	**Description**	**Amount**		**Source**
(A)	(B)	(C)		(D)
	FUEL Rider			
1	Forecasted FUEL Costs June 2015 - August 2015	$ 9,921,753		Case No. 15-0042-EL-FAC
2	FUEL Deferral Balance May 31, 2015	$ 2,711,379		Case No. 15-0042-EL-FAC
3	10% Threshold	$ 992,175		Line 1 * 10%
4	**Amount Exceeding Threshold**	**$ 1,719,204**		Line 2 - Line 3
5				
6	**CBT Rider**			
7	Forecasted CBT Costs June 2015 - August 2015	$ 34,918,818		Case No. 15-0044-EL-RDR
8	CBT Deferral Balance May 31, 2015	$ 7,658,963		Case No. 15-0044-EL-RDR
9	10% Threshold	$ 3,491,882		Line 7 * 10%
10	**Amount Exceeding Threshold**	**$ -**		Line 8 - Line 9

Schedule B: This schedule reflects the calculation of the amount of the Fuel Rider deferral balance that exceeds the 10% threshold. Specifically, the amount exceeding the threshold was calculated by multiplying the forecasted fuel costs for the period June through August 2015 by 10% and then subtracting the result from the Fuel Rider deferred balance as of May 31, 2015. The result is the $1,719,204 ($2,711,379 - $992,175) that is reflected on Line 1 of Schedule A.

Lines 6-10, reflect the amounts that would be used to calculate the amount exceeding the 10% threshold for the CBT Rider. As shown on Line 10 of Schedule B, the Company indicated $0 for the amount exceeding the threshold. This appeared to be an error by Larkin since the amount exceeding the threshold should be $4,167,081 as shown in the following exhibit:

CBT Rider	Amount
Forecasted CBT Costs June 2015 - August 2015	$ 34,918,818
CBT Deferral Balance May 31, 2015	$ 7,658,963
10% Threshold	$ 3,491,882
Amount Exceeding Threshold	$ 4,167,081

Larkin inquired about this discrepancy including why the $4,167,081 was not flowed through the RR-N and in response to LA-2015-4-2 the Company stated:

> Staff filed its Review and Recommendation in PUCO Case No. 15-43-EL-RDR on 5/8/2015. In its filing, Staff recommended that the CBT deferral balance of $4,167,081 be adjusted to $3,743,977 and that this balance should not be deferred to the RR-N Rider and instead should be collected through the bypassable CBT rider. Staff recommended to the Commission that is deny DP&L's request to

defer balances exceeding the ten percent threshold of the base amount of the CBT rider. On 5/29/2016, DP&L filed a letter of notification agreeing to the recommendations referenced above.

The Dayton Power and Light Company
Case No. 15-0043-EL-RDR
Reconciliation Rider Nonbypassable - Calculation of Carrying Costs
June 2014 - August 2015

Data: Actual and Forecasted
Type of Filing: Original — WPA-1
Work Paper Reference No(s).: None — Page 1 of 1

		MONTHLY ACTIVITY							CARRYING COST CALCULATION	
Line	Period	First of Month Balance	Reconciliation Rider -N Costs	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost @ 4.943%	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (4.943% / 12)	(I) = (G) + (H)	(J) = - (F) * 0.5	(K) = (J) + (G)
1	Jun-14	$ -	$ 5,111,592	$ (1,581,277)	$ 3,530,315	$ 3,530,315	$ 7,271	$ 3,537,586	$ (1,765,158)	$ 1,765,158
2	Jul-14	$ 3,537,586	$ -	$ (1,728,036)	$ (1,728,036)	$ 1,809,550	$ 11,013	$ 1,820,563	$ 864,018	$ 2,673,568
3	Aug-14	$ 1,820,563	$ -	$ (1,680,318)	$ (1,680,318)	$ 140,246	$ 4,038	$ 144,284	$ 840,159	$ 980,405
4	Sep-14	$ 144,284	$ 6,885,252	$ (2,681,408)	$ 4,203,845	$ 4,348,129	$ 9,252	$ 4,357,381	$ (2,101,922)	$ 2,246,207
5	Oct-14	$ 4,357,381	$ -	$ (2,247,860)	$ (2,247,860)	$ 2,109,521	$ 13,319	$ 2,122,840	$ 1,123,930	$ 3,233,451
6	Nov-14	$ 2,122,840	$ -	$ (2,279,268)	$ (2,279,268)	$ (156,428)	$ 4,050	$ (152,378)	$ 1,139,634	$ 983,206
7	Dec-14	$ (152,378)	$ 1,627,579	$ (416,709)	$ 1,210,870	$ 1,058,493	$ 1,866	$ 1,060,359	$ (605,435)	$ 453,058
8	Jan-15	$ 1,060,359	$ -	$ (489,862)	$ (489,862)	$ 570,497	$ 3,359	$ 573,856	$ 244,931	$ 815,428
9	Feb-15	$ 573,856	$ -	$ (467,267)	$ (467,267)	$ 106,589	$ 1,401	$ 107,990	$ 233,634	$ 340,222
10	Mar-15	$ 107,990	$ 5,544,543	$ (2,283,128)	$ 3,261,415	$ 3,369,405	$ 7,162	$ 3,376,567	$ (1,630,708)	$ 1,738,698
11	Apr-15	$ 3,376,567	$ -	$ (1,853,044)	$ (1,853,044)	$ 1,523,523	$ 10,092	$ 1,533,615	$ 926,522	$ 2,450,045
12	May-15	$ 1,533,615	$ -	$ (1,852,620)	$ (1,852,620)	$ (319,005)	$ 2,502	$ (316,503)	$ 926,310	$ 607,305
13	Jun-15	$ (316,503)	$ 1,719,204	$ (434,313)	$ 1,284,891	$ 968,388	$ 1,343	$ 969,730	$ (642,445)	$ 325,942
14	Jul-15	$ 969,730	$ -	$ (487,510)	$ (487,510)	$ 482,220	$ 2,990	$ 485,211	$ 243,755	$ 725,975
15	Aug-15	$ 485,211	$ -	$ (504,318)	$ (504,318)	$ (19,107)	$ 960	$ (18,147)	$ 252,159	$ 233,052
16										
17						Total Carrying Cost June - August:	$ 5,293			

WPA-1: This workpaper presents the calculation of the carrying costs that are applied to the amounts exceeding the 10% threshold as shown on Schedule A for the period June through August 2015. [redacted].

Larkin inquired about this discrepancy and in response to LA-2015-4-2 the Company stated:

[redacted]

The Dayton Power and Light Company		
Case No. 15-0043-EL-RDR		
Reconciliation Rider Nonbypassable - Forecasted Sales		
June 2015 - August 2015		
Data: Forecasted		
Type of Filing: Original		WPB-1
Work Paper Reference No(s).: None		Page 1 of 1
Line	**Description**	**Sales Forecast (kWh)**
(A)	(B)	(C)
1	**Distribution Sales Forecast (kWh)**	
2	June 2015	1,118,772,735
3	July 2015	1,255,805,362
4	August 2015	1,299,102,599
5	**Total Distribution Sales Forecast (kWh)**	**3,673,680,697**
Source: Company's monthly forecast consistent with 2015 LTFR Case No. 15-663-EL-FOR		

WPB-1: This workpaper reflects the forecasted distribution sales for the period June through August 2015, which totals the 3,673,680,697 kWh that are reflected on Line 15 of Schedule A.

The Dayton Power and Light Company				
Case No. 15-0043-EL-RDR				
Reconciliation Rider Nonbypassable - Calculation of Private Outdoor Lighting Charges				
Data: Forecasted				
Type of Filing: Original				WPC-1
Work Paper Reference No(s).: None				Page 1 of 1
Line	**Description**	**kWh / Fixture**	**RR-N Rate**	**Source**
(A)	(B)	(C)	(D)	(E)
1	**Private Outdoor Lighting Rate ($/kWh)**		$0.0003910	Schedule A, Line 17
2				
3	**Private Outdoor Lighting Charge ($/Fixture/Month)**			
4	9500 Lumens High Pressure Sodium	39	$0.0152490	Line 1 * Col (C), Line 4
5	28000 Lumens High Pressure Sodium	96	$0.0375360	Line 1 * Col (C), Line 5
6	7000 Lumens Mercury	75	$0.0293250	Line 1 * Col (C), Line 6
7	21000 Lumens Mercury	154	$0.0602140	Line 1 * Col (C), Line 7
8	2500 Lumens Incandescent	64	$0.0250240	Line 1 * Col (C), Line 8
9	7000 Lumens Fluorescent	66	$0.0258060	Line 1 * Col (C), Line 9
10	4000 Lumens PT Mercury	43	$0.0168130	Line 1 * Col (C), Line 10

WPC-1: As shown on Line 1, this workpaper reflects for the Private Outdoor Lighting Rate, the RR-N ($/kWh) rate of $0.0003910 that was calculated on Line 17 of Schedule A.

As it relates to the Fuel Rider deferrals of $5,544,543 (March - May 2015) and $1,719,204 (June - August 2015) discussed above, by examining the monthly Excel workbook for December 2015, Larkin verified that the Company removed these amounts from the Fuel Rider. Specifically, the tab titled ".2 Account Reconciliation" reflects the removal of the $5,544,543 in March 2015 and the removal of the $1,719,204 in May 2015.

Competitive Bid True-Up Rider

As noted in an earlier section of this report, DP&L stated that it transferred the Fuel Rider deferral of $1,075,667 to the Competitive Bid True-Up Rider ("CBT") at the end of March 2016. During the interviews on June 29, 2016, DP&L stated that in addition to the deferred Fuel Rider balance, the balances associated with the Transmission Cost Recovery Rider ("TCRR"), RPM Rider balance and the RR-N Rider balances were also transferred to the CBT at the same time.

Larkin requested that the Company provide the journal entries and related journal entry support and any other documentation related to the transfer of the aforementioned balances to the CBT. In response to LA-2015-2-1, DP&L provided the requested information. Included with this information was a letter dated March 29, 2016 from DP&L to the Commission, which stated in part:

> The Fuel Rider is currently collecting its final reconciliation balance and will be set to $0.00 for April 1, 2016 billing. The TCRR-B and PJM RPM Rider rates were both set to $0.00 on January 1, 2016. The Reconciliation Rider-Nonbypassable was set to $0.00 on March 1, 2016. These riders were ended with the goal of a $0.00 balance, but there are inevitable small balances remaining. Since these riders were based on bypassable charges, DP&L plans to include any final balances in the next quarterly reconciliation of the Competitive Bid True-up Rider. Additionally, in the event of reconciliation billings from PJM that date back into 2015, DP&L will notify Staff and include the credit or charge in the Competitive Bid True-up Rider. Below is a summary of the rider balances projected through March:
>
> a. Reconciliation Rider: ($51,945)
> b. TCRR-B Rider: ($423,283)
> c. PJM RPM Rider: $587,982
> d. Fuel Rider: $1,100,000

The amount noted above for the Fuel Rider refers to the aforementioned $1,075,667 rounded up. For each of the balances listed above, Larkin reviewed the journal entries and related support from the data provided in response to LA-2015-2-1, which included the related general ledger pages. Pursuant to this review, Larkin is satisfied that that these transactions were recorded properly.

Memorandum Of Findings And Recommendations

Our findings and recommendations are summarized in Chapter 1.

6 RENEWABLES AND THE ALTERNATIVE ENERGY RIDER (AER) COMPONENT

Alternative Energy Portfolio Requirements

S.B. 221 included an Alternative Energy Portfolio Standard (R.C. 4928.64-65) which required 25 percent of all kilowatt hours of electricity sold by electric distribution utilities and electric services companies to retail electric consumers to be obtained from "alternative energy sources" by 2025. Alternative energy sources are defined as "advanced energy resources" and "renewable energy resources" that satisfy the applicable placed in-service requirement. The final Commission rules implementing the Alternative Energy Portfolio Standard were issued December 10, 2009. At least half of the alternative energy requirement must be satisfied from "renewable energy sources" which must include solar.

The requirements were modified by S.B. 310 which was passed in May 2014 by the Ohio General Assembly. Pursuant to S.B. 310's passage, several provisions of the Ohio Revised Code, including those referenced above, were amended.[42] S.B. 310 does the following:

- Freezes, for 2015 and 2016, the renewable and solar energy benchmarks (required of electric distribution utilities ("EDUs")) and electric services companies ("ESCs") at the 2014 level required under prior law, and requires the annual escalations to the benchmarks to resume in 2017 starting at the 2015 levels of prior law;
- Eliminates the option that EDUs and ESCs provide, by 2025, up to 12.5% of the former 25% alternative energy requirement from advanced energy;
- Extends the benchmark period by which EDUs and ESCs must provide 12.5% of their electricity supply from renewable energy resources by two years to 2027;
- Eliminates the requirement that at least one-half of the renewable energy resources implemented to meet the benchmarks must be met through facilities located in Ohio;
- Permits the renewable energy resources implemented to meet the benchmarks to be met either through facilities in Ohio or with resources shown to be deliverable into Ohio;
- Freezes the solar energy compliance payment at $300 for 2014, 2015, and 2016 and resumes, in 2017, the gradual reduction of the payment amounts to a minimum of $50 in 2026 and thereafter;

[42] Prior to the passage of S.B. 310, the Ohio compliance requirement was referred to as Alternative Energy Portfolio Standard ("AEPS"). However, subsequent to the passage of S.B. 310, the Ohio compliance requirement was changed to the Renewable Portfolio Standard ("RPS").

- Requires that recovery from customers of ongoing costs that are associated with EDUs' contracts to procure renewable energy resources, entered into before April 1, 2014, continue on a bypassable basis until the prudently incurred costs are fully recovered;
- States that renewable energy resources do not need to be converted to electricity in order to be eligible to receive renewable energy credits ("RECs"),
- Requires that rules of the PUCO specify that for RECs, one megawatt hour of energy derived from biologically derived methane gas equals 3,412,142 British Thermal Units;
- Repeals the Alternative Energy Advisory Committee and its duty under prior law to study the alternative energy resources requirements and to submit a semiannual report to the PUCO;
- Permits EDUs and ESCs to use a baseline of the compliance-year's sales to measure compliance with the renewable energy benchmarks, rather than the most recent three-year average of sales; and
- Requires EDUs and ESCs that switch back to the three-year baseline to use that baseline methodology for at least three consecutive years before again using the compliance year baseline.

The percentages required by year are provided in Exhibit 6-1 below.

Exhibit 6-1. Renewable Energy Benchmark Requirements as Amended

Year	Renewable Energy	Minimum Solar
2009	0.25%	0.00%
2010	0.50%	0.01%
2011	1.00%	0.03%
2012	1.50%	0.06%
2013	2.00%	0.09%
2014	2.50%	0.12%
2015	2.50%	0.12%
2016	2.50%	0.12%
2017	3.50%	0.15%
2018	4.50%	0.18%
2019	5.50%	0.22%
2020	6.50%	0.26%
2021	7.50%	0.30%
2022	8.50%	0.34%
2023	9.50%	0.38%
2024	10.50%	0.42%
2025	11.50%	0.46%
2026	12.50%	0.50%

To ensure compliance with the renewable portfolio standards, utilities are required to file an annual report which details their performance. If the utility has failed to meet its requirements in any year and such under-compliance is deemed to have been avoidable, the utility will be assessed a monetary penalty referred to as the "alternative compliance payment" ("ACP"). The non-solar ACP was initially set at $45 per MWh and is adjusted annually by the PUCO according to changes in the Consumer Price Index. The solar ACP was initially set at $450 per MWh and is reduced by $50 every two years until it hits $50 per MWh in 2024.[43] ACPs are deposited into the Ohio Advanced Energy Fund which provides funding for renewable and energy efficient projects within the state.

Utilities can obtain relief from certain requirements and avoid paying the ACP if they demonstrate that compliance with the portfolio standard is "reasonably expected" to increase generating costs by three percent or more. In addition, a utility can obtain relief through the force majeure provisions which state that the PUCO has the ability to waive compliance if the utility can demonstrate that sufficient renewable energy products were not reasonably available in the market place

Larkin asked DP&L whether the passage of S.B. 310 had any impact on the Company's alternative energy costs, REC[44] inventory management, REC purchase strategies, or accounting for alternative energy. In response to LA-2015-91, DP&L stated that S.B. 310 had the following impacts:

- ORC §4928.643 specifies that the distribution utility's Renewable Energy Benchmarks must be based on sales made to standard offer retail customers in either the preceding three calendar years, or the utility may choose for its baseline to be the total kilowatt hours sold in the applicable compliance year. Beginning with compliance year 2014, DP&L began calculating its baseline using the total kilowatt hours sold in the applicable compliance year.

- The REC costs are now forecasted by taking the forecasted sales (100% SSO) from the compliance filing and multiplying them by the requirements in ORC 4928.64(B)(2) for both Non Solar and Solar and then multiplying those requirements by the weighted average cost for RECs.

- Senate Bill 310 eliminated the in-state requirement for both solar and non-solar energy resources. DP&L is longer buying based on the in-state requirement, it is only buying based on the solar and non-solar requirements. There is no weight or relevance given to REC generating location, so long as it is deliverable to Ohio. The AER WACI inventory has been reconfigured to adjust for the elimination of the in-state requirements. The four previous categories of RECs have been consolidated down to two: Non-Solar and Solar.

[43] As noted above, with the passage of S.B. 310, the solar ACP was frozen at $300 for 2014, 2015, and 2016. Starting in 2017, the reduction of the solar ACP is to resume with the gradual reduction in payment amounts leveling off at $50 in 2026 and thereafter.

[44] The use of the term "REC" refers to both RECs and S-RECs unless stated otherwise.

- Senate Bill 310 froze the requirements listed under ORC §4928.64(B)(2) for compliance years 2015 and 2016. This decreased the projected number of RECs needed for compliance in those years, thereby increasing DP&L's REC inventory.

- DP&L no longer keeps as long a REC position as it has in prior years. This is due in large part because there is uncertainty with the annual requirement "freeze". The Energy Mandates Study Committee released a report in September 2015 in which it recommended an extension of the freeze. There is also uncertainty on the future of the overall requirements listed under ORC §4928.64.

REC Procurement Strategy and REC Purchases

DP&L states its strategy [redacted]

Exhibit 6-2. REC Position

[redacted].

REC Purchases

RECs purchases are usable within a five-year period. Any RECs held by DP&L at December 31, 2015 that are in excess of its 2015 Benchmarks will be applied to future year benchmarks. The REC's purchased by the Company in 2015 are summarized by category in Exhibit 6-3. The solar REC's are significantly higher in costs than the non-solar REC's. The costs of all RECs have come down.

Exhibit 6-3. Summary of 2015 REC Purchases by Category

[redacted]

Audit Period Purchases

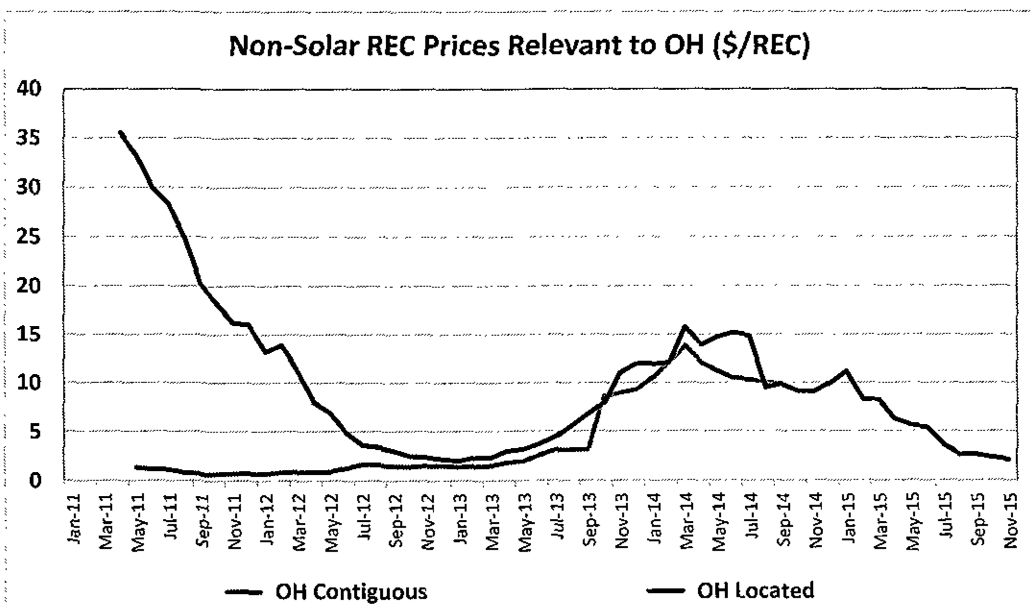
REC purchases during the audit period are listed by month and supplier in Exhibit 6-4. The purchases consist of commitments made prior to 2015 with delivery during 2015, as well as commitments made in 2015. The prices are compared to the price indices in effect at the time of delivery. The prices paid for RECs purchased in 2015 compare favorably to market prices. The prices for RECs purchased in earlier years are significantly higher than the current market. Prior audits have determined that the pricing in earlier years was also consistent with the contemporaneous market.

Exhibit 6-4. REC Purchases During 2015 Audit Period

[redacted]

REC Market and Procurement Strategy

REC pricing has been volatile as shown below. Currently, prices are relatively low compared to where they have been. This is explained by a surplus of RECs in the market. The surplus derived from lower than expected utility sales combined with over-purchasing of RECs assuming higher requirements. The net result has been limited market activity similar to what occurs in the coal market when utilities have reduced demand and high inventories. As the REC inventories are consumed and the annual REC requirements increase, the availability of RECs is likely to fall and the price of RECs is likely to rise [redacted]



EVA recommends that DP&L develop and implement a REC procurement strategy. At a minimum, this strategy should consider the following:

- Expected REC requirements (solar and non-solar) by Ohio utilities
- Impact of future actual and potential Federal/state RPS requirements on REC availability
- Expected REC supply from qualifying sources
- Opportunities to develop a portfolio risk management strategy wherein commitments for future REC requirements can be layered in
- Cost of and opportunity for long-term commitments for RECs

The strategy should be updated no less than annually to reflect changes to the market.

Audit Period Compliance

According to the Company's Annual Compliance Plan Status Reports for 2015, DP&L achieved compliance by meeting the 2015 benchmarks for the Ohio Renewable Portfolio Standard for both solar and non-solar renewables.

Financial Audit

Scope and Objectives

To accomplish the review of DP&L's 2015 AER, the following aspects were included in the verification and testing:

- Review the Company's AER filings applicable to DP&L's actual 2015 renewables costs, revenues and carrying costs to verify the accuracy of the calculations
- Review the individual components of all transactions that have been included within the AER calculations
- Review the accuracy of calculations relate to any carrying charges included in the Company's quarterly AER calculations,
- Review the Company's performance related to the 3% provision contained within Section 4928.64(C)(3), Revised Code as detailed in Rule 4901:1-40-47, OAC.
- Compare the costs recovered in the AER to the costs incurred.

Minimum Review Requirements

Larkin referred to the objectives and procedures outlined in Attachment 4 of the RFP as guidance for the review requirements of this project. The Financial Audit Program Standards are intended to be used as a guide for the auditor in conformance with the specific requirements of the Alternative Energy Rider and should not be used to the exclusion of the auditor's initiative, imagination, and thoroughness.

The information included here was used as guidance, in addition to appropriate discretion on the part of the auditor in order to conduct the regulatory verification of DP&L's renewables costs and REC inventory accounting in conformance with the specific requirements of the Company's AER that applied for the 2015 review period. Larkin reviewed and applied relevant criteria in review of the Company's decisions and actions related to its RPS compliance activities.

The guidelines provide that the financial audit shall include at least the following items:

(1) A review of the Company's AER quarterly filings during the audit period to verify the accuracy of the calculations;

(2) A review of the individual components (including, but not limited to, transactions of RECs or S-RECs and costs of implementing associated RFPs) that have been included within the Company's AER calculations in order to verify that the costs were appropriately included;

(3) A review to verify the accuracy of calculations related to any carrying charges included in the Company's quarterly AER calculations;

(4) A review of the Company's status relative to the 3% provision contained within Section, 4928.64(C)(3), Revised Code, and as further detailed in the Rule 4901:1-40-07, Ohio Administrative Code;

(5) A review comparing the costs recovered through the Company's AER during the audit period to the costs incurred; and

(6) A review of any other specific items as identified by the Commission or its Staff.

The Alternative Energy Rider is intended to compensate DP&L for compliance costs realized in meeting the renewable portfolio standards prescribed by Section 4928.64 of the Ohio Revised Code.

As part of its review of renewable energy resources, Larkin asked DP&L a series of questions pertaining to its renewable energy purchases and RECs from data requests LA-2015-89 through LA-2015-121. Larkin also asked DP&L about certain renewable cost/AER matters in informal follow-up questions.

Period for Review of Renewables Cost and AER

The audit period for DP&L's renewables is calendar 2015 and we reviewed the Company's renewables costs for that period. DP&L's Alternative Energy Rider was in effect for 2015.

Background

On June 24, 2009, the Commission adopted a Stipulation and Recommendation ("Stipulation") in DP&L's electric security plan proceeding authorizing, among other things, DP&L to institute an avoidable Alternative Energy Rider ("AER") to recover costs incurred to comply with Section 4928.64, Revised Code. *In re Dayton Power and Light Company,* Case Nos. 08-1094-EL-SSO et al., Opinion and Order (June 24, 2009) *(ESP Proceeding).* DP&L's AER was approved subject to an annual true-up for actual costs incurred.

On April 15, 2010, DP&L filed an application to update its AER. Subsequently, DP&L revised its application on July 22, 2010, to reflect improvements in its costing methodology and presentation, including revisions to its affiliate cost and renewable energy credit ("REC") allocations.

On March 21, 2012, the Commission issued its Finding and Order in Case No. 10-89-EL-RDR approving an amended application filed DP&L on June 1, 2011. On March 5, 2012, Staff had filed a letter in that docket recommending that the Commission approve the amended application filed by DP&L on June 1, 2011. Staff had verified that DP&L properly allocated both REC costs and REC-related administrative costs to DPLER and that its AER costs were reasonable.

DP&L's AER rates were approved by the Commission by Finding and Order dated March 21, 2012 in Case No. 10-89-EL-RDR. DP&L filed its annual true-up Application in Case No. 12-1519-EL-RDR.

By Opinion and Order dated June 24, 2009, in Case Nos. 08-1094-EL-SSO, *et al.*, the Commission approved a Stipulation and Recommendation ("ESP Stipulation") which provides at paragraph 6 that the annual true-up of DP&L's AER is to be filed by no later than June 1st of each year.

Consequently, DP&L submitted an Application in Case No. 13-1200-EL-RDR in compliance with its ESP Stipulation. In support of its Application to true-up the AER, DP&L attached the following schedules:

Schedule A-1	–	Copy of redlined tariff schedules;
Schedule A-2	–	Copy of proposed tariff schedules;
Schedule B-1	–	AER Summary;
Schedule C-1	–	Projected Monthly Cost Calculation
Schedule D-1	–	Summary of Actual Costs for 2012;
Schedule E-1	–	Typical Bill Comparison; and
WPD-1	–	Calculation of Carrying Cost.

The adjustment proposed by DP&L's true-up application resulted in an AER rate of $0.0017847 per kWh, which reflects an increase of $0.86 per bill based on typical residential customer usage of 750 kWh per month. DP&L had initially applied carrying charges of 5.86%, based on the cost of debt approved in the 08-1094-EL-SSO ESP proceeding, to the under and/or over recovery of costs when computing the components of the proposed AER rate. However, the Commission's Order and Opinion in Case No. 12-426-EL-SSO updated the cost of debt to 4.943% beginning in January 2014.

Quarterly Alternative Energy Rider Filings

Larkin's review of DP&L's quarterly AER filings covered the forecast periods encompassing calendar 2015. Our review also covered DP&L's calculations of the Reconciliation Adjustment (RA) components included within the quarterly AER filings. Larkin's review of DP&L's RA information included verification to actual recorded results on a test basis for the months of January through December 2015.

The following sections discuss DP&L's 2015 quarterly AER filings[45] by reproducing Schedules 1 through 4[46] as well as Workpaper 1 as Exhibits 6-5 through 6-26.

[45] DP&L provided the Excel versions of its quarterly AER filings in response to LA-2014-1-112.

Quarterly Alternative Rider Filing – March through May 2015

Exhibit 6-5. Forecasted Quarterly Rate Summary, Schedule 1, March through May 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Mar-15 (C)	Apr-15 (D)	May-15 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$103,268	$77,473	$79,428	$260,169	Schedule 3, Line 3
2	*Gross Revenue Conversion Factor*				*1.0072*	*Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21*
3	Total Forecasted Expense				$262,042	Line 1 * Line 2
4	Forecasted Metered Level Sales	289,651,505	216,746,778	222,097,118	728,495,400	Schedule 2, Line 13
5	AER Rate before Adjustments $/kWh				$0.0003597	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0006026)	Schedule 2, Line 14
7	Yankee Adjustment $/kWh				$0.0005055	Schedule 4, Line 8
8	Forecasted AER Rate $/kWh				$0.0002626	Sum of Lines 5 - 7

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense it expected to incur during the period March through May 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for March through May 2015, which totaled $260,169 (column F). As shown on line 2 of Schedule 1, the Company included its Gross Revenue Conversion Factor[47] of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $260,169 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period March through May 2015 (see Schedule 2 discussion below) of 728.495 million kWh on line 4. The Company then divided the total forecasted expense by the forecasted meter level sales to calculate the AER rate before Reconciliation Adjustment of $0.0003597 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0006026) per kWh on line 6. Line 7 reflects DP&L's Yankee Adjustment of $0.0005055 per kWh. DP&L added its Reconciliation Adjustment to the $0.0003597 per kWh and the Yankee adjustment noted above to derive its forecasted AER rate of $0.0002626 per kWh as shown on line 8 of Schedule 1.

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[46] The historical Yankee costs were fully recovered as of August 2015, thus Schedule 4 was removed from the subsequent quarterly AER filings, as stated in response to LA-2015-90.
[47] The Gross Revenue Conversion Factor is used to gross up the return deficiency to account for the increase in income taxes..

Exhibit 6-6. Summary of Actual Costs – Schedule 2, October 2014 through May 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Historical Yankee Costs (E)	Total Expenses (F)	Revenue (G)	(Over) / Under Recovery (H)	Carrying Costs (I)	Total (J)	YTD[1] (K)	Source (L)
1	Prior Period									($482,642)	Accounting Records
2	Oct-14	($104,082)	$992	$121,882	$18,792	($179,210)	($160,418)	($2,318)	($162,737)	($645,379)	Accounting Records
3	Nov-14	$177,108	($534)	$121,882	$298,456	($191,022)	$107,434	($2,437)	$104,997	($540,382)	Accounting Records
4	Dec-14	$167,715	$2,325	$121,882	$291,922	($282,582)	$9,340	($2,207)	$7,133	($533,248)	Accounting Records
5	Jan-15	$168,411	$353	$121,882	$290,646	($312,286)	($21,640)	($2,241)	($23,881)	($557,129)	Corporate Forecast
6	Feb-15	$168,411	$353	$121,882	$290,646	($164,672)	$125,975	($2,035)	$123,939	($433,190)	Corporate Forecast
7	Mar-15	$102,299	$969	$121,882	$225,150	($225,150)	$0	($1,476)	($1,476)	($434,666)	Corporate Forecast
8	Apr-15	$76,505	$969	$121,882	$199,356	($199,356)	$0	($880)	($880)	($435,546)	Corporate Forecast
9	May-15	$78,459	$969	$121,882	$201,310	($201,310)	$0	($294)	($294)	($435,840)	Corporate Forecast
10	(Over) / Under Recovery									($435,840)	Line 9
11	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
12	Total (Over) / Under Recovery with Carrying Costs									($438,978)	Line 10 * Line 11
							Mar-15	Apr-15	May-15		
13	Standard Offer Sales Forecast (kWh)						289,651,505	216,746,778	222,097,118	728,495,400	Corporate Forecast
14	AER Reconciliation Rate $/kWh									($0.0006026)	Line 12 / Line 13

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column C of Schedule 2 reflects DP&L's actual and forecasted REC expenses during the period of October 2014 through May 2015, which totaled $834,825. Column D of Schedule 2 reflects DP&L's actual and forecasted Compliance Administration expenses for the same period, which totaled $6,396. Column E reflects the Historical Yankee Costs for October 2014 through May 2015. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $1.816 million, as shown in column F. Column G reflects DP&L's actual and forecasted revenues for October 2014 through May 2015 for a total of ($1.756) million. The difference between the Company's actual and forecasted fuel costs and actual and forecasted revenues results in an under-recovery in the amount of $60,691, as shown in column H. Column I reflects the carrying costs for the period of October 2014 through May 2015, which total ($13,889). The under-recovery for the period of October 2014 through May 2015, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the October 2014 through May 2015 period, resulted in a YTD over-recovery of ($435,840) (column K, line 10). DP&L's over-recovery stated above is then multiplied by the gross revenue conversion factor of 1.0072, resulting in total over-recovery with carrying costs of ($438,978), as shown on line 12. Line 13 reflects the Standard Offer Sales Forecast for the period of March through May 2015, totaling 728.495 million kWh. The Company derived its AER Reconciliation Rate of ($0.0006026) per kWh by dividing the total over-recovery with carrying costs of ($438,978) by its standard offer sales forecast for the period March through May 2015.

Exhibit 6-7. Projected Monthly Cost Calculation – March through May 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Mar-15 (C)	Apr-15 (D)	May-15 (E)	Total (F)	Source (G)
1	REC Expense	$102,299	$76,505	$78,459	$ 257,263	Corporate Forecast
2	Compliance Administration	$969	$969	$969	$2,907	Corporate Forecast
3	Total AER Expense	$103,268	$77,473	$79,428	$260,169	Line 1 + Line 2
4	*Gross Revenue Conversion Factor*				1.0072	*Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21*
5	Total Projected AER Costs				$262,042	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh)				728,495,400	Corporate Forecast
7	AER Base Rate $/kWh				$0.0003597	Line 5 / Line 6

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to incur during the period March through May 2015. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for March through May 2015, which totaled $257,263 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $2,907. This results in total AER expense for March through May 2015 of $260,169, as shown on line 3. Line 4 reflects its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the total AER expense of $260,169 by the gross revenue conversion factor as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of March through May 2015, totaling 728.495 million kWh on line 6. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0003597 per kWh as shown on line 7.

Exhibit 6-8. Historical Yankee REC Costs – Schedule 4, March through May 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Historical Yankee REC Costs

Line (A)	Description (B)	2010 (C)	2011 (D)	2012 (E)	2013 (F)	2014 (G)	Total (H)	Source (I)
1	REC Output	1,322	1,336	1,532	1,343	703	6,236	Accounting Records
2	Fair Market Value (FMV) of Ohio SRECs	$400	$325	$260	$40	$68		Expert Report - Fair Market Valuation of Ohio Solar Renewable Energy Credits
3	Total FMV of RECs	$528,800	$434,200	$398,320	$53,720	$47,548	$1,462,588	Line 1 x Line 2
4	Quarterly Recovery Amount						$365,647	Line 3 / 4
5	Gross Revenue Conversion Factor						1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
6	Total Quarterly Recovery Amount						$368,279.68	Line 4 *Line 5
				Mar-15	Apr-15	May-15		
7	Standard Offer Sales Forecast (kWh)			289,651,505	216,746,778	222,097,118	728,495,400	Corporate Forecast
8	Yankee Adjustment $/kWh						$ 0.0005055	Line 6 / Line 7

Schedule 4: Schedule 4 presents the calculation of the Yankee REC cost adjustment for the period March through May 2015. Line 1 reflects the Yankee REC Output for the years 2010 through 2014, totaling 6,236. Line 2 reflects the Fair Market Value of Ohio SRECs for the same period. The total FMV of RECs is derived by multiplying the REC output by the FMV of Ohio RECs, totaling $1.463 million, as shown on line 3. The total FMV of RECs is divided by 4 to calculate the Quarterly Recovery Amount of $365,647, as shown on line 4. Line 5 reflects the Gross Revenue Conversion Factor. The quarterly recovery amount is multiplied by the gross revenue conversion factor to derive the Total Quarterly Recovery Amount of $368,280, as shown on line 6. Line 7 reflects the Standard Offer Sales Forecast for the period of March through May 2015 totaling 728.495 million kWh. The total quarterly recovery amount is divided by the Standard Offer Sales Forecast to calculate the Yankee adjustment of $.0005055 per kWh shown on line 8, which is used on Schedule 1 (discussed above) in the calculation of the forecasted AER rate.

Exhibit 6-9. Calculation of Carrying Costs – Workpaper 1, October 2014 through May 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY							Carrying Cost Calculation	
Line	Period	First of Month Balance	New AER Charges	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (COD % / 12)	(I) = (G) + (H)	(J) = - (F) * .5	(K) = (G) + (J)
1	Prior Period							($482,642)	$0	$0
2	Oct-14	($482,642)	$18,792	($179,210)	($160,418)	($643,060)	($2,318)	($645,379)	$80,209	($562,851)
3	Nov-14	($645,379)	$298,456	($191,022)	$107,434	($537,945)	($2,437)	($540,382)	($53,717)	($591,662)
4	Dec-14	($540,382)	$291,922	($282,582)	$9,340	($531,042)	($2,207)	($533,248)	($4,670)	($535,712)
5	Jan-15	($533,248)	$290,646	($312,286)	($21,640)	($554,888)	($2,241)	($557,129)	$10,820	($544,068)
6	Feb-15	($557,129)	$290,646	($164,672)	$125,975	($431,154)	($2,035)	($433,190)	($62,987)	($494,142)
7	Mar-15	($433,190)	$225,150	($75,519)	$149,632	($283,558)	($1,476)	($285,034)	($74,816)	($358,374)
8	Apr-15	($285,034)	$199,356	($56,511)	$142,845	($142,189)	($880)	($143,069)	($71,422)	($213,612)
9	May-15	($143,069)	$201,310	($57,906)	$143,404	$335	($294)	$41	($71,702)	($71,367)

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period October 2014 through May 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0006026). First, 50% of the net amount of AER costs (the new monthly AER costs minus the amount collected by the AER) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Exhibit 6-10. Forecasted Quarterly Rate Summary, Schedule 1, June through August 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Jun-15 (C)	Jul-15 (D)	Aug-15 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$90,170	$112,951	$107,914	$311,035	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
3	Total Forecasted Expense				$313,274	Line 1 * Line 2
4	Forecasted Metered Level Sales	268,897,890	337,341,793	322,149,150	928,388,832	Schedule 2, Line 16
5	AER Rate before Adjustments $/kWh				$0.0003374	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0010469)	Schedule 2, Line 17
7	Yankee Adjustment $/kWh				$0.0003967	Schedule 4, Line 8
8	Forecasted AER Rate $/kWh				($0.0003128)	Sum of Lines 5 - 7

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense it expected to incur during the period June through August 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for June through August 2015, which totaled $311,035 (column F). As shown on line 2 of Schedule 1, the Company included its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $311,035 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period June through August 2015 (see Schedule 2 discussion below) of 928.389 million kWh on line 4. The Company then divided the total forecasted expense by the forecasted meter level sales to calculate the AER rate before Reconciliation Adjustment of $0.0003374 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0010469) per kWh on line 6. Line 7 reflects DP&L's Yankee Adjustment of $0.0003967 per kWh. DP&L added its Reconciliation Adjustment to the $0.0003374 per kWh and the Yankee adjustment noted above to derive its forecasted AER rate of ($0.0003128) per kWh as shown on line 8 of Schedule 1.

Exhibit 6-11. Summary of Actual Costs – Schedule 2, October 2014 through August 2015

The Dayton Power and Light Company
Case No 15-0045-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Historical Yankee Costs (E)	Total Expenses (F)	Revenue (G)	(Over) / Under Recovery (H)	Carrying Costs (I)	Total (J)	YTD[1] (K)	Source (L)
1	Prior Period									($482,642)	Accounting Records
2	Oct-14	($104,082)	$992	$121,882	$18,792	($179,210)	($160,418)	($2,318)	($162,737)	($645,379)	Accounting Records
3	Nov-14	$177,108	($534)	$121,882	$298,456	($191,022)	$107,434	($2,437)	$104,997	($540,382)	Accounting Records
4	Dec-14	$167,715	$2,325	$121,882	$291,922	($282,582)	$9,340	($2,207)	$7,133	($533,248)	Accounting Records
5	Jan-15	$142,422	$628	$121,882	$264,932	($346,820)	($81,888)	($2,365)	($84,253)	($617,501)	Accounting Records
6	Feb-15	$153,666	$707	$121,882	$276,255	($335,001)	($58,746)	($2,665)	($61,410)	($678,912)	Accounting Records
7	Mar-15	($573,735)	$1,086	$121,882	($450,767)	($102,527)	($553,295)	($3,936)	($557,231)	($1,236,142)	Accounting Records
8	Apr-15	$76,505	$969	$121,882	$199,356	($56,511)	$142,845	($4,798)	$138,047	($1,098,095)	Corporate Forecast
9	May-15	$78,459	$969	$121,882	$201,310	($57,906)	$143,404	($4,228)	$139,176	($958,919)	Corporate Forecast
10	Jun-15	$89,600	$570	$121,882	$212,052	($212,052)	$0	($3,341)	($3,341)	($962,260)	Corporate Forecast
11	Jul-15	$112,381	$570	$121,882	$234,833	($234,833)	$0	($2,047)	($2,047)	($964,307)	Corporate Forecast
12	Aug-15	$107,344	$570	$121,882	$229,797	($229,797)	$0	($676)	($676)	($964,983)	Corporate Forecast
13	(Over) / Under Recovery									($964,983)	Line 12
14	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
15	Total (Over) / Under Recovery with Carrying Costs									($971,931)	Line 13 * Line 14
							Jun-15	Jul-15	Aug-15		
16	Standard Offer Sales Forecast (kWh)						268,897,890	337,341,793	322,149,150	928,388,832	Corporate Forecast
17	AER Reconciliation Rate $/kWh									($0.0010469)	Line 15 / Line 16

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column C of Schedule 2 reflects DP&L's actual and forecasted October 2014 through August 2015, which totaled $427,382. Column D of Schedule 2 reflects DP&L's actual and forecasted Compliance Administration expenses for the same period, which totaled $8,851. Column E reflects the Historical Yankee Costs for October 2014 through August 2015. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $1.777 million, as shown in column F. Column G reflects DP&L's actual and forecasted revenues for October 2014 through August 2015 for a total of ($2.228) million. The difference between the Company's actual and forecasted fuel costs and actual and forecasted revenues results in an over-recovery in the amount of ($451,323), as shown in column H. Column I reflects the carrying costs for the period of October 2014 through August 2015, which total ($31,018). The over-recovery for the period of October 2014 through August 2015, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the October 2014 through August 2015 period, resulted in a YTD over-recovery of ($964,983) (column K, line 13). DP&L's over-recovery stated above is then multiplied by the gross revenue conversion factor of 1.0072, resulting in total over-recovery with carrying costs of ($971,931), as shown on line 15. Line 16 reflects the Standard Offer Sales Forecast for the period of June through August 2015, totaling 928.389 million kWh. The Company derived its AER Reconciliation Rate of ($0.0010469) per kWh by dividing the total over-recovery with carrying costs of ($971,931) by its standard offer sales forecast for the period June through August 2015.

Exhibit 6-12. Projected Monthly Cost Calculation – June through August 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Jun-15 (C)	Jul-15 (D)	Aug-15 (E)	Total (F)	Source (G)
1	REC Expense	$ 89,600	$112,381	$107,344	$ 309,325	Corporate Forecast
2	Compliance Administration	$570	$570	$570	$1,710	Corporate Forecast
3	Total AER Expense	$ 90,170	$112,951	$107,914	$311,035	Line 1 + Line 2
4	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
5	Total Projected AER Costs				$313,274	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh)				928,388,832	Corporate Forecast
7	AER Base Rate $/kWh				$0.0003374	Line 5 / Line 6

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to incur during the period June through August 2015. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for June through August 2015, which totaled $309,325 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,710. This results in total AER expense for June through August 2015 of $311,035, as shown on line 3. Line 4 reflects its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the total AER expense of $311,035 by the gross revenue conversion factor as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of June through August 2015, totaling 928.389 million kWh on line 6. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0003374 per kWh as shown on line 7.

Exhibit 6-13. Historical Yankee REC Costs – Schedule 4, June through August 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Historical Yankee REC Costs

Line (A)	Description (B)	2010 (C)	2011 (D)	2012 (E)	2013 (F)	2014 (G)	Total (H)	Source (I)
1	REC Output	1,322	1,336	1,532	1,343	703	6,236	Accounting Records
2	Fair Market Value (FMV) of Ohio SRECs	$400	$325	$260	$40	$68		Expert Report - Fair Market Valuation of Ohio Solar Renewable Energy Credits
3	Total FMV of RECs	$528,800	$434,200	$398,320	$53,720	$47,548	$1,462,588	Line 1 x Line 2
4	Quarterly Recovery Amount						$365,647	Line 3 / 4
5	Gross Revenue Conversion Factor						1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
6	Total Quarterly Recovery Amount						$368,279 68	Line 4 *Line 5
				Jun-15	Jul-15	Aug-15		
7	Standard Offer Sales Forecast (kWh)			268,897,890	337,341,793	322,149,150	928,388,832	Corporate Forecast
8	Yankee Adjustment $/kWh						$ 0.0003967	Line 6 / Line 7

Schedule 4: Schedule 4 presents the calculation of the Yankee REC cost adjustment for the period June through August 2015. Line 1 reflects the REC Output for the years 2010 through 2014, totaling $6,236. Line 2 reflects the Fair Market Value of Ohio SRECs for the same period. The total FMV of RECs is derived by multiplying the REC output by the FMV of Ohio SRECs, totaling $1.463 million, as shown on line 3. The total FMV of RECs is divided by 4 to calculate the Quarterly Recovery Amount of $365.647, as shown on line 4. Line 5 reflects the Gross Revenue Conversion Factor. The quarterly recovery amount is multiplied by the gross revenue conversion factor to derive the Total Quarterly Recovery Amount of $368,280, as shown on line 6. Line 7 reflects the Standard Offer Sales Forecast for the period of June through August 2015 totaling 928.389 million kWh. The total quarterly recovery amount is divided by the Standard Offer Sales Forecast to calculate the Yankee adjustment of $.0003967 per kWh shown on line 8, which is used on Schedule 1 (discussed above) in the calculation of the forecasted AER rate.

Exhibit 6-14. Calculation of Carrying Costs – Workpaper 1, October 2014 through August 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY							Carrying Cost Calculation	
Line (A)	Period (B)	First of Month Balance (C)	New AER Charges (D)	Amount Collected (CR) (E)	Net Amount (F)	End of Month before Carrying Cost (G)	Carrying Cost (H)	End of Month Balance (I)	Less: One-half Monthly Amount (J)	Total Applicable to Carrying Cost (K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (COD % / 12)	(I) = (G) + (H)	(J) = - (F) * .5	(K) = (G) + (J)
1	Prior Period							($482,642)	$0	$0
2	Oct-14	($482,642)	$18,792	($179,210)	($160,418)	($643,060)	($2,318)	($645,379)	$80,209	($562,851)
3	Nov-14	($645,379)	$298,456	($191,022)	$107,434	($537,945)	($2,437)	($540,382)	($53,717)	($591,662)
4	Dec-14	($540,382)	$291,922	($282,582)	$9,340	($531,042)	($2,207)	($533,248)	($4,670)	($535,712)
5	Jan-15	($533,248)	$264,932	($346,820)	($81,888)	($615,136)	($2,365)	($617,501)	$40,944	($574,192)
6	Feb-15	($617,501)	$276,255	($335,001)	($58,746)	($676,247)	($2,665)	($678,912)	$29,373	($646,874)
7	Mar-15	($678,912)	($450,767)	($102,527)	($553,295)	($1,232,206)	($3,936)	($1,236,142)	$276,647	($955,559)
8	Apr-15	($1,236,142)	$199,356	($56,511)	$142,845	($1,093,297)	($4,798)	($1,098,095)	($71,422)	($1,164,720)
9	May-15	($1,098,095)	$201,310	($57,906)	$143,404	($954,691)	($4,228)	($958,919)	($71,702)	($1,026,393)
10	Jun-15	($958,919)	$212,052	$83,510	$295,562	($663,357)	($3,341)	($666,698)	($147,781)	($811,138)
11	Jul-15	($666,698)	$234,833	$104,766	$339,600	($327,098)	($2,047)	($329,145)	($169,800)	($496,898)
12	Aug-15	($329,145)	$229,797	$100,048	$329,844	$699	($676)	$23	($164,922)	($164,223)

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period October 2014 through August 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0003128). First, 50% of the net amount of AER costs (the new monthly AER costs minus the amount collected by the AER) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly Alternative Rider Filing – September through November 2015

Exhibit 6-15. Forecasted Quarterly Rate Summary, September through November 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Sep-15 (C)	Oct-15 (D)	Nov-15 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$81,513	$69,964	$81,984	$233,461	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
3	Total Forecasted Expense				$235,142	Line 1 * Line 2
4	Forecasted Metered Level Sales	245,201,863	210,221,495	246,457,263	701,880,621	Schedule 2, Line 20
5	AER Rate before Adjustments $/kWh				$0.0003350	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$0.0000337	Schedule 2, Line 21
7	Forecasted AER Rate $/kWh				$0.0003687	Line 5 + Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense it expected to incur during the period September through November 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for September through November 2015, which totaled $233,461 (column F). As shown on line 2 of Schedule 1, the Company included its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $233,461 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period September through November 2015 (see Schedule 2 discussion below) of 701.881 million kWh on line 4. The Company then divided the total forecasted expense by the forecasted meter level sales to calculate the AER rate before Reconciliation Adjustment of $0.0003350 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.000037) per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0003350 per kWh to derive its forecasted AER rate of $0.0003687 per kWh as shown on line 7 of Schedule 1.

Exhibit 6-16. Summary of Actual Costs – January 2015 through November 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Historical Yankee Costs (E)	Total Expenses (F)	Revenue (G)	(Over) / Under Recovery (H)	Carrying Costs (I)	Total (J)	YTD[1] (K)	Source (L)
1	Prior Period									($533,248)	Accounting Records
2	Jan-15	$142,422	$628	$121,882	$264,932	($346,820)	($81,888)	($2,365)	($84,253)	($617,501)	Accounting Records
3	Feb-15	$153,666	$707	$121,882	$276,255	($335,001)	($58,746)	($2,665)	($61,410)	($678,912)	Accounting Records
4	Mar-15	($573,735)	$1,086	$121,882	($450,767)	($102,527)	($553,295)	($3,936)	($557,231)	($1,236,142)	Accounting Records
5	Apr-15	$87,251	$361	$121,882	$209,494	($77,317)	$132,177	($4,820)	$127,357	($1,108,785)	Accounting Records
6	May-15	$88,325	$17,549	$121,882	$227,756	($65,318)	$162,438	($4,233)	$158,206	($950,580)	Accounting Records
7	Jun-15	$113,678	($15,590)	$121,882	$219,970	$93,038	$313,008	($3,271)	$309,737	($640,842)	Accounting Records
8	Jul-15	$112,381	$570	$121,882	$234,833	$104,766	$339,600	($1,940)	$337,659	($303,183)	Corporate Forecast
9	Aug-15	$107,344	$570	$121,882	$229,797	$100,048	$329,844	($570)	$329,275	$26,092	Corporate Forecast
10	Sep-15	$80,881	$632	$0	$81,513	($81,513)	$0	$85	$85	$26,177	Corporate Forecast
11	Oct-15	$69,332	$632	$0	$69,964	($69,964)	$0	$48	$48	$26,225	Corporate Forecast
12	Nov-15	$81,351	$632	$0	$81,984	($81,984)	$0	$17	$17	$26,242	Corporate Forecast
13	(Over)/Under Recovery									$26,242	Line 12
14	(Over)/Under Recovery Through August 2015									$26,092	Line 9
15	10% Quarterly Threshold									$23,346	(Sum of Column F, Lines 10 - 12) * 10%
16	Amount Exceeding Threshold									$2,746	Line 14 - Line 15
17	(Over) / Under Recovery									$23,496	Line 13 - Line 16
18	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
19	Total (Over) / Under Recovery with Carrying Costs									$23,665	Line 17 * Line 18
							Sep-15	Oct-15	Nov-15		
20	Standard Offer Sales Forecast (kWh)						245,201,863	210,221,495	246,457,263	701,880,621	Corporate Forecast
21	AER Reconciliation Rate $/kWh									$0.0000337	Line 19 / Line 20

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column C of Schedule 2 reflects DP&L's actual and forecasted REC expenses during the period of January through November 2015, which totaled $462,896. Column D of Schedule 2 reflects DP&L's actual and forecasted Compliance Administration expenses for the same period, which totaled $7,777. Column E reflects the Historical Yankee Costs for January through August 2015.[48] The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $1.446 million, as shown in column F. Column G reflects DP&L's actual and forecasted revenues for January through November 2015 for a total of ($862,592). The difference between the Company's actual and forecasted fuel costs and actual and forecasted revenues results in an under-recovery in the amount of $583,139, as shown in column H. Column I reflects the carrying costs for the period of January through November 2015, which total ($23,649). The under-recovery for the period of January through August 2015, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the January through November 2015 period, resulted in a YTD under-recovery of $26,242 (column K, line 13). Line 14 reflects the under-recovery of $26,092 million for the period of January through August 2015. The amount on Line 15 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted expenses for the period September through November 2015 by 10% which totals $23,346. This amount was then subtracted from the under-recovery through August 2015 to calculate the Amount Exceeding Threshold of $2,746, as shown on line 16. The result is an under-recovery of $23,496, which is derived by subtracting the amount exceeding the threshold from the under recovery through November 2015, as shown on line 17. DP&L's under-recovery stated above is then multiplied by the gross revenue conversion factor of 1.0072, resulting in total under-recovery with carrying costs of $23,665, as shown on line 19. Line 20 reflects the Standard Offer Sales Forecast for the

[48] According to the response to LA-2015-90, the historical Yankee costs were fully recovered in August 2015.

period of September through November 2015, totaling 701.881 million kWh. The Company derived its AER Reconciliation Rate of $0.0000337 per kWh by dividing the total under-recovery with carrying costs of $23,665 by its standard offer sales forecast for the period September through November 2015.

Exhibit 6-17. Projected Monthly Cost Calculation – September through November 2015

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Sep-15 (C)	Oct-15 (D)	Nov-15 (E)	Total (F)	Source (G)
1	*REC Expense*	$ 80,881	$ 69,332	$ 81,351	$ 231,564	*Corporate Forecast*
2	Compliance Administration	$632	$632	$632	$1,897	Corporate Forecast
3	*Total AER Expense*	$ 81,513	$ 69,964	$ 81,984	$233,461	*Line 1 + Line 2*
4	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
5	*Total Projected AER Costs*				$235,142	*Line 3 x Line 4*
6	Standard Offer Sales Forecast (kWh)				701,880,621	Corporate Forecast
7	*AER Base Rate $/kWh*				$0.0003350	Line 5 / Line 6

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to incur during the period September through November 2015. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for September through November 2015, which totaled $231,564 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,897. This results in total AER expense for September through November 2015 of $233,461, as shown on line 3. Line 4 reflects its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the total AER expense of $233,461 by the gross revenue conversion factor, as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of September through November 2015, totaling 701.881 million kWh on line 6. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0003350 per kWh as shown on line 7.

Exhibit 6-18. Calculation of Carrying Costs – Workpaper 1, January through November 2015

Alternative Energy Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								Carrying Cost Calculation	
Line	Period	First of Month Balance	New AER Charges	Amount Exceeding Threshold	Amount Collected FUEL Rider (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								($533,248)	$0	$0
2	Jan-15	($533,248)	$264,932		($346,820)	($81,888)	($615,136)	($2,365)	($617,501)	$40,944	($574,192)
3	Feb-15	($617,501)	$276,255		($335,001)	($58,746)	($676,247)	($2,665)	($678,912)	$29,373	($646,874)
4	Mar-15	($678,912)	($450,767)		($102,527)	($553,295)	($1,232,206)	($3,936)	($1,236,142)	$276,647	($955,559)
5	Apr-15	($1,236,142)	$209,494		($77,317)	$132,177	($1,103,966)	($4,820)	($1,108,785)	($66,088)	($1,170,054)
6	May-15	($1,108,785)	$227,756		($65,318)	$162,438	($946,347)	($4,233)	($950,580)	($81,219)	($1,027,566)
7	Jun-15	($950,580)	$219,970		$93,038	$313,008	($637,571)	($3,271)	($640,842)	($156,504)	($794,076)
8	Jul-15	($640,842)	$234,833		$104,766	$339,600	($301,243)	($1,940)	($303,183)	($169,800)	($471,043)
9	Aug-15	($303,183)	$229,797		$100,048	$329,844	$26,661	($570)	$26,092	($164,922)	($138,261)
10	Sep-15	$26,092	$81,513	($2,746)	($89,760)	($10,992)	$15,099	$85	$15,184	$5,496	$20,596
11	Oct-15	$15,184	$69,964		($76,955)	($6,990)	$8,194	$48	$8,242	$3,495	$11,689
12	Nov-15	$8,242	$81,984		($90,219)	($8,236)	$6	$17	$23	$4,118	$4,124

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period January through November 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of $0.0000337. First, 50% of the net amount of AER costs (the new monthly AER costs minus the amount exceeding the threshold and the amount collected by the AER) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly Alternative Rider Filing – December 2015 through February 2016

Exhibit 6-19. Forecasted Quarterly Rate Summary, December 2015 through February 2016

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Dec-15 (C)	Jan-16 (D)	Feb-16 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$98,155	$83,700	$65,362	$247,218	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
3	Total Forecasted Expense				$248,998	Line 1 * Line 2
4	Forecasted Metered Level Sales	355,160,727	302,432,780	235,574,247	893,167,753	Schedule 2, Line 20
5	AER Rate before Adjustments $/kWh				$0.0002788	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0001676)	Schedule 2, Line 21
7	Forecasted AER Rate $/kWh				$0.0001112	Line 5 + Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense it expected to incur during the period December 2015 through February 2016. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for December 2015 through February 2016, which totaled $247,218 (column F). As shown on line 2 of Schedule 1, the Company included its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $247,218 by the gross revenue conversion factor, as shown on line 3. The Company reflected forecasted meter level sales for the period December 2015 through February 2016 (see Schedule 2 discussion below) of 893.168 million kWh on line 4. The Company then divided the total forecasted expense by the forecasted meter level sales to calculate the AER rate before Reconciliation Adjustment of $0.0002788 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0001676) per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0002788 per kWh noted above to derive its forecasted AER rate of $0.0001112 per kWh as shown on line 7 of Schedule 1.

Exhibit 6-20. Summary of Actual Costs – March 2015 through February 2016

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Historical Yankee Costs (E)	Total Expenses (F)	Revenue (G)	(Over) / Under Recovery (H)	Carrying Costs (I)	Total (J)	YTD[1] (K)	Source (L)
1	Prior Period									$ (678,912)	Accounting Records
2	Mar-15	($573,735)	$1,086	$121,882	($450,767)	($102,527)	($553,295)	($3,936)	($557,231)	($1,236,142)	Accounting Records
3	Apr-15	$87,251	$361	$121,882	$209,494	($77,317)	$132,177	($4,820)	$127,357	($1,108,785)	Accounting Records
4	May-15	$88,325	$17,549	$121,882	$227,756	($65,318)	$162,438	($4,233)	$158,206	($950,580)	Accounting Records
5	Jun-15	$113,678	($15,590)	$121,882	$219,970	$93,038	$313,008	($3,271)	$309,737	($640,842)	Accounting Records
6	Jul-15	$105,445	($1,191)	$121,882	$226,137	$106,223	$332,359	($1,955)	$330,404	($310,438)	Accounting Records
7	Aug-15	$108,686	$648	$121,882	$231,216	$112,827	$344,042	($570)	$343,472	$33,034	Accounting Records
8	Sep-15	($45,432)	$701	$0	($44,731)	($119,500)	($164,231)	($202)	($164,433)	($131,400)	Accounting Records
9	Oct-15	$69,332	$632	$0	$69,964	($76,955)	($6,990)	($556)	($7,546)	($138,946)	Corporate Forecast
10	Nov-15	$81,351	$632	$0	$81,984	($90,219)	($8,236)	($589)	($8,825)	($147,771)	Corporate Forecast
11	Dec-15	$97,523	$632	$0	$98,155	($98,155)	$0	($487)	($487)	($148,258)	Corporate Forecast
12	Jan-16	$83,068	$632	$0	$83,700	($83,700)	$0	($264)	($264)	($148,522)	Corporate Forecast
13	Feb-16	$64,730	$632	$0	$65,362	($65,362)	$0	($81)	($81)	($148,603)	Corporate Forecast
14	(Over)/Under Recovery									($148,603)	Line 13
15	(Over)/Under Recovery Through November 2015									($147,771)	Line 10
16	10% Quarterly Threshold									$24,722	(Sum of Column F, Lines 11 - 13) * 10%
17	Amount Exceeding Threshold									$0	Line 15 - Line 16 (if Line 15 > Line 16); if not, 0
18	(Over) / Under Recovery									($148,603)	Line 14 - Line 17
19	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
20	Total (Over) / Under Recovery with Carrying Costs									($149,673)	Line 18 * Line 19
							Dec-15	Jan-16	Feb-16		
21	Standard Offer Sales Forecast (kWh)						355,160,727	302,432,780	235,574,247	893,167,753	Corporate Forecast
22	AER Reconciliation Rate $/kWh									($0.0001676)	Line 20 / Line 21

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column C of Schedule 2 reflects DP&L's actual and forecasted REC expenses during the period of March 2015 through February 2016, which totaled $280,222. Column D of Schedule 2 reflects DP&L's actual and forecasted Compliance Administration expenses for the same period, which totaled $6,724. Column E reflects the Historical Yankee Costs for March 2015 through August 2015. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $1.018 million, as shown in column F. Column G reflects DP&L's actual and forecasted revenues for March 2015 through February 2016 for a total of ($466,967). The difference between the Company's actual and forecasted fuel costs and actual and forecasted revenues results in an under-recovery in the amount of $551, 273, as shown in column H. Column I reflects the carrying costs for the period of March 2015 through February 2016, which total ($20,964). The under-recovery for the period of January through November 2015, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the March 2015 through February 2016 period, resulted in a YTD over-recovery of ($148,603) (column K, line 14). Line 15 reflects the over-recovery of ($147,771) million for the period of January through November 2015. The amount on Line 16 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted expenses for the period December 2015 through February 2016 by 10% which totals $24,722. This amount was then subtracted from the over-recovery through November 2015 to calculate the Amount Exceeding Threshold of $0 (since the over-recovery amount was less than the threshold amount), as shown on line 17. The result is an over-recovery of ($148,603), which is derived by subtracting the amount exceeding the threshold from the over-recovery through November 2015, as shown on line 18. DP&L's over-recovery stated above is then multiplied by the gross revenue conversion factor of 1.0072, resulting in total under-recovery with carrying costs of ($149,673), as shown on line 20. Line 21 reflects the Standard Offer Sales Forecast for the period of December 2015 through February 2016, totaling 893.168 million kWh. The Company derived its AER Reconciliation Rate of $0.0001676 per kWh by dividing the total over-recovery with carrying costs of ($149,673) by its standard offer sales forecast for the period December 2015 through February 2016.

Exhibit 6-21. Projected Monthly Cost Calculation – December 2015 through February 2016

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Dec-15 (C)	Jan-16 (D)	Feb-16 (E)	Total (F)	Source (G)
1	REC Expense	$ 97,523	$ 83,068	$ 64,730	$ 245,321	Corporate Forecast
2	Compliance Administration	$632	$632	$632	$1,897	Corporate Forecast
3	Total AER Expense	$ 98,155	$ 83,700	$ 65,362	$247,218	Line 1 + Line 2
4	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
5	Total Projected AER Costs				$248,998	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh)				893,167,753	Corporate Forecast
7	AER Base Rate $/kWh				$0.0002788	Line 5 / Line 6

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to incur during the period December 2015 through February 2016. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for December 2015 through February 2016, which totaled $245,321 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,897. This results in total AER expense for December 2015 through February 2016 of $247,218, as shown on line 3. Line 4 reflects its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the total AER expense of $247,218 by the gross revenue conversion factor, as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of December 2015 through February 2016, totaling 893.168 million kWh on line 6. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0002788 per kWh as shown on line 7.

Exhibit 6-22. Calculation of Carrying Costs – Workpaper 1, March 2015 through February 2016

The Dayton Power and Light Company
Case No. 15-0045-EL-RDR
Alternative Energy Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								Carrying Cost Calculation	
Line	Period	First of Month Balance	New AER Charges	Amount Exceeding Threshold	Amount Collected FUEL Rider (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$ (678,911.66)	$0	$0
2	Mar-15	($678,912)	($450,767)		($102,527)	($553,295)	($1,232,206)	($3,936)	($1,236,142)	$276,647	($955,559)
3	Apr-15	($1,236,142)	$209,494		($77,317)	$132,177	($1,103,966)	($4,820)	($1,108,785)	($66,088)	($1,170,054)
4	May-15	($1,108,785)	$227,756		($65,318)	$162,438	($946,347)	($4,233)	($950,580)	($81,219)	($1,027,566)
5	Jun-15	($950,580)	$219,970		$93,038	$313,008	($637,571)	($3,271)	($640,842)	($156,504)	($794,076)
6	Jul-15	($640,842)	$226,137		$106,223	$332,359	($308,483)	($1,955)	($310,438)	($166,180)	($474,663)
7	Aug-15	($310,438)	$231,216		$112,827	$344,042	$33,604	($570)	$33,034	($172,021)	($138,417)
8	Sep-15	$33,034	($44,731)		($119,500)	($164,231)	($131,198)	($202)	($131,400)	$82,116	($49,082)
9	Oct-15	($131,400)	$69,964		($76,955)	($6,990)	($138,390)	($556)	($138,946)	$3,495	($134,895)
10	Nov-15	($138,946)	$81,984		($90,219)	($8,236)	($147,181)	($589)	($147,771)	$4,118	($143,063)
11	Dec-15	($147,771)	$98,155		($39,212)	$58,944	($88,827)	($487)	($89,314)	($29,472)	($118,299)
12	Jan-16	($89,314)	$83,700		($33,390)	$50,310	($39,004)	($264)	($39,268)	($25,155)	($64,159)
13	Feb-16	($39,268)	$65,362		($26,009)	$39,353	$85	($81)	$5	($19,677)	($19,591)

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period March 2015 through February 2016, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0001676). First, 50% of the net amount of AER costs (the new monthly AER costs minus the amount collected by the AER) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly Alternative Rider Filing – March through May 2016

Exhibit 6-23. Forecasted Quarterly Rate Summary, Schedule 1, March through May 2016

The Dayton Power and Light Company
Case No. 16-0035-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Mar-16 (C)	Apr-16 (D)	May-16 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$59,840	$40,225	$40,932	$140,997	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
3	Total Forecasted Expense				$142,012	Line 1 * Line 2
4	Forecasted Metered Level Sales	237,703,816	158,808,443	161,829,099	558,341,358	Schedule 2, Line 24
5	AER Rate before Adjustments $/kWh				$0.0002543	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0002510)	Schedule 2, Line 25
7	Forecasted AER Rate $/kWh				$0.0000033	Line 5 + Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense it expected to incur during the period March through May 2016. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for March through May 2016, which totaled $140,997 (column F). As shown on line 2 of Schedule 1, the Company included its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $140,997 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period March through May 2016 (see Schedule 2 discussion below) of 558.341 million kWh on line 4. The Company then divided the total forecasted expense by the forecasted meter level sales to calculate the AER rate before Reconciliation Adjustment of $0.0002543 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0002510) per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0002543 per kWh noted above to derive its forecasted AER rate of $0.0000033 per kWh as shown on line 7 of Schedule 1.

Exhibit 6-24. Summary of Actual Costs – Schedule 2, March 2015 through May 2016

The Dayton Power and Light Company
Case No. 16-0035-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Historical Yankee Costs (E)	Total Expenses (F)	Revenue (G)	(Over) / Under Recovery (H)	Carrying Costs (I)	Total (J)	YTD[1] (K)	Source (L)
1	Prior Period									$ (678,912)	Accounting Records
2	Mar-15	($573,735)	$1,086	$121,882	($450,767)	($102,527)	($553,295)	($3,936)	($557,231)	($1,236,142)	Accounting Records
3	Apr-15	$87,251	$361	$121,882	$209,494	($77,317)	$132,177	($4,820)	$127,357	($1,108,785)	Accounting Records
4	May-15	$88,325	$17,549	$121,882	$227,756	($65,318)	$162,438	($4,233)	$158,206	($950,580)	Accounting Records
5	Jun-15	$113,678	($15,590)	$121,882	$219,970	$93,038	$313,008	($3,271)	$309,737	($640,842)	Accounting Records
6	Jul-15	$105,445	($1,191)	$121,882	$226,137	$106,223	$332,359	($1,955)	$330,404	($310,438)	Accounting Records
7	Aug-15	$108,686	$648	$121,882	$231,216	$112,827	$344,042	($570)	$343,472	$33,034	Accounting Records
8	Sep-15	($45,432)	$701	$0	($44,731)	($119,500)	($164,231)	($202)	($164,433)	($131,400)	Accounting Records
9	Oct-15	$64,963	$841	$0	$65,803	($97,927)	($32,124)	($607)	($32,732)	($164,131)	Accounting Records
10	Nov-15	$61,000	$646	$0	$61,646	($91,825)	($30,178)	($738)	($30,917)	($195,048)	Accounting Records
11	Dec-15	$965	$2,169	$0	$3,134	($33,761)	($30,627)	($867)	($31,494)	($226,542)	Accounting Records
12	Jan-16	$83,068	$632	$0	$83,700	($33,390)	$50,310	($830)	$49,481	($177,061)	Corporate Forecast
13	Feb-16	$64,730	$632	$0	$65,362	($26,009)	$39,353	($648)	$38,705	($138,356)	Corporate Forecast
14	Mar-16	$59,243	$597	$0	$59,840	($59,840)	$0	($448)	($448)	($138,804)	Corporate Forecast
15	Apr-16	$39,628	$597	$0	$40,225	($40,225)	$0	($247)	($247)	($139,051)	Corporate Forecast
16	May-16	$40,335	$597	$0	$40,932	($40,932)	$0	($83)	($83)	($139,134)	Corporate Forecast
17	(Over)/Under Recovery									($139,134)	Line 16
18	(Over)/Under Recovery Through February 2016									($138,356)	Line 13
19	10% Quarterly Threshold									$14,100	(Sum of Column F, Lines 14 - 16) * 10%
20	Amount Exceeding Threshold									$0	
21	(Over) / Under Recovery									($139,134)	Line 17 - Line 20
22	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
23	Total (Over) / Under Recovery with Carrying Costs									($140,136)	Line 21 * Line 22
							Mar-16	Apr-16	May-16		
24	Standard Offer Sales Forecast (kWh)						237,703,816	158,808,443	161,829,099	558,341,358	Corporate Forecast
25	AER Reconciliation Rate $/kWh									($0.0002510)	Line 23 / Line 24

[1] YTD = current month Total + previous month YTD total

Schedule 2: Column C of Schedule 2 reflects DP&L's actual and forecasted REC expenses during the period of March 2015 through May 2016, which totaled $298,150. Column D of Schedule 2 reflects DP&L's actual and forecasted Compliance Administration expenses for the same period, which totaled $10,273. Column E reflects the Historical Yankee Costs for March 2015 through August 2015. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $1.040 million, as shown in column F. Column G reflects DP&L's actual and forecasted revenues for March 2015 through May 2016 for a total of ($476,484). The difference between the Company's actual and forecasted fuel costs and actual and forecasted revenues results in an under-recovery in the amount of $563,233, as shown in column H. Column I reflects the carrying costs for the period of March 2015 through May 2016, which total ($23,455). The under-recovery for the period of March 2015 through February 2016, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the March 2015 through May 2016 period, resulted in a YTD over-recovery of ($139,134) (column K, line 17). Line 18 reflects the over-recovery of ($138,356) for the period of March 2015 through February 2016. The amount on Line 19 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted expenses for the period March through May 2016 by 10% which totals $14,100. For this reporting period the Amount Exceeding Threshold was $0, as shown on line 20. This results in an over-recovery of ($139,134), which is derived by subtracting the amount exceeding the threshold from the over-recovery through May 2016, as shown on line 21. DP&L's over-recovery stated above is then multiplied by the gross revenue conversion factor of 1.0072, resulting in total over-recovery with carrying costs of ($140,136), as shown on line 23. Line 24 reflects the Standard Offer Sales Forecast for the period of March through May 2016, totaling 558.341 million kWh. The

Company derived its AER Reconciliation Rate of ($0.0002510) per kWh by dividing the total over-recovery with carrying costs of ($140,136) by its standard offer sales forecast for the period March through May 2016.

Exhibit 6-25. Projected Monthly Cost Calculation – Schedule 3, March through May 2016

The Dayton Power and Light Company
Case No. 16-0035-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Mar-16 (C)	Apr-16 (D)	May-16 (E)	Total (F)	Source (G)
1	REC Expense	$ 59,243	$ 39,628	$ 40,335	$ 139,207	Corporate Forecast
2	Compliance Administration	$597	$597	$597	$1,790	Corporate Forecast
3	Total AER Expense	$ 59,840	$ 40,225	$ 40,932	$140,997	Line 1 + Line 2
4	*Gross Revenue Conversion Factor*				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
5	Total Projected AER Costs				$142,012	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh)				558,341,358	Corporate Forecast
7	AER Base Rate $/kWh				$0.0002543	Line 5 / Line 6

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to *incur during the period March through May 2016. As shown on line 1 of Schedule 3, the* category included DP&L's forecasted REC expense for March through May 2016, which totaled $139,207 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,790. This results in total AER expense for March through May 2016 of $140,997, as shown on line 3. Line 4 reflects its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the total AER expense of $140,997 by the gross revenue conversion factor, as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of March through May 2016, totaling 558.341 million kWh on line 6. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0002543 per kWh as shown on line 7.

Exhibit 6-26. Calculation of Carrying Costs – Workpaper 1, March 2015 through May 2016

The Dayton Power and Light Company
Case No. 16-0035-EL-RDR
Alternative Energy Rider
Calculation of Carrying Costs

		MONTHLY ACTIVITY								Carrying Cost Calculation	
Line	Period	First of Month Balance	New AER Charges	Amount Exceeding Threshold	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
						(G) = (D) + (E) + (F)	(H) = (C) + (G)	(I) = (L) * (4.943% / 12)	(J) = (H) + (I)	(K) = - (G) * 0.5	(L) = (H) + (K)
1	Prior Period								$ (678,911.66)	$0	$0
2	Mar-15	($678,912)	($450,767)		($102,527)	($553,295)	($1,232,206)	($3,936)	($1,236,142)	$276,647	($955,559)
3	Apr-15	($1,236,142)	$209,494		($77,317)	$132,177	($1,103,966)	($4,820)	($1,108,785)	($66,088)	($1,170,054)
4	May-15	($1,108,785)	$227,756		($65,318)	$162,438	($946,347)	($4,233)	($950,580)	($81,219)	($1,027,566)
5	Jun-15	($950,580)	$219,970		$93,038	$313,008	($637,571)	($3,271)	($640,842)	($156,504)	($794,076)
6	Jul-15	($640,842)	$226,137		$106,223	$332,359	($308,483)	($1,955)	($310,438)	($166,180)	($474,663)
7	Aug-15	($310,438)	$231,216		$112,827	$344,042	$33,604	($570)	$33,034	($172,021)	($138,417)
8	Sep-15	$33,034	($44,731)		($119,500)	($164,231)	($131,198)	($202)	($131,400)	$82,116	($49,082)
9	Oct-15	($131,400)	$65,803		($97,927)	($32,124)	($163,524)	($607)	($164,131)	$16,062	($147,462)
10	Nov-15	($164,131)	$61,646		($91,825)	($30,178)	($194,310)	($738)	($195,048)	$15,089	($179,221)
11	Dec-15	($195,048)	$3,134		($33,761)	($30,627)	($225,675)	($867)	($226,542)	$15,314	($210,362)
12	Jan-16	($226,542)	$83,700		($33,390)	$50,310	($176,232)	($830)	($177,061)	($25,155)	($201,387)
13	Feb-16	($177,061)	$65,362		($26,009)	$39,353	($137,708)	($648)	($138,356)	($19,677)	($157,385)
14	Mar-16	($138,356)	$59,840		($779)	$59,061	($79,295)	($448)	($79,744)	($29,530)	($108,826)
15	Apr-16	($79,744)	$40,225		($520)	$39,705	($40,039)	($247)	($40,286)	($19,852)	($59,891)
16	May-16	($40,286)	$40,932		($530)	$40,402	$116	($83)	$33	($20,201)	($20,085)

Workpaper 1: Workpaper 1 presents the calculation of the carrying costs that are applied to the (over)/under recovery balances reflected on Schedule 2 (discussed above) for the period March 2015 through May 2016, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0002510). First, 50% of the net amount of AER costs (the new monthly AER costs minus the amount collected by the AER) is subtracted from the end of the month balance before carrying costs (beginning of the month balance plus the net amount of fuel rider costs) to derive the total monthly amounts that are applicable to carrying costs. The monthly carrying costs are calculated by multiplying the amounts under the Total Applicable to Carrying Cost column by 4.943%, which is the weighted cost of debt that became effective January 1, 2014, then dividing the result by 12. These amounts are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Review of DP&L's Alternative Energy Rider Results for the 2015 Review Period

Larkin reviewed DP&L's monthly AER workbooks that were provided in LA-2015-113 and which provide the support for the amounts in the quarterly AER filings for the 2015 review period. Because DP&L's AER costs are trued-up to actuals, Larkin's review focused on the workbook for December 2015, which reflects DP&L's weighted average cost of RECs for the year.

During the interviews conducted on June 29, 2016, DP&L stated that it posted a journal entry in March 2016, which related to the retirement of the RECs associated with meeting the 2015 compliance requirements for solar and non-solar RECs. Larkin requested the journal entry and related support in order to show how the amounts from the March 2016 journal entry reconcile with the 2015 retirements for 2015 and related costs. The Company provided the requested information in response to LA-2015-2-3. Using this information, Larkin tied the amounts from the March 2016 journal entry and related support to the Company's Annual Alternative Energy Portfolio Status Report for calendar year 2015, which DP&L filed on April 15, 2016 in PUCO Case No. 16-0752-EL-ACP as well as to the solar and non-solar REC expense data that was provided in response to LA-2015-113.

Actual AER Costs

On September 1, 2015, in Case No. 15-0045-EL-RDR, the Company filed Schedules, Workpapers, and Tariffs for its AER. Included with that filing was a Schedule 2 which reflected actual 2015 costs from January through June. In addition, on March 1, 2016, in Case No. 16-0035-EL-RDR, DP&L made a similar filing in which Schedule 2 reflected actual 2015 AER costs from March through December. In the March 1, 2016 quarterly filing, Larkin noted that the actual amounts reflected for the period July through November had been adjusted as compared to what was reflected in the September 1, 2015 filing. Larkin had requested that DP&L provide a complete set of supporting workpapers for all calculations in the Rider AER, including costs incurred and revenues recorded in the review period. The Company provided this information electronically in Excel in response to LA-2015-113. Included in this documentation was an Excel file titled "Actuals", which reflected a tab for each month of 2015. The monthly amounts in this file tied back to the actuals reflected in the March 1, 2016 quarterly AER filing. As part of the current review cycle, Larkin reviewed DP&L's actual costs for January through December 2015 from those filings, which are summarized in the following exhibit:

Exhibit 6-27. Summary of Actual Costs for January through December 2015

Line No.	Period	REC Expense	Compliance Administration Expense	Historical Yankee Costs	Total Expenses	Revenue	(Over)/Under Recovery	Carrying Costs	Total	Year to Date	Source
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1	Prior Period									$ (533,248)	Accounting Records
2	Jan-15	$142,422	$628	$ 121,882	$ 264,932	$ (346,820)	$ (81,888)	$ (2,365)	$ (84,253)	$ (617,501)	Accounting Records
3	Feb-15	$153,666	$707	$ 121,882	$ 276,255	$ (335,001)	$ (58,746)	$ (2,665)	$ (61,410)	$ (678,912)	Accounting Records
4	Mar-15	($573,735)	$1,086	$ 121,882	$ (450,767)	$ (102,527)	$ (553,295)	$ (3,936)	$ (557,231)	$(1,236,142)	Accounting Records
5	Apr-15	$87,251	$361	$ 121,882	$ 209,494	$ (77,317)	$ 132,177	$ (4,820)	$ 127,357	$(1,108,785)	Accounting Records
6	May-15	$88,325	$17,549	$ 121,882	$ 227,756	$ (65,318)	$ 162,438	$ (4,233)	$ 158,206	$ (950,580)	Accounting Records
7	Jun-15	$113,678	($15,590)	$ 121,882	$ 219,970	$ 93,038	$ 313,008	$ (3,271)	$ 309,737	$ (640,842)	Accounting Records
8	Jul-15	$105,445	($1,191)	$ 121,882	$ 226,137	$ 106,223	$ 332,359	$ (1,955)	$ 330,404	$ (310,438)	Accounting Records
9	Aug-15	$108,686	$648	$ 121,882	$ 231,216	$ 112,827	$ 344,042	$ (570)	$ 343,472	$ 33,034	Accounting Records
10	Sep-15	($45,432)	$701	$ -	$ (44,731)	$ (119,500)	$ (164,231)	$ (202)	$ (164,433)	$ (131,400)	Accounting Records
11	Oct-15	$64,963	$841	$ -	$ 65,803	$ (97,927)	$ (32,124)	$ (607)	$ (32,732)	$ (164,131)	Accounting Records
12	Nov-15	$61,000	$646	$ -	$ 61,646	$ (91,825)	$ (30,178)	$ (738)	$ (30,917)	$ (195,048)	Accounting Records
13	Dec-15	$965	$2,169	$ -	$ 3,134	$ (33,761)	$ (30,627)	$ (867)	$ (31,494)	$ (226,542)	Accounting Records
14	2015 Totals	$ 307,233	$ 8,553	$ 975,059	$1,290,845	$ (957,909)	$ 332,935	$(26,229)	$ 306,707	$(6,227,290)	

Notes and Source:
January through February 2015 amounts from the September 1, 2015 AER filing and March through December 2015 amounts from the March 1, 2016 AER filing
Year-to-Date amounts are based on the current month Total + previous month YTD Total

Historical Yankee Costs

As shown in the table above, the Company's costs included the monthly amount of $121,882 related to the recovery of the costs associated with the Yankee Street solar photovoltaic facility ("Yankee"). Specifically, as discussed in the confidential response to LA-2015-96, in its second ESP, DP&L had requested a nonbypassable charge, or an Alternative Energy Rider - Nonbypassable ("AER-N") in order to recover the costs of Yankee. Historically, the Company had assigned a cost of $0 to the Yankee solar renewable energy credits ("SRECs") based on the expectation that it would recover the Yankee costs through the AER-N. However, the Commission denied DP&L's request for the AER-N and instead directed the Company to "consult with Staff to determine an appropriate methodology to recover through the AER the cost of past renewable energy resources used to serve its SSO customers."

Subsequent to the Company's consultation with Staff per the Commission's directive, in its AER filing dated July 18, 2014, DP&L proposed a methodology by which it would recover the past Yankee costs that was based on a report prepared by Charles River Associates ("CRA").[49] Specifically, DP&L commissioned CRA to estimate the fair market value of SRECs in Ohio during the period 2010 through 2013.[50] The Yankee facility began service in 2010 with a capacity of 1.1 MW. In its evaluation of Ohio SRECs, in addition to relying exclusively on market prices, CRA also took into account (1) the PUCO's Alternative Energy Portfolio Standard Report; (2) trading by brokers; and (3) SREC programs offered by utilities and aggregators. Pursuant to this approach, CRA developed the fair market values for Ohio SRECs shown in the exhibit below:

Exhibit 6-28. Fair Market Value of Ohio In-State SRECs by Year

[redacted]

In its July 18, 2014 AER filing, using CRA's estimated fair market value estimations, DP&L identified historical costs for Yankee which totaled approximately $1.4 million, which it proposed to recover over a four quarters beginning on September 1, 2014 as summarized in the following exhibit:

Exhibit 6-29. Recovery of Yankee Costs Over Four Quarters

2010	2011	2012	2013	Total
1,322	1,336	1,532	1,343	
$400	$325	$260	$40	
$528,800	$434,200	$398,320	$53,720	$1,415,040

Pursuant to this approach, the Company had proposed that $365,647 be included in the rate going into effect on September 1, 2014. However, this amount was based on including Yankee's

[49] Charles River Associates is a global consulting firm which offers economic, financial and strategic expertise to major law firms, corporations, accounting firms and governments worldwide.
[50] The report by CRA was included in the response to LA-2015-96.

2014 costs of $47,548 in the calculation as well as shown on Schedule 4 from the Company's quarterly AER filings dated March 1, 2015 and June 1, 2015 and replicated in the exhibit below:

Exhibit 6-30. Calculation of Yankee Quarterly Recovery Amount

2010	2011	2012	2013	2014	Total
1,322	1,336	1,532	1,343	703	
$400	$325	$260	$40	$68	
$528,800	$434,200	$398,320	$53,720	$47,548	$1,462,588
					4
					$365,647

The Commission approved DP&L proposed recovery of the Yankee historical costs in its Order and Opinion dated August 27, 2014 in Case No. 14-806-EL-RDR. In addition, the generation currently produced at Yankee is valued at market prices and SRECs that were generated during and after July 2014 were added to the AER weighted average cost of inventory ("WACI") using the offer price date from ICAP market sheets in each respective month. In its confidential response to LA-2015-96, DP&L stated in part:

[redacted]

According to the response to LA-2015-90, the historical Yankee costs were fully recovered as of August 2015, thus Schedule 4 was removed from the subsequent quarterly AER filings. Upon reviewing the Company's quarterly AER filings that were filed subsequent to August 2015, Larkin verified that (1) Schedule 4 had been removed from the filings, and (2) Schedule 2, which includes a column titled "Historical Yankee Costs", reflected $0 from September 2015 and going forward.

Larkin also asked DP&L to provide the accounting support for the $8,553 compliance administrative expense for 2015 from DP&L's September 1, 2015 and March 1, 2016 filings. DP&L's compliance administrative expense is addressed in a subsequent subsection of this chapter.

Review of Carrying Charges

RFP No. U16-FAC/AER-1 provides at Attachment 4, Item 3 that the auditor conduct:

> A review to verify the accuracy of calculations related to any carrying charges included in the Company's quarterly AER calculations.

For the DP&L's 2015 AER costs, carrying charges were based on a cost of debt of 4.943%.[51]

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[51] The Opinion and Order in Case No. 12-426-EL-SSO updated the cost of debt from 5.86% to 4.943% beginning in January 2014.

The Company's September 1, 2015 filing in Case No. 15-0045-EL-RDR and its March 1, 2016 filing in Case No. 16-0035-EL-RDR included Workpaper 1, which shows the calculation of carrying costs by month for the 2015 review period, as follows:

Exhibit 6-31. Summary of Carrying Costs for January through December 2015

		MONTHLY ACTIVITY							Carrying Cost Calculation	
Line No.	Period	First of Month Balance	New AER Charges	Amount Collected (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost*	End of Month Balance	Less: One-half Monthly Amount	Total Applicable to Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E)	(G) = (C) + (F)	(H) = (K) * (COD % / 12)	(I) = (G) + (H)	(J) = - (F) * .5	(K) = (G) + (J)
1	Prior Period							$ (533,248)	$ -	$ -
2	Jan-15	$ (533,248)	$ 264,932	$ (346,820)	$ (81,888)	$ (615,136)	$ (2,365)	$ (617,501)	$ 40,944	$ (574,192)
3	Feb-15	$ (617,501)	$ 276,255	$ (335,001)	$ (58,746)	$ (676,247)	$ (2,665)	$ (678,912)	$ 29,373	$ (646,874)
4	Mar-15	$ (678,912)	$ (450,767)	$ (102,527)	$ (553,295)	$ (1,232,206)	$ (3,936)	$ (1,236,142)	$ 276,647	$ (955,559)
5	Apr-15	$ (1,236,142)	$ 209,494	$ (77,317)	$ 132,177	$ (1,103,966)	$ (4,820)	$ (1,108,785)	$ (66,088)	$ (1,170,054)
6	May-15	$ (1,108,785)	$ 227,756	$ (65,318)	$ 162,438	$ (946,347)	$ (4,233)	$ (950,580)	$ (81,219)	$ (1,027,566)
7	Jun-15	$ (950,580)	$ 219,970	$ 93,038	$ 313,008	$ (637,571)	$ (3,271)	$ (640,842)	$ (156,504)	$ (794,076)
8	Jul-15	$ (640,842)	$ 226,137	$ 106,223	$ 332,359	$ (308,483)	$ (1,955)	$ (310,438)	$ (166,180)	$ (474,663)
9	Aug-15	$ (310,438)	$ 231,216	$ 112,827	$ 344,042	$ 33,604	$ (570)	$ 33,034	$ (172,021)	$ (138,417)
10	Sep-15	$ 33,034	$ (44,731)	$ (119,500)	$ (164,231)	$ (131,198)	$ (202)	$ (131,400)	$ 82,116	$ (49,082)
11	Oct-15	$ (131,400)	$ 65,803	$ (97,927)	$ (32,124)	$ (163,524)	$ (607)	$ (164,131)	$ 16,062	$ (147,462)
12	Nov-15	$ (164,131)	$ 61,646	$ (91,825)	$ (30,178)	$ (194,310)	$ (738)	$ (195,048)	$ 15,089	$ (179,221)
13	Dec-15	$ (195,048)	$ 3,134	$ (33,761)	$ (30,627)	$ (225,675)	$ (867)	$ (226,542)	$ 15,314	$ (210,362)
14	2015 Totals	$ (6,533,995)	$ 1,290,845	$ (957,909)	$ 332,935	$ (6,201,060)	$ (26,229)	$ (6,227,289)	$ (166,468)	$ (6,367,528)

Notes and Source:
Workpaper 1 from DP&L's September 1, 2016 AER Filing in Case No. 15-0045-EL-RDR and March 1, 2016 AER Filing in Case No. 16-0035-EL-RDR
*The Opinion and Order in Case No. 12-426-EL-SSO updated the cost of debt (COD) from 5.86% to 4.943% starting in January 2014.

Larkin recalculated the AER carrying costs for each month of 2015 using the 4.943% rate that applied in 2015. No exceptions were noted.

Status Relative to the 3% Provision in Section, 4928.64(C)(3), Revised Code/ Compliance with 2015 Renewable Energy Requirements

RFP No. U16-FAC/AER-1 provided standards for reviewing the Company's AER which included Attachment 4, Item 4, which states:

> A review of the Company's status relative to the 3% provision contained within Section, 4928.64(C)(3), Revised Code, and as further detailed in the Rule 4901:1-40-07, Ohio Administrative Code.

In accordance with Section 4928.64(C)(1) of the revised Ohio Code, the Commission annually reviews electric distribution utilities and/or electric services companies compliance with the benchmarks reflected in the Renewable and Solar Benchmarks exhibit above. As part of that review, the Commission identifies under-compliance or non-compliance that it determines is related to weather, equipment, resource shortages for advanced energy, or renewable energy sources, and which is outside a utility's or electric service company's control. Section 4928.64(C)(3) of the revised code states that:

> An electric distribution utility or an electric services company need not comply with a benchmark division (B)(1) or (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three percent or more. The cost of compliance shall be calculated as though any exemption from

taxes and assessments had not been granted under section 5727.75 of the Revised Code.

On page 34 of its Opinion and Order dated August 7, 2013 in Case No. 11-5201-EL-RDR, the Commission adopted the following methodology for calculating the 3% cost cap:

> (1) Determine the sales baseline in MWhs for the applicable compliance year consisting of an average of each electric distribution utility's annual Ohio retail electric sales from the preceding three years; (2) calculate a "reasonably expected" dollar per MWh figure for the compliance year, consisting of a weighted average of the cost of SSO supply for the delivery during the compliance year, net of distribution system losses; (3) calculate the total cost by multiplying the Step 2 dollar per MWh figure by the baseline calculated in Step 1; and (4) multiply the total cost from Step 3 by three percent with the result representing the maximum funds available to be applied toward compliance resources for that compliance year.

Larkin requested that DP&L provide needed to perform the 2% cost cap calculation and in response to our inquiry, the Company stated:

> The Ohio Revised Code and the Ohio Administrative Code does not dictate that an electric utility has to perform the 3% cost cap calculation, only that an electric utility "may file an application" and "need not comply". However, to show that DP&L has not exceeded the 3% cost cap per the calculations in the Opinion and Order in PUCO Case No. 11-5201-EL-RDR, the following calculation is being provided:

Exhibit 6-32. DP&L's 2015 3% Cost Cap Calculation

[redacted]

For the first step of the Commission's adopted methodology for calculating the 3% cost cap, the Company used the baseline for compliance obligations that it reported in its 2015 annual compliance filing. While the Commission's Opinion and Order in Case No. 11-5201-EL-RDR specified that this amount was to be based on an average of DP&L's annual Ohio retail sales from the preceding three years, the Company's baseline amount is based on the total sales in the applicable compliance year (i.e., 2015).[52]

As shown in the exhibit above, for 2015, the 3% cost cap was [redacted] As shown on line 7 of the exhibit, the total REC cost for the 2015 compliance year of [redacted] is well below the cost cap calculated on line 6. It should be noted that Exhibit 6-27 above reflects total 2015 REC expense in the amount of $307,233, or a difference of $672,398. The response to LA-2015-113, which provided the support for the amounts in the quarterly AER filings for the 2015 review period, included a workpaper which summarized REC expense for each month of 2015. The total of these REC expenses total the $979,631 noted in the exhibit above.[53] This workpaper also reflects a correction that was booked in March 2015 that relates to a downward revision of the Company's 2014 REC compliance quantities. Specifically, this correction was a credit amount [redacted] which related to 2014 solar compliance quantities and $[redacted] related to non-solar quantities. The sum of these two corrections totaled the [redacted] difference noted above.

DP&L provided its confidential REC Details Sheets which relate to the Company's compliance obligations for 2015 in the response to LA-2015-110 as well as its related Annual Alternative Energy Portfolio Status Report that was filed with the PUCO on April 15, 2016 in Case No. 16-0752-EL-ACP. The Company's 2015 compliance report stated that DP&L achieved compliance by meeting the 2015 benchmark for the Ohio Renewable Portfolio Standard for both solar and non-solar renewables.

Ohio Revised Code Section 4928.643 specifies that a distribution utility's Renewable Energy Benchmarks must be based on sales made to standard offer retail customers in either (1) the last three years, or (2) the utility may choose for its baseline to be the kilowatt hours sold in the applicable compliance year. For DP&L, the Company's Renewable Energy requirement was calculated by applying the renewable energy standard multiplied by DP&L's 2015 retail sales sold under its standard service offer.

To comply with this requirement, companies must surrender renewable energy credits (RECs) from qualified resources (Note: 1 REC = 1 MWh) equal to the renewable obligation. Given that RECs have a five-year lifetime following their acquisition, surplus unused credits can be carried over and consumed in a following year.

The Company's 2015 renewable requirement and compliance is summarized in the following table:[54]

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[52] DP&L's 2015 annual compliance filing cites Ohio Revised Code §4928.643 as it basis for using standard offer sales experienced in the compliance year in determining its baseline compliance obligation.
[53] This amount includes the Yankee RECs at market cost.
[54] From page 2 of DP&L's 2015 Alternative Energy Portfolio Status Report filed on April 15, 2016 in Case No. 16-0752-EL-ACP.

Exhibit 6-33. 2015 Renewables Compliance Summary

Line	(A) Description	(B) MWh Sales	(C) Source
1	Baseline (2015 Sales)	3,928,597	Internal Records
2	2015 Statutory Compliance Obligation		
3	Renewable Energy Resource Benchmark	2.50%	ORC 4928.64(B)(2)
4	Solar Energy Resource Benchmark	0.12%	ORC 4928.64(B)(2)
5	2015 Compliance Obligation		
6	Non-Solar RECs Needed for Compliance	93,501	(Line 3 * Line 1) - Line 7
7	Solar RECs Needed for Compliance	4,714	Line 4 * Line 1
8	RECs Acquired for Compliance Year 2015		
9	Acquired Non-Solar RECs	93,501	Internal Records
10	Acquired Solar RECs	4,714	Internal Records

As shown in the above Exhibit, DP&L met each of the 2015 alternative energy compliance obligations. DP&L's confidential response to LA-2015-110 shows the facility, location, dates, and certificate numbers for the 93,501 Non-Solar RECs and 4,714 Solar RECs used to meet its 2015 renewables requirements. Consistent with DP&L's initial renewable compliance plan approved by Commission order dated June 24, 2009 in the context of DP&L's Electric Security Plan ("ESP") (Case No. 08-1094-EL-SSO), DP&L satisfied its 2015 renewable energy requirements largely through the purchase of RECs. Specifically, DP&L worked with brokers who are active daily in trying to find willing buyers and sellers of renewable energy and/or associated RECs. DP&L also made direct purchases from renewable generation owners of RECs.

In accordance with Ohio Administrative Code Section 4901:1-40-03(C), the Company also submitted its Ten Year Renewable Energy Benchmark Compliance Plan ("10-Year Plan) in conjunction with its Annual Alternative Energy Portfolio Status Report.[55] As stated in the 10-Year Plan, for purposes of developing benchmarks over the next 10 years, DP&L developed a forecast of standard offer sales based on the Company's recorded standard offer sales through December 31, 2015. DP&L's renewable energy and solar benchmarks for the next ten years are summarized in the exhibit below:

[55] DP&L's Annual Alternative Energy Portfolio Status Report and Ten Year Renewable Energy Benchmark Compliance Plan were filed simultaneously on April 15, 2016 in Case No. 16-0752-EL-ACP.

Exhibit 6-34. DP&L's Forecasted 10-Year Retail Sales and Renewables Requirements

	DP&L's Annual Baseline ORC §4928.64 Requirement*	ORC §4928.64 Compliance Requirement %		Renewable Requirement	Solar Requirement
Year	MWh	Renewable Energy Resource	Solar Energy Resource	Total MWh	Total MWh
2015	3,928,597	2.50%	0.12%	93,501	4,714
2016	3,928,597	2.50%	0.12%	93,501	4,714
2017	3,928,597	3.50%	0.15%	131,608	5,893
2018	3,928,597	4.50%	0.18%	169,715	7,071
2019	3,928,597	5.50%	0.22%	207,430	8,643
2020	3,928,597	6.50%	0.26%	245,144	10,214
2021	3,928,597	7.50%	0.30%	282,859	11,786
2022	3,928,597	8.50%	0.34%	320,574	13,357
2023	3,928,597	9.50%	0.38%	358,288	14,929
2024	3,928,597	10.50%	0.42%	396,003	16,500

* Baseline ORC §4928.64 Requirements are based on average MWh standard offer sales from either the preceding three calendar years or the applicable compliance year. Requirements beyond 2015 are forecasted assuming annual sales in year 2016 and later are recorded at 2015 levels, and are subject to change.

REC Inventories

Pursuant to Ohio Revised Code §4928.65, RECs that were purchased by the Company are usable within a five-year period. Any RECs held by DP&L at December 31, 2015 that are in excess of its 2015 Benchmarks will be applied to future year benchmarks.

Larkin had requested that DP&L explain its monthly position with respect to non-solar RECs for each month of 2015, starting with the REC balance as of January 1, 2015, and to indicate whether it was in a short position (i.e., held insufficient RECs to fully meet anticipated RPS compliance requirements). In response to LA-2015-105, the Company stated in part:

[redacted]

The referenced response also included the Company's current position report which has been replicated in the exhibit below:

Exhibit 6-35. DP&L's Current Position Report

[redacted]

As shown in the exhibit, after accounting for the solar and non-solar retirements to meet compliance requirements, the Company was in a long position (i.e., held sufficient RECs to fully meet anticipated RPS compliance requirements) at the end of 2015 with [redacted] non-solar RECs and [redacted] solar RECs.

In terms of the accounting guidance used by DP&L for how items are entered into or extracted from REC inventory, the response to LA-2015-96 stated:

> The FASB Codification guidance for inventory, "330-10-30 *Inventory - Initial Measurement*" stipulates, "The primary basis of accounting for inventories is cost, which has been defined generally as the price paid or consideration given to acquire an asset. As applied to inventories, cost means in principle the sum of the applicable expenditures and charges directly or indirectly incurred in bringing an article to its existing condition and location." The guidance goes on to stipulate that cost of inventory used may be determined under any one of several assumptions as to the flow of cost factors, such as first-in first-out (FIFO), average, and last-in first-out (LIFO). The major objective in selecting a method should be to choose the one which, under the circumstances, most clearly reflects periodic income. DP&L has chosen to expense inventory using the weighted average cost method, which we believe most clearly reflects periodic income.
>
> Additionally, the Code of Federal Regulations General Instruction 21, which applies to all United Stated regulated utilities, requires that emission allowances be issued from inventory using a monthly weighted-average method of costing. This guidance does not require DP&L to use weighted-average costing for RECs,

but since RECs have similar characteristics of emission allowances, it is additional support for that method being appropriate.

According to the response to LA-2015-94, DP&L maintained two sets of REC inventories during 2015. One set (solar and non-solar) for DP&L and the other set (solar and non-solar) for DPLER[56], with a weighted average cost that is updated monthly. As discussed previously, with the passage of SB 310, the Company's requirement to purchase at least 50% of it renewable energy resources through facilities located in the State of Ohio was eliminated. As a result, inventories are now maintained by DP&L for the following two types of RECs:

(1) Non-Solar RECs,

(2) Solar RECs,

Larkin reviewed DP&L's Renewable Energy Credit Weighted Average Cost of Inventory ("REC WACI") worksheet, which was provided in the response to LA-2015-97. This document was discussed with DP&L representatives during Larkin's on-site interviews that were conducted on June 29, 2016. Among the issues discussed was that the REC WACI worksheet reflected the non-solar and solar RECs that were retired in 2016 for 2015 compliance purposes as well as the separation of the solar RECs purchased by DP&L and those purchased by DPLER (see additional discussion below).

As discussed above, DP&L's compliance requirements in 2015 for solar and non-solar RECs totaled 4,714 and 93,501, respectively. For the solar RECs, the Company retired these RECs using a WACI amount of [redacted], which does not include the Yankee RECs at market cost (see additional discussion below). For the non-solar RECs, the Company retired these RECs using a WACI amount of [redacted]. Larkin tested DP&L's weighted average REC calculations, which are summarized in the exhibit below:

Exhibit 6-36. Summary of Cost of Solar and Non-Solar RECs Needed for Compliance in 2015

[redacted]

[56] The response to LA-2015-94 stated that the Company currently only maintains DP&L REC inventory as a result of the sale of DPLER at the end of 2015.

As shown in the exhibit, the cost of the solar and non-solar RECs retired to meet DPL's compliance requirement totaled [redacted] and [redacted], respectively. These amounts tie to the March 1, 2016 journal entry previously discussed in which DP&L recorded the retirements associated with 2015 compliance requirements. As noted above, the solar WACI of [redacted] does not include the Yankee RECs at cost. In its response to LA-2015-2-3, which requested the journal entry and related support for the 2015 retirements, the Company stated the following with regard to the Yankee RECs:

> Please be aware that the dollar amounts on page 2 and 3 of the journal entry attached herewith differs from the full requirement compliance cost because the journal entry only considers the Solar REC cost without the 2015 Yankee RECs cost of [redacted]. The cost of Yankee RECs projected to be used for compliance is expensed each month as recorded. It is not reflected in the cost of inventories held for general ledger assets, nor is it reflected in the compliance liability which offsets the inventory assets until the certificate retirements take place the following year.

Each REC used by DP&L for 2015 compliance can be tied to a PJM-GATS certificate number.

For purposes of tying REC inventory quantities to PJM-GATS REC quantity reports, DP&L and DPLER REC quantities are combined. However, DP&L's REC inventory details are sufficient to separately identify the DP&L and DPLER RECs. Specifically, the DP&L and DPLER solar REC costs are appropriately separated on the REC WACI worksheet that was provided in LA-2015-97[57] and there is no evidence of subsidization between the two companies nor did Larkin observe any advantage with the RECs that were purchased by DPLER.

For accounting purposes, the costs of DP&L's and DPLER's solar RECs are recorded separately. DP&L records the REC activity for each month in its general ledger. As noted above, the details are input into the REC inventory spreadsheets to update the weighted average cost.

2015 Renewables Compliance Administrative Expense

For 2015, DP&L reported renewables compliance administrative costs which totaled $8,553. In response to a follow up inquiry, DP&L provided the following breakout of compliance administrative cost:

[57] DP&L made only two non-solar REC purchases during 2015, neither of which were allocated to DPLER

Exhibit 6-37. 2015 Renewables Compliance Administrative Expense

[redacted]

Memorandum Of Findings And Recommendations

Our findings and recommendations are summarized in Chapter 1.