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REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDIT OF THE FUEL AND PURCHASED POWER RIDER OF THE DAYTON POWER AND LIGHT COMPANY

Case No.15-042-EL-FAC

October 2, 2015

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TABLE OF CONTENTS

LIST OF EXHIBITS

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 an 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 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 DPLER 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.

The PUCO solicited proposals for the performance of the FAC Rider and AER audits of the years 2013 and 2014. 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, and 2012.

A Stipulation and Recommendation (2011 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, 2011 through December 31, 2011 on December 5, 2012. The Stipulation was approved by the PUCO by entry on January 23, 2013.

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 2010.)

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, 2014 through December 31, 2014. 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. EVA and Larkin visited the Stuart power plant on June 25, 2015. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-1 on June 24, 2015. DP&L regulatory staff and PUCO Staff also attended interviews.

Exhibit 1-1. Interviews Conducted

Department	Participants
Accounting for Fuel and CCD Partners	[redacted]
Generation	
Treasury - Counter-Party Risk	
Commercial Operations/Coal Procurement	
Internal Audit/Physical Coal Inventory	
Regulatory Operations/Fuel Rider, AER	
Accounting	
Commercial Structuring - Forecasting	
Risk Management	
Commercial Structuring/Forecasting	
Stuart Plant Visit	

Major Management Audit Findings

1. In 2014, DP&L purchased 6.9 million tons of coal at an average delivered price of $50.91 or $2.193 per MMBtu which is about the same volume and price experienced in 2013.
2. In 2014, DP&L generation decreased by 13 percent overall with DP&L plant-operated generation by 11 percent. The large decrease was due to large reductions in generation across much of the coal fleet. The only two coal plants which experienced an increase in 2014 were Conesville #4 and Killen. Coal accounts for over 99 percent of DP&L generation. About 48 percent of its coal-fired generation comes from DP&L-operated plants.

3. The performance of the Stuart power plant in 2014 was very poor. [redacted]

4. The poor performance increased jurisdictional power prices as Stuart is typically a low cost generator. DP&L's 2014 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 price of coal to the Killen and Stuart Stations in 2014 are competitive with the average delivered cost to 11 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. There were no changes to the DP&L fuel procurement organization in 2014.

7. DP&L conducted two formal RFP's in 2014 generally consistent with its revised guidelines. DP&L considered all coals whether they were consistent with the boxed specifications and evaluated option values. From the February 2014 RFP, DP&L made two Q2 purchases from [redacted] for a total of [redacted] tons. From the October 2014 RFP, DP&L purchased [redacted] tons from [redacted] for delivery in [redacted] and [redacted] *tons from* [redacted].

8. DP&L also conducted a spot RFP in September 2014. DP&L generally followed the format of the formal RFP. DP&L made three purchases all for the fourth quarter of 2014. DP&L purchased [redacted] tons from [redacted], [redacted] tons through [redacted], and [redacted] tons from [redacted]. When the coal was purchased through [redacted], the origin is unknown until terms are reached. The [redacted] purchased turned out to be of [redacted] coal. While [redacted] and [redacted] were the lowest cost options, there were several supply options after [redacted] that were lower in cost than [redacted]. Subsequent to this issue being raised, DP&L indicated that the coal from [redacted] was purchased to replenish the low sulfur coal pile at Killen. The justification package for the [redacted] coal purchase, however, did not mention this fact.

9. The justification packages were not changed in 2014. They continue to be inadequate for auditing purposes.

10. No changes were made in the credit policy in 2014 with respect to coal supplier concentration.

11. The purchases made in 2014 show that DP&L has concentrated over [redacted]. The concentration going forward will be worse with [redacted] having acquired [redacted] and [redacted] having acquired [redacted].

12. The inventory levels at both Killen and Stuart ranged between [redacted] days of maximum burn throughout the audit period. After the very low inventories at the start of the year were restored, DP&L did a good job maintaining inventories between [redacted].

13. DP&L needed to transfer coal purchased for Stuart to Killen due in part to [redacted], which required inter-company transfers due to the different ownership shares.
14. Physical inventories were conducted in 2014 at Killen and Stuart. The difference between book inventory and physical inventory at Killen were within the tolerances. The difference between book inventory and physical inventory at Stuart were not. Despite a policy stating that an analysis should be performed if the tolerances were exceeded, only a very modest review was conducted which neither had definitive conclusions nor an action plan.
15. In 2013, DP&L finalized four agreements with [redacted], LLC ([redacted]) related to the production of Refined Coal at the Stuart Station. DP&L indicated that virtually all of the coal consumed at Stuart in 2014 was Refined Coal. DP&L did not flow any of the revenues associated with the Refined Coal through the FUEL Rider.
16. DP&L sold the Hutchings stockpile.
17. DP&L exercised a provision under its [redacted] contract with [redacted].
18. During the Audit Period, DP&L entered into several agreements related [redacted]. DP&L indicated it did not pass any [redacted] costs through the FUEL Rider in 2014 and has no intention of passing such costs through in 2015.
19. AES indicated it intended to transfer the generating stations to an affiliate by January 1, 2017 [redacted].
20. DP&L purchased [redacted] RECs in 2014 of which [redacted] were solar. The prices paid for the REC's were below 2013 levels and were favorable to the market.

Management Audit Recommendations

1. The jurisdictional share of the entire proceeds DP&L received in 2014 related to the consumption of Refined Coal at Stuart should flow through the FUEL Rider.
2. DP&L should perform a more rigorous analysis of the net incremental costs and benefits of increasing the use of higher quality coals at Stuart.
3. Should DP&L attempt to pass through any [redacted], a full review should be conducted and include consideration of prudence issues regarding [redacted].
4. DP&L should revise its credit policy with regard to coal procurement to restore limits with respect to the share of supply by producer.
5. DP&L should conduct a proper root-cause analysis of the physical inventory variances at Stuart.

6. DP&L should develop a strategy to address the financial weakness of its counter-parties in coal supply agreements.
7. For all procurements in 2015, DP&L should prepare comprehensive recommendations which incorporate compliance with the credit policy.
8. DP&L should recalculate the jurisdictional portion of the [redacted] payment received in 2015 based upon the dates when the money was due, not received.

Financial Audit Findings

1. DP&L's Fuel Rider deferral (i.e., the 2014 undercollection) has been impacted by customer supplier switching that has occurred. Larkin reviewed a schedule provided in response to LA-2014-1-82 that reflected statistical data for the 2014 review period. This schedule indicated that over the course of 2014 that (1) DP&L lost [redacted] customers across its various billing categories (residential, secondary, etc.), (2) [redacted] customers and other suppliers customer bases increased by [redacted] customers.
2. In preparing its Fuel Rider sales forecasts for its quarterly Fuel Rider filings affecting 2014, DP&L reflected the impact of known customer supplier switching.
3. 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
4. DP&L now 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.
5. 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.
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. On December 30, 2014, Dayton Power & Light ("DP&L") sold its 31% ownership interest (186 MW) in East Bend Unit 2 to Duke Energy, Kentucky, Inc. The journal entry from December 2014 reflects the elimination of the East Bend coal inventory balance of [redacted] tons at a value of [redacted]. A second journal entry from February

2015 reflects the elimination of an additional [redacted] tons valued at [redacted]. There were no costs or other effects on the Fuel Rider resulting from the sale of East Bend.

8. DP&L's deferral amounts by account totaled [redacted] as of December 31, 2014.

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

10. Based on the results of physical inventories, DP&L made adjustments to its coal inventory balances at the Stuart and Killen Stations during 2014.

11. The adjustment related to Stuart increased coal inventory (and reduced Fuel expense) by [redacted] which reflects DP&L ownership share and the adjustment to Killen increased coal inventory (and reduced Fuel expense) by [redacted], which reflected DP&L's ownership share.

12. The coal inventory adjustments at Stuart ([redacted]) and Killen ([redacted]) were the subject of a physical inventory audit overseen by AES's Internal Audit Group. The IA group utilizes color coding in determining whether controls DP&L has in place are sufficient at mitigating risk. The IA group designated the yellow color code to the internal audits of the physical inventories of Stuart and Killen, which means that controls to mitigate risk are operating effectively but some weaknesses exist.

13. DP&L performed an additional review related to the substantial coal inventory adjustment at Stuart pursuant to Section 5.6.1 of its accounting policy for fuel inventories. As a result, DP&L does not plan to conduct a root cause analysis of the physical inventory variance at Stuart.

14. DP&L transferred [redacted] tons and [redacted] tons of coal from Stuart to Killen in September 2014 which resulted in a combined [redacted] for Stuart. These transactions were posted to the general ledger in September 2014. Due to the stacking of costs in September 2014, approximately [redacted]% of this [redacted] was allocated to wholesale sales and not flowed through the Fuel Rider.

15. DP&L transferred [redacted] tons and [redacted] tons of coal from Stuart to Killen in December 2014 which resulted in a combined [redacted] for Stuart. These transactions were posted to the general ledger in December 2014. Due to the stacking of costs in December 2014, approximately [redacted]% of this [redacted] was allocated to wholesale sales and not flowed through the Fuel Rider.

16. Pursuant to the previous two findings, the Company allocated approximately [redacted]% of the September Stuart [redacted], and approximately [redacted]% of the December Stuart [redacted] to wholesale coal sales. DP&L stated that the majority of the Stuart gains were allocated to wholesale coal sales due to the stacking of costs for those months. Larkin reviewed the monthly Excel workbooks for September and December 2014 and noted that the fuel purchases related to Stuart in those months were allocated to wholesale sales by [redacted]% and [redacted]%, respectively. While these percentages are slightly different than the allocation percentages of the related coal gains, Larkin considered the differences immaterial.

17. 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.

18. DP&L is appropriately accounting for the cost of demurrage as part of the transportation cost of delivering coal to the generating plants. For 2014, DP&L had demurrage costs of [redacted], which was substantially higher than in 2013, but generally in line with 2012.

19. As described in the response to LA-2014-1-43, DP&L has taken various actions in 2014 throughout the year in efforts to mitigate demurrage costs.

20. In conforming with 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 2014.

21. Larkin reviewed DP&L's audit trail for Fuel Rider includable costs, focusing on the test month of July 2014 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 2014 and for its Reconciliation Adjustments.

22. The Company modified its monthly Excel workbooks for the 2014 review period. Specifically, prior to the 2014 review period, DP&L retail and DPLER related costs were combined on Tab .7 then flowed through to Tab .6, which was titled "DP&L Allocation". This tab had started with the total combined retail and DPLER costs included in the FERC accounts referenced above. Then there was an allocation between DPLER and DP&L retail based on the ratio of DP&L's and DPLER's monthly MWh to the total billed monthly MWh. However, beginning with the 2014 review period, the Risk Management Group provided Accounting with the Standard Service Offer ("SSO") retail MWh exclusively, thus negating the need to allocate the retail costs between DP&L and DPLER.

23. As a result of the modification to the monthly Excel workbooks described in the previous finding, Tab .6 of the monthly Excel workbooks now reflect the calculation of the carrying costs for the over or under recovery of the Fuel deferral.

24. Pursuant to Section J of the Optimization Provisions from the Stipulation and Recommendation dated December 5, 2012, in which 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 2014 Optimizations included in DP&L's Fuel Rider for any months of 2014.

25. DP&L made three adjustments to the Fuel Rider during the months of June, September, and December 2014 in the amounts of $4,655,545, $6,737,745, and $1,627,579, respectively. These adjustments related to reclassifying 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. The Commission approved these specific adjustments in its Finding and Orders dated May 28, 2014, August 20, 2014, and November 20, 2014.

26. DP&L made one additional adjustment to the Fuel Rider in August 2014 in the amount of $63,639, which related to the disallowance of Optimizations J and K pursuant to EVA's recommendation in the 2012 Fuel audit and addressed in the PUCO's Order and Opinion dated August 20, 2014 in Case No. 12-2881-EL-FAC.

27. Hutchings Unit 4 was retired on June 1, 2013 and DP&L has no remaining capacity obligation with PJM. In addition, per an agreement between DP&L and the U.S. Environmental Protection Agency ("EPA"), the remaining coal-fired Hutchings units cannot be operated on coal after October 31, 2013. The last coal delivery at Hutchings via rail occurred in 2011.

28. DP&L stated that Hutchings Units 3, 5, or 6 were deactivated on June 1, 2015, but that Hutchings Unit 7 (a natural gas peaking plant) is still in operation.

29. The remaining Hutchings coal inventory of 15,337 tons with a revalued cost of [redacted] was disposed of in November 2014. None of the associated costs were flowed through the Fuel Rider.

30. DP&L uses a year-to-date "calendar" analysis of residential, DPLER and wholesale sales to calculate the allocation factor related to emission allowance sales on a year-to-date basis each month. An allocation schedule is provided by the Accounting Department to calculate the allocation factors in order to determine the jurisdictional share of emission allowance sales.

31. Larkin reviewed a sampling of customer billing information to test whether DP&L had accurately applied the Fuel Rider rates. No exceptions were noted.

32. LA-2014-1-46 asked the Company to provide the following information: "For purchases of power recorded in July 2014 that are included in the Fuel Rider, please provide the related invoices, and paid cash voucher or cash payment receipt." The Company provided (1) copies of purchase power invoices for July 2014, (2) "Available Power Statements" from Ohio Valley Electric Corporation ("OVEC Statements"), (3) PJM Settlement statements, and (4) a spreadsheet titled "Fuel Clause Purchase Sale Summary – July 2014 – PJM Summary", which DP&L referred to as the "PJM Reconciliation". Larkin was able to trace the amounts from the purchased power invoices and OVEC Statements to documentation titled "Fuel Recovery 2010 - Current Period: Jul 2014" (provided in response to LA-2014-1-71, LA-201-1-72 and LA-2014-1-75) as well as pages from the Company's general ledger which were provided in the response to Data Request LA-2014-1-70. 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 2014 power purchases from PJM to the amounts included in the Fuel Rider. Other than some immaterial variances, no exceptions were noted.

33. During the interviews conducted on June 24, 2015, the Company stated that beginning with 2014 review period, the Risk Management Group provided Accounting with the Standard Service Offer ("SSO") retail MWh exclusively, thus negating the need to allocate the retail costs between DP&L and DPLER. As a result of this modification, Tab

.6 of the monthly Excel workbooks now reflects the calculation of the carrying costs for the over or under recovery of the Fuel deferral.

34. On February 18, 2013, DP&L entered into four separate contract agreements with [redacted], including a (1) [redacted]; (2) [redacted]; (3) [redacted]; and (4) [redacted].

35. Pursuant to a Notice of Suspension dated May 31, 2013, [redacted] suspended refined coal production and coal feedstock purchases at Stuart Station in connection with the [redacted] and [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 [redacted].

36. In a Letter Agreement from [redacted] to DP&L dated August 27, 2013, [redacted] stated that it was in negotiations with two affiliates of the [redacted], which discussed [redacted] making an investment in the refined coal project which would allow production of refined coal to resume at Stuart.

37. Pursuant to the investment by [redacted], [redacted] transferred ownership of its plant to a new wholly-owned subsidiary called [redacted] ("[redacted]").

38. DP&L provided documentation related to the sale of coal to [redacted], as well as the 2014 accruals and accounting analysis reflecting all postings to FERC Account 456099.

39. DP&L stated that the coal sales to [redacted] were not included in the Fuel Rider during 2014.

40. DP&L provided a schedule with LA-2014-1-17, which provided, by month, a breakout of the [redacted] coal sales revenue and monthly lease revenue during 2014. The DP&L net revenue for the coal sales, after apportioning Duke's and AEP's share, totaled [redacted]. DP&L net revenue for the real estate lease, after apportioning Duke's and AEP's share, totaled [redacted].

41. Larkin reviewed DP&L's quarterly AER filings, which covered the forecasted periods encompassing calendar 2014. 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 2014.

42. Starting in September 2014, 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. 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.

43. 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. Pursuant to this approach, the Company proposed that $365,647 be included in the rate going into effect on September 1, 2014.

44. For 2014, DP&L reported total REC expense of $2,145,077 and compliance administrative expense in the credit amount of ($52,794) as reported on Schedule 2 in (1) DP&L's October 17, 2014 filing in Case No. 14-806-EL-RDR, which reflected actual costs from January through September 2014; and (2) DP&L's January 15, 2015 filing in Case No. 15-0045-EL-RDR, which reflected actual costs from October through December 2014. Compared with 2014 AER revenue of $5,256,430, DP&L had an over recovery of $2,676,617.

45. In May 2014, the Ohio General Assembly passed 2014 Sub. S.B. No. 310 ("SB 310"), which became effective on September 12, 2014. Pursuant to SB 310's passage, several provisions of the Ohio Revised Code were amended. Among these amendments is elimination of 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 and the remainder with resources deliverable into Ohio.

46. For 2014, DP&L calculated AER carrying costs totaling a credit amount of $8,278, 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 2014 were without exception.

47. DP&L provided its confidential Annual Compliance Plan Status Reports for 2014 as well as its related Annual Alternative Energy Portfolio Status Report that was filed with the PUCO on April 15, 2015 in Case No. 15-0171-EL-ACP. The Company's 2014 compliance report stated that DP&L achieved compliance by meeting the 2014 benchmark for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables.

48. 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,

49. In January, April and June 2014, DP&L purchased [redacted] RECs generated by [redacted] at [redacted] per unit for a total cost of [redacted]. The REC WACI worksheet indicates that the [redacted] RECs were initially allocated to DP&L in the months indicated, but in July 2014, all [redacted] RECs and the associated costs were transferred to [redacted]. Subsequent to that transfer, an additional [redacted] solar RECs, which brought the total to the [redacted] RECs indicated in the Agreement for 2014, were allocated directly to [redacted]. DP&L stated that all [redacted] RECs were intended to be allocated to [redacted] and that the purchase agreement inadvertently named DP&L as the purchaser.

50. DP&L's compliance requirement for solar RECs totaled [redacted] for 2014 and the Company retired these RECs using a weighted average cost of inventory amount of [redacted], which includes the Yankee RECs at market cost. After including the Yankee RECs at market cost, the cost of the RECs retired to meet DPL's compliance requirement totaled [redacted].

Financial Audit Recommendations

1. Larkin concurs with EVA's recommendation that DP&L conduct a root cause analysis in order to determine the reason(s) for the substantial physical inventory variance which occurred at Stuart Station.
2. Larkin recommends that the revenues associated with the sales of coal to [redacted] and related lease payments, which totaled $15,881 and $161, respectively, on a DP&L retail basis, should flow through the Fuel Rider.

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

Following approvals by the Federal Energy Regulatory Commission ("FERC"), the PUCO, and others, the AES Corporation completed its purchase of DPL Inc., owner of DP&L, in November 2011. In 2012, AES recorded a goodwill impairment charge of approximately $1.82 billion for DPL. AES noted in both its 2012 10-K filing that it had "not realized the anticipated benefits and cost savings of the DPL acquisition, and DPL continues to face business and regulatory challenges."

AES is a global power company which was incorporated in Delaware in 1981. As of the end of 2013, AES owns and/or operates a diversified generation portfolio of approximately 37,150 MW world-wide. As a percentage of installed capacity, coal and natural gas account for 30 and 36 percent and 35 percent, respectively; oil, diesel and petroleum coke comprise five percent. The balance is renewables, primarily hydro, wind, and solar.

AES has 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. IPL generates, transmits, distributes and sells electricity to approximately 470,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. DP&L generates, transmits, and distributes electricity to more than 500,000 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 wholly and commonly owns 12 power generating facilities with a total capacity of 3,251 megawatts (2,829 MW of coal and 422 MW of other capacity). Exhibit 2-1 lists the facilities; Exhibit 2-2 displays their locations.

DP&L's coal capacity will decline with the retirement of Hutchings in 2015, the sale of DP&L's share to Duke Energy Kentucky which was completed in January 2015. DPL's ownership in Beckjord 6 is not included because it was retired in 2014.

Additionally, 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 has announced that rather than sell the generating assets to an unaffiliated third party, it will

Exhibit 2-1. DP&L Ownership in Fossil Generation Facilities as of December 31, 2014

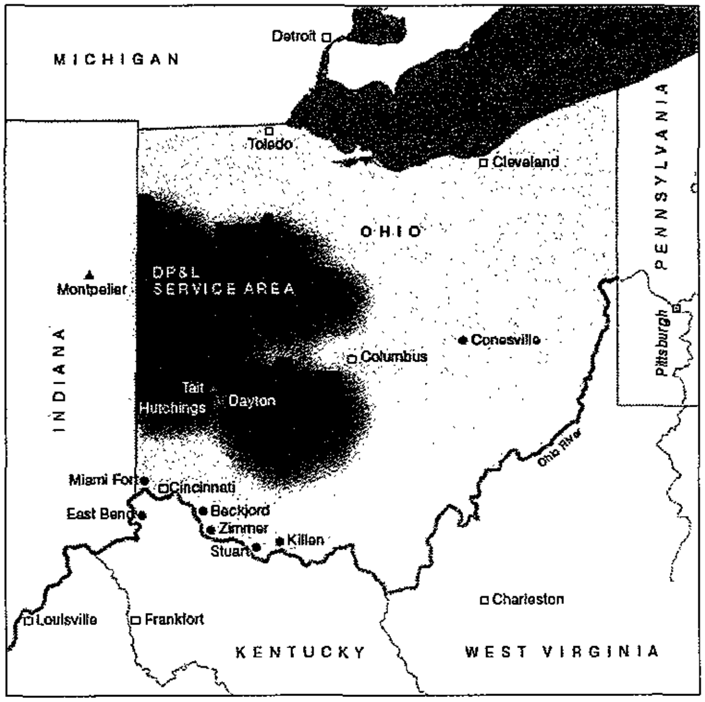
Utility	Plant Name	Units	Location	Ownership %	Capacity (MW)		Fuel Type
					Total	DP&L Share	
COAL GENERATING ASSETS							
Dayton P&L	O.H. Hutchings	1-6	Miamisburg, OH	100%	365	365	Coal
Dayton P&L	J.M. Stuart	1-4	Aberdeen, OH	35%	2,308	808	Coal
Dayton P&L	Killen	2	Wrightsville, OH	67%	600	402	Coal
AEP 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 CT	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

instead transfer 2,897 – the 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."

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.

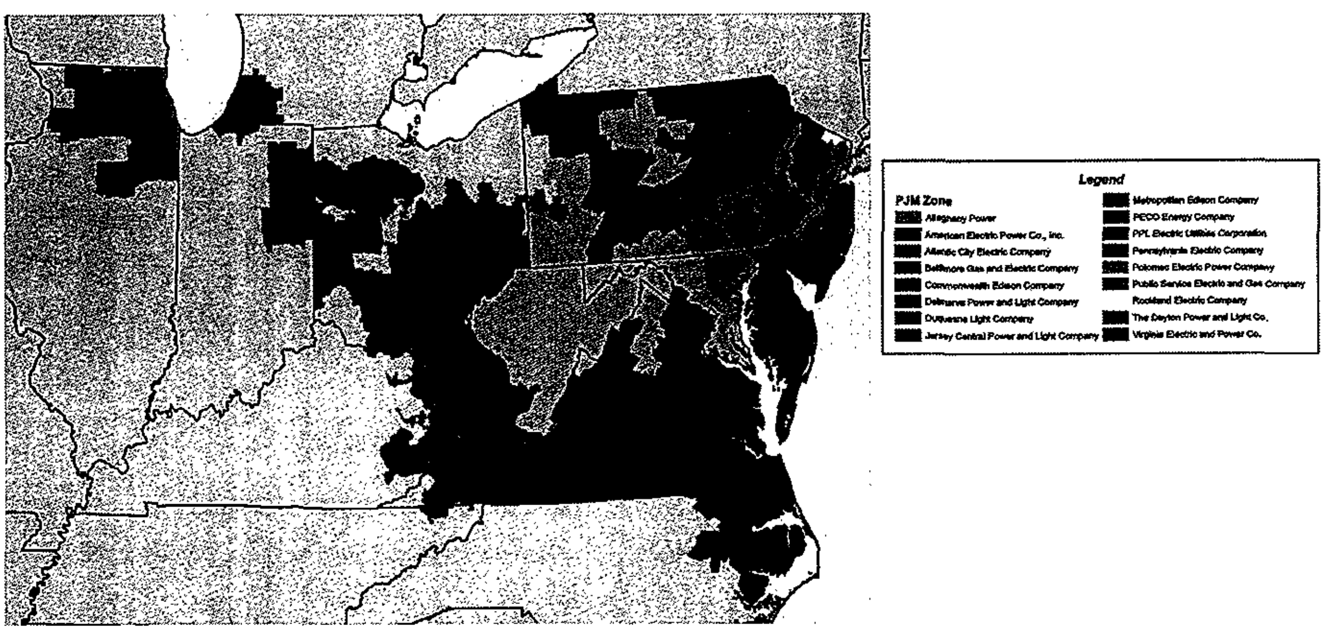
Exhibit 2-2. Location of DP&L Power Generation Facilities[12]



▲ *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 2014 is summarized in Exhibit 2-4. Coal accounted for 99.9 percent of DP&L generation. About 48 percent of its coal-fired generation came from DP&L-operated plants.

Exhibit 2-4. DP&L 2014 Generation by Plant (GWH)

Plant Name	Coal	Gas	Oil	Total 2014	2013	% Change
Conesville 4	689.2	-	-	689.2	536.2	29%
East Bend	910.2	-	-	910.2	1,165.7	-22%
Frank M. Tait CT 1-3	-	13.6	-	13.6	20.8	-35%
Frank M. Tait IC	-	-	0.1	0.1	0.1	0%
J.M. Stuart	3,627.5	-	-	3,627.5	4,654.8	-22%
J.M. Stuart IC	-	-	0.2	0.2	0.1	60%
Killen CT	-	0.6	-	0.6	0.2	159%
Killen	2,546.9	-	-	2,546.9	2,281.2	12%
Miami Fort 7/8	2,402.4	-	-	2,402.4	2,788.4	-14%
Monument IC	-	-	0.1	0.1	0.1	0%
O.H. Hutchings CT	-	-	-	-	-	-
Sidney IC	-	-	0.1	0.1	0.1	0%
W.H. Zimmer	2,089.3	-	-	2,089.3	2,641.7	-21%
W.C Beckjord 6	544.6	-	-	544.6	726.9	-25%
Yankee CT	-	0.3	-	0.3	0.8	-64%
TOTAL	12,810.1	14.5	0.5	12,825.1	14,817.2	-13%

Source: Form 1

Generation year on year declined by 13 percent overall and 11 percent for DP&L operated plants. The large decline in Stuart generation (22 percent) was partially offset by increased Killen generation (12 percent). With the exception of Conesville 4, all of the coal plants in which DP&L is a non-operating partial owner also had lower generation in 2014.

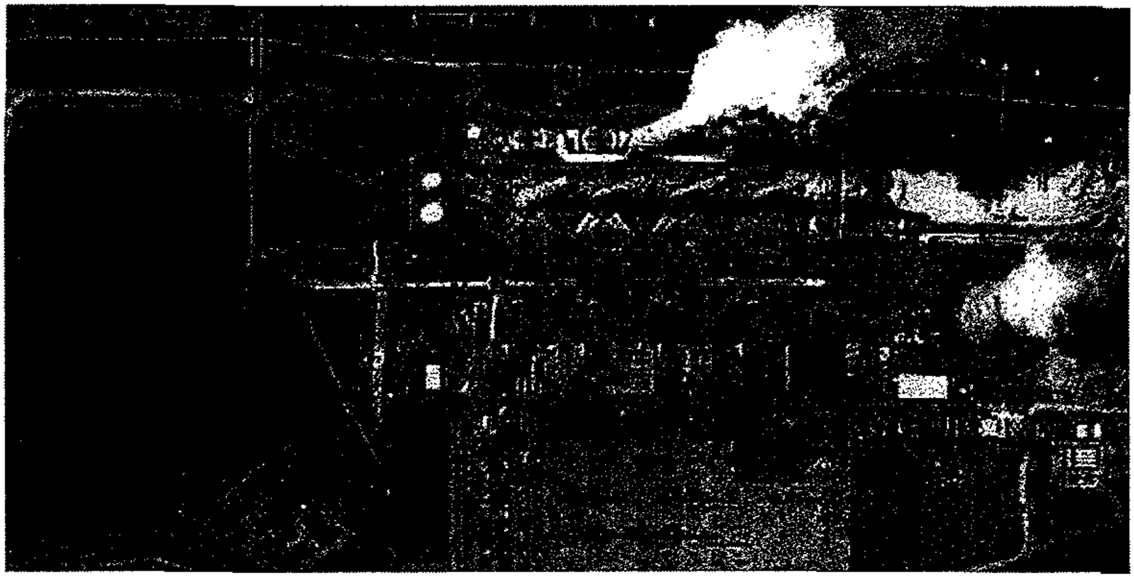
Coal Plants

This section provides background information on the two coal plants operated by DP&L in 2014. These are the only coal plants for which DP&L has responsibility for coal procurement.

J. M. Stuart

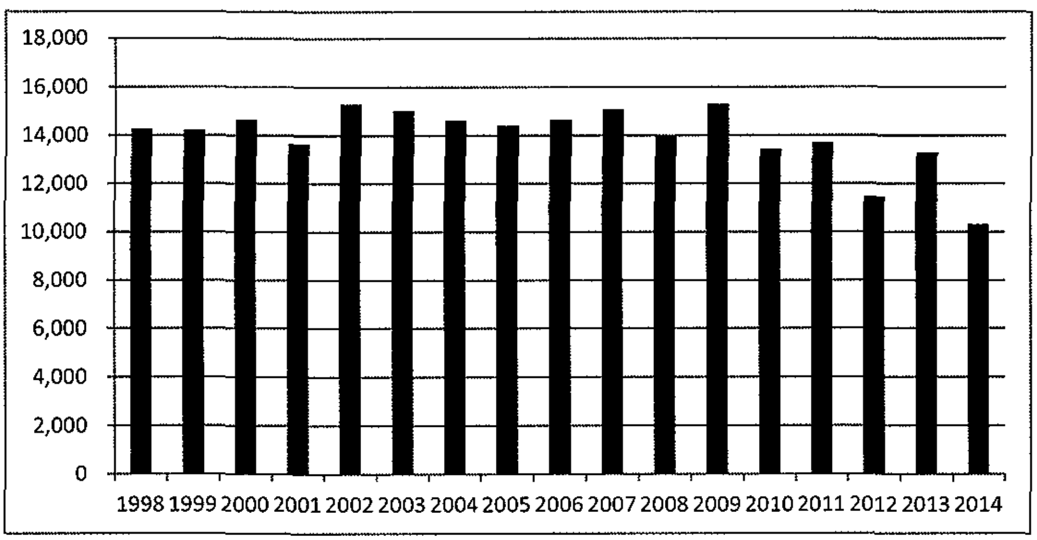
The Stuart Station consists of four units with a total generating capacity of 2,308 MW. The retrofits of flue gas desulfurization units on all four units were completed in 2008. As can be seen in Exhibit 2-5, the four units now share a common stack. All coal to this station is delivered by barge.

Exhibit 2-5. Aerial View of Stuart Plant



Generation in 2014 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

	2014	2013	2012	2011	2010	2009
Generation (MWh)	10,336,967	13,314,057	11,509,341	13,739,923	13,461,635	15,323,885
Consumption						
Coal (tons)	4,643,164	5,780,295	7,139,309	7,386,506	8,125,893	7,984,101
Oil (barrels)	65,434	59,039	78,049	82,765	76,406	55,257
Capacity Factor	50.9%	65.9%	56.9%	68.0%	66.6%	75.8%
Heat Rate (Btu/kWh)	9,999	9,927	9,906	9,942	9,950	9,800

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.

DP&L dispatches Stuart on a two-tiered basis. Based upon its finding that slagging was a controllable problem when the load was 537 MW or less, DP&L established two operating levels. Tier I is the operating level at which no on-line deslagging is needed. Tier II is operations above the Tier I level. DP&L added a cost rider to the last 40 MW's when operated above the Tier I level.

DP&L entered into multiple agreements with [redacted], LLC ([redacted]) during 2013 related to the installation of a Refined Coal plant at Stuart. The interest in Refined Coal is related to the tax credit under Section 45 of the Internal Revenue Code ("Code"). Refined Coal is coal which has been treated in a manner which provides for a 40 percent reduction in emissions of nitrogen oxide (NOx) and at least 20 percent of the emissions of either sulfur dioxide (SO_2) or mercury when the coal is burned as compared to emission when burning the coal without treatment. In order to qualify for the tax credit, the refined coal must be purchased from an unrelated party. As a result, in order for [redacted] to qualify for the tax credit, DP&L sells the coal to [redacted] and repurchases it after it has been treated. The treatment occurs as the coal is moving onto the conveyor into the plant, the sale and repurchase occurs at that point. In May of 2013, [redacted] suspended refined coal production and feedstock (coal) purchases at Stuart. This service restarted in September 2013, once [redacted] identified a replacement tax host. The plant burns 100 percent refined coal.

Poor performance at Stuart has been a major issue for DP&L over the last year. In response to EVA -2014-OS-5 which asked for DP&L's strategy to improve performance, DP&L indicated *it adopted a multi-faceted approach that includes the following:*

- Significant restructuring of the DPL Generation team in early 2015 including a new Vice President of Generation, a new Director of Planning, Outages & Engineering, a new Stuart station manager, and new managers in many of the key plant roles
- Complete reorganization of the Stuart team to create a more team-driven, performance-based business
- Improved culture within the business
- Development of an improved Asset Life Cycle Program that matches the challenging operations using ILB coal as a main source of fuel

While DP&L's admission of problems is quite remarkable, it seems largely driven by (a) the lack of market interest in acquiring the assets at values acceptable to AES and (b) the poor performance in 2014. In 2014, the Equivalent Forced Outage Rate (EFOR) for Stuart was 21.5 percent versus the stated corporate target of 6-7 percent.

Email correspondence on this subject provided by DP&L analyzes the cost of returning to design coal as well as the penalties with the new PJM capacity premium product for EFOR during peak periods. The fuel cost analysis is simplistic with DP&L simply assuming a [redacted] per ton *premium to return to* [redacted] *coal and an* [redacted] *per ton premium to burn* [redacted] coal. The problem with the premiums is two-fold. One is they did not align with the contemporaneous forecast of market prices for these coals[1]. Two is that DP&L in its solicitations received only a few bids for these products as the market believed DP&L has largely become a [redacted] coal consumer.[2] EVA also notes that DP&L remains convinced the Refined Coal is not contributing to operating problems.

While this matter now appears to be getting the attention it deserves, jurisdictional customers were adversely affected in 2014 due to lower generation from what should have been one of the lowest cost resources.

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[1] In DP&L's evaluation of Q4 2014 bids, the second lowest cost option was the [redacted] coal. Yet not one bid for this coal was received.

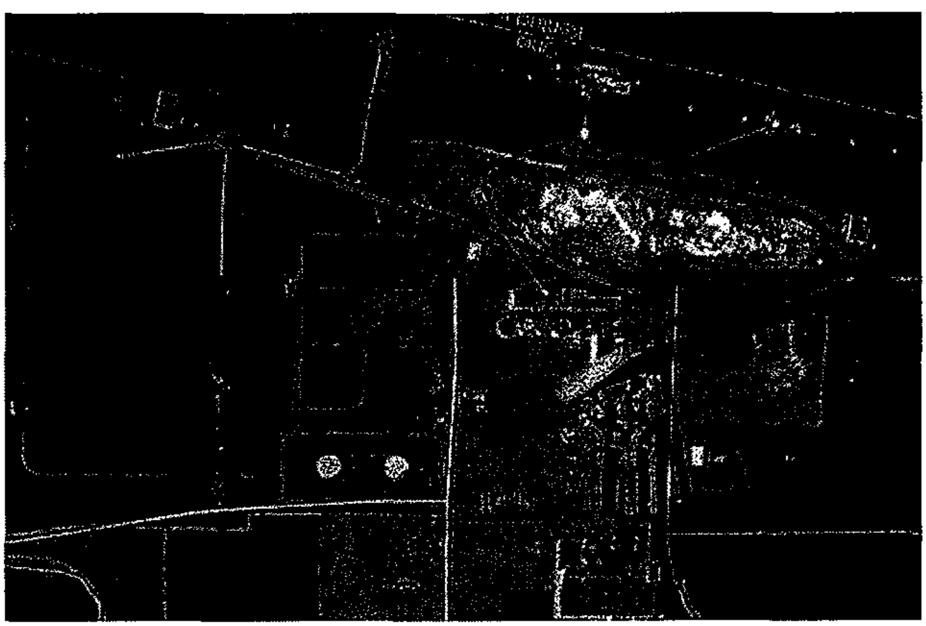
[2] This is confirmed in the bid response to the two RFPs conducted in 2014. DP&L did not get bids from [redacted].

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 2-9. All of the coal consumed by Killen is delivered by barge. Killen has converted almost completely to high sulfur Illinois Basin coal, which currently sells at a discount to the Central Appalachian coal for which it was designed. The discount is substantially lower than what it was in 2013. The single boiler at Killen is substantially larger than the boilers at Stuart. 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 can now 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 2-10. The plant operated above 70 percent capacity factor in 2014 and burned approximately 1.8 million tons.

Exhibit 2-9. Historical Operational Statistics for Killen

Plant		Units	Location	Ownership %	Total MW	Utility Share
Killen		2	Adams, OH	67	600	402
	2014	2013	2012	2011	2010	2009
Generation (MWh)	3,820,619	3,442,966	3,605,364	3,872,867	4,052,724	4,268,653
Consumption						
Coal (tons)	1,799,987	1,578,242	1,610,257	1,740,912	1,811,732	1,864,977
Oil (barrels)	20,155	23,286	21,985	18,838	14,926	18,935
Capacity Factor	72.5%	65.5%	68.6%	73.7%	77.1%	81.2%
Heat Rate (Btu/kWh)	10,322	10,214	10,489	10,296	10,296	9,787

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 2014, DP&L purchased 6.9 million tons of coal at an average delivered price of $50.91 per ton or $2.19 per MMBtu. (Exhibit 3-1) According to DP&L's classification, 57 percent of purchases were on a spot basis. Total tons and average prices were approximately the same in 2014 as they were in 2013.

Exhibit 3-1. DP&L Coal Purchases, 2014

	Contract					Spot					TOTAL				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
Killen	1,065,568	11,404	2.8	50.87	2.230	845,192	11,325	3.0	48.12	2.125	3,921,566	11,598	2.9	49.65	2.184
Stuart	1,891,985	11,734	2.7	52.17	2.223	3,076,374	11,673	2.8	50.92	2.181	4,968,359	11,696	2.7	51.39	2.197
TOTAL	2,957,553	11,605	2.7	51.70	2.226	3,921,566	11,598	2.8	50.31	2.169	6,879,119	11,605	2.8	50.91	2.193

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.

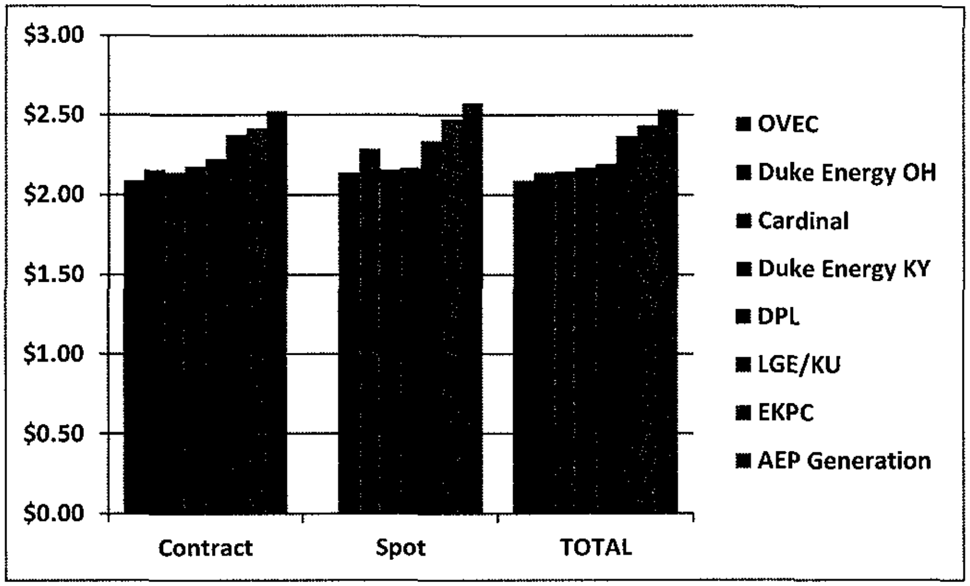
Another relevant metric for DP&L is how the delivered prices to Stuart and Killen compare to the delivered prices to other plants located nearby on the river which are equipped with scrubbers and/or burn high sulfur coal. Of the 11 plants shown in Exhibit 3-4, Killen and Stuart are the sixth and seven lowest cost plants. This is similar to their relative performance in 2013. Also provided on the exhibit is the average sulfur dioxide (SO_2) content of the 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.

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 2014, 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 2014. DP&L indicated it no longer restricts bids to these limits.

Exhibit 3-2. Ohio and Nearby Utility Coal Purchase Costs, 2014 ($/MMBtu)



Source: Form 923.

Exhibit 3-3. Coal Purchase Details for Other Ohio and Nearby Utilities, 2014

	Contract					Spot					TOTAL				
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu
OVEC	2,273,748	12,215	4.2	51.04	2.089	-					2,273,748	12,215	4.2	51.04	2.089
Duke Energy OH	594,161	11,828	2.8	50.99	2.156	5,249,194	11,938	3.1	50.99	2.136	5,843,355	11,926	3.1	50.99	2.138
Cardinal	4,087,832	12,504	3.5	53.51	2.140	195,327	12,921	2.1	59.09	2.287	4,283,159	12,523	3.4	53.76	2.147
Duke Energy KY	832,396	11,303	3.1	49.24	2.178	594,161	11,828	2.8	50.99	2.156	1,426,557	11,522	3.0	49.97	2.169
DPL	2,957,553	11,605	2.7	51.70	2.226	3,921,566	11,598	2.8	50.31	2.169	6,879,119	11,605	2.8	50.91	2.193
LGE/KU	13,353,892	11,430	3.1	54.26	2.374	2,422,350	11,450	2.3	53.56	2.339	15,776,242	11,433	3.0	54.15	2.368
EKPC	3,061,404	11,223	3.6	54.26	2.417	1,227,553	11,825	2.3	58.54	2.475	4,288,957	11,395	3.2	55.49	2.435
AEP Generation	9,896,216	12,149	3.5	61.33	2.524	1,985,370	12,151	2.5	62.55	2.574	11,881,586	12,149	3.3	61.54	2.533

Source: Form 923.

Exhibit 3-4. Delivered Prices to Proximate River Plants, 2014

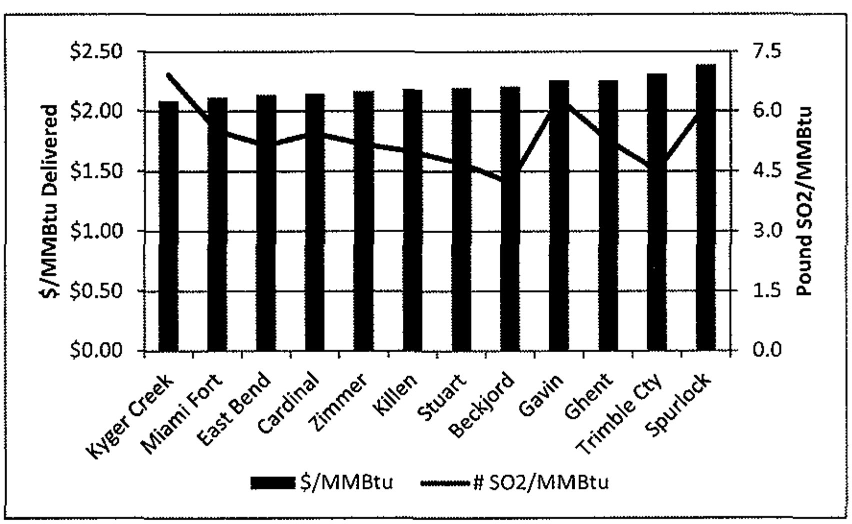


Exhibit 3-5. Killen and Stuart Coal Specifications

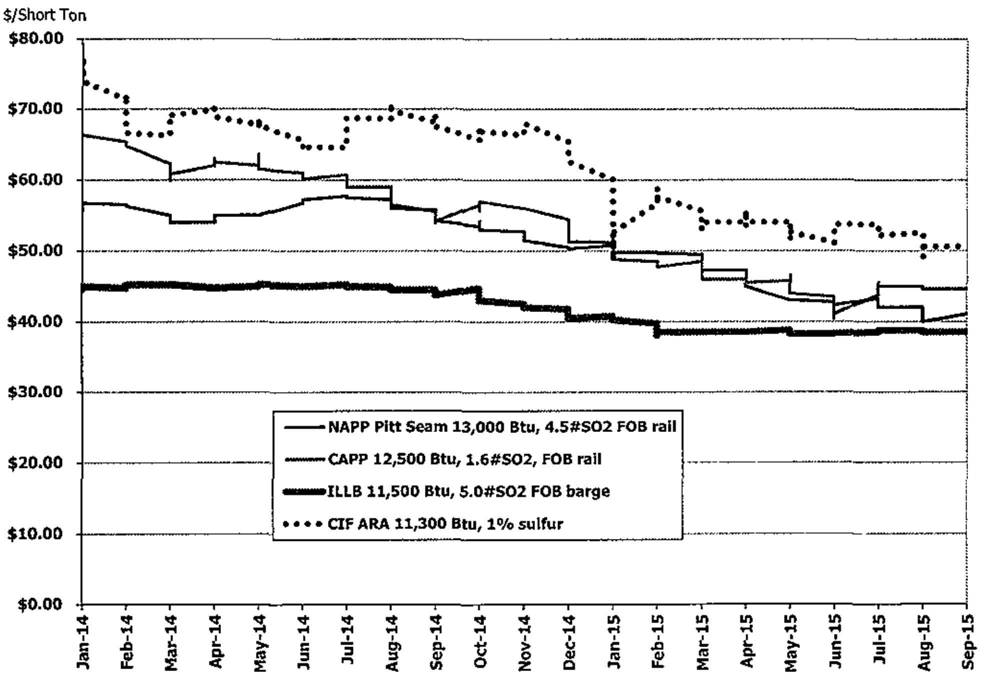
[redacted]

State of the Coal Market

Given DP&L's reliance on coal, the dramatic changes that occurred in the coal market in 2014 are relevant to the management/performance audit. Power sector demand for coal contracted during 2014 as the price for natural gas fell in order for natural gas-fired combined cycles to displace coal generation.[3] 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 2014, 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 was pronounced in 2014, as shown in Exhibit 3-6, but has been worse in 2015.

[3] 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 consequences related to the price decline in addition to 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 2014, several smaller coal producers had filed for bankruptcy and the specter of additional insolvencies began to loom. [4] The concern about counter-party credit has increased as a result heightening the importance of supply and supplier diversification. The management of stockpile levels has become more challenging as many power generators have coal under contract in excess of their demand.

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. As noted above, there were significant personnel changes. The current SBU organization is shown in Exhibit 3-6.

The organization of the fuel procurement team is provided in Exhibit 3-7. 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,

[4] In 2015, Patriot Coal reentered bankruptcy; Alpha Natural Resources filed as did Walter Energy.

- 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 3-6. U.S. Strategic Business Unit Organization Chart

[redacted]

Exhibit 3-7. Fuel Procurement Team

[redacted]

This 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 concentration of suppliers with respect to DP&L's purchases. While a secondary concern may be being too large a customer for a single supplier, the primary risk concern is being over–reliant on a 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 2014. 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.

In 2014, DP&L issued two formal coal RFPs and one spot coal RFP. DP&L made one distress coal purchase from [redacted] for [redacted] coal for Killen.

The spot RFP issued in September requested offers of higher Btu coal (i.e., > 11,500) for delivery in Q4 2014. DP&L received 12 offers although a number of them were disqualified because they did not meet the minimum quality standards.

While this RFP was characterized as a spot RFP because of its size, DP&L did its standard evaluation of bids. The purchases recommended from the evaluation are summarized in Exhibit 3-8. [redacted] and [redacted] were the low cost bidders. [redacted] was not.

Exhibit 3-8. Purchases from September 2014 Spot Coal RFP

[redacted]

There were three offers lower in cost than [redacted] in the evaluation, and DP&L provided no basis for their disqualification in its justification memorandum as shown in Exhibit 3-9. Subsequent to raising this issue, DP&L informed EVA the coal was purchased to replenish its low sulfur coal pile at Killen. This omission is indicative of the weakness of DP&L's justification memorandum as discussed below.

Exhibit 3-9. Justification Memorandum

[redacted]

DP&L did make a small number of spot purchases in 2014. These purchases, summarized in Exhibit 3-10 were for a total of about 125,000 tons. Five of the seven were purchases of Illinois Basin coal from [redacted], one was the single barge of distress coal from [redacted] described above, and one was a small number of Central Appalachia coal through [redacted]. The reported quality was generally superior to the specifications.

Exhibit 3-10. 2014 Spot Coal Purchases

[redacted]

Following a review of DP&L's RFP practices, both of the formal RFP's are reviewed below.

RFP Practices

DP&L's RFP process generally remained the same in 2014. 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. The procurement summary (which replaced the recommendation) consists of two pages and a new form. The two pages are mostly boiler plate information about POP along with a summary of the purchases. The form seeks responses to the following questions.

[redacted]

[redacted]

[redacted]

While the questions if answered thoroughly are not bad, most of the questions produced a short form response. For example, in response to "Why are we doing this transaction?", the answer was "To balance fuel supply with forecasted dispatch."

EVA noted in the prior audit that it did not find this form to be particularly suitable to utility procurement efforts given the broad nature of most of the questions and the limited responses provided. EVA recommended a more thorough package that contains at a minimum a summary of the RFP (what was solicited), a summary of the bids received and a summary of DP&L's evaluation (both fuel and credit), and a review of the implications of each award on each supplier's position with respect to overall DP&L requirements. DP&L did not comply with EVA's recommendation.

February 21, 2014

DP&L issued an RFP for up to 250,000 tons per quarter for the second, third, and fourth quarters of 2014. The RFP made it clear that each quarterly bid was independent, i.e., DP&L had the right to purchase the coal for any quarter. DP&L had an acceptable bid response with 15 bids received for Q2 2014, 11 bids received for Q3 2014, and 10 bids received for Q4 2014. Most of the bids were for [redacted] coal which is disappointing given DP&L's own analysis shows that [redacted] coals should be competitive.

The analysis performed by DP&L was generally reasonable. DP&L did not consider the volume option in its economic analysis, which may have changed the results. Also, DP&L continues not to quantify supplier concentration as part of its bid process.

From the RFP, DP&L made the purchases summarized in Exhibit 3-11. All of the purchased coal was for the Killen station.

Exhibit 3-11. Purchases from February 2014 RFP

[redacted]

October 27, 2014

DP&L issued a RFP for discrete "offers of coal for 250,000 tons for each quarter of 2015 and for 1.0 million tons calendar year 2016. DP&L had an acceptable bid response with 17 bids received for Q1 2015 business, 11 bids for Q2 2015 business, and eight bids for 2016 business. The most disappointing result is the limited number of bids for [redacted] coal. DP&L may want to cultivate additional participation from [redacted] producers, particularly given the quality issues at Stuart in 2014.

The analysis performed by DP&L was generally reasonable. While DP&L did not consider a value associated with the volume option, it was able to negotiate a volume option with [redacted] which improved the value of the offer. Virtually all of the bids contained ash contents greater than the station maximum specification. Three of the four lowest bidders for the Q1 business were eliminated for legitimate quality reasons.

From this RFP, DP&L made the purchases summarized in Exhibit 3-12.

Exhibit 3-12. Purchases from October 2014 RFP

[redacted]

Given DP&L's limited supplier base, there should have been explicit consideration of supplier concentration as a result of the purchases. Further, the concentration analysis should consider the sourcing, if known, by the traders. The [redacted] bid implied the likely suppliers [redacted] or [redacted] as the primary terminals were [redacted] and [redacted]. The bid however did allow for deliveries through [redacted] which suggests different sourcing. Most importantly, should there be a supply issue at any of the mines, [redacted] should have no basis for declaring a force majeure.

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:

<u>Establish Inventory Goals</u>

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

<u>Approve Inventory Goal</u>

- 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 2014.

Inventory performance (as measured by end-of-month inventory) since December 2012 is provided on Exhibit 3-13. The Stuart inventory trended downward through 2013 and trended upward in 2014 due to the plant's poor performance.

Exhibit 3-13. Monthly Coal Inventory for J.M. Stuart (DP&L Share)

[redacted]

Stuart's inventory days based upon maximum burn are displayed in Exhibit 3-14. Inventory started the year under 30 days but ended the year over 50 days.

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

[redacted]

Stuart's days of inventory compared to actual stockpile days of Illinois Basin coal (based upon three-year max burn) are shown in Exhibit 3-15. Stuart days have below actual days although by the end of the year they were similar.

Exhibit 3-15. Days of Inventory Versus Industry Average*

[redacted]

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

Killen Coal Inventory

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

Inventory performance for 2013 and 2014 is displayed on Exhibit 3-16. DP&L drew down the Killen inventory over the last nine months of 2013. At the end of December 2013, the end-of-month inventory was at very low levels. In 2014, the Killen inventory was restored to more normal levels, although the year ended high.

The days of inventory based upon maximum burn started 2014 at very low levels. By the end of March, 30 days had been restored and the plant had 30 or more days throughout the balance of the year. (Exhibit 3-17)

Killen's days of inventory compared to average stockpile days of Illinois Basin coal based upon three-year max burn is shown in Exhibit 3-15 above. With one exception, Killen days were below industry average Illinois Basin days of inventory. Like Stuart, by the end of the year, the days of coal in inventory were similar to industry average.

Exhibit 3-16. Monthly Coal Inventory for Killen (DP&L Share)

[redacted]

Exhibit 3-17. Killen Days of Burn in Inventory Based on Maximum Burn

[redacted]

Hutchings Coal Inventory

Hutchings was not operated in 2014.

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 2014 are summarized in Exhibit 3-18.

Exhibit 3-18. Physical Inventory Results, 2014

[redacted]

The results from the surveys triggered the requirements for additional investigation at Stuart. DP&L claims to have done a review but the brief report summarizing the review did not reach definitive conclusions or identify any action items. The report identified two possibilities: a divergence between the barge draft surveys and the certified #3 belt scales and/or the reconfiguration of the coal pile. With respect to the former, DP&L made a comparison between the barge draft survey weights and the belt weights. According to DP&L, these results should be close but they were not. Even though "most the 2014 inventory error could be accounted for between the book values and the 2014 Survey results", DP&L did not propose an action plan to address the difference.

With respect to the second possibility, DP&L that the coal pile at Stuart had been reconfigured in 2014 from an approximate 25 foot deep pile over a large storage are to a very tall pile (60-80 feet) over a smaller area. While the ASTM pile measurement methods presumable consider account for this difference, the experience of the Performance Engineer at the plant was that there are often larger differences in the year following the configuration.

Coal Procurement

In 2014, DP&L primarily bought high sulfur coal on both a contract and spot basis. Small amounts of low sulfur coal were purchased on a spot basis because they were economic or needed at Killen.

Master Agreements

DP&L uses Master Agreements as the primary contractual document with suppliers. While the content of the Master Agreements vary somewhat between parties, the basic components of the Master Agreements are listed in Exhibit 3-19. 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 2014, DP&L received coal under 29 confirmations. The confirmations are listed in Exhibit 3-20 with the contract identification and the 2014 tonnage obligation.

A summary of commitments by supply region and supplier are provided in Exhibit 3-21. Over 90 percent of the commitments were for [redacted] coal with most of the balance from [redacted].

Exhibit 3-19. Components of the Master Agreements

Article	Sections
Transactions	Procedures Confirmations Representations
Term	*Term and Survival Provisions* Termination due to Operational Issues
Obligations	Obligations for Purchase and Sale of Coal Resale of Coal Scheduling Delivery Title and Indemnity Substitute Coal Sources Substitute Coal for Synfuel Taxes and Other Liabilities
Specifications	Specifications Unit Train or Truck Weighing Barge Weights Sampling and Analysis Representative Presence: Inspection
Quality Adjustments and Rejection Rights	Quality Adjustments Buyer's Rejection Rights Buyer's Suspension Rights
Settlement; Security	Billing and Payment Netting and Setoff Audit *Reasonable Grounds for Insecurity* Adequate Assurances
Force Majeure	Force Majeure Force Majeure: Definition Pro Rata Reductions Termination Rights Settlements and Capital Expenditures
Events of Default, Remedies, and	Events of Default
Limitations of Liability	Early Termination Early Termination Payment Remedies Damages Stipulation Expenses Limitation of Liability
Arbitration	
Miscellaneous	Successors and Assigns: Assignment Warranties Notices Confidentiality Governing Law Entire Agreement; Amendments; Interpretation Counterparts; Serverability; Survival Non-Waiver; Duty to Mitigate; Not Partnership or Third-Party Beneficiaries Administrator Definititions
Form of Transaction Confirmation	

Exhibit 3-20. DP&L Contracts

[redacted]

Exhibit 3-21. 2014 Commitments by Supply Region and by Supplier

[redacted]

Three companies ([redacted]/[redacted], [redacted] and [redacted]/[redacted]) accounted for about [redacted] percent of the supply. With the recent acquisitions of [redacted] by [redacted] and [redacted] by [redacted], the concentration going forward absent diversification of the supply will be more significant. Assuming the 2014 commitments, [redacted] would account for almost [redacted] percent of the supply and [redacted] over [redacted] percent. This is a high risk situation in any market, but particularly high risk in the current market. DP&L should be actively working to expand its supplier base.

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

[redacted]

In 2014, DP&L received coal under two contracts with [redacted]. Both contracts were entered into in 2013. The contracts are both for coal from the [redacted] mine. The basic terms of the agreements are provided in Exhibit 3-22.

Exhibit 3-22. [redacted] Contracts

[redacted]

The agreements provide some volume optionality as well as [redacted] quality adjustments. The Btu adjustment is pro rata. The SO_2 adjustment provides a [redacted] per ton penalty per 0.1 pounds of SO_2/MMBtu per ton greater than the SO_2 specification. The SO_2 specification is [redacted] pounds for Confirm [redacted] and [redacted] pounds for Confirm [redacted].

The contracts were both amended during 2014. Confirm [redacted] was amended twice. In February, it was amended to modify the volatility specification in the contract. In December, it was amended to allow for any 2014 under-shipments to be carried over into 2015. Confirm [redacted] was amended once in September to extend the term from the end of the third quarter to the end of November.

Tonnage shipped by contract and plant under the [redacted] Agreements are provided in Exhibit 3-23. During the audit period, DP&L exercised its option to decrease volumes under [redacted] and increase its volumes under [redacted]. While shipments under both agreements were close to adjusted tonnages, the division of shipments between Killen and Stuart were different than anticipated with almost [redacted] tons more going to Killer than budgeted.

Exhibit 3-23. Shipments under the [redacted] Agreements by Purchase Order, 2014

[redacted]

Quality of shipments under the [redacted] agreement [redacted] is summarized in Exhibits 3-24. [redacted] was slightly out of compliance with its guaranteed Btu specifications during the first four months of the year.

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

[redacted]

Quality of shipments under the [redacted] agreement [redacted] is summarized in Exhibits 3-25. The SO_2 specification in this agreement is [redacted] pounds per MMBtu versus the [redacted] pounds in [redacted]. The ash specification in this agreement was [redacted] percent versus [redacted] percent in [redacted]. As a result, in addition to not meeting the Btu guarantee in the first few months of the year, the coal did not meet the ash specification in several months and the SO_2 specification in two months.

Exhibit 3-25. Quality of Shipments under [redacted] Agreement [redacted]

[redacted]

[redacted]

In 2014, DP&L received coal under three contracts with [redacted]. One contract was entered into in 2012, one in 2013, and one in 2014. The [redacted] coal had been the original source of coal when the plants were initially retrofit with scrubbers. This coal was periodically purchases ever since when it was the most economic source. This source is currently part of DP&L's efforts to determine whether the operating problems at Stuart can be mitigated through a change in coal supply.

The basic terms of the three agreements are provided in Exhibit 3-26.

Exhibit 3-26. [redacted] Contract

[redacted]

Tonnage shipped under the [redacted] Agreements is summarized in Exhibit 3-27.

Exhibit 3-27. 2014 Shipments under the [redacted] Agreements

[redacted]

Quality of shipments under the [redacted] agreements is summarized in Exhibits 3-28. The actual Btu content was below the Btu specifications in several months.

DP&L entered into a new agreement with [redacted] in 2014. The contract is summarized in Exhibit 3-29.

Exhibit 3-28. Quality of Shipments under the [redacted] Contracts

[redacted]

Exhibit 3-29. Contract with [redacted] for 2015 Delivery

[redacted]

[redacted]

In 2014, DP&L received coal under one contract with [redacted]. The basic provisions of this contract are summarized in Exhibit 3-30.

Exhibit 3-30. [redacted] Contract

[redacted]

The contract was amended twice in 2014. The amendments provided for a change in the monthly average specification for ash starting in September from [redacted] pounds per MMBtu to nine percent and the rejection specifications from [redacted] pounds per MMBtu to 10 percent, a contract price reduction of [redacted] per ton, and the institution of an ash penalty of [redacted] per ton for each 0.1 percent of ash greater than nine percent. Based upon the quality of the coal shipments, as shown below, ash was clearly a problem beginning in May and since the contract contained no ash adjustment DP&L is commended for obtaining these temporary ash-related changes. This also confirms that ash adjustments should be included in future agreements.

Tonnage shipped under this agreement is provided in Exhibit 3-31. Neither the upward nor downward quarterly quantity adjustments were nominated in 2014. As is DP&L's practice when the total tonnage is unlikely to be received during the calendar year for which it is purchased, DP&L entered into a letter agreement to provide for the carry-over of unshipped tonnage into 2015.

Exhibit 3-31. 2014 Shipments Under [redacted] Contract

[redacted]

Quality of shipments under the [redacted] agreement [redacted] is summarized in Exhibits 3-32. As discussed above, ash was a problem beginning in May that DP&L addressed through contract amendments.

Exhibit 3-32. Quality of Shipments under the [redacted] Contract [redacted]

[redacted]

[redacted]

In February 2013, DP&L entered into four agreements with [redacted] II, LLC ([redacted]) that collectively provide the basis for the installation of a Refined Coal facility at Stuart. The interest in refined coal is related to the tax credit parties can receive for Refined Coal under Section 45 of the Internal Revenue Code ("Code"). Refined Coal is coal which has been treated in a manner which provides for a 20 percent reduction in emissions of nitrogen oxide (NOx) and 40 percent reduction in the emissions of either sulfur dioxide (SO_2) or mercury. In order to qualify for the tax credit, the refined coal must be purchased from an unrelated party. As a result, in order to qualify for the tax credit, DP&L must sell the coal to a third party and then repurchase the coal from the third party after the coal has been treated. The agreements all expire December 13, 2021 unless they have been terminated early.

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

Under the [redacted], DP&L sells the coal it has purchased for Stuart to [redacted] at the [redacted] for the month of purchase.

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

Under the [redacted], DP&L agrees to buy all the refined coal produced. The price is based upon the number of tons of Refined Coal delivered minus the number of tons of chemicals used to produce such tons [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 Section 45 plant 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 Refined Coal agreement. 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 Refined Coal from an un-related third party. For example, the agreements could have been structured to purchase the Refined Coal at a price below what the coal feedstock was purchased.

In EVA's interviews with DP&L, DP&L confirmed that it was [redacted]. It is EVA's belief that this was simply the agreed-upon mechanism for a payment.

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 2013, there was relatively little refined coal produced and consumed. In 2014, DP&L indicated that [redacted].

[redacted]

In 2014, DP&L received coal under 11 contracts with [redacted]. [redacted] is the operator for the [redacted] mines including [redacted]. For all intents and purposes, [redacted] are the same company. Two of the 11 of the contracts, which are summarized in Exhibit 3-33, were for 2013 deliveries. The shipments in 2014 represent tonnage not shipped in the contract year. Four of the contracts were entered into in 2013 for deliveries started in 2014. The remaining five contracts were entered into in 2014.

Exhibit 3-33. [redacted] Contracts With Deliveries During 2014

[redacted]

Contracts [redacted] and [redacted] were amended in 2014 to provide for reduced 2014 and 2015 shipments in consideration of entering into [redacted] and [redacted], respectively.

[redacted]'s success derives in part from aggressive pricing of its [redacted] product. This coal is relatively low cost to produce if it can be sold on a partially-washed basis. As a partially washed coal, [redacted]. This off-spec coal is burned exclusively at Killen where a major initiative to use lower quality coals has been successful. According to DP&L, approximately 33 percent of Killen's feedstock can be the lower quality coals, such as [redacted]. [redacted] standard product such as [redacted] can go to either plant.

Shipments by contract are shown below. (Exhibit 3-34) As noted above, all of the lower quality [redacted] coal moved to Killen as did some of the higher quality [redacted] coal.

Exhibit 3-34. Shipments of [redacted] Contract Coal in 2014

[redacted]

As discussed above, [redacted]. This situation poses a significant risk to any consumer and should be addressed.

[redacted]

In 2014, DP&L received coal under one contract with [redacted]. The basic provisions of this contract are provided in Exhibit 3-35. Most of the [redacted] goes to Killen.

Exhibit 3-35. Long Term Contracts with [redacted]

[redacted]

Shipments under the [redacted] agreement in 2014 are summarized in Exhibits 3-36.

Exhibit 3-36. Shipments under [redacted] Agreement [redacted]

[redacted]

The quality of the 2014 shipments is summarized in Exhibit 3-37. The Btu content, more often than not, was slightly below the guarantee. In four of the months, the SO_2 content was slightly greater than the guarantee. The contract has no SO_2 adjustment.

Exhibit 3-37. Quality of [redacted] Shipments, 2014

[redacted]

[redacted] filed for bankruptcy protection under Chapter 11 of the Bankruptcy Code. As required, [redacted] filings included DP&L on the list of the 50 largest general unsecured claims against the debtor. DP&L's claim arises from unpaid amounts due under the terms of the [redacted] entered into [redacted]. A dispute arose at the end of 2008 when [redacted] notified DP&L that it would cease deliveries under the [redacted] between DP&L and [redacted] unless the terms of which were renegotiated.[5] DP&L has represented that at the time, it was concerned that [redacted] may be facing a financial insolvency. DP&L entered into two agreements to avoid [redacted] non-performance. The first was a [redacted] whereby [redacted] pays DP&L an amount per ton for coal not taken. The second was a new coal supply contract. DP&L recognized in its analysis that the combined value of the settlement was less than the value of the [redacted] but was vastly superior to the loss of the value of the contract in its entirety.

On or before August 1st of each year, DP&L was required to propose a market price to [redacted] indicating the market value the coal has to DP&L. [redacted] could accept or propose an alternative. If the parties could not reach an agreement within a fixed period of days, then the agreement would expire as of the following December. With respect to 2011, if the parties failed to agree, Seller would be obligated to make all the pay-down payments for 2012 with no opportunity to resume shipments relative to calendar year 2012. The parties did not agree. Therefore, no shipments from [redacted] were scheduled for 2012.

Given [redacted], DP&L was asked to update the status of these payments. DP&L's response was as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]. DP&L indicated that it distributed the payments to its co-owners in proportion to their generation during the month the payment was booked. DP&L share of the settlement payment was credited to the FUEL Rider based on the retail allocation factors for Stuart and Killen in the month the payment was booked.

EVA believes the settlement payment should be booked to the FUEL Rider based on the retail allocation factors for Stuart and Killen in the year(s) the payment should have been received. EVA recommends that adjustment be made.

[redacted]

A result of the October 2014 RFP was a new contract with [redacted]. [redacted]. A summary of the new contract is provided in Exhibit 3-38.

Exhibit 3-38. 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 provides for [redacted] to deliver at the [redacted] although deliveries via [redacted] would be at a [redacted] per ton discount to reflect the higher barge rate to DP&L plants. In addition, the weight of the coal delivered through [redacted] would be based upon [redacted].

The purchase agreement is similar to other DP&L purchase agreements. DP&L's general terms and conditions are incorporated. EVA is concerned that the Force Majeure provision was not customized for this transaction. [redacted], as a trader not offering source or dock-specific tonnage,

[6] Response to EVA-2013-1-15.

should not be entitled to claim a mine or dock event of force majeure. The use of a general force majeure provision does not make this clear.

[redacted]

In 2014, DP&L received coal under two contracts with [redacted]. In 2012, DP&L entered into a contract ([redacted]) for 2014 tonnage with [redacted] from the [redacted]. In 2013, DP&L entered into a second agreement with [redacted] following the March 2013 RFP for deliveries in the last four months of 2013.[7] The basic provisions of these contracts are provided in Exhibit 3-39.

Exhibit 3-39. Contracts with [redacted]

[redacted]

[redacted]

[redacted]

In October 2013, DP&L agreed to modify the end date in [redacted]. The amendment also provided that no tons under [redacted] be delivered until all tons under [redacted] were delivered.

Deliveries in 2014 are summarized on Exhibit 3-40. As shown, the deliveries under [redacted] were completed before shipments under [redacted] began. DP&L correctly exercised its right in [redacted] to reduce tonnages by 10 percent in each quarter, reducing the annual volume from [redacted] tons.

[redacted]

Exhibit 3-40. 2014 Shipments under [redacted] Agreements

[redacted]

The quality of the 2014 shipments for [redacted] is summarized in Exhibit 3-41 and for [redacted] in Exhibit 3-42. Shipment under [redacted] largely did not meet the quality guarantees for ash and Btu. Performance under [redacted] was slightly better. Under both agreements, the SO_2 content of the coal delivered was significantly better than the contract specifications.

Exhibit 3-41. Quality of Shipments under [redacted]

[redacted]

Exhibit 3-42. Quality of Shipments under [redacted] Agreement [redacted]

[redacted]

From the October 2014 RFP, DP&L entered into a new agreement [redacted] for deliveries in 2015 and 2016. The basic terms are summarized in Exhibit 3-43.

Exhibit 3-43. New Contract with [redacted]

[redacted]

In 2014, DP&L received coal under a long-term contract with [redacted]. This contract, the terms of which are summarized in Exhibit 3-44, represents DP&L's [redacted]. Pricing was determined for only the first two years. Pricing thereafter is based upon negotiation or baseball arbitration. Unlike most other agreements with price reopeners, the volume commitment is firm. It is only the price that is unknown. In other words, neither party can terminate the agreement if it is unhappy with the price.

Exhibit 3-44. Overview of [redacted] Long-Term Contract

[redacted]

[redacted]

The quantity of the shipments under the [redacted] contract is summarized in Exhibits 3-45. Some of the [redacted] coal was diverted to Killen in 2014 for the reasons discussed above.

Exhibit 3-45. 2014 Shipments Under the [redacted] Contract

[redacted]

The quantity of the shipments under the [redacted] contract is summarized in Exhibits 3-46

Exhibit 3-46. Quality of Shipments Under the [redacted] Contract, 2014

[redacted]

Shipments in almost every month were non-compliant with the monthly guaranteed SO_2 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 2014 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. [redacted].

[redacted].

The information provided by DP&L to EVA was heavily redacted "to remove legal counsel's thoughts and impressions regarding the legal issues involved and alternatives considered." The redaction made it impossible to evaluate whether DP&L's payment was prudent.

Simultaneous with the amendment, the parties executed four agreements related to the termination of the original [redacted] and the settlement of disputes. A [redacted] was in response to claims by DP&L and the other owners against [redacted]. An Agreement Treatment provided for the payment of the parties to [redacted]

[redacted]

DP&L advised EVA that it would not be asking to recover any of the buy-out costs through the FUEL Rider. Given DP&L's representation, EVA did not pursue further disclosure. Should DP&L attempt to pass through any of the [redacted], a full review should be conducted and should include consideration of the prudence issues in the buy-down.

Transportation

Coal is delivered by barge to Killen and Stuart. Hutchings previously received coal by rail and truck but no deliveries were made to it in 2014. The transportation agreements are reviewed in this section.

Barge

DP&L is a party to a [redacted]

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

However, due to [redacted]

DP&L also is a party to a [redacted]. The [redacted] agreement was not amended during the audit period.

Rail

DP&L was party to a rail agreement with the Norfolk Southern Railway for Hutchings coal delivery. The two-year agreement which started January 1, 2008 was been extended through 2014. The agreement appropriately has no minimum tonnage requirements and expired December 31, 2014.

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.

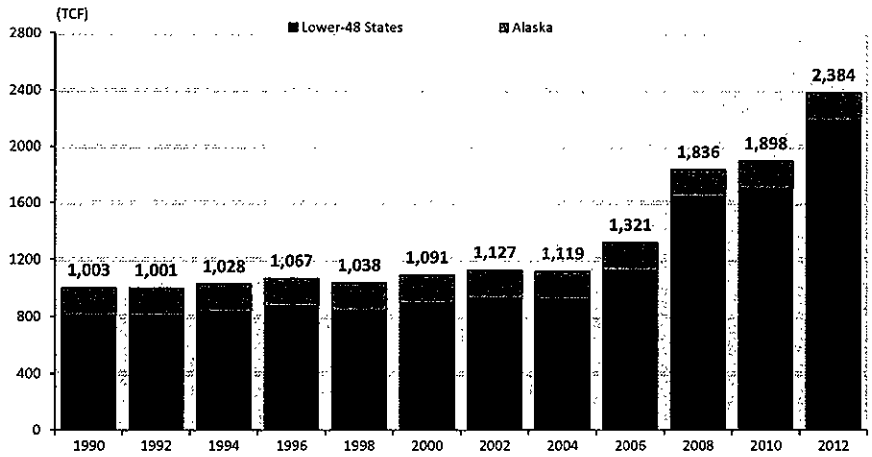
When looking at the shifts in natural gas over the last several years, there are three primary focus areas that will be critical to DP&L going forward:

- 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 3-47 shows the rapid change in this resource base over the last eight years.

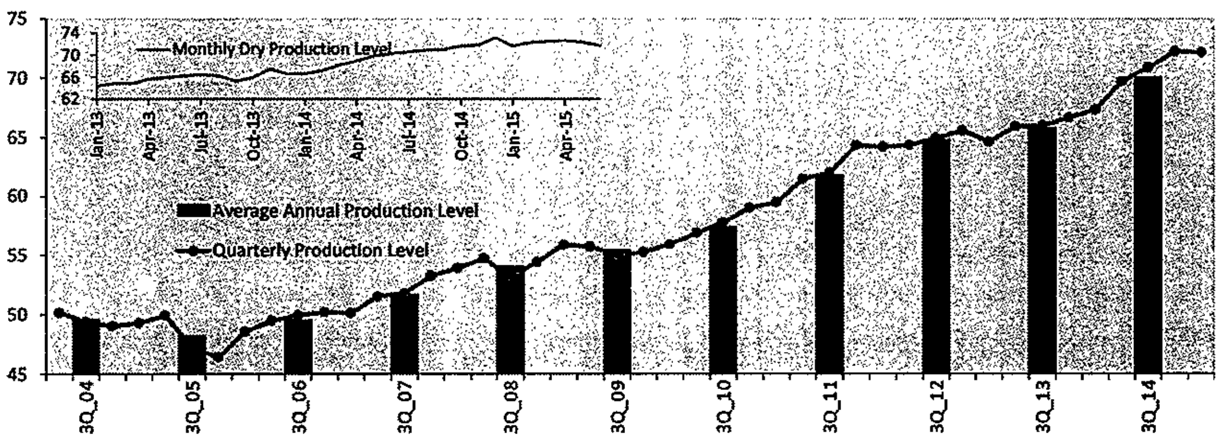
Exhibit 3-47. Potential Gas Committee Natural Gas Reserve Base Estimates



Source: Potential Gas Committee.

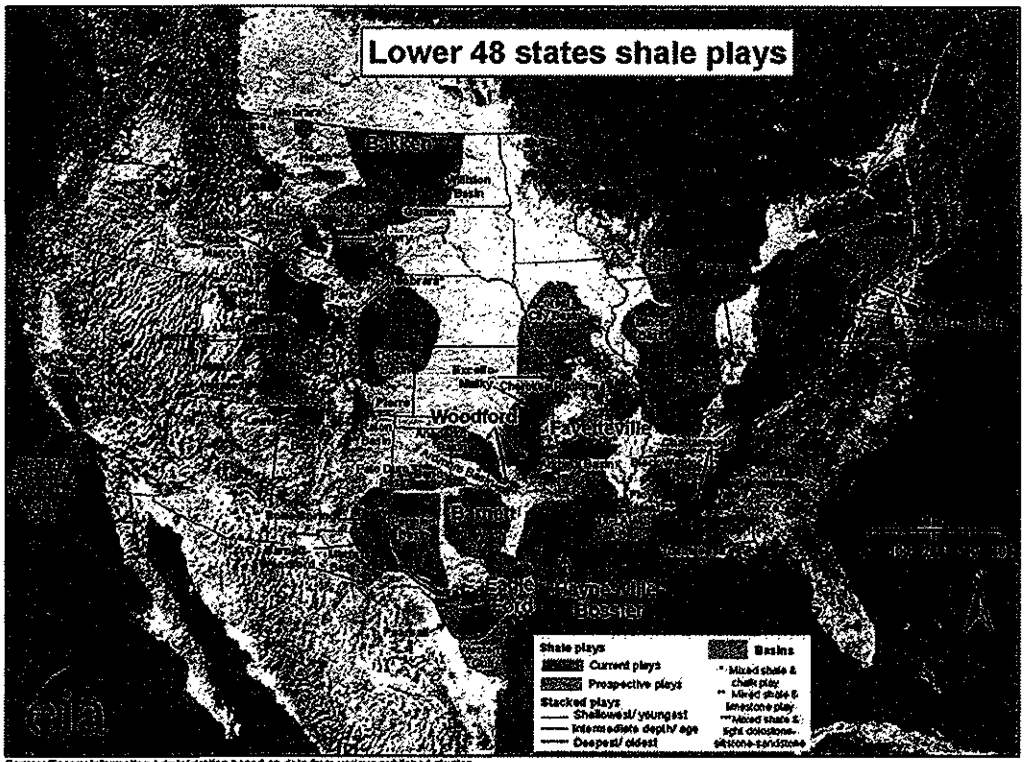
Exhibit 3-48 shows the rapid growth in Lower 48 Natural Gas production since 2004. Exhibit 3-49 shows the location of the shale plays accounting for this incremental production.

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



Note: Bars represent average annual production levels, while dots on the line graphs represent quarterly production levels.
Source: Lippman Consulting, EVA

Exhibit 3-49. Shale Gas Reserve Map from EIA



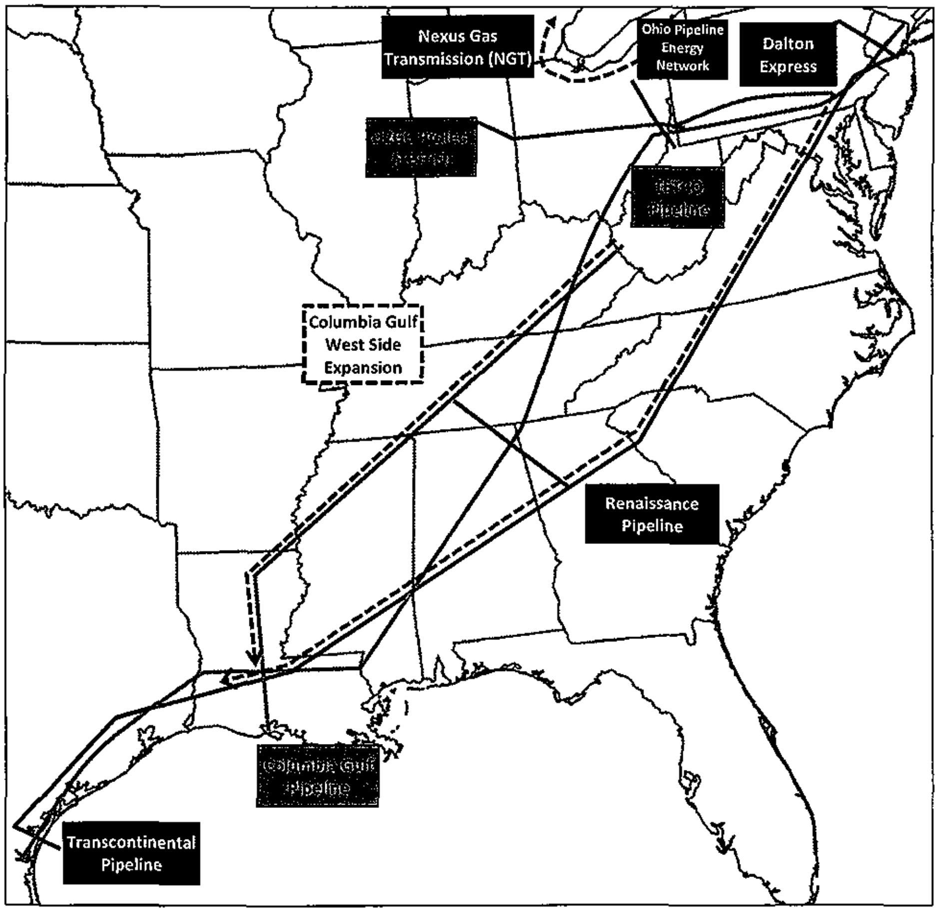
Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

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 3-50 shows an example of some of the larger projects that have taken place over the past several years.

Exhibit 3-50. Major Northeast Pipeline Expansion Projects



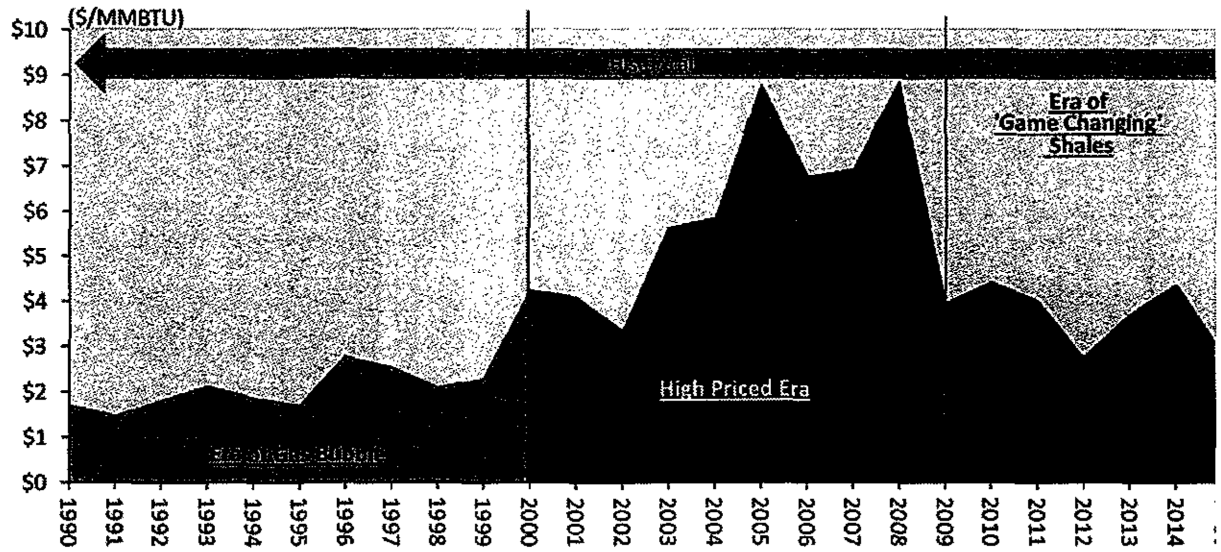
The implications of this new infrastructure are numerous and must be a critical input to any procurement strategy at DP&L. Some examples include:

- 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 3-51. In 2012, prices hit lows not seen in close to a decade, dropping below $2.00/MMBtu in March/April. While it is yet to be seen how prices will evolve going forward, it is readily apparent that prices are likely to remain substantially below the previous decade, where price spikes above $10.00/MMBtu were not uncommon. This "new era" of prices is a vital consideration to DP&L's natural gas procurement practices and, even more critically, its long term review of reliability and generation issues.

Exhibit 3-51. Henry Hub Natural Gas Price History



Source: NGW and EVA, Inc.

2014 Gas Purchase Review

In 2014, DP&L Energy acting for itself and to meet DP&L needs purchased [redacted] million cubic feet (Mcf) of natural gas with a total cost of [redacted]. Natural gas volumes and charges by month are shown in Exhibit 3-52.

Exhibit 3-52. DP&L Natural Gas Purchases

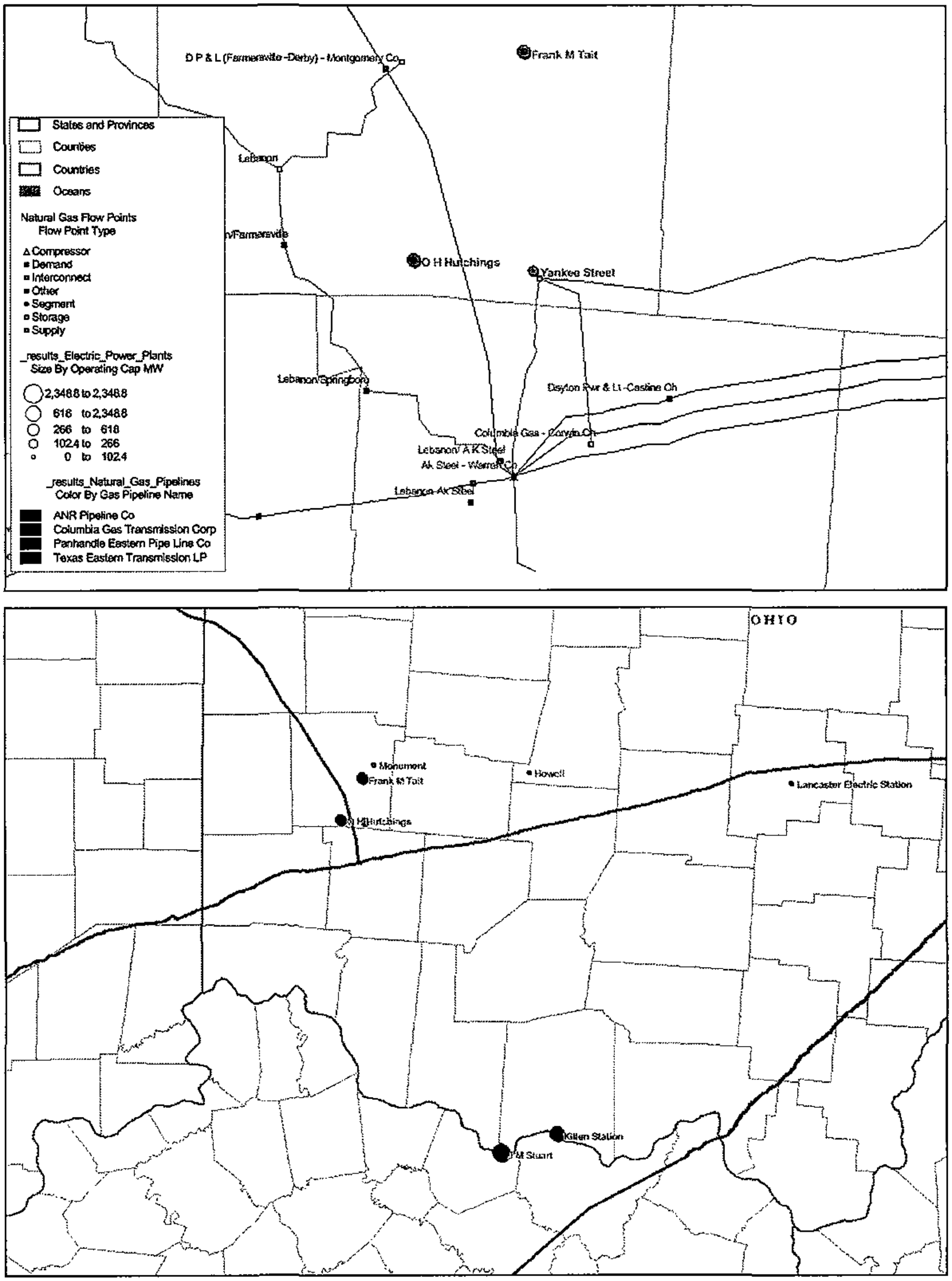
[redacted]

Upon review of the gas purchases, all prices paid and volumes purchased appeared to be prudent. Additionally, the transactions entered into that were for DP&L were with counterparties with whom it has up-to-date master agreements.

Upon review of pipeline charges, they also appeared prudent. Pipeline contracts are held with four major interstate pipeline systems: [redacted]. The most heavily used path for natural gas flow has been through the [redacted].

Exhibit 3-53 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 3-53. Key Gathering Assets and Pipelines



Firm Capacity Recommendations

Recommendations were previously made to review the DP&L's firm capacity agreements with [redacted]. The following was in the prior audit report:

Based on reviews of both DP&L's purchase data as well as third party source data, it is recommended that DP&L review eliminating its firm capacity agreement with [redacted] *and moving to interruptible service (IT). The rationale is as follows:*

- *Due to large gas production volumes in the northeast – particularly from the Marcellus shale, the* [redacted] *is not heavily utilized within the segment that services DP&L*
- *Winter is the primary time there are utilization spikes (anywhere close to 90 percent or higher), whereas DP&L requires their greatest amount of gas during summer months*
- *The reversal of the Rockies Express Pipeline will continue to reduce the value of firm capacity in the region*
- *DP&L spends over* [redacted] *on its firm capacity agreement with* [redacted]*. This is particularly unnecessary in months such as December, when in 2012, DP&L only purchased* [redacted] *of natural gas*

DP&L also purchases firm capacity on [redacted].

Subsequent to the recommendation being made which saved more than [redacted] in 2014, DP&L indicated it had independently reached the same conclusion and had not renewed its firm transportation agreement with [redacted].

4 PLANT PERFORMANCE

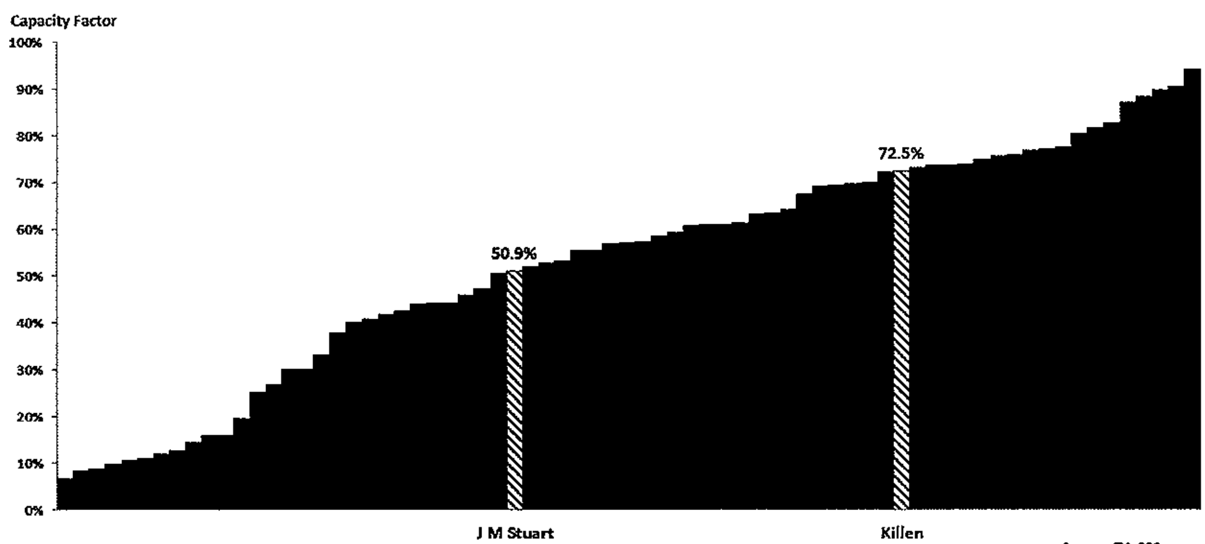
Benchmarking

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. Killen and Stuart, which had similar performances in 2013, had very different performances in 2014. Killen's capacity factor increased from 65.5 percent in 2013 to 72.5 percent in 2014. Stuart's capacity factor declined from 66 percent in 2013 to 50.9 percent in 2014.

Exhibit 4-1. PJM Coal-Fired Power Capacity Factors in 2014



Killen and Stuart have lower heat rates compared to their PJM competitors (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.

Exhibit 4-2. PJM Coal-Fired Power Plant Heat Rates in 2014

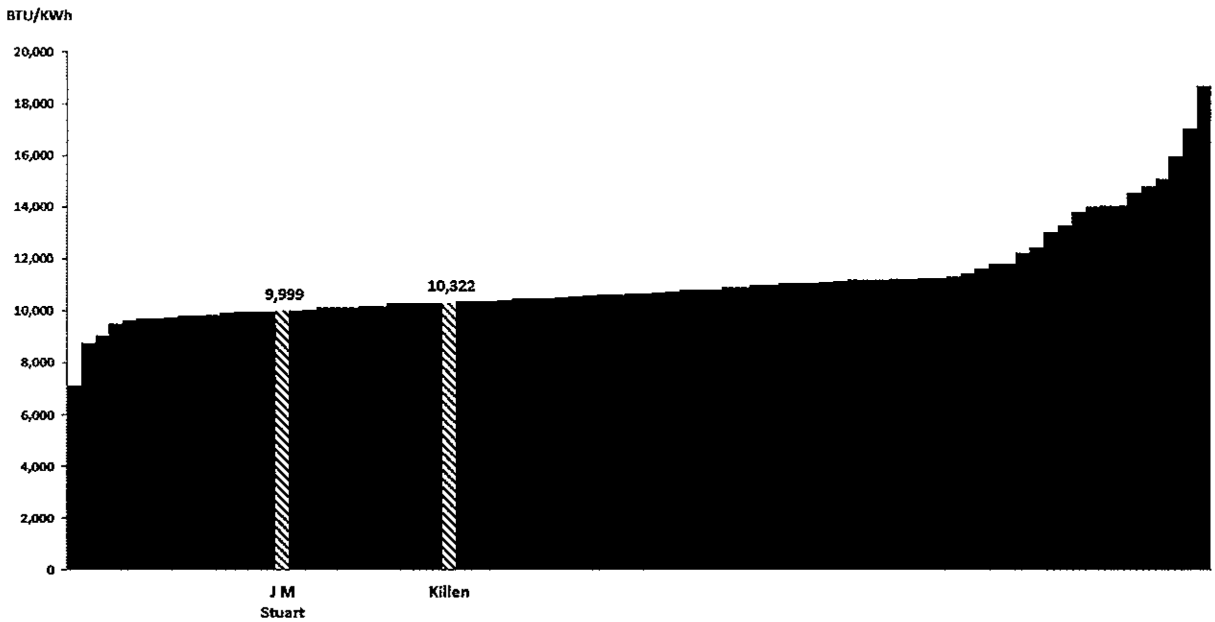


Exhibit 4-3 displays the cumulative 2014 generation of PJM coal-fired plants by heat rate. Stuart's heat rate puts it in the bottom half. Killen with a slightly higher heat rate is further up, though it is also on the front half of the dispatch curve.

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 4-3. PJM Coal-Fired Facilities Annual Cumulative Generation by Heat Rate, 2014

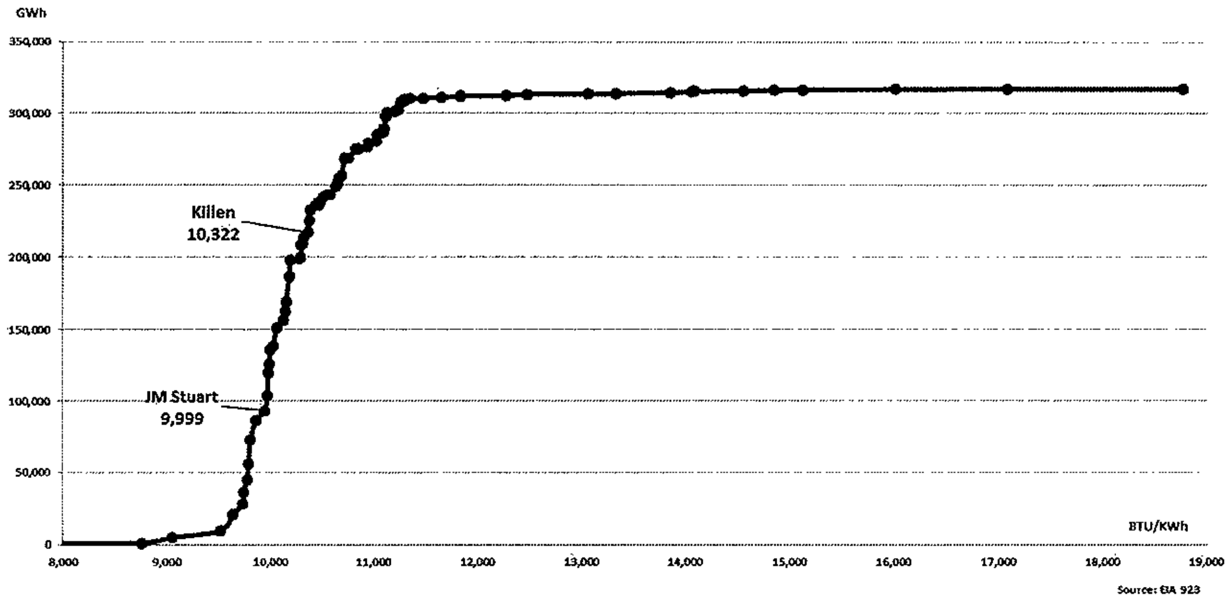


Exhibit 4-4. Ohio and Kentucky Coal-Fired Power Capacity Factors in 2014

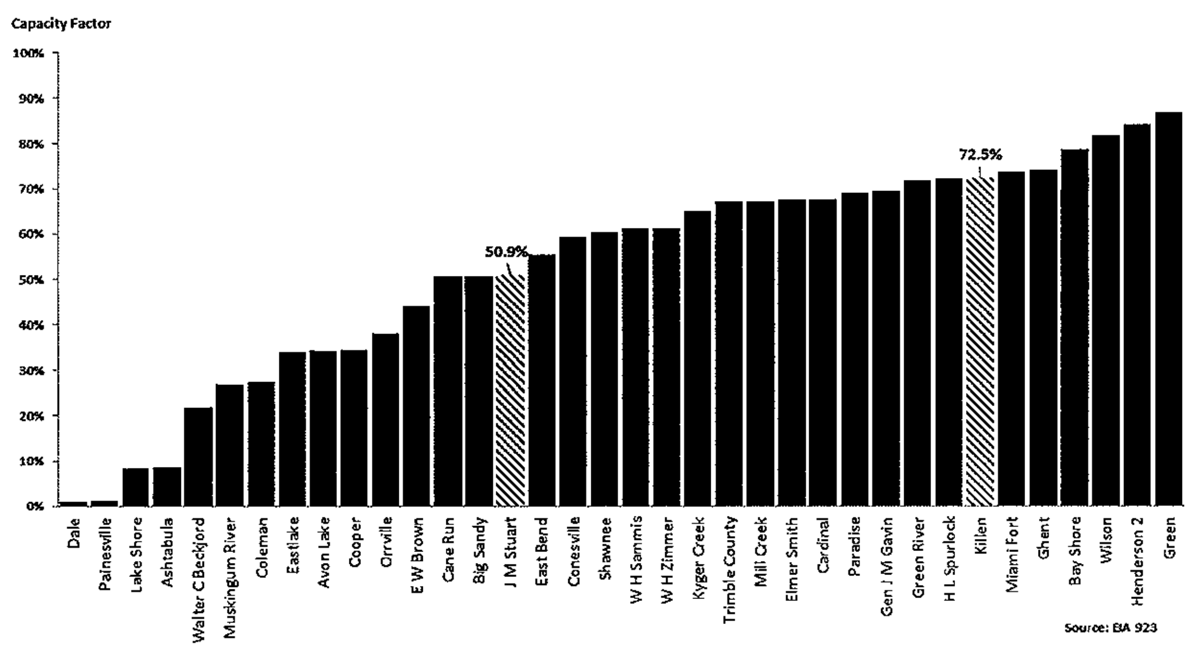
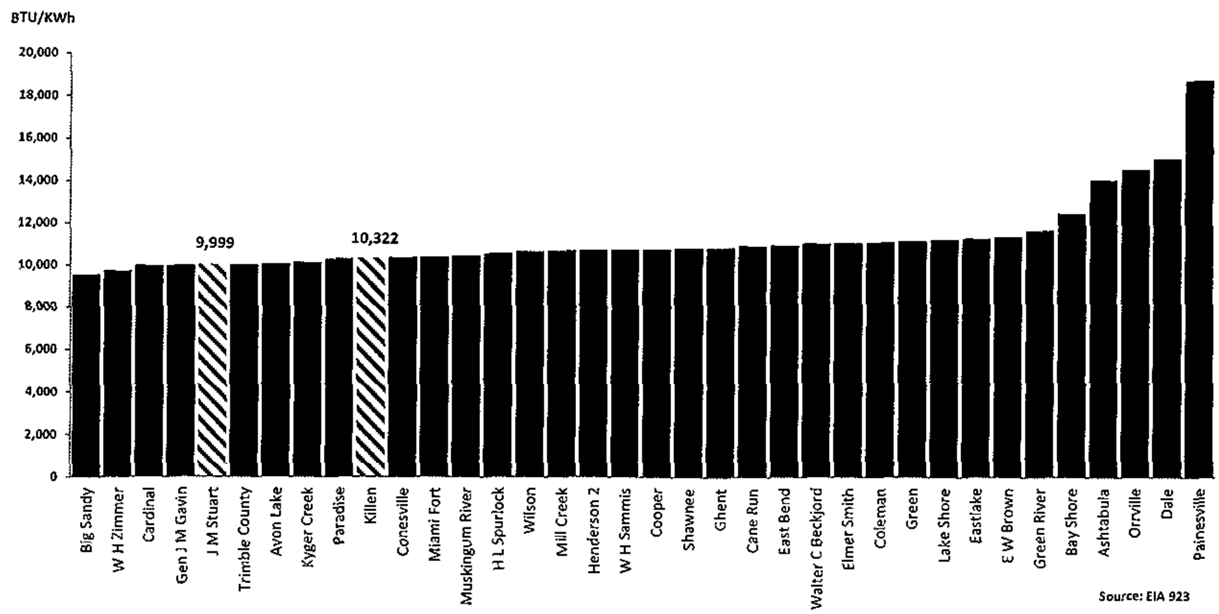


Exhibit 4-5. Ohio and Kentucky Coal-Fired Power Plant Heat Rates in 2014



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:

- Certificate of Accountability of Independent Auditors
- Background
- Stipulation from Case No. 08-1094-EL-SSO
- Accounts Included in DP&L's FUEL Rider
- Quarterly FUEL Rider Filings
- FUEL Rider Deferrals
- 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
- Hutchings Generating Station
- 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
- Customer Switching
- Internal Audits
- Section 45 Plant
- 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.

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, 2014, which support the calculations of the Fuel Rider rates for the 12-month period January through December 2014. In addition, we have examined the quarterly Alternative Energy Rider ("AER") filings, which support the calculations of the Alternative Energy Rider for the 2014 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 2014 calculated with those quarterly filings, which include the *Reconciliation Adjustments for the period January through December 2014 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 2014, 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 2014, including the Reconciliation Adjustments for the period January through December 2014 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 2014 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. 15-0042-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 2014, 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)
November 15, 2013	January - May 2014	September 2013
May 1, 2014	June - August 2014	September 2013 - March 2014
July 18, 2014	September - November 2014	January - June 2014
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

Larkin's review of DP&L's quarterly FUEL Rider filings covers the forecast periods encompassing calendar 2014. 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 2014. 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 2014.

The following sections discuss DP&L's 2014 quarterly Fuel Rider filings[8] by reproducing Schedules 1 and 2 as well as Workpaper 1 as Exhibits 5-2 through 5-25.

Quarterly FUEL Rider Filing – January through May 2014

Exhibit 5-2. Forecasted Quarterly Rate Summary, January through May 2014

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-426-EL-SSO
FUEL Rider
Forecasted Quarterly Rate Summary

Line No.	(A) Description	(B) Jan-14	(C) Feb-14	(D) Mar-14	(E) Apr-14	(F) May-14	(G) Total	(H) Source
1	Forecasted FUEL Costs	$10,475,725	$8,634,606	$7,385,249	$5,292,101	$5,179,604	$36,967,284	Workpaper 1, Line 13
2	Forecasted Generation Level	$403,073,923	$328,738,313	$278,847,822	$195,698,807	$187,971,318	$1,394,330,183	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh						$0.0265126	Line 1 / Line 2
4	SSO Blend Percentage						$0.0238613	Line 3 * 90%
5	Reconciliation Adjustment $/kWh						($0.0009663)	Schedule 2, Line 13
6	Forecasted Retail FUEL Rate $/kWh						$0.0228950	Line 3 + Line 4

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
7	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
8	FUEL Rates $/kWh	$0.0230285	$0.0232915	$0.0239681	Line 6 * Line 7

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to incur during the period January through May 2014. As shown on line 1 of Schedule 1, the category included DP&L's forecasted Fuel costs for January through May 2014, which totaled $36.967 million (column G). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 1.394 billion kWh for the period January through May 2014. The Company then calculated its retail Fuel rate before Reconciliation Adjustment of $0.0265126 per kWh by dividing the forecasted Fuel costs of $36.967 million by the forecasted Generation Level Retail Sales as shown on line 3. The Company then multiplied the Fuel rate before Reconciliation Adjustment by 90 percent to calculate the SSO Blend Percentage of $0.0238613 as shown on line 4.[9] The Company reflected a Reconciliation Adjustment for the period September 2013 through May 2014 (see Schedule 2 discussion below) of $0.0009663 per kWh on line 5. DP&L added its Reconciliation Adjustment to the $0.0238613 per kWh noted above to derive its forecasted retail Fuel rate of $0.0228950 per kWh as shown on line 6 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 &

[8] DP&L provided the Excel versions of its quarterly Fuel Rider filings in response to LA-2014-1-51.

[9] In response to LA-2014-2-3, DP&L stated that the SSO Blend Percentage was included in the ESP that was approved by the Commission on September 4, 2013. This item was also discussed in the Commission's Second Entry on Rehearing, dated March 19, 2014 in Case No. 12-426-EL-SSO, et al.

Residential voltage levels, the Company calculated Fuel rates at the distribution level of $0.0230285, $0.0232915, and $0.0239681 cents per kWh as shown on line 8.

Exhibit 5-3. Reconciliation Adjustment – September 2013 through May 2014

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-426-EL-SSO
FUEL Rider
Reconciliation Adjustment (RA)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Description	Actual Fuel Costs	Actual Revenue Recovery	(Over)/Under	Carrying Costs	Total	YTD[1]	Source
				(D) = (B) + (C)		(F) = (D) + (E)		
1	Prior Period					($13,122)	($13,122)	
2	September-13	$8,978,305	($10,297,310)	($1,319,005)	$0	($1,319,005)	($1,332,127)	
3	October-13			$0	$0	$0	($1,332,127)	
4	November-13			$0	$0	$0	($1,332,127)	
5	December-13			$0	$0	$0	($1,332,127)	
6	January-14			$0	($5,076)	($5,076)	($1,337,203)	
7	February-14			$0	($4,181)	($4,181)	($1,341,385)	
8	March-14			$0	($3,154)	($3,154)	($1,344,539)	
9	April-14			$0	($2,045)	($2,045)	($1,346,583)	
10	May-14			$0	($734)	($734)	($1,347,318)	
11	Total (Over)/Under Recovery						($1,347,318)	Sum of Lines 1 - 10
		Jan-14	Feb-14	Mar-14	Apr-14	May-14		
12	Forecasted Generation Level Sales	403,073,923	328,738,313	278,847,822	195,698,807	187,971,318	1,394,330,183	
13	**Forecasted RA Rate $/kWh**						($0.0009663)	Line 11 / Line 12

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

Schedule 2: Column B of Schedule 2 reflects DP&L's actual Fuel costs that were incurred during September 2013, which totaled $8.978 million. Column C of Schedule 2 reflects DP&L's actual revenues for the same period, which totaled ($10.297) million. The difference between the Company's actual Fuel costs and actual revenues results in an over-recovery in the amount of $1.319 million, as shown in column D. Column E reflects the carrying costs for the period of January through May 2014, which total ($15,190). The over-recovery for the period of September 2013 through May 2014, the addition of the prior reconciliation over-recovery shown on line 1, and the addition of the carrying costs for the January through May 2014 period, resulted in a YTD over-recovery of ($1.347) million (column G, line 11). Line 12 of Schedule 2 reflects DP&L's forecasted generation level sales for the period January through May 2014, which totals 1.394 billion kWh (column G). The Company derived its Reconciliation Adjustment of ($0.0009663) per kWh by dividing the total over-recovery of ($1.347) million by its forecasted sales for the period January through May 2014.

Exhibit 5-4. Forecasted Quarterly Rate – Workpaper 1, January through May 2014

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-426-EL-SSO
FUEL Rider

Line No.	(A) Description	(B) Jan-14	(C) Feb-14	(D) Mar-14	(E) Apr-14	(F) May-14	(G) Total
	Forecasted Costs ($)[1]						
1	Steam Plant Generation (501)	$7,383,040	$6,171,083	$5,227,099	$3,788,613	$3,537,661	$26,107,495
2	Steam Plant Fuel Oil Consumed (501)	$453,870	$392,019	$272,553	$207,023	$211,674	$1,537,140
3	Steam Plant Fuel Handling (501)	$221,658	$185,318	$156,958	$113,831	$106,257	$784,023
4	Steam Plant Gas Consumed (501)	$0	$0	$0	$0	$0	$0
5	Coal Sales (456)	$0	$0	$0	$0	$0	$0
6	Heating Oil Realized Gains or Losses (456)	($683)	($1,377)	$98	$45	$66	($1,851)
7	Allowances Consumed (509)	0	$0	$0	$0	$0	$0
8	Cost of Fuel, Gas and Diesel Peakers (547)	$157,062	$0	$0	$0	$0	$157,062
9	Purchased Power (555)	$2,240,950	$1,867,379	$1,718,226	$1,173,215	$1,315,140	$8,314,910
10	Purchased Power Realized Gain/Losses (421 & 426)	$0	$0	$0	$0	$0	$0
11	Allowance Sales (411.8 & 411.9)	$0	$0	$0	$0	$0	$0
12	Emission Fees (506)	$19,827	$20,183	$10,316	$9,374	$8,805	$68,505
13	Total Costs	$10,475,725	$8,634,606	$7,385,249	$5,292,101	$5,179,604	$36,967,284
14	Total Forecasted Generation Level Sales	403,073,923	328,738,313	278,847,822	195,698,807	187,971,318	1,394,330,183
15	Retail FUEL Rate $/kWh						$0.0265126
16	SSO Blend Percentage	90%					$0.0238613
	Reconciliation Adjustment						
17	Under (Over) Recovery						($1,347,318)
18	Forecasted RA Rate $/kWh						($0.0009663)

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
19	High Voltage & Substation	1.00583	$0.0230285
20	Primary	1.01732	$0.0232915
21	Secondary & Residential	1.04687	$0.0239681

Winter/Spring FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Total
22	High Voltage & Substation	6,806,180	4,470,480	2,970,487	4,703,869	4,167,401	23,118,416
23	Primary	4,153,182	3,947,042	3,339,561	3,290,062	3,329,727	18,059,575
24	Secondary & Residential	374,452,366	305,889,332	260,264,039	179,220,408	172,315,783	1,292,141,927
25	Total	385,411,728	314,306,854	266,574,087	187,214,339	179,812,911	1,333,319,918
	Standard Offer Revenue ($)						
26	High Voltage & Substation	$156,736	$102,948	$68,406	$108,323	$95,969	$532,382
27	Primary	$96,734	$91,933	$77,783	$76,630	$77,554	$420,635
28	Secondary & Residential	$8,974,912	$7,331,586	$6,238,035	$4,295,573	$4,130,082	$30,970,187
29	Total	$9,228,382	$7,526,467	$6,384,224	$4,480,526	$4,303,605	$31,923,204

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 the Fuel Rider for the period January through May 2014. Columns B, C, D, E, and F provide a breakout of the monthly forecasted expense amounts for the period January through May 2014, which totals $36.967 million as shown on column G, line 13 of Schedule 1. Lines 14 through 16 of Workpaper 1 reflect the forecasted amounts shown on Schedule 1 for DP&L's forecasted generation sales, retail Fuel rate, and the rate after applying the 90% SSO blend percentage. Lines 17 and 18 of Workpaper 1 reflect the over-recovery of $1.347 million and the forecasted RA rate of ($0.0009663) per kWh. Lines 19 through 21 of Workpaper 1 reflect the distribution line loss factors and forecasted Fuel rates at the distribution level, which are shown on Schedule 1 at lines 7 and 8, respectively, and were calculated by multiplying DP&L's forecasted retail Fuel rate by each of the distribution line loss factors. Lines 22 through 29 of Workpaper 1 reflect a breakout of DP&L's standard offer metered level sales and standard offer revenue forecast. Specifically, Columns B through F (lines 22-25) reflect the forecasted kWh for the High Voltage & Substation, Primary, and Secondary & Residential voltage levels by month for the January through May 2014 period. The forecasted kWh for each voltage level totaled 23.118 million kWh, 18.060 million kWh, and 1.292 billion kWh, respectively, resulting in an overall forecast totaling 1.333 billion kWh as shown on line 25. Lines 26-29 of Workpaper 1 reflect the Company's forecasted Fuel Rider revenue for each voltage level by month for the January through May 2014 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 standard offer revenue totals $31.923 million as shown on line 29 of Workpaper 1.

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

THE DAYTON POWER AND LIGHT COMPANY
Case No. 12-426-EL-SSO
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							($1,332,127)	$0	$0
2	Jan-14	($1,332,127)	$9,428,153	($9,228,382)	$199,771	($1,132,357)	($5,076)	($1,137,432)	($99,885)	($1,232,242)
3	Feb-14	($1,137,432)	$7,771,145	($7,526,467)	$244,678	($892,754)	($4,181)	($896,936)	($122,339)	($1,015,093)
4	Mar-14	($896,936)	$6,646,724	($6,384,224)	$262,500	($634,436)	($3,154)	($637,590)	($131,250)	($765,686)
5	Apr-14	($637,590)	$4,762,891	($4,480,526)	$282,365	($355,224)	($2,045)	($357,269)	($141,183)	($496,407)
6	May-14	($357,269)	$4,661,643	($4,303,605)	$358,038	$769	($734)	$34	($179,019)	($178,250)

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 May 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0009663). 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 amount 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 2014

Exhibit 5-6. Forecasted Quarterly Rate Summary, June through August 2014

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

Line No.	(A) Description	(B) Jun-14	(C) Jul-14	(D) Aug-14	(E) Total	(F) Source
1	Forecasted FUEL Costs	$7,454,474	$8,218,560	$7,848,761	$23,521,795	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	312,297,524	352,748,056	335,215,386	1,000,260,966	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh				$0.0235157	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh				$0.0023670	Schedule 2, Line 20
5	Forecasted Retail FUEL Rate $/kWh				$0.0258827	Line 3 + Line 4

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
6	Distribution Line Loss Factors	1.00583	1.01732	1.04687	Line Loss Study 2009
7	**FUEL Rates $/kWh**	**$0.0260336**	**$0.0263310**	**$0.0270958**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to be incurred during the period June through August 2014. As shown on line 1, DP&L's forecasted Fuel costs for the period June through August 2014 totaled $23.522 million (column E). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 1.000 billion kWh for the period June through August 2014. On line 3, the Company calculated its retail Fuel Rate before Reconciliation Adjustment, which totaled $0.0235157 per kWh, by dividing the forecasted Fuel costs of $23.522 million by the 1.000 billion kWh of forecasted Generation Level Retail Sales. The Company reflected a forecasted Reconciliation Adjustment rate for the period September 2013 through August 2014 (see Schedule 2 discussion below) of $0.0023670 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0.0235157 per kWh noted above to derive its forecasted retail Fuel rate of $0.0258827 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 $0.0260336, $0.0263310, and $0.0270958 cents per kWh as shown on line 7.

Exhibit 5-7. Reconciliation Adjustment – September 2013 through August 2014

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

Line No.	(A) Description	(B) Actual Fuel Costs	(C) Actual Revenue Recovery	(D) (Over)/Under (D) = (B) + (C)	(E) Carrying Costs	(F) Total (F) = (D) + (E)	(G) YTD[1]	(H) Source
1	Prior Period					$0	$0	Accounting Records
2	September-13	$8,978,305	($10,297,310)	($1,319,005)	$0	($1,319,005)	($1,319,005)	Accounting Records
3	October-13	$8,226,366	($8,298,782)	($72,416)	$0	($72,416)	($1,391,422)	Accounting Records
4	November-13	$8,672,253	($8,477,222)	$195,031	$0	$195,031	($1,196,391)	Accounting Records
5	December-13	$10,869,320	($9,490,321)	$1,378,999	$0	$1,378,999	$182,608	Accounting Records
6	January-14	$13,619,865	($11,057,984)	$2,561,880	$6,029	$2,567,909	$2,750,518	Accounting Records
7	February-14	$11,497,955	($10,927,437)	$570,518	$12,505	$583,023	$3,333,540	Accounting Records
8	March-14	$11,983,424	($9,037,325)	$2,946,100	$19,799	$2,965,899	$6,299,439	Accounting Records
9	April-14	$4,762,891	($4,480,526)	$282,365	$26,530	$308,895	$6,608,334	Corporate Forecast
10	May-14	$4,661,643	($4,303,605)	$358,038	$27,958	$385,996	$6,994,330	Corporate Forecast
11	June-14	$7,454,474	($7,454,474)	$0	$8,452	$8,452	$7,002,782	Corporate Forecast
12	July-14	$8,218,560	($8,218,560)	$0	$5,303	$5,303	$7,008,086	Corporate Forecast
13	August-14	$7,848,761	($7,848,761)	$0	$1,733	$1,733	$7,009,818	Corporate Forecast
14	(Over)/Under Recovery						$7,009,818	Line13
15	(Over)/Under Recovery Through May 2014						$6,994,330	Line 10
16	10% Quarterly Threshold						$2,352,179	(Sum of Column B. Lines 11 - 13) * 10%
17	Amount Exceeding Threshold						$4,642,151	Line 15 - Line 16
18	Total (Over)/Under Recovery						$2,367,668	Line 14 - Line 17
				Jun-14	Jul-14	Aug-14		
19	Forecasted Generation Level Sales			312,297,524	352,748,056	335,215,386	1,000,260,966	
20	**Forecasted RA Rate $/kWh**						$0.0023670	Line 18 / Line 19

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

Schedule 2: Column B of Schedule 2 reflects (1) DP&L's actual Fuel costs that were incurred for the period September 2013 through March 2014, and (2) DP&L's estimated Fuel costs for the period April through August 2014 for total actual and forecasted Fuel costs of $106.794 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($99.892) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $6.902 million, as shown in column D. Column E reflects the carrying costs for the period of January through August 2014, which totaled $108,309. The under-recovery for the period of September 2013 through August 2014 and the addition of the carrying costs for the January through August 2014 period resulted in a YTD under-recovery of $7.010 million (column G, line 14). Line 15 reflects the under-recovery of $6.994 million for the period of September 2013 through May 2014. The amount on Line 16 is referred to as the "10% Quarterly Threshold", and is calculated by multiplying the forecasted Fuel costs for the period June through August 2014 by 10% which totals $2.352 million. This calculation relates to the implementation of the Company's Reconciliation Rider (see additional discussion below). The 10% quarterly threshold was then subtracted from the under-recovery through May 2014 to calculate the "Amount Exceeding Threshold" of $4.642 million, as shown on line 17. The result is a total under-recovery of $2.368 million, which is derived by subtracting the amount exceeding the threshold from the under recovery through August 2014, as shown on line 18. Line 19 of Schedule 2 reflects DP&L's

forecasted generation level sales for the period June through August 2014, which totals 1.000 billion kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of ($0.0023670) per kWh by dividing the total under-recovery of $2.368 million by its forecasted sales for the period June through August 2014.

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.*

As discussed in further detail in a later section of this report, DP&L did file 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.

Exhibit 5-8. Forecasted Quarterly Rate – Workpaper 1, June through August 2014

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

Line No.	(A) Description	(B) Jun-14	(C) Jul-14	(D) Aug-14	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$5,203,977	$5,902,802	$5,558,123	$16,664,902
2	Steam Plant Fuel Oil Consumed (501)	$122,570	$134,769	$94,331	$351,670
3	Steam Plant Fuel Handling (501)	$156,119	$177,084	$166,744	$499,947
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)	($872)	($6,490)	($2,629)	($9,991)
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)	$1,964,904	$2,002,664	$2,025,050	$5,992,619
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)	$7,776	$7,730	$7,142	$22,648
13	Total Costs	$7,454,474	$8,218,560	$7,848,761	$23,521,795
14	Total Forecasted Generation Level Sales	312,297,524	352,748,056	335,215,386	1,000,260,966
15	Retail FUEL Rate $/kWh				$0.0235157
	Reconciliation Adjustment				
16	Under (Over) Recovery				$2,352,179
17	Forecasted RA Rate $/kWh				$0.0023670
	Line Loss Adjustment	Distribution Loss Factor[2]		Rate at Distribution Level	
18	High Voltage & Substation	1.00583		$0.0260336	
19	Primary	1.01732		$0.0263310	
20	Secondary & Residential	1.04687		$0.0270958	
	Summer FUEL Rider				
	Standard Offer Metered Level Sales (kWh)	Jun-14	Jul-14	Aug-14	Total
21	High Voltage & Substation	40,868,440	41,293,305	44,184,637	126,346,382
22	Primary	6,307,650	6,335,260	5,506,013	18,148,923
23	Secondary & Residential	253,023,938	291,228,854	272,495,285	816,748,077
24	Total	300,200,028	338,857,419	322,185,935	961,243,382
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$1,063,953	$1,075,013	$1,150,285	$3,289,251
26	Primary	$166,087	$166,814	$144,979	$477,879
27	Secondary & Residential	$6,855,886	$7,891,079	$7,383,478	$22,130,443
28	Total	$8,085,925	$9,132,906	$8,678,742	$25,897,573

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 June through August 2014. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for June through August 2014 which totals the $23.522 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 $2.352 million and the forecasted RA rate of ($0.0023670) 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 2014 period. For this three-month period, the forecasted kWh for each voltage level totals 126.346 million kWh, 18.149 million kWh, and 816.748 million kWh for the High Voltage & Substation, Primary and Secondary & Residential, respectively. The Company's forecast totals 961.243 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 2014 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 $25.898 million as shown on line 28.

Exhibit 5-9. 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 August 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0023670). 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 amount 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 2014

Exhibit 5-10. Forecasted Quarterly Rate Summary, September through November 2014

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

Line No.	(A) Description	(B) Sep-14	(C) Oct-14	(D) Nov-14	(E) Total	(F) Source
1	Forecasted FUEL Costs	$5,723,711	$5,581,179	$5,360,984	$16,665,874	Workpaper 1, Line 13
2	Forecasted Generation Level Sales	239,733,096	232,254,680	219,482,103	691,469,879	Workpaper 1, Line 14
3	FUEL Rate before Reconciliation Adjustment $/kWh				$0.0241021	Line 1 / Line 2
4	Reconciliation Adjustment $/kWh				$0.0024242	Schedule 2, Line 19
5	Forecasted Retail FUEL Rate $/kWh				$0.0265263	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**	**$0.0266809**	**$0.0269857**	**$0.0277696**	Line 5 * Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly Fuel costs it expected to be incurred during the period September through November 2014. As shown on line 1, DP&L's forecasted Fuel costs for the period September through November 2014 totaled $16.666 million (column E). As shown on line 2 of Schedule 1, the Company included its forecasted Generation Level Retail Sales which totaled 691.470 million kWh for the period September through November 2014. On line 3, the Company calculated its retail Fuel Rate before Reconciliation Adjustment, which totaled $0.0241021 per kWh, by dividing the forecasted Fuel costs of $16.666 million by the 691.470 million kWh of forecasted Generation Level Retail Sales. The Company reflected a forecasted Reconciliation Adjustment rate for the period January through November 2014 (see Schedule 2 discussion below) of $0.0024242 per kWh on line 4. DP&L added its Reconciliation Adjustment to the $0. 0241021 per kWh noted above to derive its forecasted retail Fuel rate of $0.0265263 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 $0.0266809 $0.0269857, and $0.0277696 cents per kWh as shown on line 7.

Exhibit 5-11. Reconciliation Adjustment – January through November 2014

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-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					$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	$10,845,445	($7,970,104)	($1,780,204) [2]	$35,424	($1,744,781)	$10,072,872	Accounting Records
8	July-14	$8,218,560	($9,132,906)	($914,346)	$39,609	($874,738)	$9,198,134	Corporate Forecast
9	August-14	$7,848,761	($8,678,742)	($829,981)	$36,179	($793,801)	$8,404,333	Corporate Forecast
10	September-14	$5,723,711	($5,723,711)	$0	$5,596	$5,596	$8,409,929	Corporate Forecast
11	October-14	$5,581,179	($5,581,179)	$0	$3,116	$3,116	$8,413,045	Corporate Forecast
12	November-14	$5,360,984	($5,360,984)	$0	$986	$986	$8,414,031	Corporate Forecast
13	(Over)/Under Recovery						$8,414,031	Line 12
14	(Over)/Under Recovery Through August 2014						$8,404,333	Line 9
15	10% Quarterly Threshold						$1,666,587	(Sum of Column B, Lines 10 - 12) * 10%
16	Amount Exceeding Threshold						$6,737,745	Line 14 - Line 15
17	Total (Over)/Under Recovery						$1,676,285	Line 13 - Line 16
				Sep-14	Oct-14	Nov-14		
18	Forecasted Generation Level Sales			239,733,096	232,254,680	219,482,103	691,469,879	
19	**Forecasted RA Rate $/kWh**						$0.0024242	Line 17 / Line 18

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

[2] June 2014 (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 2014, and (2) DP&L's estimated Fuel costs for the period July through November 2014 for total actual and forecasted Fuel costs of $99.749 million. Column C of Schedule 2 reflects DP&L's actual and forecasted revenues for the same period, which totaled ($87.100) million. The difference between the Company's actual and forecasted Fuel costs and revenues resulted in an under-recovery in the amount of $7.993 million, as shown in column D. Column E reflects the carrying costs for the period of January through November 2014, which totaled $225,060. The under-recovery for the period of January through November 2014 and the addition of the carrying costs for the same period resulted in a YTD under-recovery of $8.414 million (column G, line 13). Line 14 reflects the under-recovery of $8.404 million for the period of January through August 2014. The amount on Line 15 is the 10% Quarterly Threshold that is calculated by multiplying the forecasted Fuel costs for the period September through November 2014 by 10% which totals $1.667 million. This amount was then subtracted from the under-recovery through August 2014 to calculate the Amount Exceeding Threshold of $6.738 million, as shown on line 16. The result is a total under-recovery of $1.676 million, which is derived by subtracting the amount exceeding the threshold from the under recovery through August 2014, as shown on line 17. Line 18 of Schedule 2 reflects DP&L's forecasted

Exhibit 5-12. Forecasted Quarterly Rate – Workpaper 1, June through August 2013

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

Line No.	(A) Description	(B) Sep-14	(C) Oct-14	(D) Nov-14	(E) Total
	Forecasted Costs ($)[1]				
1	Steam Plant Generation (501)	$3,774,664	$3,702,556	$3,350,591	$10,827,811
2	Steam Plant Fuel Oil Consumed (501)	$90,518	$73,967	$84,939	$249,423
3	Steam Plant Fuel Handling (501)	$113,240	$111,077	$100,518	$324,834
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)	($938)	($1,965)	$18,278	$15,376
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)	$1,740,305	$1,688,549	$1,800,074	$5,228,928
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)	$5,921	$6,995	$6,585	$19,502
13	Total Costs	$5,723,711	$5,581,179	$5,360,984	$16,665,874
14	Total Forecasted Generation Level Sales	239,733,096	232,254,680	219,482,103	691,469,879
15	Retail FUEL Rate $/kWh				$0.0241021
	Reconciliation Adjustment				
16	Under (Over) Recovery				$1,666,587
17	Forecasted RA Rate $/kWh				$0.0024242

Line No.	Line Loss Adjustment	Distribution Loss Factor[2]	Rate at Distribution Level
18	High Voltage & Substation	1.00583	$0.0266809
19	Primary	1.01732	$0.0269857
20	Secondary & Residential	1.04687	$0.0277696

Fall FUEL Rider

Line No.	Standard Offer Metered Level Sales (kWh)	Sep-14	Oct-14	Nov-14	Total
21	High Voltage & Substation	36,490,124	40,826,390	35,527,120	112,843,634
22	Primary	6,157,783	5,735,998	5,462,544	17,356,326
23	Secondary & Residential	187,956,287	177,056,297	170,212,830	535,225,414
24	Total	230,604,195	223,618,686	211,202,493	665,425,374
	Standard Offer Revenue ($)				
25	High Voltage & Substation	$973,589	$1,089,285	$947,896	$3,010,770
26	Primary	$166,172	$154,790	$147,411	$468,373
27	Secondary & Residential	$5,219,471	$4,916,783	$4,726,742	$14,862,996
28	Total	$6,359,232	$6,160,857	$5,822,048	$18,342,138

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

generation level sales for the period September through November 2014, which totals 691.470 million kWh (column G). Finally, the Company derived its forecasted Reconciliation Adjustment of ($0.0024242) per kWh by dividing the total under-recovery of $1.676 million by its forecasted sales for the period September through November 2014.

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 2014. Columns B, C and D provide a breakout of the forecasted amounts associated with each expense category for September through November 2014 which totals the $16.666 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 $1.667 million and the forecasted RA rate of ($0.0024242) 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 2014 period. For this three-month period, the forecasted kWh for each voltage level totals 112.844 million kWh, 17.356 million kWh, and 535.225 million kWh for the High Voltage & Substation, Primary and Secondary & Residential, respectively. The Company's forecast totals 665.425 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 2014 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 $18.342 million as shown on line 28.

Exhibit 5-13. Calculation of Carrying Costs – Workpaper 2, January through November 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.	Period	First of Month Balance	New FUEL Rider Costs	Amount Collected FUEL Rider (CR)	NET AMOUNT	End of Month before Carrying Cost	Carrying Cost[2]	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) = (L) * (COD% / 12)	(I) = (G) + (H)	(J) = - (F) * 0.5	(K) = (G) + (J)
1	Prior Period							$195,730	$0	$0
2	Jan-14	$195,730	$13,619,865	($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	($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	($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	($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	($6,172,374)	$4,373,238	$11,778,143	$39,509	$11,817,652	($2,186,619)	$9,591,524
7	Jun-14	$7,162,107 [1]	$10,845,445	($7,970,104)	$2,875,341	$10,037,448	$35,424	$10,072,872	($1,437,670)	$8,599,777
8	Jul-14	$10,072,872	$8,218,560	($9,132,906)	($914,346)	$9,158,526	$39,609	$9,198,134	$457,173	$9,615,699
9	Aug-14	$9,198,134	$7,848,761	($8,678,742)	($829,981)	$8,368,154	$36,179	$8,404,333	$414,990	$8,783,144
10	Sep-14	$1,676,285 [1]	$5,723,711	($6,359,232)	($635,522)	$1,040,764	$5,596	$1,046,360	$317,761	$1,358,524
11	Oct-14	$1,046,360	$5,581,179	($6,160,857)	($579,678)	$466,681	$3,116	$469,797	$289,839	$756,520
12	Nov-14	$469,797	$5,360,984	($5,822,048)	($461,064)	$8,733	$986	$9,719	$230,532	$239,265

[1] First of Month Balance is equal to May 2014 End of Month Balance minus the amount exceeding the 10% threshold from the previous quarterly Fuel Rider filing.

[2] 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 through November 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0024242). 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 amount are then flowed through to Schedule 2 and included in the calculation of the forecasted reconciliation adjustment rate.

Quarterly FUEL Rider Filing – December 2014 through February 2015

Exhibit 5-14. 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

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
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 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 5-15. Reconciliation Adjustment – January 2014 through February 2015

THE DAYTON POWER AND LIGHT COMPANY
Case No. 14-117-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					$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 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.

Exhibit 5-16. 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 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

	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 5-17. 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. (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[1] (I) (I) = (L) * (COD% / 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								$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 5-18. 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

Line No.	FUEL Rates at Distribution Level:	High Voltage & Substation	Primary	Secondary & Residential	Source
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 5-19. 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

Exhibit 5-20. 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

$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.

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 5-21. 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 5-22. 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 5-23. 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 January 2014 through February 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

Exhibit 5-24. 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

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.

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 5-25. 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)	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	$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.

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:[10]

> 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.

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[11]. 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 2014 review period.

---

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

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

The Company's responses to data requests LA-2014-1-51and LA-2014-1-52 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-2014-2-4, DP&L provided a summary of variances between forecasted and actual 2014 Fuel Rider revenues and expenses, which is replicated in Exhibit 5-26 below.

Exhibit 5-26. Summary of Variances Between Forecast And Actual FUEL Rider Revenues and Costs during 2014

[redacted]

During 2014, DP&L *continued to experience customer switching to alternative providers*[12], including DP&L's affiliate, DPLER. 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 an earlier section of this report, DP&L has attempted to mitigate the impacts of customer switching on the deferral balance with the implementation of the RR-N, 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-2014-1-61 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 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, the Company stated that providing estimates with any precision is not possible. DP&L also stated that any true-ups necessary to align actual Fuel costs and actual Fuel recovery since the initiation of the Fuel Rider through the end of 2015 and attributable to that period will be reflected in the RR-N at the beginning of 2016 and that it will propose collection as part of its Reconciliation Rider non-bypassable filing.

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"[13] 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.

[12] 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.

[13] 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.

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-2014-1-1 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>

The Corporate Accounting Department oversees DP&L's coal accounting process. Information obtained from DP&L's three operated generation stations[14], the Risk Management/Commodity Settlement Department and Fuel bills from Cincinnati Gas & Electric ("DUKE") 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[15] 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]

[14] DP&L's operated generation stations include the O.H. Hutchings, J.M. Stuart and Killen generating stations.

[15] 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]

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 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]

[16] The FMS is an integrated, Fuel planning, procurement, logistics, inventory and cost accounting system, which integrates data from multiple plants, storage facilities and vendors with information on availability, transportation and quality.

[17] CCD/CD refers to DP&L's partners at its jointly owned generating stations. CCD is comprised of Cincinnati Gas & Electric ("DUKE"), Columbus Southern Power ("AEP") and DP&L and CD is comprised of DUKE and DP&L. DP&L operates J.M Stuart on behalf of CCD and Killen on behalf of CD. AEP operates Conesville #4 on behalf of CCD and DUKE operates Beckjord #6 and Zimmer on behalf of CCD and East Bend and Miami Fort on behalf of CD.

[18] Gas Deal Entry System ("GDES") is an integrated, Fuel planning, procurement, logistics, inventory and cost accounting system used for peaker gas. GDES integrates information from pipelines, trader deals and multiple plants.

[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 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]

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 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]

[redacted]

[redacted]

[redacted]

[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[19] 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 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]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[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]

[redacted]

The contractor's inventory reports shall include the following results:

[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]

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

[20] 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.

Coal Sales Billing

[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]

[redacted]

Larkin also reviewed the Company's procedures for weighing, testing, and reporting coal burned per data request LA-2014-1-2. The specific information provided, which pertained to the Stuart generation station, included the following:

[redacted]

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

[redacted]

[redacted]

Jointly Owned Generation

According to the response to LA-2014-1-4, 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 2014 Form 10-K states that DP&L has undivided ownership interests in five jointly owned coal generation facilities, which are provided in Exhibit 5-27.

[21] PJM sales estimates are trued-up in the following calendar month.

[22] A MISO settlement statement which lists any true-ups to sales and purchases is provided to the Accounting Department the following month.

Exhibit 5-27. DP&L's Ownership Percentage of Jointly Owned Power Plants[23]

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

As noted in Exhibit 1-22, Beckjord Unit #6 and East Bend are not listed despite LA-2014-1-4 stating that the Company participates in seven jointly owned power plants (including Beckjord Unit #6 and East Bend as noted above). According to the response to LA-2014-OS-4, 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 2014.

As for East Bend, the Company stated during the onsite interviews that DP&L sold its interest in East Bend to Duke Energy Kentucky in December 2014. In LA-2014-OS-8, Larkin requested that the Company provide all of the accounting detail and other relevant documentation related to the coal inventory and Fuel cost impacts from the sale of East Bend to Duke Energy Kentucky. In response, DP&L provided the relevant journal entries and related support along with other documentation, including a letter from DP&L to FERC dated April 22, 2015, which stated in part:

> *On December 30, 2014, Dayton Power & Light ("DP&L") sold its 31% ownership interest (186 MW) in East Bend Unit 2 to Duke Energy, Kentucky, Inc. ("DEK"). The Federal Energy Regulatory Commission approved this transaction on July 16, 2014, in Duke Energy Kentucky, Inc., Docket No. EC14-103-000. The Public Utilities Commission of Ohio ("PUCO") approved DP&L's sale to DEK on September 17, 2014, in PUCO Case No. 14-1084-EL-UNC.*

Included with the journal entry supporting documentation is an intercompany email dated December 17, 2014 which stated in part:

> *The recordation of the sale of DP&L's ownership share in the East Bend Plant to Duke Energy will be recorded in December 2014 business based on book values at November 30, 2014.*
>
> *Any resulting balances in these accounts at December 31, 2014, which pertain to the East Bend Plant will be eliminated in the first quarter of 2015 in conjunction with a true-up of the net settlement amount of the sale. Generally, the*

[23] 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%.

adjustments to the inventory and liability accounts that are recorded next year will have a corresponding impact to the net settlement amount with little impact to the gain recognized on the sale.

The journal entry from December 2014 reflects the elimination of the East Bend coal inventory balance of 79,438 tons at a value of $3,379,963, which corresponds with the November 2014 Coal Ending Balance sheet that was provided in response to EVA-2014-1-21. In addition, a second journal entry from February 2015 reflects the elimination of an additional 3,753 tons valued at $155,060. An intercompany email attached to the February 2015 journal entry support states in part:

Attached are the final sale true-up entries pertaining to East Bend Plant inventories and inter-company liabilities. These entries provide for the final eliminations of the December 30, 2014, sale of DP&L's ownership interest in the East Bend Plant. Please record these sale true-up entries in February 2015 business.

Larkin had requested that the Company explain whether any cost or financial impacts of the East Bend sale to Duke Energy Kentucky in December 2014 affected the Fuel Rider. In response to LA-2014-OS-9, DP&L stated that there were no costs or other effects 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 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:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[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-2014-1-5, 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-2014-1-5 also included a summary of the Company's deferral amounts (by FERC account) as of December 31, 2014. This summary, which is reproduced in Exhibit 5-28, used the overall deferred balance as of December 31, 2013 as the starting point.

Exhibit 5-28. DP&L's Deferral Amounts by FERC Account as of December 31, 2014

[redacted]

Review Related to Coal Order Processing

According to the response to EVA-2014-1-3, 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-2014-1-1 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 2014. This documentation was provided in the response to data request LA-2014-1-9.

The information provided in LA-2014-1-9 included a summary of payment vouchers and invoices for the period July 2014. For each invoice listed on the 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-2014-1-10 requested DP&L's Fuel ledgers for the period January through December 2014. In response, DP&L referred to the response to LA-2014-1-70, 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).

BTU Adjustments

Data request LA-2014-1-11 asked DP&L to provide documentation for Btu adjustments for Fuel purchases recorded in July 2014. [redacted]

> [redacted]

Pursuant to the narrative above, the responses to LA-2014-15 and LA-2014-26 refer to the response to LA-2014-1-11.

Freight And Barge Vouchers

Data request LA-2014-1-12 asked DP&L to provide freight cash vouchers for two days of coal receipts in July 2014 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 2014.

In data request LA-2014-1-13, Larkin requested that DP&L provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2014 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. DP&L's barging services are provided by [redacted]. In its confidential response, DP&L provided copies of invoices from Ingram, cash vouchers as well as Invoice Detail sheets,

[24] Larkin modified the narrative to reference data requests related to the 2014 review period.

which included data related to coal shipments received at the Killen and Stuart plants during July 2014 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-2014-1-14 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

DP&L has a coal supply agreement with [redacted]

Data request LA-2014-1-16 asked that DP&L identify all pending or approved retroactive escalations that affect Fuel cost for the period January through December 2014. [redacted]

[redacted]

[redacted]

In terms of other retroactive escalations, the response to LA-2014-1-16, referencing EVA-2014-1-15, also stated that there are [redacted] Each claim is summarized below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted an onsite field visit at DP&L's Stuart Generation station on June 25, 2015. Document requests LA-2014-1-18 through LA-2014-1-44 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-2014-1-18, and is as follows:

[redacted]

According to LA-2014-1-19, DP&L weighs the coal as received in the following manner:

For the Stuart and Killen plants:

[redacted]

[redacted]

[redacted]

[redacted]

The Company resolves freight bill and car number discrepancies in the following manner:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

In its confidential response to LA-2014-1-20, the Company stated that [redacted]

The procedures for how damaged cars are checked and who instigates claims for shortages are as follows:

[redacted]

[redacted]

[redacted]

In a related question, LA-2014-1-35 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]

[redacted]

[redacted]

[redacted]

[redacted]

In response to data request LA-2014-1-36, DP&L described how damaged barges are checked and who instigates claims for shortages:

[redacted]

DP&L's response to LA-2014-1-22 described the Company's month-end cut-off procedures for coal deliveries and coal burn:

[redacted]

A description of the Company's coal sampling procedures was provided in response to data request LA-2014-1-23 and are as follows:

[redacted]

[redacted]

[redacted]

Scale calibration logs for the period January through July 2014 were requested in LA-2014-1-24. 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]

DP&L's procedures for handling coal from the stockpile to the firebox or boiler were requested with data request LA-2014-1-27. 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 5-29. Diagram of Coal Barge Configuration and Coal Loading Specifications at the Stuart Station

[redacted]

DP&L's procedures for taking physical inventories of coal are described in the response to LA-2014-1-28. 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-2014-1-30, 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
- FMS Period Posting Summary Reports
- Letters from Mikon Corporation (consulting engineers who conducted the inventory)
- FMS to Oracle G/L Control Reports
- Journal voucher for Fuel Oil Inventory adjustments
- General Ledgers for Accounts 151 (Fuel Inventory) and 501 (Fuel Consumption)
- Narrative which addresses the 2014 Coal Pile Inventory error

Larkin reviewed DP&L's records and was able to trace the amounts from the FMS 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 physical inventory adjustment of [redacted] tons ([redacted]). 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 5-30 below.

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

[redacted]

As reflected in the Exhibit 5-30, 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]. The dollar impact of the Killen inventory adjustment is summarized in Exhibit 5-31 below.

Exhibit 5-31. Summary of Physical Coal Inventory Adjustment at Killen

[redacted]

As reflected in the Exhibit 5-31, Killen's physical inventory was [redacted] after applying DP&L's ownership percentage).

The Killen inventory adjustment was the subject of an internal audit conducted by AES' Internal Audit group ("IA"), the report of which was issued on October 24, 2014[25].

As noted above, DP&L made a substantial adjustment to increase coal inventory at Stuart Station by [redacted]. Upon Larkin's inquiry during its field visit to Stuart Station on June 25, 2015, the Company stated that a root cause analysis to determine the specific reason(s) for the substantial inventory adjustment had not been requested by the Accounting Department. Larkin inquired as to whether DP&L intends to conduct such a root cause analysis, and if so, to state when the analysis would be conducted. In response to LA-2014-OS-15, the

[25] A copy of this internal audit report was provided in the response to EVA-2014-1-43.

Company stated that it had conducted an additional review in accordance with Accounting Policy FA-40.A01 - Fuel Inventories: Accounting for Coal Purchases, Consumption and Inventory. Specifically, DP&L cited Section 5.6.1 of this policy which states:

> *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 12-month (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.*

Using the guidance set forth by Section 5.6.1, the Company stated that the Accounting Department requested that Stuart Station personnel conduct an additional review of the large physical coal inventory adjustment. Pursuant to that review, the Company provided the following narrative in its response to LA-2014-OS-15, which is titled "J.M. Stuart Station: 2014 Coal Pile Inventory Error Discussion" and in which possible reasons for the coal inventory variance are discussed:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

In light of this additional review, DP&L stated that there are no plans to conduct a root cause analysis since the Accounting Policy cited above was followed.

As discussed in the management section of this report, EVA is recommending that DP&L conduct a proper root cause analysis to determine the reason(s) for the substantial physical inventory variance at Stuart. Larkin concurs with EVA's recommendation.

The Company's response to LA-2014-1-31 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 departments for cross-checking 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 2014 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-2014-1-34 provided copies of generating station reports for Killen and Stuart for the period January through December 2014. Attachments to LA-2014-1-34 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 Stuart generating station includes details on the following datasets.

Exhibit 5-32. Generating Unit Datasets Used In Stuart Station Monthly Operating Reports for 2014

Gross Generation, MWH		Heat/Coal, MMBTU
Aux. Usage MWh		Total Heat, MMBTU
Net Generation, MWH		Steam Gen., KLBS
Net HR, BTU/KWH		Coal Equiv Oil, KLBS
Coal Burned, Tons		Oil Ht Val, BTU/GAL
Station Power Ratio %		Oil on Hand
Capacity Factor %		Oil Received, GAL
Wtr. Rt. LB/KWH Gr		Diesel, MWH
Evap. Rate, LB/LB		Diesel Oil, Gal
Make Up, KLBS		Total Oil, Gal
Make Up %		Service Oil, GAL
Coal Rt. LB/KWH Gr		Heat in Service Oil
Coal Ht Val, BTU/LB		Start Up Oil, GAL
Gross Peak		Heat in Start Up Oil
Day/Time Gr Peak		Auxiliary Boiler Oil
Net Peak		Heat in Aux Boiler Oil
Day/Time Net Peak		Heat in Oil
Service Hours		Limestone Usage

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

Data Request LA-2014-1-37 asked for the base coal inventory amounts at Stuart Station for both total plant and DP&L's share for 2013 and 2014 that shows any adjustments. In response, the Company provided the amounts shown in Exhibit 5-33 and stated that [redacted]

Exhibit 5-33. Base Coal Inventory at Stuart Station for 2013 and 2014

[redacted]

Review Related to Coal Transfers Between Generating Stations

Documentation related to the treatment of coal transfers between power plants was requested in LA-2014-1-39. DP&L's response to LA-2014-1-39 referred to the response to LA-2014-1-87, Attachment F. The documentation provided in that attachment related to four coal transfers from Stuart to Killen. Two of the transfers occurred in September 2014 and the remaining two occurred in December 2014. The specifics of each of the four coal transfers are discussed below.

<u>First Coal Transfer - September 2014</u>

According to the response to LA-2014-OS-14, the first coal transfer of [redacted] tons of [redacted] from Stuart to Killen occurred in early September 2014 and was done to address [redacted]. The components related to this transfer are summarized in Exhibit 5-34 below.

Exhibit 5-34. Summary of [redacted] Transfer from Stuart to Killen in September 2014

[redacted]

As shown in Exhibit 5-34, this transfer resulted in a [redacted] to Stuart. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2014-70 and confirmed that the [redacted] was posted as a [redacted] to FERC Account 456 in September 2014.

<u>Second Coal Transfer - September 2014</u>

According to LA-2014-OS-14, the second coal transfer in September 2014 involved [redacted] tons that were transferred from Stuart to Killen because Stuart [redacted]. DP&L further stated that the transfer was completed [redacted]. The components related to this transfer are summarized in Exhibit 5-35 below.

Exhibit 5-35. Summary of Second Coal Transfer from Stuart to Killen in September 2014

[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-2014-70 and confirmed that the [redacted] was posted as a credit to FERC Account 456 in September 2014.

<u>Coal Transfers - December 2014</u>
As noted above, the documentation provided in LA-2014-1-87, Attachment F indicated that two coal transfers from Stuart to Killen occurred during December 2014. In response to LA-2014-OS-14, DP&L stated that coal that had been committed to Stuart was diverted to Killen prior to the barges reaching Stuart. [redacted]. The specific coal transferred to Killen was from [redacted], [redacted] Coal Sales, [redacted], and [redacted] Company. The components related to these transfers are summarized in Exhibits 5-36 and 5-37 below.

Exhibit 5-36. Summary of First Coal Transfer from Stuart to Killen in December 2014

[redacted]

Exhibit 5-37. Summary of Second Coal Transfer from Stuart to Killen in December 2014

[redacted]

As shown in Exhibits 5-36 and 5-37, these transfers resulted in [redacted] to Stuart of [redacted]. Larkin reviewed the detailed general ledger for FERC Account 456 that was provided in LA-2014-1-70 and confirmed that the [redacted] were posted as [redacted] to FERC Account 456 in ember 2014.

It was unclear whether the [redacted] from the two coal transfers from September 2014 which totaled $[redacted] and the two coal transfers from December 2014 which totaled [redacted] flowed through the Fuel Rider. Upon Larkin's follow-up inquiry, in response to LA-2014-2-1, DP&L stated that the [redacted] totaling [redacted] for the September 2014 transfers were embedded in a gain for Stuart in the amount of [redacted], which was recorded in September 2014. In addition, the Company stated that the gains totaling [redacted] for the December 2014 transfers were embedded in a [redacted] for Stuart in the amount of [redacted]. DP&L stated that the $[redacted] related to a journal entry for a [redacted], which is recorded monthly to true-up the difference between [redacted]. Larkin confirmed that the Stuart related gains totaling [redacted] were reflected in the monthly Excel workbooks for September and December 2014, respectively (provided in LA-2014-1-52). However, Larkin noted that the

Company allocated approximately [redacted]% of the September Stuart gain, and approximately [redacted]% of the December Stuart gain to wholesale coal sales. For both September and December, DP&L stated in the response to LA-2014-2-1 that the majority of the Stuart [redacted] were allocated to wholesale coal sales due to the stacking of costs for those months.

In order to determine whether the coal that was the subject of the transfers was allocated to wholesale sales in a manner that was proportionate to how the related gains were allocated, Larkin asked DP&L to state when the coal that was transferred from Stuart to Killen in September and December 2014 was actually purchased and the costs flowed through the Fuel Rider. In response to Larkin's inquiry, the Company stated the weighted average cost of inventory ("WACI") used to record coal consumption was updated as of the unload date. Therefore, the relevant coal purchases impacted the Fuel Rider in the same months (September and December) of 2014 in which the gains from the aforementioned coal transfers were recorded. Larkin reviewed the monthly Excel workbooks for September and December 2014 and noted that the fuel purchases related to Stuart in those months were allocated to wholesale sales by [redacted]% and [redacted]%, respectively. While these percentages are slightly different than the allocation percentages of the related coal [redacted], Larkin considered the differences immaterial.

Hutchings Generating Station

As discussed in an earlier section of this report, Hutchings Unit 4 has been retired and per an agreement between DP&L and the EPA, the remaining Hutchings units cannot be operated on coal after October 31, 2013. The response to EVA-2014-1-21, which had requested the beginning and end of month inventory levels by plant and coal type during 2014, indicated that for Hutchings, the Company reflected the December 31, 2013 coal balance of [redacted] tons, valued at [redacted] in January and February 2014. However, as of March 2014, the [redacted] tons indicated a revised value of [redacted]. The response to LA-2014-OS-11 indicated that the [redacted] change in value was due to the Hutchings coal pile being revalued in March 2014. DP&L reflected the [redacted] tons at the revised value of [redacted] on its books through October 2014, but as of November, these amounts are zeroed out. Data request LA-2014-OS-11 had requested that DP&L show how the remaining Hutchings coal inventory was disposed of and accounted for in 2014 and to quantify and explain any impacts that the disposition of Hutchings coal inventory had on the Fuel Rider. In response, DP&L provided the following summary of the journal entry related to the disposition of Hutchings coal inventory:

Exhibit 5-38. Hutchings Coal Disposition - 2014

[redacted]

DP&L stated that the journal entries related to the disposition of Hutchings coal did not flow through the Fuel Rider and that no costs associated with these tons were charged to the Fuel Rider since such costs are booked only as used and not as received.

Review Related To Fuel Supplies Owned Or Controlled By The Company

DP&L's confidential response to data request LA-2014-1-45 stated that [redacted].

Review Related To Purchased Power

DP&L's response to LA-2014-1-46 provided documentation relating to the review of purchased power. Specifically, LA-2014-1-46 asked "For DPL, for purchases of power recorded in July 2014 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].

Larkin was able to trace the amounts from purchase power invoices and [redacted] to the general ledger and/or the RA workpapers provided with LA-2014-1-52 (see additional discussion below). As it relates to the weekly [redacted], the Company provided the following narrative:

> [redacted]
>
> [redacted]
>
> [redacted]

[26] DP&L stated that the "Fuel Recovery 2010" documents represent the Company's general ledger.

[redacted]

Through reviewing the "Fuel Clause Purchase Sale Summary – July 2014 – PJM Summary" (PJM Reconciliation), Larkin was able to tie out the July 2014 power purchases from PJM to the amounts included in the FUEL Rider. Other than some immaterial variances, no exceptions were noted.

With respect to system dispatch, Data Request LA-2014-1-47 inquired as to whether the dispatch related to the Company's generating units were under the control of PJM during the January through December 2014 review period. In its confidential response, DP&L stated [redacted]

LA-2014-1-48 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, DP&L stated [redacted]

Exhibit 5-39. "Must Run" Generating Units For Tait CT 3 for Transmission Constraint - May 2014

[redacted]

Exhibit 5-40. "Must Run" Generating Units For Stuart Diesel for Transmission Constraint - May 2014

[redacted]

Exhibit 5-41. "Must Run" Generating Units For Stuart Diesel for Voltage Control - October 2014

[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-2014-1-41 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-2014-1-40, during the 2014 review period, [redacted].

As discussed above, during 2014, [redacted], which is substantially higher than 2013 levels, and slightly higher, but generally on par with 2012 as summarized in the following exhibit:

Exhibit 5-42. Net Demurrage Charges For Years 2012 through 2014

[redacted]

It should be noted that the schedules provided in LA-2014-1-40 and LA-2014-1-42 (from which the amounts in Exhibit 5-42 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-2014-1-43:

[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-2014-1-49 and LA-2014-1-50.

Exhibit 5-43 illustrates a few examples of the longest forced outages at DP&L's generating units during 2014 from DP&L's response to part 1 of LA-2014-1-50:

Exhibit 5-43. Examples of Longest Forced Outages

[redacted]

Data request LA-2014-1-49 asked about customer power supply interruptions during the review period January through December 2014. 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 2014 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-2014-1-50 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-2014-1-50 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 5-43 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-2014-1-52 as well as LA-2014-1-54 through LA-2014-1-57.

Data request LA-2014-1-51 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 2014 review period. In response, DP&L provided Fuel Cost forecasts for January-May, June-August, September-November, and December 2014. DP&L also provided the related revenue class to tariff class conversions.

LA-2014-1-52 asked for a complete set of supporting workpapers for all calculations in the FUEL Rider filings for the review period January through December 2014 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 2014 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 – These tabs have been modified for the 2014 review period and are where the retail costs and revenues are allocated between retail, billed, unbilled and carrying costs (see additional discussion below).

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.

As noted above, the Company modified its monthly Excel workbooks for the 2014 review period. Specifically, prior to the 2014 review period, DP&L retail and DPLER related costs were combined on Tab .7 then flowed through to Tab .6, which was titled "DP&L Allocation". This tab had started with the total combined retail and DPLER costs included in the FERC accounts referenced above. Then there was an allocation between DPLER and DP&L retail based on the ratio of DP&L's and DPLER's monthly MWh to the total billed monthly MWh. However, during the interviews conducted on June 24, 2015, the Company stated that beginning with 2014 review period, the Risk Management Group provided Accounting with the Standard Service Offer ("SSO") retail MWh exclusively, thus negating the need to allocate the retail costs between DP&L and DPLER. As a result of this modification, Tab .6 now reflects the calculation of the carrying costs for the over or under recovery of the Fuel deferral.

From there, the DP&L retail costs then flow through to Tab .5, which is titled "Allocation 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, pursuant to the modifications that DP&L made to the monthly Excel workbooks, as discussed above, Tab .5 now 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 2010 Oracle Report" and represents amounts recorded in the general ledger.

Larkin had selected July 2014 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-2014-1-71, LA-2014-1-72, and LA-2014-1-75 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 2014 actual RA Fuel costs and revenues. In response, the Company provided detailed support from its internal accounting systems for the July 2014 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 2014 (provided in LA-2014-1-52), which in turn was traced to the RA adjustment in the quarterly Fuel Rider filing dated October 17, 2014 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 2014.

LA-2014-1-53 asked whether DP&L engaged in "active management" of its Fuel, purchased power, or emission allowance positions during the January through December 2014 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-2014-1-54</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-2014-55</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-2014-1-54 and LA-2014-1-55 was provided in LA-2014-1-52. In its responses to LA-2014-1-54 and LA-2014-1-55 (which were combined into a single response), DP&L discussed four adjustments that it made during the review period and which are summarized in Exhibit 5-44 below.

Exhibit 5-44. 2014 Adjustments to Fuel Rider

[redacted]

The Company provided documentation which showed how each of the four adjustments was derived. The second adjustment listed in the exhibit above of [redacted] relates to the disallowance of Optimizations J and K pursuant to EVAs recommendation in the 2012 Fuel audit and addressed in the PUCO's Order and Opinion dated August 20, 2014 in Case No. 12-2881-EL-FAC.

The three adjustments related to reclassifying the Fuel deferral balance which exceeds the 10% threshold pertains 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 RR-N, DP&L filed three separate applications in Case No. 14-0629-EL-RDR to include rider amounts above the 10% threshold, which the Commission approved in its Finding and Orders dated May 28, 2014, August 20, 2014 and November 20, 2014. Larkin noted that DP&L reflected these four adjustments in the relevant monthly Excel workbooks that were provided in LA-2014-1-52 as well as the quarterly Fuel Rider filings.

As noted previously, Larkin selected July 2014 as its test month for the 2014 review of the Fuel Rider. As such, data requests LA-2014-1-71 and LA-2014-1-72 requested the Company to provide the following data:

<u>LA-2014-1-71</u>
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 2014 actual RA Fuel costs.

<u>LA-2014-1-72</u>
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 2014 actual RA Fuel revenue.

As noted above, in the combined response to LA-2014-71 & 72, DP&L provided detailed support for the amounts reflected in the monthly Excel workbook for July 2014 (provided in LA-2014-52)[27].

[27] Data requests LA-2014--173 and LA-2014-1-74 requested similar actual Fuel revenue and expense data for January 2014.

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.

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 2014. In response to LA-2014-1-80, the Company stated:

> There were no costs related to 2014 Optimizations included in DP&L's Fuel Rider for any months of 2014.

In a related question, Larkin asked DP&L whether there were any adjustments, costs or credits to recorded Fuel costs during 2014 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-2014-1-81, DP&L stated in part:

> There were no adjustments, costs, or credits to Fuel cost recorded in 2014 related to any prior years.

Upon reviewing the monthly Excel workbooks that were provided in LA-2014-1-52, Larkin confirmed that no system optimization transactions flowed through the Fuel Rider during 2014.

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-2014-1-58 through LA-2014-1-60.

Data request LA-2014-1-58 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-2014-1-1-5 and LA-2014-1-1-70.

Data request LA-2014-1-59 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-2014-1-70.

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-2014-1-68 asked the Company to explain fully and in detail the methodology developed for updating the ratios used to determine the jurisdictional share of emission allowance sales proceeds. In response, DP&L referred to allocation schedules that were provided in the response to LA-2014-1-67. The Company stated that these schedules, from which a 12-month rolling average is calculated, are used to derive the allocation factors to determine the jurisdictional share of emission allowance sales. Larkin compared the monthly allocation schedules provided in LA-2014-1-67 to the monthly Excel workbooks provided in LA-2014-1-52 and confirmed that, with one minor exception, the allocation factors tied out between the two sets of schedules. The one exception was in July whereby the allocation schedule provided in LA-2014-1-67 indicated a wholesale emission allowance percentage of 33% whereas the monthly Excel workbook for July indicated a wholesale emission allowance percentage of 34%.

In terms of emission allowance purchases, sales and gains and losses flowing through the Fuel Rider, with the exception of May, which reflected a credit of [redacted] there was no activity in FERC Accounts 411.8 and 411.9 during 2014. In a related data request, the Company's response to EVA-2014-1-30 stated:

> [redacted]

[redacted]

Data request LA-2014-1-60 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 referred to the responses to LA-2014-67 and LA-2014-68, with the attachments to LA-2014-1-67 showed the EA allocations between native and non-native customers.

DP&L's response to LA-2014-1-60 also included an attachment that 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 2014 review period.

Exhibit 5-45. DP&L Emission Allowance Inventory

[redacted]

Larkin requested that DP&L provide documentation related to the purchase of annual NOx allowances in 2015 to meet the 2014 requirement including quantity, price, transaction dates, associated accounting (journal entries) and related invoices. In its response to LA-2014-1-69, the Company stated [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 2014, which were provided in the confidential response to data request LA-2014-1-77. This sample included eight 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 Rdr". No exceptions were noted as reflected in Exhibit 1-43 below. Larkin then compared the results of its analysis to a summary sheet that was provided in LA-2014-1-77, and which contained calculations similar to those performed by Larkin. Again, no exceptions were noted.

Exhibit 5-46. Summary of Customer Bill Analysis

Tariff Class	Rate	Fuel Rate	Usage	Calculated Total	Bill Amount	Difference
Residential	111	0.0270958	1,729	$ 46.85	$ 46.85	$ -
Residential Heat	141	0.0270958	1,900	$ 51.48	$ 51.48	$ -
Secondary	117	0.0270958	11,205	$ 303.61	$ 303.61	$ -
Primary	532	0.0263310	731,499	$ 19,261.10	$ 19,261.10	$ -
Primary Substation				No SSO Customers		
High Voltage	531	0.0260336	38,450,156	$ 1,000,995.98	$ 1,000,995.98	$ -
Private Outdoor Lighting	25	0.0270958	375	$ 10.16	$ 10.16	$ -
School	162	0.0270958	100	$ 2.71	$ 2.71	$ -
Street Light	65	0.0270958	168	$ 4.55	$ 4.55	$ -
Source: LA-2014-1-77						

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 2014 includes DP&L's responses to LA-2014-1-63 through LA-2014-1-69.

Data request LA-2014-1-63 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 three employees who left the Company during 2014. The three employees in question had worked in Competitive Market Services.

Data request LA-2014-1-64 requested information similar to LA-2014-1-63 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 2014 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 the Company's accounting practices as it relates to derivative assets and liabilities. Although this document indicated a "last revision" date of July 31, 2009, the Acknowledgements and Approvals, in which Company personnel signed off on the policy, was dated January 31, 2012.

General Ledger Detail and Audit Trail

Data request LA-2014-1-70 requested general ledgers for the various FERC accounts which the Company has requested be included in the FUEL Rider. In response, DP&L provided the requested general ledger account sheets for January through December 2014.

As discussed above, data requests LA-2014-1-71 and LA-2014-1-72 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 2014 actual RA Fuel costs and revenues. In its confidential response, DP&L provided the detailed support for July 2014, which agreed to the monthly data provided in the response to LA-2014-1-52 as well as the related general ledger FERC accounts.

Data requests LA-2014-1-73 and LA-2014-1-74 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-2014-1-70 and any other accounts used by DP&L for January 2014 actual RA Fuel costs and revenues. In its confidential response, DP&L provided the detailed support for January 2014, which agreed to the monthly data provided in response to LA-2014-1-52 as well as the related general ledger accounts.

Data request LA-2014-1-75 asked the Company to provide the complete audit trail from the general ledgers for each account listed in LA-2014-1-70 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-2014-1-71 and LA-2014-1-72 (previously discussed above) as well as LA-2014-1-52 for the requested supporting documentation. Additional documentation was provided in responses to follow-up data requests.

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-2014-1-83, 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-2014-1-82 asked DP&L provide statistics on 2014 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 2014. Exhibit 5-47 provides a summary by month of those DP&L customers who switched to either DPLER or another alternative supplier during 2014.

Exhibit 5-47. Number of Customers who Switched to an Alternative Supplier in 2014

[redacted]

As shown in the exhibit above, during 2014, the number of customers who switched from DP&L to an alternative supplier totaled [redacted]

[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.[28] In LA-2014-1-84, 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 5-48 below.

Exhibit 5-48. Trend Line Analysis Related to Residential Customer Switching (Actual Sales Billed per Month)

Residential Trend Line

Actual billed sales per month

[redacted]

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

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-2014-1-83 (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 three 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 2014, DP&L reflected the impact of known customer supplier switching.
2. DP&L's Fuel Rider deferral (i.e., the 2014 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-2014-1-78 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 its confidential response, DP&L referred to the confidential response to EVA-2014-1-43, which had requested any internal audits of Fuel and purchased power that DP&L had conducted during 2014. The response to EVA-

2014-1-43 was comprised of three internal audit reports with supporting documentation for internal audits conducted during the 2014 review period[29], each of which is discussed below.

<u>Fuel and Materials & Supplies Inventory</u>

According to the Executive Summary of this internal audit report, the Internal Audit ("IA") group, in providing direct assistance to Ernst & Young ("E&Y"), conducted this internal audit which covered the period August 1, 2013 through July 31, 2014. The scope of this internal audit included (1) the observation of the coal inventory flyover at the Stuart and Killen generation stations; (2) the observation of coal inventory drilling and density procedures at Stuart Station; (3) the testing of coal physical inventory reports prepared by SGS Minerals North America, Inc. ("SGS") for Stuart and Killen Stations; (4) the observation of parts inventory stock count at Stuart and Killen Stations; and (5) the testing of the coal and parts inventory adjustments booked in the general ledger ("G/L").

The IA group provided the following Summary of Significant Observations pursuant to this internal audit:

[redacted]

[redacted]

As it relates to the first item noted above, the IA group noted the following while observing the cycle count procedures at Killen:

[redacted]

[redacted]

The internal audit report provides some additional discussion of these two items and culminates with the following IA recommendation:

[redacted]

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[29] The internal audit reports provided did not include an internal audit of the Fuel Rider. 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 is scheduled for the 2015 review period.

[redacted]

In response to the IA group's recommendations, Company management agreed with IA's observation in the internal audit report and stated that it was in the process of developing a detailed plan to address the noted issues. Specifically, management stated that its goal was to ensure:

[redacted]

[redacted]

[redacted]

[redacted]

According to the internal audit report, the due date for management's adherence to these four bullet points was December 31, 2014. In response to Larkin's inquiry as to whether DP&L has in fact adhered to its proposed action plan related to the first of the IA group's observations, the Company stated:

[redacted]

As for the IA group's second observation that controls to ensure inventory optimization are not operating effectively, IA stated that the Killen Station general ledger had not been updated for materials and supplies items existing physically and not accounted for in Oracle inventory or corresponding financial records. In addition, IA noted several items of inventory that were not included in the Oracle inventory records. The IA group determined that these items were valued at [redacted].

The internal audit report included some additional discussion of this issue and IA made the following recommendation:

[redacted]

In response to the IA group's recommendation, Company management agreed with IA's observation in the internal audit report and stated that it was coordinating with plant warehouse and maintenance teams for identification of all items not reflected in inventory and financial records and that it would work closely with relevant teams and adjust Killen's general ledger accordingly.

According to the internal audit report, the due date for management's adherence to its proposed action plan was January 1, 2015. In response to Larkin's inquiry as to whether DP&L has in fact adhered to its proposed action plan related to the second of the IA group's observations, the Company stated:

> *The action plan does not involve fuel related costs. The action plan is dependent on completion of recommendations from first observation. Accounting will perform complete adjustments once a list of all un-utilized items and non-stock items have been developed and a further assessment (scrap/returned inventory) is made.*

<u>2014 Rate Tracker Audit Report</u>

According to the Executive Summary of this internal audit report, the IA group conducted an internal audit of the following riders:

[redacted]

The scope of this internal audit, which covered the period January 1 through June 30, 2014, included (1) reviewing processes and calculations that support the PUCO rate filings; (2) evaluating the effectiveness of the process for recording the deferral and recovery of costs in the general ledger; and (3) confirming the accuracy of customers' bills. The report provided for this internal audit was confined to the Executive Summary in which the IA group stated this conclusion:

[redacted]

During the onsite interviews conducted at the Company's offices on June 24, 2015, the IA group's senior manager reiterated that there were no significant findings to report with respect to the Rate Tracker internal audit.

Killen Station Coal Physical Inventory Audit

As discussed previously in this report, the IA group conducted an internal audit of coal physical inventory at the Killen generating station, which covered the period August 1, 2013 through July 31, 2014. The objective of this internal audit was to observe the third party coal physical inventory procedures and to test any inventory adjustments. The actual physical inventory as performed by [redacted] and the IA group used [redacted] inventory report, which was dated October 24, 2014, as a template to document its audit findings. However, upon reviewing the [redacted] report, Larkin noted that the IA group's notations consisted primarily of cross-referencing other pages within the [redacted] report. Larkin asked DP&L if there was an additional document which summarized and discussed the IA group's findings and conclusions. In response, the Company stated that the IA group's overall summary of its internal audit of Killen's coal pile inventory is included in the Executive Summary of the audit report issued for the Fuel and Materials Inventory audit discussed above. The referenced Executive Summary, under the heading "Report Conclusion", indicated the following audit procedures as it relates to the physical coal inventories of both the Killen and Stuart generating stations:

- Observation of the coal inventory flyover at Stuart and Killen stations;
- Observation of the coal inventory drilling and density procedures at Stuart Station;
- Testing of the coal physical inventory reports prepared [redacted] for the Stuart and Killen generating stations;
- Testing of the coal and parts inventory adjustments booked in the General Ledger.

The IA group utilizes the following color codes in determining whether controls DP&L has in place are sufficient at mitigating risk:

[redacted]

The IA group designated the yellow color code to the internal audits of the physical inventories of Stuart and Killen.

Section 45 Plant

On February 18, 2013, DP&L entered into four separate contract agreements with [redacted] ("[redacted]"), all of which relate to the installation of a refined coal facility at Stuart Station pursuant to a tax credit under Section 45 of the Internal Revenue Code. Specifically, DP&L The four contracts include [redacted]. A brief summary of each contract agreement is as follows[30]:

[redacted]

A "Letter Agreement" to DP&L from [redacted] dated June 12, 2013, which referenced a Notice of Suspension dated May 31, 2013 that was also issued to DP&L by [redacted]. Pursuant to the Notice of Suspension, [redacted] suspended refined coal production and coal feedstock purchases at Stuart Station in connection with the [redacted] and [redacted]. This Letter Agreement set forth the understanding between DP&L and [redacted] regarding the suspension of certain ongoing obligations (as discussed in the letter) of both parties pursuant to the [redacted], [redacted], and [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 [redacted].

In another Letter Agreement from [redacted] to DP&L dated August 27, 2013, [redacted] stated that it was in negotiations with two affiliates of the [redacted] Group Limited ("[redacted]"), which discussed [redacted] making an investment in the refined coal project which would allow production of refined coal to resume at Stuart. The Letter Agreement set forth the understanding

[30] These contracts are discussed in further detail in the EVA section of this report.

[31] 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-2014-1-17 provided documentation relating to the sales of coal to [redacted]. Specifically, LA-2014-1-17 asked

> "Please provide the accounting entries in 2014, by plant, for coal sales, coal repurchases and lease revenues for each Internal Revenue Code Section 45 coal treatment/synFuel plant. Show the amounts recorded in each account for each month of 2014 for synFuel/treated-coal related (1) coal sales, (2) coal repurchases and (3) lease revenue.
>
> 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 confidential response to LA-2014-1-17, the Company provided documentation related to the sale of coal to [redacted], as well as the 2014 accruals and accounting analysis reflecting all postings to FERC Account 456099 and 4560025. DP&L stated that the coal sales to [redacted] were not included in the Fuel Rider during 2014.

The aforementioned documentation consisted of a schedule which summarized the 2014 monthly activity associated with [redacted] coal spray and the lease and rental revenue as well as the relevant pages from the Company's general ledger ("G/L") that relates to the [redacted] coal washing as well as lease and rental 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 & AEP Share of Revenue.

Conclusion:

As stated in the response to LA-2014-1-17, DP&L did not include the [redacted] related revenues in the Fuel Rider during 2014. For the reasons discussed in the EVA section of this report, Larkin concurs with EVA that the [redacted] related service payment and leases revenues should flow through the Fuel Rider since the refined coal was effectively purchased on behalf of DP&L's jurisdictional customers. Therefore, Larkin has modified the schedule that DP&L provided in the response to LA-2014-1-17 to include the wholesale allocation in order to derive the net

DP&L retail share of the [redacted] coal spray and lease revenues. Upon reviewing the wholesale allocation related data in the monthly Excel workbooks provided in LA-2014-1-52, Larkin noted that the wholesale allocation percentages for Stuart Station for June, October, and November 2014 were greater than [redacted]%. The exhibits below reflect the DP&L retail share of the [redacted] coal spray and related lease revenue by (1) capping the June, October and November 2014 wholesale allocation percentages for Stuart at [redacted]%; and (2) allocating the wholesale portion of the June, October and November 2014 [redacted] coal washing and lease revenue using the wholesale allocation percentages, which are greater than [redacted]%, that are reflected for Stuart in the monthly Excel workbooks.

Exhibit 5-49. DP&L Share of [redacted] Coal Spray Revenue With Wholesale Allocators for June, October and November capped at [redacted]%

[redacted]

Exhibit 5-50. DP&L Share of [redacted] Coal Spray Revenue With Wholesale Allocators for June, October and November greater than [redacted]%

[redacted]

As shown in Exhibit 5-49, with the wholesale allocators for June, October and November capped at [redacted]%, the DP&L retail portion of the [redacted] coal spray revenue totaled [redacted]. As shown in Exhibit 5-50, with the wholesale allocators for June, October and November at greater than [redacted]%, the DP&L retail portion of the [redacted] coal spray revenue totaled [redacted], or a difference of [redacted].

Exhibit 5-51. DP&L Share of [redacted] Revenue With Wholesale Allocators for June, October and November capped at [redacted]%

[redacted]

Exhibit 5-52. DP&L Share of [redacted] Revenue With Wholesale Allocators for June, October and November greater than [redacted]%

[redacted]

As shown in Exhibit 5-51, with the wholesale allocators for Stuart for June, October and November capped at [redacted]%, the DP&L retail portion of the [redacted] lease revenue totaled [redacted]. As shown in Exhibit 5-52, with the wholesale allocators for June, October and November at greater than [redacted], the DP&L retail portion of the [redacted] related lease 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. As shown in the foregoing exhibits, after applying the monthly wholesale allocation factors, including the June, October and November factors that exceeded [redacted]%, the DP&L retail portion of the [redacted] coal spray revenue that should flow through the Fuel Rider for 2014 totaled [redacted] and the [redacted] related lease revenue that should flow through the Fuel Rider totaled [redacted] for 2014.

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 (O.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 under their standard service offers to be obtained by "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. Alternative energy sources can also include new and existing customer-sited advanced and renewable energy resources that the customer commits to integrate into the utility's demand-response, energy efficiency, or peak demand reduction programs. Examples include a resource that has the effect of improving the relationship between real and reactive power; a resource that makes efficient use of waste heat; storage technology that allows customers to modify their demand or load and usage characteristics; and any advanced renewable energy resource that can be utilized effectively. The final rules implementing the Alternative Energy Portfolio Standard were not issued until December 10, 2009.

In accordance with the provisions of S.B. 221, at least half of the alternative energy requirement was to have been satisfied from "renewable energy sources" which must include solar. The percentage required by year is provided on Exhibit 6-1. The other requirement was that at least 50 percent of the renewable energy must come from in-state facilities and the balance must come from facilities that can deliver into the state. Technologies that qualify under the renewable category include: solar, wind, hydroelectric, geothermal, waste derived Fuel, biomass, biologically derived methane gas, wood waste, Fuel cells, and storage facilities.

Exhibit 6-1. Renewable Energy Benchmark Requirements

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	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024	12.50%	0.50%

The remaining up to half of the alternative energy requirement could come from "advanced energy resources." Technologies which would qualify include: any method or device which would increase electricity output without an increase in carbon emissions; a distributed generation system consisting of customer cogeneration and thermal output; clean coal technology which limits emissions of carbon; advanced nuclear technology; Fuel cells; and demand side management and energy efficiency improvements. Unlike the renewables, there are no interim requirements, simply a cumulative 25 percent requirement by 2025 (see additional discussion below).

To ensure compliance with the alternative energy standards, utilities are required to file an annual report which details its 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 is initially set at $45 per MWh and will be adjusted annually by the PUCO according to changes in the Consumer Price Index. The solar ACP is initially set at $450 per MWh and is reduced by $50 every two years until it hits $50 per MWh in 2024. ACPs are deposited into the Ohio Advanced Energy Fund which provides funding for renewable and energy efficient projects within the state. ACPs are not recoverable through the FAC.

Utilities can obtain relief from certain requirements and avoid paying the ACP. A utility does not have to comply if it demonstrates 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 there were insufficient renewable energy products in the market place.

Senate Bill 310

In May 2014, the Ohio General Assembly passed 2014 Sub. S.B. No. 310 ("SB 310"), which became effective on September 12, 2014. Pursuant to SB 310's passage, several provisions of the Ohio Revised Code, including those referenced above, were amended. These amendments to the renewable energy and advanced energy requirements of S.B. 310 are summarized below.

- 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 benchmarks to resume beginning in 2017 starting at the 2015 levels of prior law.
- Eliminates the requirement 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 and the remainder with resources deliverable into 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.
- 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 have to be converted to electricity in order to be eligible to receive renewable energy credits.
- Requires that rules of the Public Utilities Commission of Ohio ("PUCO") specify that for renewable energy credits, 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.

- Requires EDUs and ESCs that switch back to the three-year baseline and to use that baseline for at least three consecutive years before again using the compliance year baseline.
- Permits the PUCO to adjust the compliance year baseline to adjust for new economic growth in the EDUs and ESCs territory or service area.

The biggest impact may be on Ohio in-state solar REC's which has historically been the highest cost component of the REC portfolio. The general consensus is that the differentials between in-state and out-of-state REC's will narrow. What is not clear is whether this is just a two-year freeze or a precursor for major changes going forward.

REC Procurement Strategy and REC Purchases

DP&L's strategy is [redacted]. This strategy has worked well for DP&L in 2014 give adequate availability and competitive prices. Further, this strategy [redacted].

REC Purchases

RECs purchases are usable within a five-year period. Any RECs held by DP&L at December 31, 2014 that are in excess of its 2014 Benchmarks will be applied to future year benchmarks. The REC's purchased by the Company are summarized by category in Exhibit 6-2. The solar REC's are significantly higher in costs than the non-solar REC's. However, the cost of the solar REC's is much less than the solar REC's in 2013.

Exhibit 6-2. Summary of REC Purchases by Category

[redacted]

Audit Period Purchases

REC purchases during the audit period are summarized in Exhibit 6-3. The prices paid for REC's compare favorably to market prices.

Exhibit 6-3. REC Purchases During 2014 Period

[redacted]

Audit Period Compliance

According to the Company's Annual Compliance Plan Status Reports for 2014, DP&L achieved compliance by meeting the 2014 benchmarks for the Ohio Alternative Energy Portfolio Standard for both solar and non-solar renewables.

Financial Audit

Scope and Objectives

To accomplish the review of DP&L's 2014 AER, the following aspects were included in the verification and testing:

- Review the Company's AER filings applicable to DP&L's actual 2014 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 D&PL's renewables costs and REC inventory accounting in conformance with the specific requirements of the Company's AER that applied for the 2014 review period. Larkin reviewed and applied relevant criteria in review of the Company's decisions and actions related to its AEPS 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 advanced generation plant investments and 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-2014-1-88 through LA-2014-1-115. 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 2014. We reviewed the Company's renewables costs for 2014. DP&L's Alternative Energy Rider was in effect for 2014.

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 2014. 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 2014.

The following sections discuss DP&L's 2014 quarterly AER filings[32] by reproducing Schedules 1 through 4 as well as Workpaper 1 as Exhibits 6-2 through 6-29.

Quarterly Alternative Rider Filing – January through May 2014

Exhibit 6-4. Forecasted Quarterly Rate Summary, January through May 2014

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Alternative Energy Rider Summary

Line (A)	Description (B)	Jan-14 (C)	Feb-14 (D)	Mar-14 (E)	Apr-14 (F)	May-14 (G)	Total (H)	Source (I)
1	Forecasted REC & Project Expense with Carrying Costs	$ 268,341	$ 266,386	$ 264,943	$ 264,050	$ 263,532	$ 1,327,253	Schedule 3, Line 5
2	Gross Revenue Conversion Factor						1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2.
3	Total Forecasted Expense						$ 1,336,810	Line 1 * Line 2
4	Forecasted Metered Level Sales	385,411,728	314,306,854	266,574,087	187,214,339	179,812,911	1,333,319,918	Schedule 2, Line 17
5	AER Rate before Reconciliation Adjustment $/kWh						$ 0.0010026	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh						$ 0.0011005	Schedule 2, Line 18
7	Forecasted AER Rate $/kWh						$ 0.0021031	Line 5 + Line 6

Schedule 1: This schedule reflects DP&L's estimates of the monthly REC and project expense with carrying costs it expected to incur during the period January through May 2014. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense with carrying costs for January through May 2014, which totaled $1.327 million (column H). 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 with carrying cost of $1.327 million by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period January 2014 through May 2014 (see Schedule 2 discussion below) of 1.333 billion 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 $0.0010026 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion

[32] DP&L provided the Excel versions of its quarterly AER filings in response to LA-2014-1-109.

below) of $0.0011005 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0010026 per kWh noted above to derive its forecasted AER rate of $0.0021031 per kWh as shown on line 7 of Schedule 1.

Exhibit 6-5. Summary of Actual Costs – January 2013 through September 2013

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Total Expenses (E)	Revenue (F)	(Over) / Under Recovery (G)	Carrying Costs (H)	Total (I)	YTD[1] (J)	Source (K)
1	Prior Period								$ 3,929,057	
2	Jan-13	$ 228,179	$ 16,896	$ 245,075	$ (320,604)	$ (75,528)	$ 19,002	$ (56,526)	$ 3,872,531	
3	Feb-13	$ 225,548	$ 12,217	$ 237,765	$ (307,343)	$ (69,578)	$ 18,741	$ (50,838)	$ 3,821,693	
4	Mar-13	$ 223,422	$ 14,865	$ 238,287	$ (262,340)	$ (24,053)	$ 18,604	$ (5,449)	$ 3,816,245	
5	Apr-13	$ 225,024	$ 14,469	$ 239,493	$ (242,361)	$ (2,868)	$ 18,629	$ 15,761	$ 3,832,005	
6	May-13	$ 223,807	$ 22,896	$ 246,703	$ (197,056)	$ 49,647	$ 18,834	$ 68,481	$ 3,900,487	
7	Jun-13	$ 221,034	$ 53,531	$ 274,565	$ (204,250)	$ 70,315	$ 19,219	$ 89,534	$ 3,990,021	
8	Jul-13	$ 227,358	$ 19,610	$ 246,969	$ (256,680)	$ (9,712)	$ 19,461	$ 9,749	$ 3,999,770	
9	Aug-13	$ 223,734	$ 18,405	$ 242,139	$ (684,807)	$ (442,668)	$ 18,451	$ (424,217)	$ 3,575,553	
10	Sep-13	$ 183,811	$ 74,443	$ 258,255	$ (645,334)	$ (387,079)	$ 16,516	$ (370,564)	$ 3,204,989	
11	Total	$ 1,981,917	$ 247,333	$ 2,229,250	$ (3,120,774)	$ (891,525)	$ 167,457	$ (724,067)		
12	Total (Over)/Under Recovery								$ 3,204,989	
13	Recovery Over 3 Seasonal Quarter Rate Periods								$ 1,456,813	Line 12 * (5/11)
14	(Over) / Under Recovery								$ 1,456,813	Line 13
15	Gross Revenue Conversion Factor								1.0072	Case No. 12-426-EL-SSO, WP-11, Col(C), Line 21
16	Total (Over) / Under Recovery with Carrying Costs								$ 1,467,302	Line 14 * Line 15
				Jan-14	Feb-14	Mar-14	Apr-14	May-14		
17	Standard Offer Sales Forecast (kWh)			385,411,728	314,306,854	266,574,087	187,214,339	179,812,911	1,333,319,918	Corporate Forecast
18	AER Reconciliation Rate $/kWh								$ 0.0011005	Line 16 / Line 17

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

Schedule 2: Column C of Schedule 2 reflects DP&L's actual REC expenses during the period of January through September 2013, which totaled $1.982 million. Column D of Schedule 2 reflects DP&L's actual Compliance Administration expenses for the same period, which totaled $247,333. The REC expenses and compliance administration expense were combined for Total expenses of $2.229 million, as shown in column E. Column F reflects DP&L's actual revenues for January through September 2013 for a total of ($3.121) million. The difference between the Company's actual fuel costs and actual revenues results in an over-recovery in the amount of ($891,525), as shown in column G. Column H reflects the carrying costs for the period of January through September 2013, which total $167,457. The over-recovery for the period of January through September 2013, the addition of the prior reconciliation under-recovery shown on line 1, and the addition of the carrying costs for the January through September 2013 period, resulted in a YTD under-recovery of ($3.205) million (column J, line 12). Line 13 of Schedule 2 reflects DP&L's under-recovery over three seasonal quarter rate periods, which totals $1.457 million. 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 $1.467 million, as shown on line 16. Line 17 reflects the Standard Offer Sales Forecast for the period of January through May 2014, totaling 1.333 billion kWh. The Company derived its AER Reconciliation

Rate of $0.0011005 per kWh by dividing the total under-recovery with carrying costs of $1.467 million by its standard offer sales forecast for the period January through May 2014.

Exhibit 6-6. Projected Monthly Cost Calculation – January 2014 through May 2014

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
Projected Monthly Cost Calculation

Line (A)	Description (B)	Jan-14 (C)	Feb-14 (D)	Mar-14 (E)	Apr-14 (F)	May-14 (G)	Total (H)	Source (I)
1	REC Expense	$ 255,352	$ 255,352	$ 255,352	$ 255,352	$ 255,352	$ 1,276,760	Corporate Forecast
2	Compliance Administration	$ 751	$ 751	$ 751	$ 751	$ 751	$ 3,755	Corporate Forecast
3	Total AER Expense	$ 256,103	$ 256,103	$ 256,103	$ 256,103	$ 256,103	$ 1,280,516	Line 1 + Line 2
4	Projected Carrying Cost of Under/(Over) Recovery	$ 12,238	$ 10,283	$ 8,840	$ 7,947	$ 7,429	$ 46,738	Workpaper 1, Col (H)
5	Projected Under/(Over) Recovery with Carrying Costs	$ 268,341	$ 266,386	$ 264,943	$ 264,050	$ 263,532	$ 1,327,253	Line 3 + Line 4
6	Gross Revenue Conversion Factor						1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2
7	Total Projected AER Costs						$ 1,336,810	Line 5 x Line 6
8	Standard Offer Sales Forecast (kWh) Jan - May 14						1,333,319,918	Corporate Forecast
9	AER Base Rate $/kWh						$ 0.0010026	Line 7 / Line 8

Schedule 3: This schedule reflects DP&L's estimates of the monthly expenses it expected to incur during the period January through May 2014. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for January through May 2014, which totaled $1.277 million (column H). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $3,755. This results in total AER expense for January through May 2014 of $1.281 million, as shown on line 3. Line 4 reflects DP&L's projected carrying cost of DP&L's under-recovery, which totals $46,738. The projected carrying cost and total AER expense are added together, resulting in projected under-recovery with carrying costs of $1.327 million, as shown on line 5. As shown on line 6 of Schedule 3, the Company included its Gross Revenue Conversion Factor of 1.0072. The Company then calculated its total projected AER costs by multiplying the projected under-recovery with carrying cost of $1.327 million by the gross revenue conversion factor as shown on line 7. The Company reflected its Standard Offer Sales Forecast for the period of January through May 2014, totaling 1.333 billion kWh on line 8. The Company then divided the total projected AER costs by the Standard Offer Sales Forecast to calculate the AER base rate of $0.0010026 per kWh as shown on line 9.

Exhibit 6-7. Calculation of Carrying Costs – Workpaper 1, January 2013 through May 2014

The Dayton Power and Light Company
Case No. 12-426-EL-SSO
January 2013 - May 2014

		MONTHLY ACTIVITY								
		First of Month	New AER	Amount Collected	NET	End of Month before	Carrying Cost*	End of Month	Less: One-half Monthly	Total Applicable to
Line	Period	Balance	Charges	(CR)	AMOUNT	Carrying Cost	Carrying Cost*	Balance	Amount	Carrying Cost
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					(F) = (D) + (E	(G) = (C) + (F)	(H) = (L) * (COD % / 12)	(I) = (G) + (H)	(J) = - (F) * .5	(K) = (G) + (J)
1	Prior Period							$3,929,056.65	$ -	$ -
2	Jan-13	$3,929,057	$245,075	$ (320,604)	$ (75,528)	$ 3,853,528	$ 19,002	$ 3,872,531	$ 37,764	$ 3,891,292
3	Feb-13	$3,872,531	$237,765	$ (307,343)	$ (69,578)	$ 3,802,952	$ 18,741	$ 3,821,693	$ 34,789	$ 3,837,741
4	Mar-13	$3,821,693	$238,287	$ (262,340)	$ (24,053)	$ 3,797,641	$ 18,604	$ 3,816,245	$ 12,026	$ 3,809,667
5	Apr-13	$3,816,245	$239,493	$ (242,361)	$ (2,868)	$ 3,813,376	$ 18,629	$ 3,832,005	$ 1,434	$ 3,814,810
6	May-13	$3,832,005	$246,703	$ (197,056)	$ 49,647	$ 3,881,653	$ 18,834	$ 3,900,487	$ (24,824)	$ 3,856,829
7	Jun-13	$3,900,487	$274,565	$ (204,250)	$ 70,315	$ 3,970,802	$ 19,219	$ 3,990,021	$ (35,157)	$ 3,935,644
8	Jul-13	$3,990,021	$246,969	$ (256,680)	$ (9,712)	$ 3,980,309	$ 19,461	$ 3,999,770	$ 4,856	$ 3,985,165
9	Aug-13	$3,999,770	$242,139	$ (684,807)	$ (442,668)	$ 3,557,102	$ 18,451	$ 3,575,553	$ 221,334	$ 3,778,436
10	Sep-13	$3,575,553	$258,255	$ (645,334)	$ (387,079)	$ 3,188,474	$ 16,516	$ 3,204,989	$ 193,540	$ 3,382,013
11	Oct-13	$3,204,989	$ -	$ -	$ -	$ 3,204,989	$ 15,651	$ 3,220,640	$ -	$ 3,204,989
12	Nov-13	$3,220,640	$ -	$ -	$ -	$ 3,220,640	$ 15,727	$ 3,236,368	$ -	$ 3,220,640
13	Dec-13	$3,236,368	$ -	$ -	$ -	$ 3,236,368	$ 15,804	$ 3,252,172	$ -	$ 3,236,368
14	Jan-14	$3,252,172	$256,103	$ (818,406)	$ (562,303)	$ 2,689,869	$ 12,238	$ 2,702,108	$ 281,151	$ 2,971,021
15	Feb-14	$2,702,108	$256,103	$ (667,418)	$ (411,314)	$ 2,290,793	$ 10,283	$ 2,301,076	$ 205,657	$ 2,496,450
16	Mar-14	$2,301,076	$256,103	$ (566,059)	$ (309,956)	$ 1,991,121	$ 8,840	$ 1,999,961	$ 154,978	$ 2,146,098
17	Apr-14	$1,999,961	$256,103	$ (397,542)	$ (141,439)	$ 1,858,522	$ 7,947	$ 1,866,469	$ 70,719	$ 1,929,241
18	May-14	$1,866,469	$256,103	$ (381,825)	$ (125,722)	$ 1,740,747	$ 7,429	$ 1,748,176	$ 62,861	$ 1,803,608

*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 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 2013 through May 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of $0.0011005. 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 – June through August 2014

Exhibit 6-8. Forecasted Quarterly Rate Summary, June through August 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Jun-14 (C)	Jul-14 (D)	Aug-14 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$ 211,773	$ 211,773	$ 211,773	$ 635,319	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2
3	Total Forecasted Expense				$ 639,893	Line 1 * Line 2
4	Forecasted Metered Level Sales	300,200,028	338,857,419	322,185,935	961,243,382	Schedule 2, Line 25
5	AER Rate before Reconciliation Adjustment $/kWh				$ 0.0006657	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$ (0.0001753)	Schedule 2, Line 26
7	Forecasted AER Rate $/kWh				$ 0.0004904	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 June through August 2014. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for June through August 2014, which totaled $635,319 (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 $635,319 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period June through August 2014 (see Schedule 2 discussion below) of 961.243 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 $0.00066657 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of $0.0001753 per kWh on line 6. DP&L added its Reconciliation Adjustment to the $0.0006657 per kWh noted above to derive its forecasted AER rate of $0.0004904 per kWh as shown on line 7 of Schedule 1.

Exhibit 6-9. Summary of Actual Costs – January 2013 through August 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Summary of Actual Costs

Line (A)	Description (B)	REC Expense (C)	Compliance Administration Expense (D)	Total Expenses (E)	Revenue (F)	(Over) / Under Recovery (G)	Carrying Costs (H)	Total (I)	YTD[1] (J)	Source (K)
1	Prior Period								$ 3,929,051	Accounting Records
2	Jan-13	$ 228,179	$ 16,896	$ 245,075	$ (320,604)	$ (75,528)	$ 19,002	$ (56,526)	$ 3,872,525	Accounting Records
3	Feb-13	$ 225,548	$ 12,217	$ 237,765	$ (307,343)	$ (69,578)	$ 18,741	$ (50,838)	$ 3,821,688	Accounting Records
4	Mar-13	$ 223,422	$ 14,865	$ 238,287	$ (262,340)	$ (24,053)	$ 18,604	$ (5,449)	$ 3,816,239	Accounting Records
5	Apr-13	$ 225,024	$ 14,469	$ 239,493	$ (242,361)	$ (2,868)	$ 18,629	$ 15,761	$ 3,832,000	Accounting Records
6	May-13	$ 223,807	$ 22,896	$ 246,703	$ (197,056)	$ 49,647	$ 18,840	$ 68,487	$ 3,900,487	Accounting Records
7	Jun-13	$ 221,034	$ 53,531	$ 274,565	$ (204,250)	$ 70,315	$ 19,219	$ 89,534	$ 3,990,021	Accounting Records
8	Jul-13	$ 227,358	$ 19,610	$ 246,969	$ (256,680)	$ (9,712)	$ 19,461	$ 9,749	$ 3,999,770	Accounting Records
9	Aug-13	$ 223,734	$ 18,405	$ 242,139	$ (684,807)	$ (442,668)	$ 18,451	$ (424,217)	$ 3,575,553	Accounting Records
10	Sep-13	$ 183,811	$ 74,443	$ 258,255	$ (645,334)	$ (387,079)	$ 16,516	$ (370,564)	$ 3,204,989	Accounting Records
11	Oct-13	$ 651,305	$ 49,926	$ 701,231	$ (520,304)	$ 180,927	$ 16,093	$ 197,020	$ 3,402,009	Accounting Records
12	Nov-13	$ (299,847)	$ 3,722	$ (296,125)	$ (531,335)	$ (827,460)	$ 14,619	$ (812,841)	$ 2,589,168	Accounting Records
13	Dec-13	$ 185,309	$ 5,725	$ 191,034	$ (640,103)	$ (449,068)	$ 11,547	$ (437,521)	$ 2,151,647	Accounting Records
14	Jan-14	$ 228,317	$ 523	$ 228,840	$ (967,797)	$ (738,957)	$ 7,341	$ (731,616)	$ 1,420,031	Accounting Records
15	Feb-14	$ 228,317	$ 3,209	$ 231,526	$ (955,442)	$ (723,916)	$ 4,358	$ (719,558)	$ 700,473	Accounting Records
16	Mar-14	$ 223,705	$ (34,433)	$ 189,272	$ (790,365)	$ (601,093)	$ 1,725	$ (599,368)	$ 101,104	Accounting Records
17	Apr-14	$ 255,352	$ 751	$ 256,103	$ (397,542)	$ (141,439)	$ 125	$ (141,314)	$ (40,209)	Corporate Forecast
18	May-14	$ 255,352	$ 751	$ 256,103	$ (381,825)	$ (125,722)	$ (425)	$ (126,147)	$ (166,356)	Corporate Forecast
19	Jun-14	$ 211,022	$ 751	$ 211,773	$ (211,773)	$ -	$ (553)	$ (553)	$ (166,909)	Corporate Forecast
20	Jul-14	$ 211,022	$ 751	$ 211,773	$ (211,773)	$ -	$ (331)	$ (331)	$ (167,241)	Corporate Forecast
21	Aug-14	$ 211,022	$ 751	$ 211,773	$ (211,773)	$ -	$ (57)	$ (57)	$ (167,298)	Corporate Forecast
22	(Over) / Under Recovery								$ (167,298)	Line 21
23	Gross Revenue Conversion Factor								1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
24	Total (Over) / Under Recovery with Carrying Costs								$ (168,503)	Line 22 * Line 23
						Jun-14	Jul-14	Aug-14		
25	Standard Offer Sales Forecast (kWh)					300,200,028	338,857,419	322,185,935	961,243,382	Corporate Forecast
26	AER Reconciliation Rate $/kWh								$ (0.0001753)	Line 24 / Line 25

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

Schedule 2: Column C of Schedule 2 reflects DP&L's actual REC expenses during the period of January 2013 through August 2014, which totaled $4.343 million. Column D of Schedule 2 reflects DP&L's actual Compliance Administration expenses for the same period, which totaled $279,759. The REC expenses and compliance administration expense were combined for Total expenses of $4.623 million, as shown in column E. Column F reflects DP&L's actual revenues for January 2013 through August 2014 for a total of ($8.941) million. The difference between the Company's actual fuel costs and actual revenues results in an over-recovery in the amount of ($4.318) million, as shown in column G. Column H reflects the carrying costs for the period of January 2013 through August 2014, which total $221,904. The over-recovery for the period of January 2013 through August 2014, the addition of the prior reconciliation under-recovery shown on line 1, and the addition of the carrying costs for the January 2013 through August 2014 period, resulted in a YTD over-recovery of ($167,298) (column J, line 22). 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 ($168,503), as shown on line 24. Line 25 reflects the Standard Offer Sales Forecast for the period of June through August 2014, totaling 961.243 million kWh. The Company derived its AER Reconciliation Rate of $0.0001753 per kWh by dividing the total over-recovery with carrying costs of ($168,503) by its standard offer sales forecast for the period June through August 2014.

Exhibit 6-10. Projected Monthly Cost Calculation – June 2014 through August 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Jun-14 (C)	Jul-14 (D)	Aug-14 (E)	Total (F)	Source (G)
1	REC Expense	$211,022	$211,022	$211,022	$ 633,065	Corporate Forecast
2	Compliance Administration	$ 751	$ 751	$ 751	$ 2,253	Corporate Forecast
3	Total AER Expense	$211,773	$211,773	$211,773	$ 635,318	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				$ 639,892	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh) June - August				961,243,382	Corporate Forecast
7	AER Base Rate $/kWh				$0.0006657	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 2014. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for June through August 2014, which totaled $633,065 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $2,253. This results in total AER expense for June through August 2014 of $635,318, 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 $635,318 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 2014, totaling 961,243 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 $0.0006657 per kWh as shown on line 7.

Exhibit 6-11. Calculation of Carrying Costs – Workpaper 1, January 2013 through May 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Alternative Energy Rider
Calculation of Carrying Costs

Line (A)	Period (B)	MONTHLY ACTIVITY First of Month Balance (C)	New AER Charges (D)	Amount Collected (CR) (E)	NET AMOUNT (F) (F) = (D) + (E)	End of Month before Carrying Cost (G) (G) = (C) + (F)	Carrying Cost* (H) (H) = (L) * (COD % / 12)	End of Month Balance (I) (I) = (G) + (H)	Carrying Cost Calculation Less: One-half Monthly Amount (J) (J) = - (F) * .5	Total Applicable to Carrying Cost (K) (K) = (G) + (J)
1	Prior Period							$ 3,929,051	$ -	$ -
2	Jan-13	$3,929,051	$ 245,075	$ (320,604)	$ (75,528)	$ 3,853,523	$ 19,002	$ 3,872,525	$ 37,764	$ 3,891,287
3	Feb-13	$3,872,525	$ 237,765	$ (307,343)	$ (69,578)	$ 3,802,947	$ 18,741	$ 3,821,688	$ 34,789	$ 3,837,736
4	Mar-13	$3,821,688	$ 238,287	$ (262,340)	$ (24,053)	$ 3,797,635	$ 18,604	$ 3,816,239	$ 12,026	$ 3,809,661
5	Apr-13	$3,816,239	$ 239,493	$ (242,361)	$ (2,868)	$ 3,813,371	$ 18,629	$ 3,832,000	$ 1,434	$ 3,814,805
6	May-13	$3,832,000	$ 246,703	$ (197,056)	$ 49,647	$ 3,881,647	$ 18,840	$ 3,900,487	$ (24,824)	$ 3,856,823
7	Jun-13	$3,900,487	$ 274,565	$ (204,250)	$ 70,315	$ 3,970,802	$ 19,219	$ 3,990,021	$ (35,157)	$ 3,935,644
8	Jul-13	$3,990,021	$ 246,969	$ (256,680)	$ (9,712)	$ 3,980,309	$ 19,461	$ 3,999,770	$ 4,856	$ 3,985,165
9	Aug-13	$3,999,770	$ 242,139	$ (684,807)	$ (442,668)	$ 3,557,102	$ 18,451	$ 3,575,553	$ 221,334	$ 3,778,436
10	Sep-13	$3,575,553	$ 258,255	$ (645,334)	$ (387,079)	$ 3,188,474	$ 16,516	$ 3,204,989	$ 193,540	$ 3,382,013
11	Oct-13	$3,204,989	$ 701,231	$ (520,304)	$ 180,927	$ 3,385,916	$ 16,093	$ 3,402,009	$ (90,463)	$ 3,295,453
12	Nov-13	$3,402,009	$ (296,125)	$ (531,335)	$ (827,460)	$ 2,574,549	$ 14,619	$ 2,589,168	$ 413,198	$ 2,987,747
13	Dec-13	$2,589,168	$ 191,034	$ (640,103)	$ (449,068)	$ 2,140,099	$ 11,547	$ 2,151,647	$ 224,534	$ 2,364,634
14	Jan-14	$2,151,647	$ 228,840	$ (967,797)	$ (738,957)	$ 1,412,690	$ 7,341	$ 1,420,031	$ 369,479	$ 1,782,168
15	Feb-14	$1,420,031	$ 231,526	$ (955,442)	$ (723,916)	$ 696,114	$ 4,358	$ 700,473	$ 361,958	$ 1,058,072
16	Mar-14	$ 700,473	$ 189,272	$ (790,365)	$ (601,093)	$ 99,380	$ 1,725	$ 101,104	$ 300,546	$ 399,926
17	Apr-14	$ 101,104	$ 256,103	$ (397,542)	$ (141,439)	$ (40,334)	$ 125	$ (40,209)	$ 70,719	$ 30,385
18	May-14	$ (40,209)	$ 256,103	$ (381,825)	$ (125,722)	$ (165,931)	$ (425)	$ (166,356)	$ 62,861	$ (103,070)
19	Jun-14	$ (166,356)	$ 211,773	$ (147,218)	$ 64,555	$ (101,801)	$ (552)	$ (102,353)	$ (32,277)	$ (134,079)
20	Jul-14	$ (102,353)	$ 211,773	$ (166,176)	$ 45,597	$ (56,756)	$ (328)	$ (57,084)	$ (22,799)	$ (79,555)
21	Aug-14	$ (40,209)	$ 211,773	$ (159,257)	$ 52,516	$ 12,307	$ (57)	$ 12,250	$ (26,258)	$ (13,951)

*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 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 2013 through May 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0001753). 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 2014

Exhibit 6-12. Forecasted Quarterly Rate Summary, Schedule 1, September through November 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Sep-14 (C)	Oct-14 (D)	Nov-14 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$ 211,375	$ 211,375	$ 211,375	$ 634,125	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2
3	Total Forecasted Expense				$ 638,691	Line 1 * Line 2
4	Forecasted Metered Level Sales	230,604,195	223,618,686	211,202,493	665,425,374	Schedule 2, Line 16
5	AER Rate before Adjustments $/kWh				$ 0.0009598	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				$ (0.0008084)	Schedule 2, Line 17
7	Yankee Adjustment $/kWh				$ 0.0005495	Schedule 4, Line 6
8	Forecasted AER Rate $/kWh				$ 0.0007009	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 September through November 2014. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for September through November 2014, which totaled $634,125 (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 $634,125 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period September through November 2014 (see Schedule 2 discussion below) of 665.425 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 $0.0009598 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0008084) per kWh on line 6. Line 7 reflects DP&L's Yankee Adjustment (see discussion below) of $0.0005495 per kWh. DP&L added its Reconciliation Adjustment to the $0.0009598 per kWh and the Yankee adjustment noted above to derive its forecasted AER rate of $0.0007009 per kWh as shown on line 8 of Schedule 1.

Exhibit 6-13. Summary of Actual Costs – Schedule 2, January through November 2014

The Dayton Power and Light Company
Case No. 14-806-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									$ 2,151,647	Accounting Records
2	Jan-14	$ 228,317	$ 523	$ -	$ 228,840	$ (967,797)	$ (738,957)	$ 7,341	$ (731,616)	$ 1,420,031	Accounting Records
3	Feb-14	$ 228,317	$ 3,209	$ -	$ 231,526	$ (955,442)	$ (723,916)	$ 4,358	$ (719,558)	$ 700,473	Accounting Records
4	Mar-14	$ 223,705	$ (34,433)	$ -	$ 189,272	$ (790,365)	$ (601,093)	$ 1,725	$ (599,368)	$ 101,104	Accounting Records
5	Apr-14	$ 238,075	$ (35,996)	$ -	$ 202,079	$ (653,005)	$ (450,926)	$ (2,520)	$ (453,446)	$ (352,341)	Accounting Records
6	May-14	$ 196,728	$ 2,527	$ -	$ 199,255	$ (540,707)	$ (341,452)	$ (2,155)	$ (343,607)	$ (695,948)	Accounting Records
7	Jun-14	$ 213,910	$ 2,003	$ -	$ 215,913	$ (141,366)	$ 74,547	$ (2,713)	$ 71,833	$ (624,115)	Accounting Records
8	Jul-14	$ 211,022	$ 751	$ -	$ 211,773	$ (166,176)	$ 45,597	$ (2,477)	$ 43,120	$ (580,994)	Corporate Forecast
9	Aug-14	$ 211,022	$ 751	$ -	$ 211,773	$ (159,257)	$ 52,516	$ (2,285)	$ 50,231	$ (530,763)	Corporate Forecast
10	Sep-14	$ 211,022	$ 353	$ 121,882	$ 333,257	$ (333,257)	$ -	$ (1,830)	$ (1,830)	$ (532,593)	Corporate Forecast
11	Oct-14	$ 211,022	$ 353	$ 121,882	$ 333,257	$ (333,257)	$ -	$ (1,116)	$ (1,116)	$ (533,710)	Corporate Forecast
12	Nov-14	$ 211,022	$ 353	$ 121,882	$ 333,257	$ (333,257)	$ -	$ (373)	$ (373)	$ (534,083)	Corporate Forecast
13	(Over) / Under Recovery									$ (534,083)	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									$ (537,928.60)	Line 13 * Line 14
							Sep-14	Oct-14	Nov-14		
16	Standard Offer Sales Forecast (kWh)						230,604,195	223,618,686	211,202,493	665,425,374	Corporate Forecast
17	AER Reconciliation Rate $/kWh									$ (0.0008084)	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 REC expenses during the period of January through November 2014, which totaled $2.384 million. Column D of Schedule 2 reflects DP&L's actual Compliance Administration expenses for the same period, which totaled ($59,605). Column E reflects the Historical Yankee Costs for September through November 2014. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $2.690 million, as shown in column F. Column G reflects DP&L's actual revenues for January through November 2014 for a total of ($5.374) million. The difference between the Company's actual fuel costs and actual revenues results in an over-recovery in the amount of ($2.684) million, as shown in column H. Column I reflects the carrying costs for the period of January through November 2014, which total ($2,406). The over-recovery for the period of January through November 2014, the addition of the prior reconciliation under-recovery shown on line 1, and the addition of the carrying costs for the January through November 2014 period, resulted in a YTD over-recovery of ($534,083) (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 ($537,929), as shown on line 15. Line 16 reflects the Standard Offer Sales Forecast for the period of September through November 2014, totaling 665.425 million kWh. The Company derived its AER Reconciliation Rate of ($0.0008084) per kWh by dividing the total over-recovery with carrying costs of ($537,929) by its standard offer sales forecast for the period September through November 2014.

Exhibit 6-14. Projected Monthly Cost Calculation – Schedule 3, September through November 2014

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Sep-14 (C)	Oct-14 (D)	Nov-14 (E)	Total (F)	Source (G)
1	REC Expense	$ 211,022	$ 211,022	$ 211,022	$ 633,065	Corporate Forecast
2	Compliance Administration	$ 353	$ 353	$ 353	$ 1,060	Corporate Forecast
3	Total AER Expense	$ 211,375	$ 211,375	$ 211,375	$ 634,125	Line 1 + Line 2
4	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2:
5	Total Projected AER Costs				$ 638,691	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh) September - November				665,425,374	Corporate Forecast
7	AER Base Rate $/kWh				$0.0009598	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 2014. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for September through November 2014, which totaled $633,065 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,060. This results in total AER expense for September through November 2014 of $634,125, 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 $634,125 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 2014, totaling 665.425 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 $0.0009598 per kWh as shown on line 7.

Exhibit 6-15. Historical Yankee REC Costs – Schedule 4, September through November 2014

The Dayton Power and Light Company
Case No. 14-806-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
				Sep-14	Oct-14	Nov-14		
5	Standard Offer Sales Forecast (kWh)			230,604,195	223,618,686	211,202,493	665,425,374	Corporate Forecast
6	Yankee Adjustment $/kWh						$ 0.0005495	Line 4 / Line 5

Schedule 4: Schedule 4 presents the calculation of the Yankee REC cost adjustment for the period September through November 2014. A more detailed description about the Historical Yankee Costs is addressed below. 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 Standard Offer Sales Forecast for the period of September through November 2014 totaling 665.425 million kWh. The quarterly recovery amount is divided by the Standard Offer Sales Forecast to calculate the Yankee adjustment of $.0005495 per kWh shown on line 6, which is used on Schedule 1 (discussed above) in the calculation of the forecasted AER rate.

Exhibit 6-16. Calculation of Carrying Costs – Workpaper 1, January through November 2014

The Dayton Power and Light Company
Case No. 14-806-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) = (L) * (COD % / 12)	(I) = (G) + (H)	(J) = - (F) * .5	(K) = (G) + (J)
1	Prior Period							$ 2,151,647	$ -	$ -
2	Jan-14	$ 2,151,647	$ 228,840	$ (967,797)	$ (738,957)	$ 1,412,690	$ 7,341	$ 1,420,031	$ 369,479	$ 1,782,168
3	Feb-14	$ 1,420,031	$ 231,526	$ (955,442)	$ (723,916)	$ 696,114	$ 4,358	$ 700,473	$ 361,958	$ 1,058,072
4	Mar-14	$ 700,473	$ 189,272	$ (790,365)	$ (601,093)	$ 99,380	$ 1,725	$ 101,104	$ 300,546	$ 399,926
5	Apr-14	$ 101,104	$ 202,079	$ (653,005)	$ (450,926)	$ (349,822)	$ (2,520)	$ (352,341)	$ 225,463	$ (124,359)
6	May-14	$ (352,341)	$ 199,255	$ (540,707)	$ (341,452)	$ (693,793)	$ (2,155)	$ (695,948)	$ 170,726	$ (523,067)
7	Jun-14	$ (695,948)	$ 215,913	$ (141,366)	$ 74,547	$ (621,401)	$ (2,713)	$ (624,115)	$ (37,273)	$ (658,675)
8	Jul-14	$ (624,115)	$ 211,773	$ (166,176)	$ 45,597	$ (578,517)	$ (2,477)	$ (580,994)	$ (22,799)	$ (601,316)
9	Aug-14	$ (580,994)	$ 211,773	$ (159,257)	$ 52,516	$ (528,478)	$ (2,285)	$ (530,763)	$ (26,258)	$ (554,736)
10	Sep-14	$ (530,763)	$ 333,257	$ (160,474)	$ 172,784	$ (357,979)	$ (1,830)	$ (359,810)	$ (86,392)	$ (444,371)
11	Oct-14	$ (359,810)	$ 333,257	$ (155,613)	$ 177,645	$ (182,165)	$ (1,116)	$ (183,281)	$ (88,822)	$ (270,987)
12	Nov-14	$ (183,281)	$ 333,257	$ (146,972)	$ 186,285	$ 3,004	$ (373)	$ 2,631	$ (93,675)	$ (90,670)

*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 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 2014, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0008084). 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 – December 2014 through February 2015

Exhibit 6-17. Forecasted Quarterly Rate Summary, Schedule 1, December 2014 through February 2015

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Alternative Energy Rider Summary

Line (A)	Description (B)	Dec-14 (C)	Jan-15 (D)	Feb-15 (E)	Total (F)	Source (G)
1	Forecasted REC & Project Expense	$202,327	$168,764	$168,764	$539,855	Schedule 3, Line 3
2	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2:
3	Total Forecasted Expense				$543,742	Line 1 * Line 2
4	Forecasted Metered Level Sales	372,835,578	380,423,920	200,601,509	953,861,007	Schedule 2, Line 19
5	AER Rate before Adjustments $/kWh				$0.0005700	Line 3 / Line 4
6	Reconciliation Adjustment $/kWh				($0.0001293)	Schedule 2, Line 20
7	Yankee Adjustment $/kWh				$0.0003861	Schedule 4, Line 8
8	Forecasted AER Rate $/kWh				$0.0008268	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 December 2014 through February 2015. As shown on line 1 of Schedule 1, the category included DP&L's forecasted REC and project expense for December 2014 through February 2015, which totaled $539,855 (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 $539,855 by the gross revenue conversion factor as shown on line 3. The Company reflected forecasted meter level sales for the period December 2014 through February 2015 (see Schedule 2 discussion below) of 953.861 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 $0.0005700 per kWh as shown on line 5. The Company then reflected its Reconciliation Adjustment (see Schedule 2 discussion below) of ($0.0001293) per kWh on line 6. Line 7 reflects DP&L's Yankee Adjustment (see discussion below) of $0.0003861 per kWh. DP&L added its Reconciliation Adjustment to the $0.0005700 per kWh and the Yankee adjustment noted above to derive its forecasted AER rate of $0.0008268 per kWh as shown on line 8 of Schedule 1.

Exhibit 6-18. Summary of Actual Costs – Schedule 2, January 2014 through February 2015

The Dayton Power and Light Company
Case No. 14-806-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									$2,151,647	Accounting Records
2	Jan-14	$228,317	$523	$0	$228,840	($967,797)	($738,957)	$7,341	($731,616)	$1,420,031	Accounting Records
3	Feb-14	$228,317	$3,209	$0	$231,526	($955,442)	($723,916)	$4,358	($719,558)	$700,473	Accounting Records
4	Mar-14	$223,705	($34,433)	$0	$189,272	($790,365)	($601,093)	$1,725	($599,368)	$101,104	Accounting Records
5	Apr-14	$238,075	($35,996)	$0	$202,079	($653,005)	($450,926)	($2,520)	($453,446)	($352,341)	Accounting Records
6	May-14	$196,728	$2,527	$0	$199,255	($540,707)	($341,452)	($2,155)	($343,607)	($695,948)	Accounting Records
7	Jun-14	$213,910	$2,003	$0	$215,913	($141,366)	$74,547	($2,713)	$71,833	($624,115)	Accounting Records
8	Jul-14	$166,130	$2,100	$0	$168,230	($165,283)	$2,947	($2,565)	$383	($623,732)	Accounting Records
9	Aug-14	$192,304	($21,207)	$0	$171,097	($156,172)	$14,924	($2,539)	$12,386	($611,346)	Accounting Records
10	Sep-14	$216,849	$25,699	$121,882	$364,430	($233,478)	$130,952	($2,249)	$128,704	($482,642)	Accounting Records
11	Oct-14	$211,022	$353	$121,882	$333,257	($155,613)	$177,645	($1,622)	$176,023	($306,620)	Corporate Forecast
12	Nov-14	$211,022	$353	$121,882	$333,257	($146,972)	$186,285	($882)	$185,404	($121,216)	Corporate Forecast
13	Dec-14	$201,973	$353	$121,882	$324,209	($324,209)	$0	($555)	($464)	($121,680)	Corporate Forecast
14	Jan-15	$168,411	$353	$121,882	$290,646	($290,646)	$0	($626)	($473)	($122,153)	Corporate Forecast
15	Feb-15	$168,411	$353	$121,882	$290,646	($290,646)	$0	($313)	($260)	($122,414)	Corporate Forecast
16	(Over) / Under Recovery									($122,414)	Line 15
17	Gross Revenue Conversion Factor									1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 21
18	Total (Over) / Under Recovery with Carrying Costs									($123,295)	Line 16 * Line 17
							Dec-14	Jan-15	Feb-15		
19	Standard Offer Sales Forecast (kWh)						372,835,578	380,423,920	200,601,509	953,861,007	Corporate Forecast
20	AER Reconciliation Rate $/kWh									($0.0001293)	Line 18 / Line 19

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

Schedule 2: Column C of Schedule 2 reflects DP&L's actual REC expenses during the period of January 2014 through February 2015, which totaled $2.865 million. Column D of Schedule 2 reflects DP&L's actual Compliance Administration expenses for the same period, which totaled ($53,810). Column E reflects the Historical Yankee Costs for September 2014 through February 2015. The REC expenses, compliance administration expense, and historical Yankee costs were combined for Total expenses of $3.543 million, as shown in column F. Column G reflects DP&L's actual revenues for January 2014 through February 2015 for a total of ($5.812) million. The difference between the Company's actual fuel costs and actual revenues results in an over-recovery in the amount of ($2.269) million, as shown in column H. Column I reflects the carrying costs for the period of January 2014 through February 2015, which total ($5,312). The over-recovery for the period of January 2014 through February 2015, the addition of the prior reconciliation under-recovery shown on line 1, and the addition of the carrying costs for the January 2014 through February 2015 period, resulted in a YTD over-recovery of ($122,414) (column K, line 16). 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 ($123,295), as shown on line 18. Line 19 reflects the Standard Offer Sales Forecast for the period of December 2014 through February 2015, totaling 935.861 million kWh. The Company derived its AER Reconciliation Rate of ($0.0001293) per kWh by dividing the total over-recovery with carrying costs of ($123,295) by its standard offer sales forecast for the period December 2014 through February 2015.

Exhibit 6-19. Projected Monthly Cost Calculation – December 2014 through February 2015

The Dayton Power and Light Company
Case No. 14-806-EL-RDR
Projected Monthly Cost Calculation

Line (A)	Description (B)	Dec-14 (C)	Jan-15 (D)	Feb-15 (E)	Total (F)	Source (G)
1	REC Expense	$201,973.32	$168,410.70	$168,410.70	$538,795	Corporate Forecast
2	Compliance Administration	$353	$353	$353	$1,060	Corporate Forecast
3	Total AER Expense	$202,326.63	$168,764.01	$168,764.01	$539,855	Line 1 + Line 2
4	Gross Revenue Conversion Factor				1.0072	Case No. 12-426-EL-SSO, WP-11, Col (C), Line 2:
5	Total Projected AER Costs				$543,742	Line 3 x Line 4
6	Standard Offer Sales Forecast (kWh)				953,861,007	Corporate Forecast
7	AER Base Rate $/kWh				$0.0005700	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 2014 through February 2015. As shown on line 1 of Schedule 3, the category included DP&L's forecasted REC expense for December 2014 through February 2015, which totaled $538,795 (column F). As shown on line 2 of Schedule 3, DP&L included forecasted compliance administration expenses for the same period, which totaled $1,060. This results in total AER expense for December 2014 through February 2015 of $539,855, 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 $539,855 by the gross revenue conversion factor as shown on line 5. The Company reflected its Standard Offer Sales Forecast for the period of December 2014 through February 2015, totaling 953.861 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 $0.0005700 per kWh as shown on line 7.

Exhibit 6-20. Historical Yankee REC Costs – Schedule 4, December 2014 through February 2015

The Dayton Power and Light Company
Case No. 14-806-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
				Dec-14	Jan-15	Feb-15		
7	Standard Offer Sales Forecast (kWh)			372,835,578	380,423,920	200,601,509	953,861,007	Corporate Forecast
8	Yankee Adjustment $/kWh						$ 0.0003861	Line 6 / Line 7

Schedule 4: Schedule 4 presents the calculation of the Yankee REC cost adjustment for the period December 2014 through February 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 December 2014 through February 2015 totaling 953.861 million kWh. The total quarterly recovery amount is divided by the Standard Offer Sales Forecast to calculate the Yankee adjustment of $.0003861 per kWh shown on line 8, which is used on Schedule 1 (discussed above) in the calculation of the forecasted AER rate.

Exhibit 6-21. Calculation of Carrying Costs – Workpaper 1, January 2014 through February 2015

The Dayton Power and Light Company
Case No. 14-806-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							$2,151,647	$0	$0
2	Jan-14	$2,151,647	$228,840	($967,797)	($738,957)	$1,412,690	$7,341	$1,420,031	$369,479	$1,782,168
3	Feb-14	$1,420,031	$231,526	($955,442)	($723,916)	$696,114	$4,358	$700,473	$361,958	$1,058,072
4	Mar-14	$700,473	$189,272	($790,365)	($601,093)	$99,380	$1,725	$101,104	$300,546	$399,926
5	Apr-14	$101,104	$202,079	($653,005)	($450,926)	($349,822)	($2,520)	($352,341)	$225,463	($124,359)
6	May-14	($352,341)	$199,255	($540,707)	($341,452)	($693,793)	($2,155)	($695,948)	$170,726	($523,067)
7	Jun-14	($695,948)	$215,913	($141,366)	$74,547	($621,401)	($2,713)	($624,115)	($37,273)	($658,675)
8	Jul-14	($624,115)	$168,230	($165,283)	$2,947	($621,167)	($2,565)	($623,732)	($1,474)	($622,641)
9	Aug-14	($623,732)	$171,097	($156,172)	$14,924	($608,808)	($2,539)	($611,346)	($7,462)	($616,270)
10	Sep-14	($611,346)	$364,430	($233,478)	$130,952	($480,394)	($2,249)	($482,642)	($65,476)	($545,870)
11	Oct-14	($482,642)	$333,257	($155,613)	$177,645	($304,997)	($1,622)	($306,620)	($88,822)	($393,820)
12	Nov-14	($306,620)	$333,257	($146,972)	$186,285	($120,334)	($882)	($121,216)	($93,675)	($214,009)
13	Dec-14	($121,216)	$324,209	($306,057)	$18,152	($103,064)	($464)	($103,528)	($9,608)	($112,672)
14	Jan-15	($103,528)	$290,646	($312,286)	($21,640)	($125,168)	($473)	($125,641)	$10,288	($114,880)
15	Feb-15	($125,641)	$290,646	($164,672)	$125,975	$334	($260)	$73	($63,519)	($63,186)

*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 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 2014 through February 2015, the total of which was then used to calculate the forecasted reconciliation adjustment rate of ($0.0001293). 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 2015

Exhibit 6-22. 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 2
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 of 1.0072. The Company then calculated its total forecasted expense by multiplying the forecasted REC and project expense of $262,042 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.

Exhibit 6-23. 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 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 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 revenues for October 2014 through May 2015 for a total of ($1.756) million. The difference between the Company's actual fuel costs and actual 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 6-24. 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 2
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 6-25. 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 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 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 6-26. 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 (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)	$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.

Quarterly Alternative Rider Filing – June through August 2015

Exhibit 6-27. 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 2:
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.