BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY

CASE NO. 15-1830-EL-AIR

CASE NO. 15-1831-EL-AAM

CASE NO. 15-1832-EL-ATA

2015 DISTRIBUTION BASE RATE CASE

BOOK I – APPLICATION AND SUPPLEMENTAL

VOLUME 4 OF 14

Dayton Power and Light Company

DP&L Case No. 15-1830-EL-AIR

Standard Filing Requirements for Rate Increases

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Dayton Power and Light Company

DP&L Case No. 15-1830-EL-AIR

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Book #	Vol #	OAC 4901-7-01 Reference	Schedule	Description
		OAC 4901-7 Appendix A, Chapter II, Section E		
2	2	Appendix A, Chapter II, Section E(B)(1)	E-1	Clean Copy of Proposed Tariff Schedules
2	3	Appendix A, Chapter II, Section E(B)(2)(a)	E-2	Current Tariff Schedules
2	4	Appendix A, Chapter II, Section E(B)(2)(b)	E-2.1	Redlined Copy of Proposed Tariff Schedules
2	1	Appendix A, Chapter II, Section E(B)(3)	E-3	Rationale for Tariff Changes
2	1	Appendix A, Chapter II, Section E(B)(4)	E-3.1	Customer Charge / Minimum Bill Rationale
2	1	Appendix A, Chapter II, Section E(B)(5)	E-3.2	Cost of Service Study
2	1	Appendix A, Chapter II, Section E(C)(2)(a)	E-4	Class and Schedule Revenue Summary
2	1	Appendix A, Chapter II, Section E(C)(2)(b)	E-4.1	Annualized Test Year Revenue at Proposed Rates vs. Most Current Rates
2	1	Appendix A, Chapter II, Section E(D)	E-5	Typical Bill Comparison

THE DAYTON POWER & LIGHT COMPANY

Case No. 15-1830-EL-AIR

Supplemental Information (C)(3)

Requirement:

Provide annual reports to shareholders of the applicant, and/or parent company, if applicant is wholly-owned subsidiary, for the most recent five years and the most recent statistical supplement.

Response:

See attached DP&L's last annual report (2010), its subsequent 10K filings (2011-2014), and its last statistical supplement (1999).

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(x) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2014**

OR

( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-9052	**DPL INC.** (An Ohio Corporation) 1065 Woodman Drive Dayton, Ohio 45432 937-224-6000	**31-1163136**
1-2385	**THE DAYTON POWER AND LIGHT COMPANY** (An Ohio Corporation) 1065 Woodman Drive Dayton, Ohio 45432 937-224-6000	**31-0258470**

Securities registered pursuant to Section 12(b) of the Act: **None**

Indicate by check mark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

DPL Inc.	Yes ☒	No ☐
The Dayton Power and Light Company	Yes ☐	No ☒

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☒	No ☐

DPL Inc. is a voluntary filer that has filed all applicable reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months.

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

DPL Inc.	Yes ☒	No ☐
The Dayton Power and Light Company	Yes ☒	No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

DPL Inc.	☒
The Dayton Power and Light Company	☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of “accelerated filer, large accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company
DPL Inc.	☐	☐	☒	☐
The Dayton Power and Light Company	☐	☐	☒	☐

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

DPL Inc.	Yes ☐	No ☒
The Dayton Power and Light Company	Yes ☐	No ☒

All of the outstanding common stock of DPL Inc. is indirectly owned by The AES Corporation. All of the common stock of The Dayton Power and Light Company is owned by DPL Inc.

As of December 31, 2014, each registrant had the following shares of common stock outstanding:

Registrant	Description	Shares Outstanding
DPL Inc.	**Common Stock, no par value**	**1**
The Dayton Power and Light Company	**Common Stock, $0.01 par value**	**41,172,173**

Documents incorporated by reference: **None**

This combined Form 10-K is separately filed by DPL Inc. and The Dayton Power and Light Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to a registrant other than itself.

THE REGISTRANTS MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION I(1)(a) AND (b) OF FORM 10-K AND ARE THEREFORE FILING THIS FORM WITH THE REDUCED DISCLOSURE FORMAT.

DPL Inc. and The Dayton Power and Light Company

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Annual Report on Form 10-K
Fiscal Year Ended December 31, 2014

GLOSSARY OF TERMS

The following select abbreviations or acronyms are used in this Form 10-K:

Abbreviation or Acronym	Definition
AEP Generation	AEP Generation Resources Inc., a subsidiary of American Electric Power Company, Inc. ("AEP"). Columbus Southern Power Company merged into the Ohio Power Company, another subsidiary of AEP, effective December 31, 2011. The Ohio Power generating assets (including jointly-owned units) were transferred into AEP Generation, effective January 1, 2014.
AER	Alternative Energy Rider allows DP&L to recover costs related to meeting the Ohio renewable portfolio standards.
AES	The AES Corporation, a global power company, the ultimate parent company of DPL
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
BTU	British Thermal Units
CFTC	Commodity Futures Trading Commission
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCEM	Customer Conservation and Energy Management
CO_2	Carbon Dioxide
ComEd	Commonwealth Edison
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
Dark spread	A common metric used to estimate returns over fuel costs of coal-fired electric generating units
DPL	DPL Inc.
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL that owns and operates peaking generation facilities from which it makes wholesale sales
DPLER	DPL Energy Resources, Inc., a wholly-owned subsidiary of DPL which sells competitive electric energy and other energy services, including its wholly-owned subsidiary MC Squared
DP&L	The Dayton Power and Light Company, the principal subsidiary of DPL and a public utility which sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. DP&L is wholly-owned by DPL
Duke Energy	Affiliates of Duke Energy with which DP&L co-owns electric generating units in Ohio (Duke Energy Ohio, Inc.)
EBITDA	Earnings before interest, taxes, depreciation and amortization
EGU	Electric generating unit

Abbreviation or Acronym	Definition
ERISA	The Employee Retirement Income Security Act of 1974
ESP	The Electric Security Plan is a cost-based plan that a utility may file with the PUCO to establish SSO rates pursuant to Ohio law
FASB	Financial Accounting Standards Board
FASC	FASB Accounting Standards Codification
FASC 805	FASB Accounting Standards Codification 805, "Business Combinations"
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
First and Refunding Mortgage	DP&L's First and Refunding Mortgage, dated October 1, 1935, as amended, with the Bank of New York Mellon as Trustee
FTR	Financial Transmission Rights
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kV	Kilovolts, 1,000 volts
kWh	Kilowatt hour
LIBOR	London Inter-Bank Offering Rate
Master Trust	DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans
MATS	Mercury and Air Toxics Standards
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier wholly-owned by DPLER
Merger	The merger of DPL and Dolphin Sub, Inc. (a wholly-owned subsidiary of AES) in accordance with the terms of the Merger agreement. At the Merger date, Dolphin Sub, Inc. was merged into DPL, leaving DPL as the surviving company. As a result of the Merger, DPL became a wholly-owned subsidiary of AES.
Merger agreement	The Agreement and Plan of Merger dated April 19, 2011 among DPL, AES and Dolphin Sub, Inc., a wholly-owned subsidiary of AES, whereby AES agreed to acquire DPL for $30 per share in a cash transaction valued at approximately $3.5 billion plus the assumption of $1.2 billion of existing debt. Upon closing, DPL became a wholly-owned subsidiary of AES.
Merger date	November 28, 2011, the date of the closing of the merger of DPL and Dolphin Sub, Inc., a wholly-owned subsidiary of AES
MRO	Market Rate Option, a market-based plan that a utility may file with PUCO to establish SSO rates pursuant to Ohio law
MTM	Mark to Market
MVIC	Miami Valley Insurance Company, a wholly-owned insurance subsidiary of DPL that provides insurance services to DPL and its subsidiaries and, in some cases, insurance services to partner companies relative to jointly-owned facilities operated by DP&L
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
Non-bypassable	Charges that are assessed to all customers regardless of whom the customer selects as their retail electric generation supplier
NOV	Notice of Violation
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSR	New Source Review is a preconstruction permitting program regulating new or significantly modified sources of air pollution
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
OCI	Other Comprehensive Income
Ohio EPA	Ohio Environmental Protection Agency
OTC	Over the counter
OVEC	Ohio Valley Electric Corporation, an electric generating company in which DP&L holds a 4.9% equity interest
PJM	PJM Interconnection, LLC, an RTO
PPM	Parts Per Million
PRP	Potentially Responsible Party
Predecessor	DPL prior to the Merger date
PUCO	Public Utilities Commission of Ohio
ROE	Return on equity
RPM	The Reliability Pricing Model is PJM's capacity construct. The purpose of the RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. Under the RPM construct, PJM procures capacity, through a multi-auction structure, on behalf of the load serving entities to satisfy the load obligations. There are three RPM auctions held for each Delivery Year (running from June 1 through May 31). The Base Residual Auction is held three years in advance of the Delivery Year and there is one Incremental Auction held in each of the subsequent three years. DP&L's capacity is located in the "rest of" RTO area of PJM.
RTO	Regional Transmission Organization
SB 221	Ohio Senate Bill 221, an Ohio electric energy bill that was signed by the Governor on May 1, 2008 and went into effect July 31, 2008. This law required all Ohio distribution utilities to file either an ESP or MRO to be in effect January 1, 2009. The law also contains, among other things, annual targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards.
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SEET	Significantly Excessive Earnings Test
Service Company	AES US Services, LLC, the shared services affiliate providing accounting, finance, and other support services to AES' U.S. SBU businesses
SFAS	Statement of Financial Accounting Standards

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
SIP	A State Implementation Plan is a plan for complying with the federal CAA, administered by the USEPA. The SIP consists of narrative, rules, technical documentation and agreements that an individual state will use to clean up polluted areas.
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SSO	Standard Service Offer represents the retail transmission, distribution and generation services offered by the utility through regulated rates, authorized by the PUCO
SSR	Service Stability Rider
Successor	DPL after the Merger
TCRR	Transmission Cost Recovery Rider
TCRR-B	Transmission Cost Recovery Rider – Bypassable
TCRR-N	Transmission Cost Recovery Rider – Nonbypassable
USEPA	U.S. Environmental Protection Agency
USF	The Universal Service Fund (USF) is a statewide program which provides qualified low-income customers in Ohio with income-based bills and energy efficiency education programs
U.S. SBU	U. S. Strategic Business Unit, AES' reporting unit covering the businesses in the United States, including DPL
VRDN	Variable Rate Demand Note

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PART I

Item 1 – Business

This report includes the combined filing of **DPL** and **DP&L**. On November 28, 2011, **DPL** became a wholly-owned subsidiary of AES, a global power company. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.

FORWARD–LOOKING STATEMENTS

Certain statements contained in this report are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Matters discussed in this report that relate to events or developments that are expected to occur in the future, including management's expectations, strategic objectives, business prospects, anticipated economic performance and financial condition and other similar matters constitute forward-looking statements. Forward-looking statements are based on management's beliefs, assumptions and expectations of future economic performance, taking into account the information currently available to management. These statements are not statements of historical fact and are typically identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will" and similar expressions. Such forward-looking statements are subject to risks and uncertainties and investors are cautioned that outcomes and results may vary materially from those projected due to various factors beyond our control, including but not limited to:

- abnormal or severe weather and catastrophic weather-related damage;
- unusual maintenance or repair requirements;
- changes in fuel costs and purchased power, coal, environmental emission allowances, natural gas and other commodity prices;
- volatility and changes in markets for electricity and other energy-related commodities;
- performance of our suppliers;
- increased competition and deregulation in the electric utility industry;
- increased competition in the retail generation market;
- availability and price of capacity;
- changes in interest rates;
- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, emission levels, rate structures or tax laws;
- changes in environmental laws and regulations to which **DPL** and its subsidiaries are subject;
- the development and operation of RTOs, including PJM to which **DP&L** has given control of its transmission functions;
- changes in our purchasing processes, pricing, delays, contractor and supplier performance and availability;
- significant delays associated with large construction projects;
- growth in our service territory and changes in demand and demographic patterns;
- changes in accounting rules and the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- financial market conditions;
- changes in tax laws and the effects of our strategies to reduce tax payments;
- the outcomes of litigation and regulatory investigations, proceedings or inquiries;
- general economic conditions; and
- the risks and other factors discussed in this report and other **DPL** and **DP&L** filings with the SEC.

Forward-looking statements speak only as of the date of the document in which they are made. We disclaim any obligation or undertaking to provide any updates or revisions to any forward-looking statement to reflect any change in our expectations or any change in events, conditions or circumstances on which the forward-looking statement is based. If we do update one or more forward-looking statements, no inference should be made that we will make additional updates with respect to those or other forward-looking statements.

COMPANY WEBSITES

DPL's public internet site is http://www.dplinc.com. **DP&L's** public internet site is http://www.dpandl.com. The information on these websites is not incorporated by reference into this report.

ORGANIZATION

DPL is a regional energy company incorporated in 1985 under the laws of Ohio. Our executive offices are located at 1065 Woodman Drive, Dayton, Ohio 45432 – telephone (937) 224-6000. **DPL** was acquired by The AES Corporation on November 28, 2011 and **DPL's** stock is owned by an AES subsidiary.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail services are still regulated. **DP&L** has the exclusive right to provide such services to its approximately 516,000 customers located in West Central Ohio. Additionally, **DP&L** offers retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at five coal-fired power stations. Beginning in 2014, **DP&L** no longer provides 100% of the generation for its SSO customers. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market prices of electricity and capacity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of DPLER's retail customers.

DPLER sells competitive retail electric service, under contract, to residential, commercial, industrial and governmental customers. DPLER's operations include those of its wholly-owned subsidiary MC Squared. DPLER has approximately 260,000 customers currently located throughout Ohio and Illinois. Approximately 131,000 of DPLER's customers are also electric distribution customers of **DP&L**. DPLER does not have any transmission or generation assets and all of DPLER's electric energy is purchased from **DP&L** to meet its sales obligations.

DPL's other significant subsidiaries include: DPLE, which owns and operates peaking generating facilities from which it makes wholesale sales of electricity and MVIC, **DPL's** captive insurance company that provides insurance services to **DP&L** and **DPL's** other subsidiaries.

DPL also has a wholly-owned business trust, DPL Capital Trust II, formed for the purpose of issuing trust capital securities to investors.

All of **DPL's** subsidiaries are wholly-owned. **DP&L** does not have any subsidiaries.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates and regulatory liabilities when current recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries had 1,182 employees as of December 31, 2014. At that date, 1,130 of these employees were employed by **DP&L**. Approximately 61% of the employees of **DPL** and its subsidiaries are under a collective bargaining agreement which expires on October 31, 2017.

In December 2013, an agreement was signed, effective January 1, 2014, whereby AES U.S. Services, LLC (the "Service Company") began providing services including accounting, legal, human resources, information technology and other services of a similar nature on behalf of companies that are part of the AES U.S. Strategic Business Unit ("U.S. SBU"), including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations.

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This includes ensuring that the regulated businesses served, including **DP&L**, are not subsidizing costs incurred for the benefit of non-regulated businesses.

ELECTRIC OPERATIONS AND FUEL SUPPLY

2014 Summer Generating Capacity (in MW)

Summer Generating Capacity	Coal fired	Combustion Turbines, Diesel Units and Solar	Total
DPL	2,078	988	3,066
DP&L	2,078	432	2,510

DPL's present summer generating capacity, including peaking units, is 3,066 MW. Of this capacity, 2,078 MW, or 68%, is derived from coal-fired steam generating stations and the balance of 988 MW, or 32%, consists of combustion turbines, diesel peaking units and solar.

DP&L's present summer generating capacity, including peaking units, is 2,510 MW. Of this capacity, 2,078 MW, or 83%, is derived from coal-fired steam generating stations and the balance of 432 MW, or 17%, consists of combustion turbines, diesel peaking units and solar.

Our all-time net peak load was 3,270 MW, occurring August 8, 2007.

100% of **DP&L's** existing steam generating capacity is provided by generating units owned as tenants in common with Duke Energy and AEP Generation. As tenants in common, each company owns a specified share of each of these units, is entitled to its share of capacity and energy output and has a capital and operating cost responsibility proportionate to its ownership share. Additionally, **DP&L,** Duke Energy and AEP Generation own, as tenants in common, 880 circuit miles of 345,000-volt transmission lines. **DP&L** has several interconnections with other companies for the purchase, sale and interchange of electricity.

Duke Energy has entered into an agreement to sell its interest in the Killen, Stuart, Conesville Unit 4, Miami Fort 7 and 8 and Zimmer generating stations to various subsidiaries of Dynegy, Inc. This transaction is currently waiting on regulatory approval.

In 2014, we generated 99% of our electric output from coal-fired units and 1% from solar, oil and natural gas-fired units.

The following table sets forth **DP&L's** and DPLE's generating stations and, where indicated, those stations which **DP&L** owns as tenants in common:

				Approximate Summer MW Rating	
Station	Ownership [(a)]	Operating Company	Location	DPL Portion [(b)]	Total
Coal Units [(c)]					
Killen - Unit 2	C	DP&L	Wrightsville, OH	402	600
Stuart - Units 1 through 4	C	DP&L	Aberdeen, OH	808	2,308
Conesville - Unit 4	C	AEP Generation	Conesville, OH	129	780
Miami Fort - Units 7 & 8	C	Duke Energy	North Bend, OH	368	1,020
Zimmer - Unit 1	C	Duke Energy	Moscow, OH	371	1,320
Solar, Combustion Turbines or Diesel					
Hutchings Unit 7 [(d)]	W	DP&L	Miamisburg, OH	25	25
Yankee Street Gas Turbine	W	DP&L	Centerville, OH	101	101
Yankee Solar	W	DP&L	Centerville, OH	1	1
Monument Diesels	W	DP&L	Dayton, OH	12	12
Tait Diesels	W	DP&L	Dayton, OH	10	10
Sidney Diesels	W	DP&L	Sidney, OH	12	12
Tait Units 1 - 3	W	DP&L	Moraine, OH	256	256
Killen Diesels	C	DP&L	Wrightsville, OH	12	18
Stuart Diesels	C	DP&L	Aberdeen, OH	3	10
Montpelier Units 1 - 4	W	DPLE	Poneto, IN	236	236
Tait Units 4 - 7	W	DPLE	Moraine, OH	320	320
Total approximate summer generating capacity				3,066	7,029

(a) W = Wholly-owned C = Commonly-owned
(b) **DP&L** portion of commonly-owned generating stations
(c) Duke Energy has entered into an agreement to sell its interest in the Killen, Stuart, Conesville Unit 4, Miami Fort 7 and 8 and Zimmer generating stations to various subsidiaries of Dynegy, Inc. This transaction is currently waiting on regulatory approval.

In addition to the above, **DP&L** also owns a 4.9% equity ownership interest in OVEC, an electric generating company. OVEC has two electric generating stations located in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of 2,109 MW. **DP&L's** share of this generation capacity is 103 MW.

On December 30, 2014, after receipt of all necessary regulatory approvals, **DP&L** sold its 31% ownership interest (186 MW) in East Bend Unit 2 to Duke Energy, Kentucky, Inc., which is the operator of the Unit and was the 69% owner. Beckjord Unit 6, in which **DP&L** had a 50% ownership interest, was retired effective October 1, 2014.

We have substantially all of the total expected coal volume needed to meet our retail and wholesale sales requirements for 2015 under contract. The majority of the contracted coal is purchased at fixed prices. Some contracts provide for periodic adjustments and some are priced based on market indices. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, the wholesale market price of power, certain provisions in coal contracts related to government imposed costs, counterparty performance and credit, scheduled/forced outages and generation station mix. Due to the installation of emission control equipment at certain commonly-owned units and barring any changes in the regulatory environment in which we operate, we expect to have balanced positions for SO_2, NO_x and renewable energy credits for 2015.

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The gross average cost of fuel consumed per kWh was as follows:

	Average cost of Fuel Consumed (cents per kWh)		
	2014	2013	2012
DPL	2.52	2.43	2.75
DP&L	2.45	2.40	2.72

SEASONALITY

The power generation and delivery business is seasonal and weather patterns have a material effect on operating performance. In the region we serve, demand for electricity is generally greater in the summer months associated with cooling and in the winter months associated with heating compared to other times of the year. Unusually mild summers and winters could have an adverse effect on our results of operations, financial condition and cash flows.

RATE REGULATION AND GOVERNMENT LEGISLATION

DP&L's sales to SSO retail customers are subject to rate regulation by the PUCO. In addition, certain of **DP&L's** recoverable costs are considered to be non-bypassable and are therefore assessed to all **DP&L** retail customers, under the regulatory authority of the PUCO, regardless of whom the customer selects to supply its retail electric service. **DP&L's** transmission rates and wholesale electric rates to municipal corporations, rural electric co-operatives and other distributors of electric energy are subject to regulation by the FERC under the Federal Power Act.

Ohio law establishes the process for determining SSO and non-bypassable rates charged by public utilities. Regulation of retail rates encompasses the timing of applications, the effective date of rate increases, the market price of power, the cost basis upon which the rates are set and other related matters. Ohio law also established the Office of the OCC, which has the authority to represent residential consumers in state and federal judicial and administrative rate proceedings.

Ohio legislation extends the jurisdiction of the PUCO to the records and accounts of certain public utility holding company systems, including **DPL**. The legislation extends the PUCO's supervisory powers to a holding company system's general condition and capitalization, among other matters, to the extent that such matters relate to the costs associated with the provision of public utility service. Based on existing PUCO and FERC authorization, regulatory assets and liabilities are recorded on the balance sheets of both **DPL** and **DP&L**. See Note 3 of Notes to **DPL's** Consolidated Financial Statements and Note 3 of Notes to **DP&L's** Financial Statements.

COMPETITION AND REGULATION

Ohio Matters

Ohio Retail Rates
The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

Ohio law requires that all Ohio distribution utilities file either an ESP or MRO to establish rates for their SSO. According to Ohio law, under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for adjustments to the SSO for costs associated with environmental compliance; fuel *and purchased power; construction of new or investment in specified generating facilities; and the provision of* standby and default service, operating, maintenance or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade or replace its electric distribution system, including cost recovery mechanisms. Both MRO and ESP options involve a SEET based on the earnings of comparable companies with similar business and financial risks.

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On October 5, 2012, **DP&L** filed an ESP with the PUCO to establish SSO rates that were to be in effect starting January 2013. An order was issued by the PUCO on September 4, 2013 and a correction to that order was issued on September 6, 2013 (ESP Order).

After several rehearing requests, the ESP Order was revised several times. Collectively, the ESP orders state that **DP&L's** current ESP began January 2014 and extends through May 31, 2017. The PUCO authorized **DP&L** to collect a non-bypassable Service Stability Rider (SSR) equal to $110 million per year from 2014 – 2016. The ESP Order also directed **DP&L** to divest its generation assets no later than January 1, 2017 and established **DP&L's** SEET threshold at a 12% ROE. Beginning in 2014, **DP&L** is no longer permitted to supply 100% of the generation service for SSO customers. Instead, the PUCO directed **DP&L** to phase-in the competitive bidding structure with 10% of **DP&L's** SSO load sourced through the competitive bid starting in 2014, 60% in 2015, and 100% by January 1, 2016. The ESP Order approved **DP&L's** rate proposal to bifurcate its transmission charges into a non-bypassable component, TCRR-N, and a bypassable component, TCRR-B. The ESP order also required **DP&L** to establish a $2.0 million per year shareholder funded economic development fund.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. Comments and reply comments were filed. **DP&L** amended its application on February 25, 2014 and again on May 23, 2014. Additional comments and reply comments were filed. On July 14, 2014, **DP&L** publicly announced its decision not to sell **DP&L's** generation assets at this time, but to maintain its plans to transfer or sell the assets in accordance with PUCO orders by January 1, 2017. On September 17, 2014, the PUCO issued a Finding and Order in which it approved of **DP&L's** plan to separate its generation assets with minor modifications. Specifically, **DP&L's** request to defer costs associated with OVEC which are not currently being recovered through existing rates was denied, and **DP&L** was ordered to transfer environmental liabilities with the generation assets.

Ohio law and the PUCO rules contain targets relating to renewable energy, demand reduction and energy efficiency standards. If any targets are not met, compliance penalties will apply unless the PUCO makes certain findings that would excuse performance. The PUCO has found that **DP&L** met its renewable targets for compliance years 2008 – 2013. PUCO staff recommended that DPLER met its targets for compliance year 2013. Both **DP&L** and DPLER are reported to be in full compliance with all renewable targets.

On June 13, 2014, Ohio Senate Bill 310 (SB 310) was signed into law, and it became effective September 12, 2014. The new law changes several aspects to renewable energy and energy efficiency sections of law that were created in 2008 referred to as SB 221. The new law freezes the renewable energy requirements at 2014 levels for 2015 and 2016 and the energy efficiency requirements if a utility modifies its portfolio plan. The law also removes the advanced energy requirement and the renewable requirement of meeting half of the compliance level through facilities within the state. **DP&L** did not file an amended portfolio plan, thereby extending its current plan through 2016. **DP&L** recovers the costs of its compliance with Ohio energy efficiency and renewable energy standards through two separate riders.

The ESP Order also provided for the continuation of a fuel and purchased power recovery rider which began January 1, 2010. The fuel rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter: March 1, June 1, September 1 and December 1 each year. As part of the PUCO approval process, an outside auditor is hired each year to review fuel costs and the fuel procurement process. On June 12, 2013, we received a 2012 audit report recommending a pre-tax disallowance of $5.3 million of costs. In August 2014, the PUCO issued an order in that case that included the disallowance of an immaterial amount of fuel costs. The impact of the order issued was a reversal in the third quarter of a previously established $2.6 million reserve. The 2013 fuel audit report found only minor disallowances. The Company, the PUCO staff and OCC reached a stipulation resolving all issues in the 2013 audit. This Stipulation is pending PUCO approval.

As a member of PJM, **DP&L** receives revenues from the RTO related to **DP&L's** transmission and generation assets and incurs costs associated with its load obligations for retail customers. Ohio law includes a provision that would allow Ohio electric utilities to seek and obtain a reconcilable rider to recover RTO-related costs and credits. **DP&L's** TCRR and PJM RPM riders were initially approved in November 2009 to recover these costs. In accordance with the ESP Order, TCRR-N and TCRR-B began on January 1, 2014. Both the TCRR-B and the RPM riders assign costs and revenues from PJM monthly bills to retail ratepayers based on the percentage of SSO retail customers' load and sales volumes to total retail load and total retail and wholesale volumes. Customer switching to CRES providers decreases **DP&L's** SSO retail customers' load and sales volumes. Therefore, increases in customer switching cause more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. RPM capacity costs and revenues are discussed further under "Regional Transmission Organizational Risks" in Item 1A – Risk Factors. **DP&L** files an annual true-up of TCRR-N and both TCRR-B and RPM are trued up on a quarterly basis beginning January 2014 through January 1, 2016, at which point they will be eliminated as a result of the SSO load being supplied 100% through the competitive bid process.

For calendar year 2012, **DP&L** was subject to a SEET threshold in which **DP&L** was required to apply general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. Pursuant to an Order issued on February 13, 2014, **DP&L's** 2012 earnings were found to not be excessive. Through the ESP Order, the PUCO established **DP&L's** ROE SEET threshold at 12% beginning with 2013. On May 15, 2014, **DP&L** filed its application to demonstrate that it did not have *significantly excessive earnings for calendar year 2013. A stipulation was reached with the PUCO staff agreeing* that **DP&L** did not exceed the SEET threshold for 2013, which was filed on July 22, 2014. At a hearing held on September 9, 2014 and on October 1, 2014, the PUCO issued an order approving the SEET Stipulation. In future years, the SEET could have a material effect on our results of operations, financial condition and cash flows.

Ohio Competitive Considerations and Proceedings

Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state-certified territory and the obligation to supply and/or procure retail generation service to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

Market prices for power, as well as government aggregation initiatives, have led and may continue to lead to the entrance of additional competitors in our service territory. As of December 31, 2014, there were forty-three CRES providers registered in **DP&L's** service territory. DPLER, an affiliated company and one of the forty-three registered CRES providers, has been marketing supply services to **DP&L** customers. During 2014, DPLER accounted for approximately 5,649 million kWh of the total 10,014 million kWh supplied by CRES providers within **DP&L's** service territory. Also during 2014, 110,536 customers with an annual energy usage of 4,365 million kWh were supplied by other CRES providers within **DP&L's** service territory. The volume supplied by DPLER represents approximately 40% of **DP&L's** total distribution sales volume during 2014. We cannot determine the extent to which customer switching to CRES providers will occur in the future and the effect this will have on us. Because DPLE was one of the winning bidders in the competitive bid auction, and therefore provides generation service to a portion of the SSO load through May 2017, future additional customer switching away from SSO load will continue to have a negative financial impact on **DPL**, but to a lesser degree. Beginning January 1, 2016, 100% of SSO load will be served through the competitive bid auction. After that date, customer switching will have no impact on **DP&L's** financial condition.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residents. To date, a number of communities have filed with the PUCO to initiate aggregation programs. If a number of the larger communities in **DP&L's** service area move forward with aggregation in 2015, it could have a material effect on our earnings. In 2014, the City of Dayton announced it decided to move forward with its plans to implement a government aggregation program. Depending on the timing of implementation of this program, it could have a significant financial impact on **DPL**. As discussed above, beginning January 1, 2016, customer switching will have no effect on **DP&L's** net income.

DPLER began providing CRES services to business customers in Ohio who are not in **DP&L's** service territory in 2010 and to residential customers in 2012. Additionally, through MC Squared, DPLER services business and residential customers in northern Illinois.

Federal Matters

Like other electric utilities and energy marketers, **DP&L** and DPLE may sell or purchase electric products in the wholesale market. **DP&L** and DPLE compete with other generators, power marketers, privately and municipally-owned electric utilities and rural electric cooperatives when selling electricity. The ability of **DP&L** and DPLE to sell this electricity will depend not only on the performance of our generating units, but also on how **DP&L's** and DPLE's prices, terms and conditions compare to those of other suppliers.

As part of Ohio's electric deregulation law, all of the state's investor-owned utilities were required to join an RTO. In October 2004, **DP&L** successfully integrated its high-voltage transmission lines into the PJM RTO. The role of the RTO is to administer a competitive wholesale market for electricity and ensure reliability of the transmission grid. PJM ensures the reliability of the high-voltage electric power system serving more than 50 million people in 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. PJM coordinates and directs the operation of the region's transmission grid, administers the world's largest competitive wholesale electricity market and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

The PJM RPM capacity base residual auction for the 2017/18 period cleared at a price of $120/MW-day for our RTO area. The prices for the periods 2016/17, 2015/16 and 2014/15 were $59/MW-day, $136/MW-day and $126/MW-day, respectively, based on previous auctions. There are proposals from PJM pending before the FERC that would modify capacity markets including near-term modifications with respect to RPM and longer-term modifications that would phase-out RPM and replace it with a Capacity Performance ("CP") program. The final form of CP program has not been established and the effects on **DP&L** cannot be predicted. In concept, however, the CP program is intended to result in higher capacity prices paid to generators, paired with larger penalties for a generator's failure to perform during periods where electricity is in high demand. Future RPM or CP auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the capacity auctions. Increases in customer switching causes more of the capacity costs and revenues to be excluded from the **DP&L's** Ohio RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but if the current auction price is not sustained or if higher penalties are incurred due to implementation of the CP program and **DP&L's** generation performance, it could have a material adverse effect on our future results of operations, financial condition and cash flows.

NERC is a FERC-certified electric reliability organization responsible for developing and enforcing mandatory reliability standards, including Critical Infrastructure Protection (CIP) reliability standards, across eight reliability regions. In December 2012, **DP&L** underwent routine, scheduled NERC audits conducted by Reliability First Corporation (RFC), which focused on our performance in supporting PJM as our transmission operator, and our compliance with the CIP standards. **DP&L** was found 100% compliant in its performance in support of PJM. In the CIP audit, four minor documentation-related Possible Alleged Violations (PAVs) were identified, which were settled through a streamlined process, without any financial penalties. In November 2013, DPLE, **DPL's** merchant generation affiliate, underwent a routine, scheduled NERC audit, during which one minor PAV was identified; **DPL** anticipates that it will be settled through a streamlined process, with no financial penalty.

ENVIRONMENTAL MATTERS

DPL's and **DP&L's** facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including SIPs) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $0.8 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable or a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to environmental matters quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows. See Note 13, "Contractual Obligations, Commercial *Commitments and Contingencies – Environmental Matters" in* **DPL's** *Consolidated Financial Statements and* Note 12, "Contractual Obligations, Commercial Commitments and Contingencies – Environmental Matters" in **DP&L's** *Financial Statements for more information regarding environmental risks, laws and regulations and legal* proceedings to which we are and may be subject to in the future.

Capital Expenditures for Environmental Matters

DP&L's environmental capital expenditures were approximately $3.6 million, $2.0 million and $8.0 million in 2014, 2013 and 2012, respectively. **DP&L** has budgeted $10.7 million in environmental-related capital expenditures for 2015.

LEGAL AND OTHER MATTERS

In February 2007, **DP&L** filed a lawsuit in the United States District Court for Southern District of Ohio against *Appalachian Fuels, LLC ("Appalachian") seeking damages incurred due to Appalachian's failure to supply* approximately 1.5 million tons of coal to two commonly-owned stations under a coal supply agreement, of which approximately 570 thousand tons was **DP&L's** share. **DP&L** obtained replacement coal to meet its needs. Appalachian has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

Also see Note 13 of Notes to **DPL's** Consolidated Financial Statements for additional information about certain legal matters.

ELECTRIC SALES AND REVENUES

The following table sets forth **DPL's** electric sales and revenues for the years ended December 31, 2014, 2013 and 2012, respectively.

	DPL		
	Year ended December 31, 2014	Year ended December 31, 2013	Year ended December 31, 2012
Electric sales (millions of kWh)	18,763	19,561	16,454
Billed electric customers (end of period)	644,483	692,670	637,708

DPL is structured in two operating segments, **DP&L** and DPLER. See Note 14 of Notes to **DPL's** Consolidated Financial Statements for more information on **DPL's** segments.

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The following tables set forth **DP&L's** and DPLER's electric sales and revenues for the years ended December 31, 2014, 2013 and 2012, respectively.

	DP&L (a)		
	Year ended December 31, 2014	Year ended December 31, 2013	Year ended December 31, 2012
Electric sales (millions of kWh)	18,613	19,423	15,606
Billed electric customers (end of period)	515,622	514,926	513,282

	DPLER (b)		
	Year ended December 31, 2014	Year ended December 31, 2013	Year ended December 31, 2012
Electric sales (millions of kWh)	9,717	9,733	8,315
Billed electric customers (end of period)	260,097	308,047	198,098

(a) **DP&L** sold 5,649 million kWh, 5,874 million kWh and 6,201 million kWh of power to DPLER (a subsidiary of **DPL**) for the years ended December 31, 2014, 2013 and 2012, respectively.
(b) This chart includes all sales of DPLER, both within and outside of the **DP&L** service territory.

Item 1A – Risk Factors

Investors should consider carefully the following risk factors that could cause our business, operating results and financial condition to be materially adversely affected. New risks may emerge at any time, and we cannot predict those risks or estimate the extent to which they may affect our business or financial performance. These risk factors should be read in conjunction with the other detailed information concerning **DPL** set forth in the Notes to **DPL's** audited Consolidated Financial Statements and **DP&L** set forth in the Notes to **DP&L's** audited Financial Statements in Item 8 – Financial Statements and Supplementary Data and in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations herein. The risks and uncertainties described below are not the only ones we face.

Customers have the opportunity to select alternative electric generation service providers, as permitted by Ohio legislation.
Customers can elect to buy generation service from a PUCO-certified CRES provider offering services to customers in **DP&L's** service territory. DPLER, a wholly-owned subsidiary of **DPL**, is one of those PUCO-certified CRES providers. Unaffiliated CRES providers also have been certified to provide energy in **DP&L's** service territory. Customer switching from **DP&L** to DPLER reduces **DPL's** revenues since the generation rates charged by DPLER are less than the SSO rates charged by **DP&L**. Increased competition by unaffiliated CRES providers in **DP&L's** service territory for retail generation service could result in the loss of existing customers and reduced revenues and increased costs to retain or attract customers. Decreased revenues and increased costs due to continued customer switching and customer loss in 2015 could have a material adverse effect on our results of operations, financial condition and cash flows. As discussed in Item 1, beginning January 1, 2016, customer switching will have no effect on **DP&L**. The following are some of the factors that could result in increased switching by customers to PUCO-certified CRES providers in the future:

- low wholesale price levels have led, and may continue to lead, to existing CRES providers becoming more active in our service territory,
- additional CRES providers entering our territory, and

- we may experience increased customer switching through "governmental aggregation," where a municipality may contract with a CRES provider to provide generation service to the customers located within the municipal boundaries.

The operation and performance of our facilities are subject to various events and risks that could negatively affect our business.

The operation and performance of our generation, transmission and distribution facilities and equipment is subject to various events and risks, such as the potential breakdown or failure of equipment, processes or facilities, fuel supply or transportation disruptions, the loss of cost-effective disposal options for solid waste generated by our facilities (such as coal ash and gypsum), accidents, injuries, labor disputes or work stoppages by employees, operator error, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental limitations and governmental interventions, performance below expected or required levels, weather-related and other natural disruptions, vandalism, events occurring on the systems of third parties that interconnect to and affect our system and the increased maintenance requirements, costs and risks associated with our aging generation units. Our results of operations, financial condition and cash flows could have a material adverse effect due to the occurrence or continuation of these events.

Diminished availability or performance of our transmission and distribution facilities could result in reduced customer satisfaction and regulatory inquiries and fines, which could have a material adverse effect on our results of operations, financial condition and cash flows. Operation of our owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and efficiency levels and likely result in lost revenues and increased expenses that could have a material adverse effect on our results of operations, financial condition and cash flows. In particular, since nearly 42% of our base-load generation is derived from co-owned generation stations operated by our co-owners, poor operational performance by our co-owners, misalignment of co-owners' interests or lack of control over costs (such as fuel costs) incurred at these stations could have an adverse effect on us. In addition, our co-owners have either taken steps to sell their co-ownership interest in these co-owned generation stations or have expressed an interest in selling such generation facilities. Any sale of these co-owned generation stations by a co-owner to a third party could enhance the risk of a misalignment of interests, lack of cost control and other operational failures. We have constructed and placed into service FGD facilities at our base-load generating stations. If there is significant operational failure of the FGD equipment at the generating stations, we may not be able to meet emission requirements at some of our generating stations or it may require us to burn more expensive types of coal or procure additional emission allowances. These events could result in a substantial increase in our operating costs. Depending on the degree, nature, extent, or willfulness of any failure to comply with environmental requirements, including those imposed by any consent decrees, such non-compliance could result in the imposition of penalties or the shutting down of the affected generating stations, which could have a material adverse effect on our results of operations, financial condition and cash flows.

Asbestos and other regulated substances are, and may continue to be, present at our facilities. We have been named as a defendant in asbestos litigation, which at this time is not material to us. The continued presence of asbestos and other regulated substances at these facilities could result in additional litigation being brought against us, which could have a material adverse effect on our results of operations, financial condition and cash flows.

The costs we can recover and the return on capital we are permitted to earn for certain aspects of our business are regulated and governed by the laws of Ohio and the rules, policies and procedures of the PUCO.

On May 1, 2008, SB 221, an Ohio electric energy bill, was signed by the Governor of Ohio and became effective July 31, 2008. This law, among other things, required all Ohio distribution utilities to file either an ESP or MRO, and established a significantly excessive earnings test for Ohio public utilities that compares the utility's earnings to the earnings of other companies with similar business and financial risks. The PUCO order in the 2012 ESP case changed the Company's rate structure and the ability to recover certain costs which will affect our results of operations, cash flows and financial condition. **DP&L's** ESP and certain filings made by us in connection with this plan are further discussed under "Ohio Retail Rates" in Item 1 – Competition and Regulation.

In Ohio, retail generation rates are no longer subject to cost-based regulation, while the distribution and transmission businesses are still regulated. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the PUCO will agree that all of our costs have been prudently incurred or are recoverable. There is also no assurance that the regulatory process in which rates are determined will always result in rates that will produce a full or timely recovery of our costs and permitted rates of return. Accordingly, the revenue **DP&L** receives may or may not match its expenses at any given time. Therefore, **DP&L** is subject to prevailing market prices for electricity and would not necessarily be able to charge rates that produce timely or full recovery of its expenses. Changes in, or reinterpretations of, the laws, rules, policies and procedures that set electric rates, permitted rates of return, changes in **DP&L's** rate structure, regulations regarding ownership of generation assets, transition to a competitive bid structure to supply retail generation service to SSO customers, reliability initiatives, fuel and purchased power (which account for a substantial portion of our operating costs), customer switching, capital expenditures and investments and other costs on a full or timely basis through rates, power market prices, and changes to the frequency and timing of rate increases could have a material adverse effect on our results of operations, financial condition and cash flows.

Our increased costs due to advanced energy and energy efficiency requirements may not be fully recoverable in the future.
SB 221 contained targets relating to advanced energy, renewable energy, peak demand reduction and energy efficiency standards. SB 310 was passed in 2014 that modified the energy efficiency and renewable targets. It eliminated the advanced energy targets and the "in state" requirement for renewable energy. Annual targets for energy efficiency began in 2009 and require increasing energy reductions each year compared to a baseline energy usage, up to 22.3% by 2025. Peak demand reduction targets began in 2009 with increases in required percentages each year, up to 7.75% by 2018. The renewable energy standards have increased our power supply costs and are expected to continue to increase (and could materially increase) these costs. **DP&L** is entitled to recover costs associated with its alternative energy compliance costs, as well as its energy efficiency and demand response programs. **DP&L** began recovering these costs in 2009. If in the future we are unable to timely or fully recover these costs, it could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, if we were found not to be in compliance with these standards, monetary penalties could apply. These penalties are not permitted to be recovered from customers and significant penalties could have a material adverse effect on our results of operations, financial condition and cash flows. The demand reduction and energy efficiency standards by design result in reduced energy and demand that could adversely affect our results of operations, financial condition and cash flows.

The availability and cost of fuel has experienced and could continue to experience significant volatility and we may not be able to hedge the entire exposure of our operations from fuel availability and price volatility.
We purchase coal, natural gas and other fuel from a number of suppliers. The coal market in particular has experienced significant price volatility in the last several years. We are now in a global market for coal in which our domestic price is increasingly affected by international supply disruptions and demand balance. Coal exports from the U.S. have increased significantly at times in recent years. In addition, domestic issues like government-imposed direct costs and permitting issues that affect mining costs and supply availability, and the variable demand of retail customer load and the performance of our generation fleet have an impact on our fuel procurement operations. Our approach is to hedge the fuel costs for our anticipated electric sales. However, we may not be able to hedge the entire exposure of our operations from fuel price volatility. As of the date of this report, **DP&L** has substantially all of the expected coal volume needed under contract to meet its retail and wholesale sales requirements for 2015. Historically, some of our suppliers and buyers of fuel have not performed on their contracts and have failed to deliver or accept fuel as specified under their contracts. To the extent our suppliers and buyers do not meet their contractual commitments and, as a result of such failure or otherwise, we cannot secure adequate fuel or sell excess fuel in a timely or cost-effective manner or we are not hedged against price volatility, we could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, **DP&L** is a co-owner of certain generation facilities where it is a non-operating owner. **DP&L** does not procure or have control over the fuel for these facilities, but is responsible for its proportionate share of the cost of fuel procured at these facilities. Co-owner operated facilities do not always have realized fuel costs that are equal to our co-owners' projections, and we are responsible for our proportionate share of any increase in actual fuel costs. Fuel and purchased power costs represent a large and volatile portion of **DP&L's** total cost. **DP&L** implemented a fuel and purchased power recovery mechanism beginning on January 1, 2010, which subjects our recovery of fuel and purchased power costs to tracking and adjustment on a seasonal quarterly basis for SSO customers but will be totally phased out by January 1, 2016. If in the future we are unable to timely or fully recover our fuel and purchased power costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Fluctuations in our sales of coal and excess emission allowances could cause a material adverse effect on our results of operations, financial condition and cash flows for any particular period.
DP&L sells coal to other parties from time to time for reasons that include maintaining an appropriate balance between projected supply and projected use and as part of a coal price optimization program where coal under

contract may be resold and replaced with other coal or power available in the market with a favorable price spread, adjusted for any quality differentials. Sales of coal are affected by a range of factors, including price volatility among the different coal basins and qualities of coal, variations in power demand and the market price of power compared to the cost to produce power. These factors could cause the amount and price of coal we sell to fluctuate, which could have a material adverse effect on our results of operations, financial condition and cash flows for any particular period.

DP&L may sell its excess emission allowances, including NO_x and SO_2 emission allowances, from time to time. Sales of any excess emission allowances are affected by a range of factors, such as general economic conditions, fluctuations in market demand, availability of excess inventory for sale and changes to the regulatory environment, including the implementation of CSAPR. These factors could cause the amount and price of excess emission allowances **DP&L** sells to fluctuate, which could have a material adverse effect on **DPL's** results of operations, financial condition and cash flows for any particular period. Although there has been overall reduced trading activity in the annual NO_x and SO_2 emission allowance trading markets in recent years, the adoption of regulations that regulate emissions or establish or modify emission allowance trading programs could affect the emission allowance trading markets and have a material effect on **DP&L's** emission allowance sales.

If legislation or regulations at the federal, state or regional levels impose mandatory reductions of greenhouse gases on generation facilities, we could be required to make large additional capital investments and incur substantial costs.

There is an ongoing concern nationally and internationally among regulators, investors and others concerning global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to interest in legislation and action at the international, federal, state and regional levels, including regulation of GHG emissions by the USEPA, and litigation seeking to compel the promulgation or enforcement of GHG requirements. Approximately 99% of the energy we produce is generated by coal. As a result of current or future legislation or regulations at the international, federal, state or regional levels imposing mandatory reductions of CO_2 and other GHGs on generation facilities, we could be required to make large additional capital investments and/or incur substantial costs in the form of taxes or emissions allowances. Such legislation and regulations could also impair the value of our generation stations or make some of these stations uneconomical to maintain or operate and could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing generation stations. Although **DP&L** is permitted under its current ESP to seek recovery of costs associated with new climate change or GHG regulations, our inability to fully or timely recover such costs could have a material adverse effect on our results of operations, financial condition and cash flows.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations, may expose us to environmental liabilities or make continued operation of certain generating units unprofitable.

Our operations and facilities (both wholly-owned and co-owned with others) are subject to numerous and extensive federal, state and local environmental laws and regulations relating to various matters, including air quality (such as reductions in NO_x, SO_2 and particulate emissions), water quality, wastewater discharge, solid waste and hazardous waste. We could also become subject to additional environmental laws and regulations and other requirements in the future (such as reductions in mercury and other hazardous air pollutants, SO_3 (sulfur trioxide), regulation of ash generated from coal-based generating stations and reductions in GHG emissions as discussed in more detail in the next risk factor). With respect to our largest generation station, the Stuart generating station, we are also subject to continuing compliance requirements related to NO_x, SO_2 and particulate matter emissions under **DP&L's** consent decree with the Sierra Club. Compliance with these laws, regulations and other requirements requires us to expend significant funds and resources and could at some point become prohibitively expensive or result in our shutting down (temporarily or permanently) or altering the operation of our facilities. Environmental laws and regulations also generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. If we are not able to timely obtain, maintain or comply with all licenses, permits, inspections and approvals required to operate our business, then our operations could be prevented, delayed or subject to additional costs. Failure to comply with environmental laws, regulations and other requirements may result in the imposition of fines and penalties or other sanctions and the imposition of stricter environmental standards and controls and other injunctive measures affecting operating assets. In addition, any alleged violation of these laws, regulations and other requirements may require us to expend significant resources to defend against any such alleged violations. **DP&L** owns a non-controlling interest in several generating stations operated by our co-owners. As a non-controlling owner in these generating stations, **DP&L** is responsible for its pro rata share of expenditures for complying with environmental laws, regulations and other requirements, but has limited control over the compliance measures taken by our co-owners. **DP&L's** ESP permits it to seek recovery for costs associated with new climate change or carbon regulations. In addition, if we were found not to be in compliance with these environmental laws, regulations or requirements, any penalties that would apply or other resulting costs would likely not be recoverable from customers. We could be subject to joint and several strict liabilities for any environmental contamination at our currently or formerly owned, leased or operated properties or third-party waste disposal sites. For example, contamination has been identified at two waste disposal sites for which we are alleged to have potential liability. In addition to potentially significant investigation and remediation costs, any such contamination matters can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage.

Our costs and liabilities relating to environmental matters could have a material adverse effect on our results of operations, financial condition and cash flows.

Our use of derivative and nonderivative contracts may not fully hedge our generation assets, customer supply activities, or other market positions against changes in commodity prices, and our hedging procedures may not work as planned.
We transact in coal, power and other commodities to hedge our positions in these commodities. These trades are affected by a range of factors, including variations in power demand, fluctuations in market prices, market prices for alternative commodities and optimization opportunities. We have attempted to manage our commodities price risk exposure by establishing and enforcing risk limits and risk management policies. Despite our efforts, however, these risk limits and management policies may not work as planned and fluctuating prices and other events could adversely affect our results of operations, financial condition and cash flows. As part of our risk management, from time to time, we use a variety of non-derivative and derivative instruments, such as swaps, futures and forwards, to manage our market risks. We also use, from time to time, interest rate derivative instruments to hedge against interest rate fluctuations related to our debt. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of these contracts. We could also recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform, which could result in a material adverse effect on our results of operations, financial condition and cash flows.

The Dodd-Frank Act contains significant requirements related to derivatives that, among other things, could reduce the cost effectiveness of entering into derivative transactions.
In July 2010, The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law. The Dodd-Frank Act contains significant requirements relating to derivatives, including, among others, a requirement that certain transactions be cleared on exchanges that would necessitate the posting of cash collateral for these transactions. We are considered an end-user under the Dodd-Frank Act and therefore are exempt from most of the collateral and margining requirements. We are required to report our bilateral derivative contracts, unless our counterparty is a major swap participant or has elected to report on our behalf. Even though we qualify for an exception from these requirements, our counterparties that do not qualify for the exception may pass along any increased costs incurred by them through higher prices and reductions in unsecured credit limits or be unable to enter into certain transactions with us. The occurrence of any of these events could have an adverse effect on our results of operations, financial condition and cash flows.

Our financial results may fluctuate on a seasonal and quarterly basis or as a result of severe weather.
Weather conditions significantly affect the demand for electric power. In our Ohio service territory, demand for electricity is generally greater in the summer months associated with cooling and in the winter months associated with heating compared to other times of the year. Unusually mild summers and winters could therefore have an adverse effect on our results of operations, financial condition and cash flows. In addition, severe or unusual weather, such as hurricanes and ice or snow storms, may cause outages and property damage that may require us to incur additional costs that may not be insured or recoverable from customers. While **DP&L** is permitted to seek recovery of storm damage costs, if **DP&L** is unable to fully recover such costs in a timely manner, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Costs associated with new transmission projects could have a material adverse effect on our results of operations, financial condition and cash flows.
Annually, PJM performs a review of the capital additions required to provide reliable electric transmission services throughout its territory. PJM traditionally allocated the costs of constructing these facilities to those entities that benefited directly from the additions. Over the last several years, however, some of the costs of constructing new large transmission facilities have been "socialized" across PJM without a direct relationship between the costs assigned to and benefits received by particular PJM members. To date, the additional costs

charged to **DP&L** for new large transmission approved projects have not been material. Over time, as more new transmission projects are constructed and if the allocation method is not changed, the annual costs could become material. **DP&L** is recovering the Ohio retail jurisdictional share of these allocated costs from its retail customers through the TCRR-N rider. To the extent that any costs in the future are material and we are unable to recover them from our customers, it could have a material adverse effect on our results of operation, financial condition and cash flows.

We have no control over the timing or terms of an order by the PUCO ordering us to separate our generation business into a separate legal entity from our distribution and transmission business.
As required by the 2014 ESP order, **DP&L** filed an application for authority to transfer or sell its generation assets no later than January 1, 2017. There can be no assurance of the terms on which the PUCO would authorize the separation of our generation business from our distribution and transmission business. Although the initial PUCO order approved our separation plan, several regulatory filings and approvals are required in connection with the separation and certain other consents or approvals may be required under other agreements to which we are party.

If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. These would likely not be recoverable from customers through regulated rates and could have a material adverse effect on our results of operations, financial condition and cash flows.
As an owner and operator of a bulk power transmission system, **DP&L** is subject to mandatory reliability standards promulgated by the NERC and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and is guided by reliability and market interface principles. In addition, **DP&L** is subject to Ohio reliability standards and targets. Compliance with reliability standards subjects us to higher operating costs or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the PUCO will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our inability to obtain financing on reasonable terms, or at all, with creditworthy counterparties could adversely affect our results of operations, financial condition and cash flows.
From time to time we rely on access to the credit and capital markets to fund certain operational and capital costs. These capital and credit markets have experienced extreme volatility and disruption and the ability of corporations to obtain funds through the issuance of debt or equity has been negatively impacted. Disruptions in the credit and capital markets make it harder and more expensive to obtain funding for our business. Access to funds under our existing financing arrangements is also dependent on the ability of our counterparties to meet their financing commitments. Our inability to obtain financing on reasonable terms, or at all, with creditworthy counterparties could adversely affect our results of operations, financial condition and cash flows. If our available funding is limited or we are forced to fund our operations at a higher cost, these conditions may require us to curtail our business activities and increase our cost of funding, both of which could reduce our profitability. **DP&L** has variable rate debt that bears interest based on a prevailing rate that is reset weekly based on a market index that can be affected by market demand, supply, market interest rates and other market conditions. We also maintain both cash on deposit and investments in cash equivalents, from time to time, that could be adversely affected by interest rate fluctuations. In addition, ratings agencies issue credit ratings on us and our debt that affect our borrowing costs under our financial arrangements and affect our potential pool of investors and funding sources. Our credit ratings also govern the collateral provisions of certain of our contracts. As a result of the Merger and assumption by **DPL** of merger-related debt and other factors, our credit ratings were downgraded, resulting in increased borrowing costs and causing us to post cash collateral with certain of our counterparties. If the rating agencies were to downgrade our credit ratings further, our borrowing costs would likely further increase, our potential pool of investors and funding resources could be reduced, and we could be required to post additional cash collateral under selected contracts. These events would likely reduce our liquidity and profitability and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our membership in a regional transmission organization presents risks that could have a material adverse effect on our results of operations, financial condition and cash flows.
On October 1, 2004, in compliance with Ohio law, **DP&L** turned over control of its transmission functions and fully integrated into PJM, a regional transmission organization. The price at which we can sell our generation capacity and energy is now dependent on a number of factors, which include the overall supply and demand of generation

and load, other state legislation or regulation, transmission congestion and PJM's business rules. While we can continue to make bilateral transactions to sell our generation through a willing-buyer and willing-seller relationship, any transactions that are not pre-arranged are subject to market conditions at PJM. To the extent we sell electricity into the power markets on a contractual basis, we are not guaranteed any rate of return on our capital investments through mandated rates. The results of the PJM RPM base residual auction are impacted by the supply and demand of generation and load and also may be impacted by congestion and PJM rules relating to bidding for Demand Response and Energy Efficiency resources and other factors. Auction prices could fluctuate substantially over relatively short periods of time and adversely affect our results of operations, financial condition and cash flows. We cannot predict the outcome of future auctions, but low auction prices could have a material adverse effect on our results of operations, financial condition and cash flows.

The rules governing the various regional power markets may also change from time to time which could affect our costs and revenues and have a material adverse effect on our results of operations, financial condition and cash flows. We may be required to expand our transmission system according to decisions made by PJM rather than our internal planning process. Various proposals and proceedings before FERC may cause transmission rates to change from time to time. In addition, PJM has been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial effect on us. We also incur fees and costs to participate in PJM.

SB 221 includes a provision that allows electric utilities to seek and obtain recovery of RTO-related charges. Therefore, non-market based costs are being recovered from all retail customers through the TCRR-N, and market based RTO-related costs associated with serving SSO load are being recovered from SSO customers through our TCRR-B. If in the future, however, we are unable to recover all of these costs in a timely manner, and since the TCRR-B rider is bypassable when additional customer switching occurs, this could have a material adverse effect on our results of operations, financial condition and cash flows.

As members of PJM, **DP&L** and DPLE are also subject to certain additional risks including those associated with the allocation of losses caused by unreimbursed defaults of other participants in PJM markets among PJM members and those associated with complaint cases filed against PJM that may seek refunds of revenues previously earned by PJM members including **DP&L** and DPLE. These amounts could be significant and have a material adverse effect on our results of operations, financial condition and cash flows.

If the pending PJM Capacity Performance proposal(s) before the FERC affecting capacity pricing and penalties for lack of performance by generators are approved as filed, we could be subject to substantial changes in capacity income and/or penalties. As the owner of generation that is a "capacity resource" within PJM, **DP&L** is subject to mandatory requirements to participate in PJM markets. The existing PJM capacity market is in the process of being restructured and the existing RPM capacity market requirements are likely to be replaced by a Capacity Performance program that offers the potential for higher capacity prices but paired with higher penalties for non-performance during times of high electricity demand. Any such penalties incurred are likely not recoverable from customers through regulated rates and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our consolidated results of operations may be negatively affected by overall market, economic and other conditions that are beyond our control.
Economic pressures, as well as changing market conditions and other factors related to physical energy and financial trading activities, which include price, credit, liquidity, volatility, capacity, transmission and interest rates, can have a significant effect on our operations and the operations of our retail, industrial and commercial customers and our suppliers. The direction and relative strength of the economy has been increasingly uncertain due to softness in the real estate and mortgage markets, volatility in fuel and other energy costs, difficulties in the financial services sector and credit markets, high unemployment and other factors. Many of these factors have affected our Ohio service territory.

Overall lower prices in the retail electricity market have led to increased switching from **DP&L** to other CRES providers, including DPLER, who may be offering retail prices lower than **DP&L's** SSO price. Also, several municipalities in **DP&L's** service territory have passed ordinances allowing them to become government aggregators and some municipalities have contracted with CRES providers to provide generation service to the customers located within the municipal boundaries, further contributing to the switching trend. CRES providers have also become more active in **DP&L's** service territory. These factors may reduce our margins and could have a material adverse effect on our results of operations, financial condition and cash flows.

Our results of operations, financial condition and cash flows may be negatively affected by sustained downturns or a sluggish economy. Sustained downturns, recessions or a sluggish economy generally affect the markets in which we operate and negatively influence our energy operations. A contracting, slow or sluggish economy could reduce the demand for energy in areas in which we are doing business. During economic downturns, our commercial and industrial customers may see a decrease in demand for their products, which in turn may lead to a decrease in the amount of energy they require. In addition, our customers' ability to pay us could also be impaired, which could result in an increase in receivables and write-offs of uncollectible accounts. Our suppliers could also be affected by the economic downturn resulting in supply delays or unavailability. Reduced demand for our electric services, failure by our customers to timely remit full payment owed to us and supply delays or unavailability could have a material adverse effect on our results of operations, financial condition and cash flows.

A material change in market interest rates could adversely affect our results of operations, financial condition and cash flows.

DPL and **DP&L** have variable rate debt that bears interest based on a prevailing rate that is regularly reset and that can be affected by market demand, supply, market interest rates and other market conditions. We also, from time to time, maintain both cash on deposit and investments in cash equivalents that could be adversely affected by interest rate fluctuations. Any event which impacts market interest rates could have a material adverse effect on our results of operations, financial condition and cash flows.

Poor investment performance of our benefit plan assets and other factors impacting benefit plan costs could unfavorably affect our liquidity and results of operations.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postemployment benefit plans. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. A decline in the market value of the pension and postemployment benefit plan assets will increase the funding requirements under our pension and postemployment benefit plans if the actual asset returns do not recover these declines in value in the foreseeable future. Future pension funding requirements, and the timing of funding payments, may also be subject to changes in legislation. The Pension Protection Act, enacted in August 2006, requires underfunded pension plans to improve their funding ratios within prescribed intervals based on the level of their underfunding. As a result, our required contributions to these plans, at times, have increased and may increase in the future. In addition, our pension and postemployment benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the discounted liabilities increase benefit expense and funding requirements. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements for the obligations related to the pension and other postemployment benefit plans. Declines in market values and increased funding requirements could have a material adverse effect on our results of operations, financial condition and cash flows.

Our businesses depend on counterparties performing in accordance with their agreements. If they fail to perform, we could incur substantial expense, which could adversely affect our liquidity, cash flows and results of operations.

We enter into transactions with and rely on many counterparties in connection with our business, including for the purchase and delivery of inventory, including fuel and equipment components (such as limestone for our FGD equipment), for our capital improvements and additions and to provide professional services, such as actuarial calculations, payroll processing and various consulting services. If any of these counterparties fails to perform its obligations to us or becomes unavailable, our business plans may be materially disrupted, we may be forced to discontinue certain operations if a cost-effective alternative is not readily available or we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and cause delays. These events could cause our results of operations, financial condition and cash flows to have a material adverse effect.

Accidental improprieties and undetected errors in our internal controls and information reporting could result in the disallowance of cost recovery, noncompliant disclosure and reporting or incorrect payment processing.

Our internal controls, accounting policies and practices and internal information systems are designed to enable us to capture and process transactions and information in a timely and accurate manner in compliance with GAAP in the United States of America, laws and regulations, taxation requirements and federal securities laws and regulations in order to, among other things, disclose and report financial and other information in connection with the recovery of our costs and with our reporting requirements under federal securities, tax and other laws and regulations and to properly process payments. We have also implemented corporate governance, internal control and accounting policies and procedures in connection with the Sarbanes-Oxley Act of 2002. Our internal controls and policies have been and continue to be closely monitored by management and our Board of

Directors. While we believe these controls, policies, practices and systems are adequate to verify data integrity, unanticipated and unauthorized actions of employees, temporary lapses in internal controls due to shortfalls in oversight or resource constraints could lead to improprieties and undetected errors that could result in the disallowance of cost recovery, noncompliant disclosure and reporting or incorrect payment processing. The consequences of these events could have a material adverse effect on our results of operations, financial condition and cash flows.

New accounting standards or changes to existing accounting standards could materially affect how we report our results of operations, financial condition and cash flows.

Our Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. The SEC, FASB or other authoritative bodies or governmental entities may issue new pronouncements or new interpretations of existing accounting standards that may require us to change our accounting policies. These changes are beyond our control, can be difficult to predict and could materially affect how we report our results of operations, financial condition and cash flows. We could be required to apply a new or revised standard retroactively, which could adversely affect our financial condition. In addition, in preparing our Consolidated Financial Statements, management is required to make estimates and assumptions. Actual results could differ significantly from those estimates.

The SEC is investigating the potential transition to the use of IFRS promulgated by the International Accounting Standards Board for U.S. companies. Adoption of IFRS could result in significant changes to our accounting and reporting, such as in the treatment of regulatory assets and liabilities and property. The SEC does not currently have a timeline regarding the mandatory adoption of IFRS. We are currently assessing the effect that this potential change would have on our Consolidated Financial Statements and we will continue to monitor the development of the potential implementation of IFRS.

We are subject to extensive laws and local, state and federal regulation, as well as related litigation that could affect our operations and costs.

We are subject to extensive laws and regulation by federal, state and local authorities, such as the PUCO, the CFTC, the USEPA, the Ohio EPA, the FERC, the Department of Labor and the Internal Revenue Service, among others. Regulations affect almost every aspect of our business, including in the areas of the environment, health and safety, cost recovery and rate making, the issuance of securities and incurrence of debt and taxation. New laws and regulations, and new interpretations of existing laws and regulations, are ongoing and we generally cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on our business. Complying with this regulatory environment requires us to expend a significant amount of funds and resources. The failure to comply with this regulatory environment could subject us to substantial financial costs and penalties and changes, either forced or voluntary, in the way we operate our business. Additional detail about the effect of this regulatory environment on our operations is included in the risk factors set forth below. In the normal course of business, we are also subject to various lawsuits, actions, proceedings, claims and other matters asserted under this regulatory environment or otherwise, which require us to expend significant funds to address, the outcomes of which are uncertain and the adverse resolutions of which could have a material adverse effect on our results of operations, financial condition and cash flows.

If we are unable to maintain a qualified and properly motivated workforce, it could have a material adverse effect on our results of operations, financial condition and cash flows.

One of the challenges we face is to retain a skilled, efficient and cost-effective workforce while recruiting new talent to replace losses in knowledge and skills due to resignations, terminations or retirements. This undertaking could require us to make additional financial commitments and incur increased costs. If we are unable to successfully attract and retain an appropriately qualified workforce, it could have a material adverse effect on our results of operations, financial condition and cash flows. In addition, we have employee compensation plans that reward the performance of our employees. We seek to ensure that our compensation plans encourage acceptable levels for risk and high performance through pay mix, performance metrics and timing. We also have policies and procedures in place to mitigate excessive risk-taking by employees since excessive risk-taking by our employees to achieve performance targets could result in events that could have a material adverse effect on our results of operations, financial condition and cash flows.

We are subject to collective bargaining agreements and other employee workforce factors that could affect our businesses.

Over half of our employees are represented by a collective bargaining agreement that is in effect until October 31, 2017. While we believe that we maintain a satisfactory relationship with our employees, it is possible that labor disruptions affecting some or all of our operations could occur during the period of the collective bargaining agreement or at the expiration of the collective bargaining agreement before a new agreement is negotiated. Work stoppages by, or poor relations or ineffective negotiations with, our employees could have a material adverse effect on our results of operations, financial condition and cash flows.

Potential security breaches (including cybersecurity breaches) and terrorism risks could adversely affect our businesses.

We operate in a highly regulated industry that requires the continued operation of sophisticated systems and network infrastructure at our generation stations, fuel storage facilities and transmission and distribution facilities. We also use various financial, accounting and other systems in our businesses. These systems and facilities are vulnerable to unauthorized access due to hacking, viruses, other cybersecurity attacks and other causes. In particular, given the importance of energy and the electric grid, there is the possibility that our systems and facilities could be targets of terrorism or acts of war. We have implemented measures to help prevent unauthorized access to our systems and facilities, including certain measures to comply with mandatory regulatory reliability standards. Despite our efforts, if our systems or facilities were to be breached or disabled, we may be unable to recover them in a timely way to fulfill critical business functions, including the supply of electric services to our customers, and we could experience decreases in revenues and increases in costs that could adversely affect our results of operations, cash flows and financial condition.

In the course of our business, we also store and use customer, employee, and other personal information and other confidential and sensitive information. If our third party vendors' systems were to be breached or disabled, sensitive and confidential information and other data could be compromised, which could result in negative publicity, remediation costs and potential litigation, damages, consent orders, injunctions, fines and other relief.

To help mitigate against these risks, we maintain insurance coverage against some, but not all, potential losses, including coverage for illegal acts against us. However, insurance may not be adequate to protect us against all costs and liabilities associated with these risks.

DPL is a holding company and parent of DP&L and other subsidiaries. DPL's cash flow is dependent on the operating cash flows of DP&L and its other subsidiaries and their ability to pay cash to DPL.

DPL is a holding company and its investments in its subsidiaries are its primary assets. A significant portion of **DPL's** business is conducted by its **DP&L** subsidiary. As such, **DPL's** cash flow is dependent on the operating cash flows of **DP&L** and its ability to pay cash to **DPL**. **DP&L's** governing documents contain certain limitations on the ability to declare and pay dividends to **DPL** while preferred stock is outstanding. Certain of **DP&L's** debt agreements also contain limits with respect to the ability of **DP&L** to incur debt. In addition, **DP&L** is regulated by the PUCO, which possesses broad oversight powers to ensure that the needs of utility customers are being met. While we are not currently aware of any plans to do so, the PUCO could impose additional restrictions on the ability of **DP&L** to distribute, loan or advance cash to **DPL** pursuant to these broad powers. As part of the PUCO's approval of the Merger, **DP&L** agreed to maintain a capital structure that includes an equity ratio of at least 50 percent and not to have a negative retained earnings balance. While we do not expect any of the foregoing restrictions to significantly affect **DP&L's** ability to pay funds to **DPL** in the future, a significant limitation on **DP&L's** ability to pay dividends or loan or advance funds to **DPL** would have a material adverse effect on **DPL's** results of operations, financial condition and cash flows.

Impairment of goodwill or long-lived assets would negatively affect our consolidated results of operations and net worth.

Goodwill represents the future economic benefits arising from assets acquired in a business combination (acquisition) that are not individually identified and separately recognized. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long-term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions, operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass along such costs to customers; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. See Note 5 of Notes to **DPL's** Consolidated Financial Statements for more information on the impairment of Goodwill.

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Long-lived assets are initially recorded at fair value when acquired in a business combination and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above. See Note 15 of Notes to **DPL's** Financial Statements for more information on the impairment of fixed assets. See Note 13 of Notes to **DP&L's** Financial Statements for more information on the impairment of fixed assets.

Item 1B – Unresolved Staff Comments

None

Item 2 – Properties

Information relating to our properties is contained in Item 1 – Electric Operations and Fuel Supply and Note 4 of Notes to **DPL's** Consolidated Financial Statements and Note 4 of Notes to **DP&L's** Financial Statements.

Substantially all property and stations of **DP&L** are subject to the lien of the First and Refunding Mortgage.

Item 3 - Legal Proceedings

DPL and **DP&L** are involved in certain claims, suits and legal proceedings in the normal course of business. **DPL** and **DP&L** have accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. **DPL** and **DP&L** believe, based upon information they currently possess and taking into account established reserves for estimated liabilities and insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on their financial statements. It is reasonably possible, however, that some matters could be decided unfavorably and could require **DPL** or **DP&L** to pay damages or make expenditures in amounts that could be material but cannot be estimated as of December 31, 2014.

The following additional information is incorporated by reference into this Item: (i) information about the legal proceedings contained in Item 1 – Competition and Regulation of Part 1 of this Annual Report on Form 10-K and (ii) information about the legal proceedings contained in Item 8 – Financial Statements and Supplementary Data – Note 13 of Notes to **DPL's** Consolidated Financial Statements and Note 12 of Notes to **DP&L's** Financial Statements of Part II of this Annual Report on Form 10-K.

Item 4 – Mine Safety Disclosures

Not applicable.

PART II

Item 5 – Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

All of the outstanding common stock of **DPL** *is owned, and has been owned throughout all of 2014, 2013 and* 2012, indirectly by AES and directly by an AES wholly-owned subsidiary. As a result, our stock is not listed for trading on any stock exchange. **DP&L's** common stock is held solely by **DPL** and, as a result, is not listed for trading on any stock exchange.

Dividends

During the years ended December 31, 2014 and 2013, **DPL** paid no dividends to AES. During the year ended December 31, 2012, **DPL** declared dividends on its common stock to its parent of $70.0 million. During the year ended December 31, 2013, **DPL's** Board of Directors amended the prior dividend declaration to be equal to the amount paid, $64.1 million, reversing $5.9 million of the 2012 dividends. **DP&L** declares and pays dividends on its common shares to its parent **DPL** from time to time as declared by the **DP&L** board. Dividends on common shares in the amount of $159.0 million, $190.0 million and $145.0 million were declared and paid in the years *ended December 31, 2014, 2013 and 2012, respectively.* ***DP&L** declared and paid dividends on preferred* shares in the amount of $0.9 million in each of the years ended December 31, 2014, 2013 and 2012.

DPL's Amended Articles of Incorporation (the "Articles") contain provisions which state that **DPL** may not make a distribution to its shareholder or make a loan to any of its affiliates (other than its subsidiaries), unless: (a) there exists no Event of Default (as defined in the Articles) and no such Event of Default would result from the making of the distribution or loan; **and** either (b)(i) at the time of, and/or as a result of, the distribution or loan, **DPL's** leverage ratio does not exceed 0.67 to 1.00 and **DPL's** interest coverage ratio is not less than 2.50 to 1.00 or, (b)(ii) if such ratios are not within the parameters, **DPL's** senior long-term debt rating from one of the three major credit rating agencies is at least investment grade. Further, the restrictions on the payment of distributions to a shareholder and the making of loans to its affiliates (other than subsidiaries) cease to be in effect if the three major credit rating agencies confirm that a lowering of **DPL's** senior long-term debt rating below investment grade by the credit rating agencies would not occur without these restrictions.

As of December 31, 2014, there was no Event of Default - **DPL's** Articles generally define an "Event of Default" as either (i) a breach of a covenant or obligation under the Articles; (ii) the entering of an order of insolvency or bankruptcy by a court and that order remains in effect and unstayed for 180 days; or (iii) **DPL**, **DP&L** or one of its principal subsidiaries commences a voluntary case under bankruptcy or insolvency laws or consents to the appointment of a trustee, receiver or custodian to manage all of the assets of **DPL**, **DP&L** or one of its principal subsidiaries – but **DPL's** leverage ratio was at 0.93 to 1.00 and **DPL's** senior long-term debt rating from all three major credit rating agencies was below investment grade. As a result, as of December 31, 2014, **DPL** was prohibited under its Articles from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

DPL's unsecured revolving credit agreement and **DPL's** unsecured term loan were refinanced on May 10, 2013. The new loan agreements include a provision which restricts all dividend payments from **DPL** to AES until after the maturity or termination of the respective credit facilities.

As long as **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not affected **DP&L's** ability to pay cash dividends and, as of December 31, 2014, **DP&L's** retained earnings of $381.8 million were all available for **DP&L** common stock dividends payable to **DPL**.

The following table presents our selected consolidated financial data which should be read in conjunction with our audited Consolidated Financial Statements and the related Notes thereto and Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations. The "Results of Operations" discussion in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations addresses significant fluctuations in operating data. **DPL's** common stock is wholly-owned by an indirect subsidiary of AES and therefore **DPL** does not report earnings or dividends on a per-share basis. Other data that management believes is important in understanding trends in our business are also included in this table.

	DPL					
	Successor [(a)]				Predecessor [(a)]	
$ in millions except per share amounts or as indicated	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Year ended December 31, 2010
Basic earnings per share of common stock [(b)]	**N/A**	N/A	N/A	N/A	$ 1.31	$ 2.51
Diluted earnings per share of common stock [(b)]	**N/A**	N/A	N/A	N/A	$ 1.31	$ 2.50
Dividends declared per share of common stock [(c)]	**N/A**	N/A	N/A	N/A	$ 1.54	$ 1.21
Dividend payout ratio [(c)]	**N/A**	N/A	N/A	N/A	117.6%	48.2%
Total electric sales (millions of kWh)	**18,763**	19,561	16,454	1,361	15,021	17,237
Results of operations:						
Revenues	**$ 1,763.0**	$ 1,636.9	$ 1,668.4	$ 156.9	$ 1,670.9	$ 1,831.4
Goodwill impairment [(d)]	**$ (135.8)**	$ (306.3)	$ (1,817.2)	$ -	$ -	$ -
Fixed asset impairment [(f)]	**$ (11.5)**	$ (26.2)	$ -	$ -	$ -	$ -
Net income / (loss) [(b)]	**$ (74.6)**	$ (222.0)	$ (1,729.8)	$ (6.2)	$ 150.5	$ 290.3
Balance sheet date (end of period):						
Total assets	**$ 3,577.8**	$ 3,721.5	$ 4,247.3	$ 6,136.2	N/A	$ 3,813.3
Long-term debt [(e)]	**$ 2,139.6**	$ 2,284.2	$ 2,025.0	$ 2,628.9	N/A	$ 1,026.6
Total construction additions	**$ 115.6**	$ 114.4	$ 179.6	$ 201.0	N/A	$ 151.4
Redeemable preferred stock of subsidiary	**$ 18.4**	$ 18.4	$ 18.4	$ 18.4	N/A	$ 22.9

DP&L					
$ in millions except per share amounts or as indicated	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012	Year ended December 31, 2011	Year ended December 31, 2010
Total electric sales (millions of kWh)	**18,613**	19,423	15,606	15,599	17,083
Results of operations:					
Revenues	**$ 1,668.3**	$ 1,551.5	$ 1,531.8	$ 1,677.7	$ 1,738.8
Fixed-asset impairment (f)	**$ -**	$ (86.0)	$ (80.8)	$ -	$ -
Earnings on common stock (g)	**$ 114.1**	$ 82.7	$ 90.3	$ 192.3	$ 276.8
Balance sheet date (end of period):					
Total assets	**$ 3,338.7**	$ 3,313.1	$ 3,464.2	$ 3,538.3	$ 3,475.4
Long-term debt (e)	**$ 877.0**	$ 876.9	$ 332.7	$ 903.0	$ 884.0
Redeemable preferred stock	**$ 22.9**	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Number of shareholders - preferred stock	**186**	196	209	223	234

(a) "Predecessor" refers to the operations of DPL and its subsidiaries prior to the Merger date. "Successor" refers to the operations of DPL and its subsidiaries subsequent to the Merger date.
(b) DPL incurred merger-related costs of $37.9 million ($24.6 million net of tax) and $15.7 million ($10.2 million net of tax) in the 2011 Predecessor and Successor periods, respectively, and had a $25.1 million ($16.3 million net of tax) favorable adjustment in the period January 1, 2011 through November 27, 2011 as a result of the approval of the fuel settlement agreement by the PUCO.
(c) Of the $1.54 declared in the January 1, 2011 through November 27, 2011 period, $0.54 was paid in the November 28, 2011 through December 31, 2011 period.
(d) Goodwill impairments of $135.8 million, $306.3 million and $1,817.2 million were recorded in 2014, 2013 and 2012, respectively.
(e) Excludes current maturities of long-term debt.
(f) For DPL, fixed-asset impairments of $11.5 million ($7.5 million net of tax) and $26.2 million ($17.0 million net of tax) were recorded in 2014 and 2013, respectively. For DP&L, fixed-asset impairments of $86.0 million ($55.9 million net of tax) and $80.8 million ($51.8 million net of tax) were recorded in 2013 and 2012, respectively.
(g) In 2011, DP&L incurred merger-related costs of $19.4 million ($12.6 million net of tax) and had a $25.1 million ($16.3 million net of tax) favorable adjustment as a result of the approval of the fuel settlement agreement by the PUCO.

Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with **DPL's** audited Consolidated Financial Statements and the related Notes thereto and **DP&L's** audited Financial Statements and the related Notes thereto included in Item 8 – Financial Statements and Supplementary Data of this Form 10-K. The following discussion contains forward-looking statements. Our actual results may differ materially from the results suggested by these forward-looking statements. Please see "Forward-Looking Statements" at the beginning of this Form 10-K and Item 1A – Risk Factors. For a list of certain abbreviations or acronyms in this discussion, see Glossary at the beginning of this Form 10-K.

BUSINESS OVERVIEW

DPL is a regional electric energy and utility company. **DPL's** two reporting segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary and DPLER's subsidiary, MC Squared. See Note 14 of Notes to **DPL's** Consolidated Financial Statements for more information relating to these reportable segments. **DP&L** does not have any reportable segments.

DP&L is primarily engaged in the generation, transmission and distribution of electricity in West Central Ohio and the sale of energy to DPLER in Ohio and Illinois. **DPL** and **DP&L** strive to achieve disciplined growth in energy margins while limiting volatility in both cash flows and earnings and to achieve stable, long-term growth through efficient operations and strong customer and regulatory relations. More specifically, **DPL's** and **DP&L's** strategy is to match energy supply with load or customer demand, maximizing profits while effectively managing exposure to movements in energy and fuel prices and utilizing the transmission and distribution assets that transfer electricity at the most efficient cost while maintaining the highest level of customer service and reliability.

We operate and manage generation assets and are exposed to a number of risks. These risks include, but are not limited to, electricity wholesale price risk, PJM capacity price risk, regulatory risk, environmental risk, fuel supply and price risk, customer switching risk and the risk associated with electric generating station performance. We attempt to manage these risks through various means. For instance, we operate a portfolio of wholly-owned and jointly-owned generation assets that is diversified as to coal source, cost structure and operating characteristics. We are focused on the operating efficiency of these stations and maintaining their availability.

We operate and manage transmission and distribution assets in a rate-regulated environment. Accordingly, this subjects us to regulatory risk in terms of the costs that we may recover and the investment returns that we may collect in customer rates. We are focused on delivering electricity and maintaining high standards of customer service and reliability in a cost-effective manner.

Additional information relating to our risks is contained in Item 1A – Risk Factors.

The following discussion should be read in conjunction with the accompanying Consolidated Financial Statements and related footnotes included in Item 8 – Financial Statements and Supplementary Data.

BUSINESS COMBINATION

Acquisition by The AES Corporation
On November 28, 2011, **DPL** merged with Dolphin Sub, Inc., a wholly-owned subsidiary of AES pursuant to the Merger agreement whereby AES acquired **DPL** for $30.00 per share in a cash transaction valued at approximately $3.5 billion. At closing, **DPL** became a wholly-owned subsidiary of AES.

See Item 1A – Risk Factors for additional risks and information related to the Merger.

Dolphin Subsidiary II, Inc., a subsidiary of AES, issued $1.25 billion in long-term Senior Notes on October 3, 2011, to partially finance the Merger. Upon the consummation of the Merger, Dolphin Subsidiary II, Inc. was merged into **DPL** and these notes became long-term debt obligations of **DPL**. This debt has had and will continue to have a material effect on **DPL's** cash requirements.

REGULATORY ENVIRONMENT

DPL, **DP&L** and our subsidiaries' facilities and operations are subject to a wide range of environmental regulations and laws by federal, state and local authorities. As well as imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at these facilities to comply, or to determine compliance, with such regulations. We record liabilities for losses that are probable of occurring and can be reasonably estimated.

- **Carbon Dioxide and Other Greenhouse Gas Emissions**

  There is on-going concern nationally and internationally about global climate change and the contribution of emissions of GHGs, including most significantly CO_2. This concern has led to regulation and interest in legislation at the federal level, actions at the state level as well as litigation relating to GHG emissions. The USEPA began regulating GHG emissions from certain stationary sources in January 2011, under regulations referred to as the "Tailoring Rule". In June 2014, the U.S. Supreme Court ruled that the USEPA had exceeded its statutory authority in issuing the so-called "Tailoring Rule" under Section 165 of the CAA by regulating sources under the PSD program based solely on their GHG emissions, but also held that the USEPA could impose GHG BACT requirements for sources already required to implement PSD for certain other pollutants.

  In January 2014, the USEPA proposed revised GHG New Source Performance Standards for new EGUs under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. In addition, new natural gas-fired EGUs must meet a standard of no greater than

1,000 pounds of CO_2 per megawatt hour (if the rule is finalized in its current form). The rule is expected to be finalized in mid-2015.

The USEPA issued proposed rules establishing GHG performance standards for existing power plants under CAA Section 111(d) on June 2, 2014. Under the proposed rule, states would be judged against state-specific carbon dioxide emissions targets beginning in 2020, with expected total U.S. power section emissions reduction of 30% from 2005 levels by 2030. The proposed rule requires states to SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one or two-year extensions under certain circumstances. The proposed rule was subject to a public comment process and the USEPA is expected to finalize it by July 2015. Among other things, the Company could be required to make efficiency improvements to existing facilities.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. If we are required to implement control of CO_2 and other GHGs at generation facilities, the cost to **DPL** and **DP&L** of such controls could be material.

- **NO_x and SO_2 Emissions – CSAPR**

  Clean Air Interstate Rule/Cross-State Air Pollution Rule
  The USEPA promulgated CAIR on March 10, 2005, which required allowance surrender for SO_2 and NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase began in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was scheduled to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission-allowance-based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an *opinion striking down much of CAIR and remanding it to the USEPA.*

  In an attempt to conform to the Court's decision, the USEPA issued CSAPR on July 6, 2011, but subsequent litigation resulted in CSAPR being vacated in 2012 and CAIR being reinstated pending the promulgation of a replacement rule. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR and on April 29, 2014, the U.S Supreme Court reversed the 2012 decision and remanded the case back to the D.C. Circuit Court. CSAPR was reinstated on October 23, 2014. The USEPA established new effective dates for compliance with the reduced emissions levels, beginning in 2015 with additional reductions in 2017. At this time, it is not possible to predict what impacts this action may have on our consolidated financial condition, results of operations or cash flows, but it is not expected to be material.

- **Climate Change Legislation and Regulation**

  On June 25, 2013, the President of the United States directed the USEPA to issue a new proposed rule establishing New Source Performance Standards for CO_2 emissions for newly constructed fossil-fueled EGUs larger than 25 MW by September 2013, and to issue a final rule in a timely fashion after considering all public comments. The USEPA issued such new proposed rule in September 2013. The proposed rule anticipates that newly constructed fossil-fueled power plants generally would need to rely upon partial implementation of carbon capture and storage technology or other pollution control technology to meet the standard.

  In his June 25, 2013, announcement, the President, as anticipated, also directed the USEPA to issue new standards, regulations, or guidelines, as appropriate, that address CO_2 emissions from existing power plants. The USEPA issued proposed rules establishing GHG performance standards for existing power plants under CAA Section 111(d) on June 2, 2014. Under the proposed rule, states would be judged against state-specific carbon dioxide emissions targets beginning in 2020, with expected total U.S. power section emissions reduction of 30% from 2005 levels by 2030. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one or two-year extensions under certain circumstances. The proposed rule was subject to a public comment process and the USEPA is expected to finalize it by July 2015. Among other things, the Company could be required to make efficiency improvements to existing facilities.

  It is impossible to estimate the impact and compliance costs associated with any future USEPA GHG regulations applicable to new, modified or existing EGUs until such regulations are finalized; however, the impact, including the compliance costs, could be material to our consolidated financial condition or results of operations.

- **SB 221 Requirements**

SB 221 and the implementation rules contained targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. SB 310 which was passed in 2014 modified those standards slightly. The renewable energy portfolio, energy efficiency and demand reduction standards began in 2009 with increased percentage requirements each year thereafter. The annual targets for energy efficiency and peak demand reductions began in 2009 with annual increases. Energy efficiency programs are to save 22.3% by 2025 and peak demand reductions are expected to reach 7.75% by 2018 compared to a baseline energy usage. If any targets are not met, compliance penalties will apply, unless the PUCO makes certain findings that would excuse performance.

SB 221 also contains provisions for determining whether an electric utility has significantly excessive earnings. The PUCO issued general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. **DP&L** was first subject to the SEET in 2013 based on 2012 earnings results, which did not have a material impact. Likewise, **DP&L** was found not to have excessive earnings in calendar year 2013. Through the ESP Order the PUCO established **DP&L's** ROE SEET threshold at 12%. In future years, the SEET could have a material effect on our results of operations, financial condition and cash flows.

SB 221 also required that all Ohio distribution utilities file either an ESP or MRO. Under the MRO, a periodic competitive bid process will set the retail generation price after the utility demonstrates that it can meet certain market criteria and bid requirements. Also, under this option, utilities that still own generation in the state are required to phase-in the MRO over a period of not less than five years. An ESP may allow for adjustments to the SSO for costs associated with environmental compliance; fuel and *purchased power; construction of new or investment in specified generating facilities; and the provision of* standby and default service, operating, maintenance, or other costs including taxes. As part of its ESP, a utility is permitted to file an infrastructure improvement plan that will specify the initiatives the utility will take to rebuild, upgrade, or replace its electric distribution system, including cost recovery mechanisms. Both the MRO and ESP options involve a SEET based on the earnings of comparable companies with similar business and financial risks.

On October 5, 2012, **DP&L** filed an ESP with the PUCO which was to be effective January 1, 2013. The plan was refiled to correct certain costs on December 12, 2012. The refiled plan requested approval of a non-bypassable charge that was designed to recover $137.5 million per year for five years from all customers. The ESP proposed a three-year, five-month transition to market, whereby a wholesale competitive bidding structure would be phased in to supply generation service to customers located in **DP&L's** service territory that have not chosen an alternative generation supplier. An evidentiary hearing on this case was held March 18, 2013 through April 3, 2013. An order was issued by the PUCO on September 4, 2013, and a correction to that order was issued on September 6, 2013 (ESP Order).

The ESP Order stated that **DP&L's** next ESP begins January 2014 and extends through May 31, 2017. The PUCO authorized **DP&L** to collect a non-bypassable Service Stability Rider (SSR) equal to $110 million per year for 2014 – 2016, with an opportunity to extend the charge through May 2017 if certain conditions were met. The ESP Order also directs **DP&L** to divest its generation assets no later than January 1, 2017 and sets **DP&L's** SEET threshold at a 12% ROE. Beginning in 2014, **DP&L** was no longer permitted to supply 100% of the generation service to its SSO customers. Instead, the PUCO directed **DP&L** to phase-in the competitive bidding structure with 10% of **DP&L's** SSO load sourced through the competitive bid starting in 2014, 60% in 2015, and 100% beginning January 1, 2016. The ESP Order approved **DP&L's** rate proposal to bifurcate its transmission charges into a non-bypassable component, TCRR-N, and a bypassable component, TCRR-B. The ESP order also required **DP&L** to establish a $2.0 million per year shareholder funded economic development fund.

Applications for rehearing were filed several times throughout 2013 and 2014 and a final order on rehearing was issued on July 23, 2014. Several parties including **DP&L** appealed the orders in this case to the Ohio Supreme court.

- **Legal separation of DP&L's generating facilities**

  In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets on or before January 1, 2017. Comments and reply comments were filed. **DP&L** amended its application on February 25, 2014 and again on May 23, 2014. Additional comments and reply comments were filed. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014, the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** continues to look at multiple options to effectuate the separation including the transfer to an unregulated affiliate or through a sale process.

COMPETITION AND PJM PRICING

- **RPM Capacity Auction Price**

  The PJM RPM capacity base residual auction for the 2017/18 period cleared at a price of $120/MW-day for our RTO area. The per megawatt-day prices for the periods 2016/17, 2015/16, and 2014/15 were $59/MW-day, $136/MW-day, and $126/MW-day, respectively, based on previous auctions. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be impacted by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions. The SSO retail costs and revenues are included in the RPM rider. Therefore increases in customer switching cause more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation. We cannot predict the outcome of future auctions or customer switching but based on actual results attained in 2014, we estimate that a hypothetical increase or decrease of $10/MW-day in the capacity auction price would affect net income by approximately $6.4 million and $5.1 million for **DPL** and **DP&L**, respectively. These estimates do not, however, take into consideration the other factors that may affect the impact of capacity revenues and costs on net income such as the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. These estimates are discussed further within Commodity Pricing Risk under the Market Risk section of this Management Discussion & Analysis.

- **Ohio Competitive Considerations and Proceedings**

  Since January 2001, **DP&L's** electric customers have been permitted to choose their retail electric generation supplier. **DP&L** continues to have the exclusive right to provide delivery service in its state certified territory and the obligation to procure and provide SSO to customers that do not choose an alternative supplier. The PUCO maintains jurisdiction over **DP&L's** delivery of electricity, SSO and other retail electric services.

  Lower market prices for power have resulted in increased levels of competition to provide retail generation services. This in turn has led to CRES providers, including DPLER, having approximately 71% of 2014 total electric sales in **DP&L's** service territory. DPLER, an affiliated company and one of the registered CRES providers, has been marketing generation services to **DP&L** customers.

The following table provides a summary of the number of electric customers and volumes provided by all CRES providers in our service territory during the years ended December 31, 2014, 2013 and 2012:

	Year ended December 31, 2014		Year ended December 31, 2013		Year ended December 31, 2012	
	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)	Electric Customers	Sales (in millions of kWh)
Supplied by DPLER	131,236	5,649	130,303	5,874	73,672	6,201
Supplied by non-affiliated CRES providers	110,536	4,365	87,951	3,471	79,936	1,981
Total supplied by CRES providers in **DP&L's** service territory	241,772	10,014	218,254	9,345	153,608	8,182
Distribution customers/sales by **DP&L** in our service territory (a)	515,622	14,006	514,926	13,877	513,266	13,999

(a) The kWh sales include all distribution sales, including those whose power is supplied by DPLER and non-affiliated CRES providers.

The volumes supplied by DPLER represent approximately 40%, 42% and 44% of **DP&L's** total distribution volumes during the years ended December 31, 2014, 2013 and 2012, respectively. We currently cannot determine the extent to which customer switching to CRES providers will occur in the future and the effect this will have on our operations, but any additional switching could have a significant adverse effect on our future results of operations, financial condition and cash flows. For the year ended December 31, 2014, approximately 71% of **DP&L's** load was supplied by CRES providers with DPLER supplying 56% of the switched load.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residents. To date, a number of communities have filed with the PUCO to initiate aggregation programs. If a number of the larger communities move forward with aggregation in **DP&L's** service area, it could have a material effect on our earnings. As discussed in Item 1, beginning January 1, 2016, customer switching will have no effect on **DP&L's** financial condition. See Item 1A – Risk Factors for more information.

FUEL AND RELATED COSTS

- **Fuel and Commodity Prices**

  The coal market is a global market in which domestic prices are affected by international supply disruptions and demand balance. In addition, domestic issues like government-imposed direct costs and permitting issues are affecting mining costs and supply availability. Our approach is to hedge the fuel costs for our anticipated electric sales. We have substantially all of the total expected coal volume needed to meet our retail and wholesale sales requirements for 2015 under contract. The majority of the contracted coal is purchased at fixed prices. Some contracts provide for periodic adjustments and some are priced based on market indices. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, the wholesale market price of power, certain provisions in coal contracts related to government imposed costs, counterparty performance and credit, scheduled/forced outages and generation station mix. Due to the installation of emission controls equipment at certain commonly-owned units and barring any changes in the regulatory environment in which we operate, we expect to have balanced positions for SO_2, NO_x and renewable energy credits for 2015. If our suppliers do not meet their contractual commitments or we are not hedged against price volatility and we are unable to recover costs through the fuel and purchased power recovery rider, our results of operations, financial condition or cash flows could be materially affected.

  Beginning January 2010, fuel price changes, including coal requirements and purchased power costs, associated with SSO load was reflected in the implementation of the fuel and purchased power recovery rider, subject to PUCO review. This fuel rider is in the process of being phased out as the SSO will be

100% sourced through the competitive bid process by 2016. In August 2014, the PUCO issued an order in a case relating to review of **DP&L's** fuel cost recovery mechanism for the calendar year 2012. The order included the disallowance of an immaterial amount of fuel costs. The impact of the order being issued was a reversal in the third quarter of 2014 of a previously established $2.6 million reserve. The audit report for calendar year 2013 had immaterial findings.

FINANCIAL OVERVIEW

The results of operations for both **DPL** and **DP&L** are separately discussed in more detail in the following pages.

The following table summarizes the significant components of **DPL's** Results of Operations for the years ended December 31, 2014, 2013 and 2012:

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Total operating revenues	$ 1,763.0	$ 1,636.9	$ 1,668.4
Cost of revenues:			
Fuel	304.5	366.7	361.9
Purchased power	**592.6**	389.0	342.1
Amortization of intangibles	1.2	7.1	95.1
Total cost of revenues	**898.3**	762.8	799.1
Total gross margin [(a)]	864.7	874.1	869.3
Operating expenses:			
Operation and maintenance	388.3	396.7	406.4
Depreciation and amortization	**139.8**	132.9	125.4
General taxes	91.7	80.9	79.5
Goodwill impairment	**135.8**	306.3	1,817.2
Fixed-asset impairment	11.5	26.2	-
Other	**(3.9)**	2.5	0.2
Total operating expenses	763.2	945.5	2,428.7
Operating income / (loss)	101.5	(71.4)	(1,559.4)
Investment income / (loss), net	0.9	1.4	2.5
Interest expense	**(126.6)**	(124.0)	(122.9)
Charge for early redemption of debt	(30.9)	(2.8)	-
Other expense, net	**(1.5)**	(2.9)	(2.3)
Loss before income taxes	(56.6)	(199.7)	(1,682.1)
Income taxes	18.0	22.3	47.7
Net loss	$ (74.6)	$ (222.0)	$ (1,729.8)

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

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RESULTS OF OPERATIONS – DPL Inc.

DPL's results of operations include the results of its subsidiaries, including the consolidated results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for **DP&L** is presented elsewhere in this report.

Income Statement Highlights – DPL

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Revenues:			
Retail	$ **1,364.0**	$ 1,297.2	$ 1,391.2
Wholesale	**198.0**	229.7	104.5
RTO revenues	**81.9**	77.9	92.2
RTO capacity revenues	**109.2**	28.7	74.5
Other revenues	**10.8**	10.6	11.0
Mark-to-market gains / (losses) [a]	**(0.9)**	(7.2)	(5.0)
Total revenues	**1,763.0**	1,636.9	1,668.4
Cost of revenues:			
Fuel	**305.4**	366.0	358.6
Losses / (gains) from sale of coal	**(1.3)**	0.7	11.8
Mark-to-market losses / (gains)	**0.4**	-	(8.5)
Net fuel cost	**304.5**	366.7	361.9
Purchased power:			
Purchased power	**328.2**	243.9	181.7
RTO charges	**154.2**	111.9	101.5
RTO capacity charges	**107.8**	34.1	68.1
Mark-to-market losses / (gains)	**2.4**	(0.9)	(9.2)
Net purchased power	**592.6**	389.0	342.1
Amortization of intangibles	**1.2**	7.1	95.1
Total cost of revenues	**898.3**	762.8	799.1
Gross margins [b]	$ **864.7**	$ 874.1	$ 869.3
Gross margins as % of revenue	**49%**	53%	52%
Operating income / (loss)	$ **101.5**	$ (71.4)	$ (1,559.4)

(a) These amounts represent the amortization of asset balances related to retail power contracts that were previously accounted for as derivatives, but in accordance with ASC 815 are no longer derivatives. The fair value of these contracts is to be amortized to earnings over the remaining term of the associated agreements.

(b) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

DPL – Revenues

Retail customers, especially residential and commercial customers, consume more electricity on warmer and colder days. Therefore, our retail sales volume is affected by the number of heating and cooling degree days occurring during a year. Cooling degree days typically have a more significant effect than heating degree days since some residential customers do not use electricity to heat their homes.

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Degree days

Number of days	Years ended December 31, 2014	2013	2012
Heating degree days (a)	**5,950**	5,542	4,752
Cooling degree days (a)	**977**	1,062	1,264

(a) Heating and cooling degree days are a measure of the relative heating or cooling required for a home or business. The heating degrees in a day are calculated as the difference of the average actual daily temperature below 65 degrees Fahrenheit. For example, if the average temperature on March 20th was 40 degrees Fahrenheit, the heating degrees for that day would be the 25 degree difference between 65 degrees and 40 degrees. In a similar manner, cooling degrees in a day are the difference of the average actual daily temperature in excess of 65 degrees Fahrenheit.

Since we plan to utilize our internal generating capacity to supply the needs of our retail customers within the **DP&L** service territory first, increases in on-system retail demand may decrease the volume of internal generation available to be sold in the wholesale market and vice versa. The wholesale market covers a multi-state area and settles on an hourly basis throughout the year. Factors affecting our wholesale sales volume each hour of the year include: wholesale market prices; our retail demand; retail demand elsewhere throughout the entire wholesale market area; our stations' and other utility stations' availability to sell into the wholesale market; and weather conditions across the multi-state region. Our plan is to make wholesale sales when market prices allow for the economic operation of our generation facilities not being utilized to meet our retail demand or when margin opportunities exist between the wholesale sales and power purchase prices.

The following table provides a summary of changes in revenues from prior periods:

$ in millions	2014 vs. 2013	2013 vs. 2012
Retail		
Rate	$ **123.3**	$ (70.0)
Volume	**(56.7)**	(33.3)
Other	**0.2**	9.3
Total retail change	**66.8**	(94.0)
Wholesale		
Rate	**(21.3)**	(8.5)
Volume	**(10.4)**	133.7
Total wholesale change	**(31.7)**	125.2
RTO capacity and other		
RTO capacity and other	**84.5**	(60.1)
Other		
Unrealized MTM	**6.3**	(2.2)
Other	**0.2**	(0.4)
Total revenue changes	$ **126.1**	$ (31.5)

During the year ended December 31, 2014, Revenues increased $126.1 million, or 8%, to $1,763.0 million from $1,636.9 million in the same period of the prior year. This increase was primarily the result of higher average retail rates, increased RTO capacity revenues; offset by lower average wholesale rates and lower retail and wholesale volume.

- Retail revenues increased $66.8 million primarily due to a 9.5% increase in average retail rates which resulted from the PUCO approved service stability rider and recovery of various regulatory riders for market based costs. **DP&L** sales volume decreased 7.4% from prior year; however, this was partially offset by increased sales procured by DPLER and MC Squared outside our service territory, or off-system sales, which resulted in an overall 3.9% decrease in total **DPL** sales volume. The aforementioned impacts resulted in a favorable $123.3 million retail price variance and an unfavorable $56.7 million retail volume variance.

- Wholesale revenues decreased $31.7 million due to a 9.7% decrease in average wholesale prices and 4.5% reduction in wholesale volume due to increased outages in 2014, which resulted in an unfavorable wholesale price variance of $21.3 million and an unfavorable wholesale sales volume variance of $10.4 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, increased $84.5 million compared to 2013. This increase was primarily a result of an $80.5 million increase in revenues realized from the PJM capacity auction and an increase of $4.0 million in RTO transmission and congestion revenues.

During the year ended December 31, 2013, Revenues decreased $31.5 million, or 2%, to $1,636.9 million from $1,668.4 million in the same period of the prior year. This decrease was primarily the result of decreased retail and wholesale average rates, decreased RTO capacity and other revenues, offset by increased retail and wholesale volume.

- Retail revenues decreased $94.0 million primarily due to decreased prices driven by customer switching from competition to provide transmission and generation services in our service territory. The **DP&L** sales volume decreased 13% from the prior year; however, the effect of sales procured by DPLER and MC Squared outside our service territory, or off-system sales, offset volume decreases resulting in an overall 1% increase in total **DPL** sales volume. The rates offered to the off-system customers are lower than the rates in our service territory causing an overall 8% decrease in average rates. There was a 16% decrease in cooling degree days to 1,062 from 1,264 in 2012, as well as a 17% increase in the number of heating degree days to 5,542 days from 4,752 days in 2012, therefore weather had a minimal impact. The above resulted in an unfavorable $70.0 million retail price variance and an unfavorable $33.3 million retail sales volume variance.
- Wholesale revenues increased $125.2 million primarily as a result of a 128% increase in wholesale sales volume due to customer switching, which makes more of our generation available for wholesale sales, including a 16% increase in total net generation by our power plants, offset slightly by a 3.6% decrease in average wholesale prices. This resulted in a favorable $133.7 million wholesale sales volume variance partially offset by an unfavorable wholesale price variance of $8.5 million.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $60.1 million. This decrease in RTO capacity and other revenues was the result of a $45.8 million decrease in revenues realized from the PJM capacity auction, and a $12.8 million decrease in RTO transmission and congestion revenues due to a 2012 settlement related to PJM SECA revenues.

DPL – Cost of Revenues
During the year ended December 31, 2014:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, decreased $62.2 million, or 17%, primarily due to a 13% decrease in internal generation as a result of increased outages combined with lower average fuel prices.
- Net purchased power increased $203.6 million, or 52%, compared to 2013. This was driven by an increase in RTO capacity and other costs of $116.0 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This increase also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. In addition, purchase power volume increased 21% as a result of increased outages at our generating stations during 2014 and average purchased power prices increased 11%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.
- Amortization of intangibles decreased due to certain customer contract intangibles recognized at the merger date becoming fully amortized.

During the year ended December 31, 2013:

- Net fuel costs increased $4.8 million, or 1%, compared to 2012, primarily due to increased fuel costs and decreased mark-to-market gains partially offset by decreased losses from the sale of coal. There was a 16% increase in the volume of generation at our stations and no fuel related mark-to-market gains or losses in 2013 compared to $8.5 million of gains in 2012. Partially offsetting these increases were $0.7 million in realized losses from the sale of coal in 2013, compared to $11.8 million of realized losses from the same period in 2012.
- Net purchased power increased $46.9 million, or 14%, compared to the same period in 2012 due largely to increased purchased power costs of $62.2 million, $48.3 million due to increased volume and $13.8 million due to higher average market prices for purchased power. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities. Partially offsetting these increases were decreased RTO capacity and other charges of $23.6 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges.
- Amortization of intangibles decreased in 2013 compared to 2012 primarily due to the full amortization of the ESP during 2012.

DPL - Operation and Maintenance

$ in millions		**2014 vs. 2013**
Low-income payment program [(a)]	$	(10.1)
Competitive retail operations		(4.7)
Health insurance and disability		(4.1)
Deferred compensation liability		(1.5)
Generating facilities operating and maintenance expenses		5.6
Maintenance of overhead transmission and distribution		5.2
Alternative energy and energy efficiency programs [(a)]		2.7
Other, net		(1.5)
Total operation and maintenance expense	$	(8.4)

(a) There is a corresponding increase / (decrease) in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2014, Operation and maintenance expense decreased $8.4 million, or 2%, compared to the same period in 2013. This variance was primarily the result of:

- decreased expenses for the low-income payment program which are funded by the USF revenue rate rider;
- decreased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of decreased sales volume;
- decreased health insurance due to cost decreases as well as a reduction in the disability reserve as a result of the 2014 actuarial study; and
- decreased deferred compensation costs.

These decreases were partially offset by:

- increased maintenance expenses at our generating facilities;
- increased expenses related to the maintenance of overhead transmission and distribution lines; and
- increased expenses relating to alternative energy and energy efficiency programs.

$ in millions	2013 vs. 2012
Generating facilities operating and maintenance expenses	$ (19.9)
Low-income payment program [(a)]	(3.8)
Pension	(1.4)
Competitive retail operations	13.3
Health insurance	3.0
Other, net	(0.9)
Total operation and maintenance expense	$ (9.7)

(a) There is a corresponding increase in Revenues associated with this program resulting in no impact to Net income.

During the year ended December 31, 2013, Operation and maintenance expense decreased $9.7 million, or 2%, compared to the same period in 2012. This variance was primarily the result of:

- decreased expenses for generating facilities largely due to outages related to maintenance activities in the first and second quarters of 2012 at jointly owned production units relative to the same periods in 2013;
- decreased expense associated with the USF revenue rate rider, which provides assistance to low-income retail customers; and
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate.

These decreases were partially offset by:

- increased marketing, customer maintenance and labor costs associated with the competitive retail business as a result of increased sales volume and number of customers; and
- increased health insurance due to cost increases as well as more employees going on to long-term disability as compared to the same period in 2013.

DPL – Depreciation and Amortization

During the year ended December 31, 2014, Depreciation and amortization expense increased $6.9 million, or 5%, compared to 2013. The increase primarily reflects additional investments in fixed assets.

During the year ended December 31, 2013, Depreciation and amortization expense increased $7.5 million, or 6%, compared to 2012. The increase primarily reflects additional investments in fixed assets.

DPL – General Taxes

During the year ended December 31, 2014, General taxes increased $10.8 million, or 13%, compared to 2013. The increase was primarily due to an adjustment to the 2013 estimated property tax liability to adjust estimates to actual payments that were made in 2014, higher property tax accruals for 2014 compared to 2013 and a favorable determination of $1.6 million from the Ohio gross receipts appeal in 2013.

During the year ended December 31, 2013, General taxes increased $1.4 million, or 2%, compared to 2012. This increase was primarily due to higher property tax accruals in 2013 compared to 2012 partially offset by a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

DPL – Goodwill Impairment

During the year ended December 31, 2014, **DPL** recorded an impairment of goodwill of $135.8 million. See Note 5 of Notes to **DPL's** Consolidated Financial Statements.

During the year ended December 31, 2013, **DPL** recorded an impairment of goodwill of $306.3 million. See Note 5 of Notes to **DPL's** Consolidated Financial Statements.

DPL – Interest Expense

During the year ended December 31, 2014, Interest expense increased $2.6 million, or 2%, compared to 2013 due primarily to reduced amortization of debt premium (which offsets interest expense) partially offset by decreased interest rates on **DP&L's** senior secured bonds.

During the year ended December 31, 2013, Interest expense decreased $1.1 million, or 1%, compared to 2012 due primarily to decreased interest due to reductions in debt and decreased interest rates on **DP&L's** senior secured bonds partially offset by reduced amortization of debt premium (which offsets interest expense).

DPL – Income Tax Expense
During the year ended December 31, 2014, Income tax expense decreased $4.3 million compared to 2013 primarily due to lower pre-tax income (excluding the effect of the goodwill impairment), a 2014 deferred tax adjustment related to the expiration of the statutes of limitation on the 2010 tax year and a decrease in the tax benefits of Internal Revenue Code Section 199 in 2014.

During the year ended December 31, 2013, Income tax expense decreased $25.4 million compared to 2012 primarily due to lower pre-tax income (excluding the effect of the goodwill impairment), a 2013 deferred tax adjustment related to the expiration of the statutes of limitation on the 2007, 2008 and 2009 tax years, an increase in the tax benefits of Internal Revenue Code Section 199 in 2013 and a 2012 adjustment to state deferred taxes.

RESULTS OF OPERATIONS BY SEGMENT – DPL Inc.

DPL's two segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its competitive retail electric service subsidiaries. These segments are discussed further below:

Utility Segment
The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and distribute electricity to residential, commercial, industrial and governmental customers. **DP&L** generates electricity at five coal-fired power stations and distributes electricity to more than 516,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. Beginning in 2014, **DP&L** was required to procure 10% of the power for SSO customers through a competitive bid process, with the percentage increasing each year, reaching 100% by January 1, 2016. Further, in December 2013, **DP&L** filed a plan with the PUCO to sell or transfer its generation assets by January 1, 2017. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while rates for its generation business are deemed competitive under Ohio law.

Competitive Retail Segment
The Competitive Retail segment is comprised of DPLER's competitive retail electric service business and includes its wholly-owned subsidiary, MC Squared. DPLER sells retail electric energy under contract to residential, commercial, industrial and governmental customers who have selected DPLER or MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 260,000 customers currently located throughout Ohio and Illinois. MC Squared, a Chicago-based retail electricity supplier, serves approximately 108,000 customers in Northern Illinois and is a subsidiary of DPLER. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. Intercompany sales from **DP&L** to DPLER are based on the market prices for wholesale power. The price approximates market prices for wholesale power at the inception of each customer's contract. The Competitive Retail segment has no transmission or generation assets. The operations of the Competitive Retail segment are not subject to cost-of-service rate regulation by federal or state regulators.

Other
Included within Other are other businesses that do not meet the GAAP requirements for separate disclosure as reportable segments as well as certain corporate costs including interest expense on **DPL's** debt.

Management evaluates segment performance based on gross margin. See Note 14 of Notes to **DPL's** Consolidated Financial Statements for further discussion of **DPL's** reportable segments.

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The following table presents **DPL's** gross margin by business segment:

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Utility	$ **771.0**	$ 807.1	$ 867.4
Competitive Retail	**41.8**	51.9	68.6
Other	**55.4**	18.7	(63.3)
Adjustments and Eliminations	**(3.5)**	(3.6)	(3.4)
Total consolidated	$ **864.7**	$ 874.1	$ 869.3

The financial condition, results of operations and cash flows of the Utility segment are identical in all material respects and for all periods presented to those of **DP&L** which are included in this Form 10-K. We do not believe that additional discussions of the financial condition and results of operations of the Utility segment would enhance an understanding of this business since these discussions are already included under the **DP&L** discussions below.

Income Statement Highlights – Competitive Retail Segment

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Revenues:			
Retail	$ **533.1**	$ 518.8	$ 496.7
RTO and other	**0.5**	(7.2)	(3.6)
Total revenues	**533.6**	511.6	493.1
Cost of revenues:			
Purchased power	**491.8**	459.7	424.5
Gross margins[(a)]	**41.8**	51.9	68.6
Operation and maintenance expense	**33.3**	38.0	24.7
Other expense	**3.3**	3.1	3.0
Total expenses	**36.6**	41.1	27.7
Earnings from operations	**5.2**	10.8	40.9
Income tax expense	**2.0**	4.2	18.1
Net income	$ **3.2**	$ 6.6	$ 22.8
Gross margin as a % of revenues	**8%**	10%	14%

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

Competitive Retail Segment – Revenue

During the year ended December 31, 2014, the segment's retail revenue increased $14.3 million or 3%, compared to 2013. The increase was primarily due to higher average retail rates for off-system sales and increased off-system sales volume, partially offset by lower on-system sales volume due to customer switching to unaffiliated third-party CRES providers. RTO and other revenues increased primarily due to the derivative-related amortization in 2013. The Competitive Retail segment sold approximately 9,717 million kWh of power to 260,000 customers in 2014 compared to approximately 9,733 million kWh of power to 308,000 customers during the same period of the prior year.

During the year ended December 31, 2013, the segment's retail revenues increased $22.1 million, or 4%, compared to 2013. The increase was primarily due to an $84.8 million positive volume variance primarily due to sales growth outside of **DP&L's** service territory in both Ohio and Illinois. The increased volume was partially offset by a $62.7 million negative price variance as increased competition in the competitive retail electric service business in the state of Ohio has resulted in decreased retail prices. The Competitive Retail segment sold approximately 9,733 million kWh of power to approximately 308,000 customers compared to approximately 8,315 million kWh of power to approximately 198,000 customers during the same period of the prior year.

Competitive Retail Segment – Purchased Power

During the year ended December 31, 2014, the segment's purchased power costs increased $32.1 million, or 7%, due to higher prices, partially offset by a slight volume decline.

During the year ended December 31, 2013, the Competitive Retail segment purchased power increased $35.2 million, or 7%, compared to 2013 primarily due to increased purchased power volume required to satisfy an increase in customer base as described in the revenue section above.

Competitive Retail Segment – Operation and Maintenance

DPLER's operation and maintenance expenses include employee-related expenses, marketing, accounting, information technology, payroll, legal and other administration expenses.

The $4.7 million, or 12%, decrease in operation and maintenance expense in 2014 compared to 2013 is reflective of decreased marketing and customer maintenance costs associated with the decreased number of customers.

The $13.3 million, or 54%, increase in operation and maintenance expense in 2013 compared to 2012 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers.

RESULTS OF OPERATIONS – Utility Segment (DP&L)

Income Statement Highlights – DP&L

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Revenues:			
Retail	$ **834.2**	$ 782.0	$ 898.4
Wholesale	**666.0**	671.3	483.7
RTO revenues	**77.6**	74.5	88.5
RTO capacity revenues	**90.5**	24.0	63.4
Mark-to-market gains / (losses)	**-**	*(0.3)*	*(2.2)*
Total revenues	**1,668.3**	1,551.5	1,531.8
Cost of revenues:			
Cost of fuel:			
Fuel	**315.8**	361.8	351.6
Losses / (gains) from sale of coal	**(1.3)**	0.7	11.8
Gains from sale of emission allowances	**-**	-	(0.1)
Mark-to-market (gains) / losses	**0.4**	-	(8.4)
Net fuel costs	**314.9**	362.5	354.9
Purchased power:			
Purchased power	**323.7**	236.9	151.6
RTO charges	**150.4**	109.8	98.8
RTO capacity charges	**106.7**	33.9	64.1
Mark-to-market (gains) / losses	**1.6**	1.3	(5.0)
Net purchased power	**582.4**	381.9	309.5
Total cost of revenues	**897.3**	744.4	664.4
Gross margins [(a)]	$ **771.0**	$ 807.1	$ 867.4
Gross margins as a % of revenues	**46%**	52%	57%
Operating income	$ **188.8**	$ 139.9	$ 184.8

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

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DP&L – Revenues

The following table provides a summary of changes in **DP&L's** Revenues from prior periods:

		2014 vs. 2013		2013 vs. 2012
Retail				
Rate	$	108.4	$	(7.3)
Volume		(55.7)		(118.5)
Other		(0.5)		9.4
Total retail change		52.2		(116.4)
Wholesale				
Rate		6.6		(64.5)
Volume		(11.9)		252.1
Total wholesale change		(5.3)		187.6
RTO capacity and other				
RTO capacity and other revenues		69.6		(53.4)
Other				
Unrealized MTM		0.3		1.9
Total revenues change	$	116.8	$	19.7

During the year ended December 31, 2014, revenues increased $116.8 million, or 8%, to $1,668.3 million from $1,551.5 million in the prior year. This increase was primarily the result of higher average retail rates and increased RTO capacity revenues; partially offset by lower retail and wholesale volume.

- Retail revenues increased $52.2 million due to a 15% increase in average retail rates which resulted from the PUCO approved service stability rider and recovery of various regulatory riders for market based costs. Retail volume decreased 7% overall due to a 26% increase in the percentage of volume in the **DP&L** service territory being supplied by third-party CRES providers. **DP&L** continues to provide distribution services to these customers but the volumes are not recorded. Heating degree days increased by 408, or 7%, while cooling degree days decreased 85, or 8%, compared to 2013. During 2014, 31% of **DP&L's** distribution sales were supplied by third-party CRES providers. As we only have distribution revenue on these sales, the weather impact is less than the weather impact on SSO sales. The above resulted in a favorable $108.4 million retail price variance partially offset by an unfavorable $55.7 million retail sales volume variance.
- Wholesale revenues decreased $5.3 million as a result of an $11.9 million decrease in wholesale sales volume, partially offset by a favorable $6.6 million price variance. Although customer switching in the **DP&L** service territory resulted in increased generation available to sell in the wholesale market, there was a 13% decrease in net generation available from **DP&L's** co-owned and operated generation plants due to higher outages which resulted in an overall decrease in wholesale sales volume.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, increased $69.6 million. This increase was primarily the result of a $66.5 million increase in revenues realized from the PJM capacity auction and an increase of $3.1 million in RTO transmission and congestion revenues.

During the year ended December 31, 2013, Revenues increased $19.7 million, or 1%, to $1,551.5 million from $1,531.8 million in the prior year. This increase was primarily the result of higher wholesale sales volumes. The revenue components for the year ended December 31, 2013 compared to 2012 are further discussed below.

- Retail revenues decreased $116.4 million primarily due to a 13% decrease in retail sales volumes compared to the prior year which was a result of customer switching due to increased levels of competition to provide transmission and generation services in our service territory. There was a 16% decrease in cooling degree days to 1,062 days from 1,264 days in 2012, as well as a 17% increase in the number of heating degree days to 5,542 days from 4,752 days in 2012, therefore weather had a minimal impact. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to CRES providers, **DP&L** continued to provide distribution services to those customers within its service territory. Average retail rates decreased slightly overall. The remaining distribution services provided by **DP&L** were billed at a lower average rate resulting in a slight reduction of total average retail rates. The above resulted in an unfavorable $118.5 million retail sales volume variance and an unfavorable $7.3 million retail price variance, partially offset by a $7.0 million shared savings accrual related to **DP&L** energy efficiency programs.

- Wholesale revenues increased $187.6 million as a result of an increase in wholesale sales volume which was largely a result of customer switching discussed in the immediately preceding paragraph. Customer switching in the **DP&L** service territory has resulted in increased generation available to sell in the wholesale market. Also contributing was a 17% increase in net generation available from **DP&L's** co-owned and operated generation plants. These increases were partially offset by a 9% decrease in average wholesale rates. These resulted in a favorable $252.1 million wholesale volume variance offset by a $64.5 million unfavorable wholesale price variance.
- RTO capacity and other revenues, consisting primarily of compensation for use of **DP&L's** transmission assets, regulation services, reactive supply and operating reserves, and capacity payments under the RPM construct, decreased $53.4 million. This decrease in RTO capacity and other revenues was primarily the result of a $39.4 million decrease in revenues realized from the PJM capacity auction, and a $12.8 million decrease in RTO transmission and congestion revenues due to a 2012 settlement related to PJM SECA revenues.

DP&L – Cost of Revenues

During the year ended December 31, 2014:

- Net fuel costs decreased $47.6 million, or 13%, due to a 13% decrease in internal generation due to increased outages combined with lower average fuel prices, partially offset by costs associated with the early termination of a fuel contract.
- Net purchased power increased $200.5 million, or 53%, compared to the same period in 2013. This was driven by increased RTO capacity and other costs of $113.4 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This increase also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. In addition, purchased power volume increased 21% as a result of increased outages at our generating stations during 2014 and average purchased power prices increased 12%. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities.

During the year ended December 31, 2013:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $7.6 million, or 2%, compared to 2012, primarily due to increased fuel costs and decreased mark-to-market gains on coal contracts partially offset by decreased losses from the sale of coal. During the year ended December 31, 2013, there was a 17% increase in the volume of generation at our stations and no fuel related mark-to-market gains or losses compared to $8.4 million of gains in 2012. Partially offsetting these increases were $0.7 million in realized losses from the sale of coal, compared to $11.8 million of realized losses from the same period in 2012.
- Net purchased power increased $72.4 million, or 23%, compared to the same period in 2012 due largely to increased purchased power costs of $85.3 million, $74.0 million due to increased volume and an increase of $11.9 million due to higher average market prices for purchased power. Purchased power volume increased due to power purchased to supply increased off-system sales. We purchase power to satisfy retail sales volume when generating facilities are not available due to planned and unplanned outages or when market prices are below the marginal costs associated with our generating facilities. Partially offsetting these increases were decreased RTO capacity and other charges of $19.2 million which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. RTO capacity prices are set by an annual auction. This decrease also includes the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges.

DP&L – Operation and Maintenance

$ in millions		2014 vs. 2013
Low-income payment program [(a)]	$	(10.1)
Health Insurance and disability		(4.7)
Pension		(1.5)
Deferred compensation liability		(1.5)
Generating facilities operating and maintenance expenses		5.7
Maintenance of overhead transmission and distribution		5.2
Alternative energy and energy efficiency programs [(a)]		1.6
Other, net		(3.6)
Total operation and maintenance expense	$	(8.9)

(a) There is a corresponding increase / (decrease) in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2014, Operation and maintenance expense decreased $8.9 million, or 2%, compared to 2013. This variance was primarily the result of:

- decreased expenses for the low-income payment program which is funded by the USF revenue rate rider;
- decreased health insurance due to cost decreases as well as a reduction in the disability reserve as a result of the 2014 actuarial study;
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate; and
- decreased deferred compensation costs.

These decreases were partially offset by:

- increased maintenance expenses at our generating facilities;
- increased expenses related to the maintenance of overhead transmission and distribution lines; and
- increased expenses relating to alternative energy and energy efficiency programs.

$ in millions		2013 vs. 2012
Generating facilities operating and maintenance expenses	$	(19.8)
Low-income payment program [(a)]		(3.8)
Pension		(2.2)
Health Insurance		3.0
Other, net		(1.0)
Total operation and maintenance expense	$	(23.8)

(a) There is a corresponding increase in Revenues associated with these programs resulting in no impact to Net income.

During the year ended December 31, 2013, Operation and maintenance expense decreased $23.8 million, or 6%, compared to 2012. This variance was primarily the result of:

- decreased expenses for generating facilities largely due to outages related to maintenance activities in the first and second quarters of 2012 at jointly owned production units relative to the same periods in 2013;
- decreased expense associated with the USF revenue rate rider, which provides assistance for low-income retail customers; and
- lower pension expenses primarily related to changes in plan assumptions, specifically a higher discount rate.

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These decreases were partially offset by:

- increased health insurance due to cost increases as well as more employees going on long-term disability as compared to the same period in 2013.

DP&L – Depreciation and Amortization
During the year ended December 31, 2014, Depreciation and amortization expense increased $4.6 million, or 3%, compared to 2013. The increase primarily reflects additional investments in fixed assets.

During the year ended December 31, 2013, Depreciation and amortization expense decreased $1.1 million, or 1%, compared to 2012. The decrease primarily reflects the full-year effect of a reduction of approximately $1.8 million related to a decrease in plant values as a result of impairment in the value of certain electric generating stations in the third quarter of 2012, partially offset by investments in plant and equipment.

DP&L – General Taxes
During the year ended December 31, 2014, General taxes increased $11.3 million, or 15%, compared to 2013. The increase was primarily due to an adjustment to the 2013 estimated property tax liability to adjust estimates to actual payments that were made in 2014, higher property tax accruals for 2014 compared to 2013 and a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

During the year ended December 31, 2013, General taxes increased $2.0 million, or 3%, compared to 2012. This increase was primarily the result of higher property tax accruals in 2013 compared to 2012 partially offset by a favorable determination of $1.6 million from the Ohio gross receipts tax appeal in 2013.

DP&L – Fixed-asset Impairment and gain on asset sale
During the year ended December 31, 2014, **DP&L** recorded a gain of $4.5 million on the sale of its interest in the East Bend generating station.

During the year ended December 31, 2013, **DP&L** had a fixed-asset impairment of $86.0 million related to the Conesville and East Bend generating stations.

DP&L – Interest Expense
During the year ended December 31, 2014, interest expense decreased $3.3 million or 9% compared to 2013 due to a reduction in outstanding debt and lower interest rates on **DP&L's** senior secured bonds.

During the year ended December 31, 2013, interest expense decreased $1.9 million or 5% compared to 2012 due to a reduction in outstanding debt and lower interest rates on **DP&L's** senior secured bonds.

DP&L – Income Tax Expense
During the year ended December 31, 2014, Income tax expense increased $21.1 million compared to 2013 primarily due to increases in pre-tax income, a 2014 deferred tax adjustment related to the expiration of the statutes of limitation on the 2010 tax year and a decrease in the tax benefits of Internal Revenue Code Section 199 in 2014.

During the year ended December 31, 2013, Income tax expense decreased $36.5 million compared to 2012 primarily due to decreases in pre-tax income, a 2013 deferred tax adjustment related to the expiration of the statutes of limitation on the 2007, 2008 and 2009 tax years and an increase in the tax benefits of Internal Revenue Code Section 199 in 2013 and a 2012 adjustment to state deferred taxes.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL REQUIREMENTS

DPL's financial condition, liquidity and capital requirements include the consolidated results of its principal subsidiary **DP&L**. All material intercompany accounts and transactions have been eliminated in consolidation. The following table provides a summary of the cash flows for **DPL** and **DP&L**:

DPL	Years ended December 31,		
$ in millions	**2014**	2013	2012
Net cash from operating activities	$ **244.1**	$ 302.8	$ 291.5
Net cash from investing activities	**(112.6)**	(123.9)	(199.2)
Net cash from financing activities	**(167.7)**	(317.8)	(73.7)
Net change	**(36.2)**	(138.9)	18.6
Cash and cash equivalents at beginning of period	**53.2**	192.1	173.5
Cash and cash equivalents at end of period	$ **17.0**	$ 53.2	$ 192.1

DP&L	Years ended December 31,		
$ in millions	**2014**	2013	2012
Net cash from operating activities	$ **251.7**	$ 335.3	$ 339.8
Net cash from investing activities	**(108.5)**	(114.5)	(197.5)
Net cash from financing activities	**(160.7)**	(226.4)	(146.0)
Net change	**(17.5)**	(5.6)	(3.7)
Cash and cash equivalents at beginning of period	**22.9**	28.5	32.2
Cash and cash equivalents at end of period	$ **5.4**	$ 22.9	$ 28.5

The significant items that have impacted the cash flows for **DPL** and **DP&L** are discussed in greater detail below:

DPL – Net Cash provided by Operating Activities

During the year ended December 31, 2014, Net cash provided by operating activities was primarily a result of Net loss adjusted for the noncash impacts of depreciation and amortization, the impairment of goodwill and fixed-assets, deferred income taxes, and a charge for the early redemption of debt.

During the year ended December 31, 2013, Net cash provided by operating activities was primarily a result of Net loss adjusted for the noncash impacts of depreciation and amortization, the impairment of goodwill and fixed-assets and deferred income taxes.

During the year ended December 31, 2012, Net cash provided by operating activities was primarily a result of Net income adjusted for noncash depreciation and amortization, as well as a noncash charge for the impairment of goodwill.

DP&L – Net Cash provided by Operating Activities

During the year ended December 31, 2014 the significant components of **DP&L's** *Net cash provided by operating* activities were primarily the result of Net income adjusted for noncash depreciation and amortization.

During the year ended December 31, 2013 the significant components of **DP&L's** Net cash provided by operating activities were primarily a result of Net income adjusted for noncash depreciation and amortization, as well as a noncash charge related to the impairment of certain generation facilities.

During the year ended December 31, 2012, the significant components of **DP&L's** Net cash provided by operating activities were primarily a result of Net income adjusted for noncash depreciation and amortization, as well as a noncash charge related to the impairment of certain generation facilities.

DPL – Net Cash used for Investing Activities
During the year ended December 31, 2014, **DPL's** cash used for investing activities was primarily related to capital expenditures, partially offset by proceeds from the sale of property.

During the year ended December 31, 2013, **DPL's** cash used for investing activities was primarily related to capital expenditures.

During the year ended December 31, 2012, **DPL's** cash used for investing activities was primarily related to capital expenditures.

DP&L – Net Cash used for Investing Activities
During the year ended December 31, 2014, **DP&L's** cash used for investing activities was primarily related to capital expenditures, partially offset by proceeds from the sale of property.

During the year ended December 31, 2013, **DP&L's** cash used for investing activities was primarily related to capital expenditures. In addition, **DP&L** received $14.2 million in insurance proceeds during the year, $6.6 million of which were from **DPL's** MVIC subsidiary.

During the year ended December 31, 2012, **DP&L's** cash used for investing activities was primarily related to capital expenditures.

DPL – Net Cash used for Financing Activities
During the year ended December 31, 2014, **DPL's** Net cash used for financing activities primarily relates to the redemption of $335.0 million of debt and associated redemption premiums, partially offset by a $200.0 million issuance of new debt.

During the year ended December 31, 2013, **DPL's** Net cash used for financing activities primarily relates to the payment at maturity of $470.0 million of **DP&L's** senior secured bonds, early redemption of $475.1 million of debt and debt issuance costs, partially offset by the issuance of $445.0 million of new senior secured bonds, the issuance of $200.0 million of new debt.

During the year ended December 31, 2012, **DPL's** Net cash used for financing activities primarily relates to common stock and payments to former warrant holders.

DP&L – Net Cash used for Financing Activities
During the year ended December 31, 2014, **DP&L's** Net cash used for financing activities primarily relates to $159.0 million in dividends.

During the year ended December 31, 2013, **DP&L's** Net cash used for financing activities primarily relates to $190.0 million in dividends and the issuance of $445.0 million of senior secured bonds, the proceeds of which were used to redeem **DP&L's** senior secured bonds at maturity.

During the year ended December 31, 2012, **DP&L's** Net cash used for financing activities primarily relates to $145.0 million in dividends.

Liquidity
We expect our existing sources of liquidity to remain sufficient to meet our anticipated operating needs. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities and carrying costs, potential margin requirements related to energy hedges, taxes and dividend payments. For 2015 and subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from debt financing as our internal liquidity needs and market conditions warrant. We also expect that the borrowing capacity under bank credit facilities will continue to be available to manage working capital requirements during those periods.

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At the filing date of this annual report on Form 10-K, **DPL** and **DP&L** have access to the following revolving credit facilities:

$ in millions	Type	Maturity	Commitment	Amounts available as of December 31, 2014
DPL	Revolving	May 2018	$ 100.0	$ 97.7
DP&L	Revolving	May 2018	$ 300.0	$ 299.3
			$ 400.0	$ 397.0

DPL's revolving credit facility was established in May 2013. This facility expires in May 2018; however, if **DPL** has not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then this credit facility shall expire in July 2016. This facility has nine participating banks with no bank having more than 20% of the total commitment. **DPL's** revolving credit facility has a $100.0 million letter of credit sublimit and a feature which provides **DPL** the ability to increase the size of the facility by an additional $50.0 million. As of December 31, 2014, there was one letter of credit issued in the amount of $2.3 million with the remaining $97.7 million available to **DPL**.

DP&L's revolving credit facility, established in May 2013, expires in May 2018 and has nine participating banks, with no bank having more than 22.5% of the total commitment. This revolving credit facility has a $100.0 million letter of credit sublimit and **DP&L** also has the option to increase the potential borrowing amount under this facility by $100.0 million. At December 31, 2014, there were two letters of credit in the aggregate amount of $0.7 million outstanding, with the remaining $299.3 million available to **DP&L**.

Cash and cash equivalents for **DPL** and **DP&L** amounted to $17.0 million and $5.4 million, respectively, at December 31, 2014. At that date, neither **DPL** nor **DP&L** had short-term investments.

Capital Requirements

Construction Additions

	Actual			Projected		
$ in millions	2012	2013	2014	2015	2016	2017
DPL	$ 180	$ 114	$ 116	$ 133	$ 140	$ 164
DP&L	$ 177	$ 111	$ 112	$ 128	$ 135	$ 115

Planned construction additions for 2015 relate primarily to new investments in and upgrades to **DP&L's** electric generating station equipment and transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments and changing environmental standards, among other factors. As discussed previously, **DP&L** must separate its generation assets by January 1, 2017. Accordingly, estimated capital expenditures related to the generation assets of $44.0 million are not included in **DP&L's** estimated spending for 2017 in the table above. Those estimated costs are included in the **DPL** amounts.

DPL, primarily through its subsidiary **DP&L**, is projecting to spend an estimated $440.0 million in capital projects for the period 2015 through 2017. **DP&L** is subject to the mandatory reliability standards of NERC and Reliability First Corporation (RFC), one of the eight NERC regions, of which **DP&L** is a member. NERC has recently changed the definition of the Bulk Electric System (BES) to include 100 kV and above facilities, thus expanding the facilities to which the reliability standards apply. **DP&L's** 138 kV facilities were previously not subject to these reliability standards. Accordingly, **DP&L** anticipates spending approximately $60.0 million within the next five years to reinforce its 138 kV system to comply with these new NERC standards. Our ability to complete capital projects and the reliability of future service will be affected by our financial condition, the availability of internal funds and the reasonable cost of external funds. We expect to finance our construction additions with a combination of cash on hand, short-term financing, long-term debt and cash flows from operations.

Debt Covenants
The **DPL** revolving credit facility and the **DPL** term loan agreement that were put in place in May 2013 have two financial covenants. The first is a Total Debt to EBITDA ratio that will be calculated, at the end of each fiscal quarter, by dividing total debt at the end of the current quarter by consolidated EBITDA for the four prior fiscal quarters. The ratio is not to exceed 8.50 to 1.00 for the fiscal quarters ending June 30, 2013 through December 31, 2014; it then steps down to not exceed 8.00 to 1.00 for the fiscal quarters ending March 31, 2015 through December 31, 2016; and it then steps down not to exceed 7.50 to 1.00 for the fiscal quarter ending March 31, 2017 through March 31, 2018. As of December 31, 2014, the financial covenant was met with a ratio of 5.77 to 1.00.

The second financial covenant is an EBITDA to Interest Expense ratio. The ratio is calculated, at the end of each fiscal quarter, by dividing consolidated EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period. The ratio is not to be less than 2.00 to 1.00 for the fiscal quarter ending June 30, 2013 through December 31, 2014; it then steps up to not to be less than 2.10 to 1.00 for the fiscal quarter ending March 31, 2015 through December 31, 2016; and it then steps up to not to be less than 2.25 to 1.00 for the fiscal quarter ending March 31, 2017 through March 31, 2018. As of December 31, 2014, the financial covenant was met with a ratio of 3.08 to 1.00.

Both **DPL's** unsecured revolving credit agreement and unsecured term loan restrict dividend payments from **DPL** to AES and adjust the cost of borrowing under the facilities under certain rating scenarios.

DP&L's revolving credit facility that was put in place in May 2013 has two financial covenants. The first requires the Total Debt to Total Capitalization ratio to not exceed 0.65 to 1.00. As of December 31, 2014, this covenant was met with a ratio of 0.45 to 1.00. The above ratio is calculated as the sum of **DP&L's** current and long-term portion of debt, including its guarantee obligations, divided by the total of **DP&L's** shareholder's equity and total debt including guarantee obligations. The second covenant, the EBITDA to Interest Expense ratio, is calculated at the end of each fiscal quarter, by dividing consolidated EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period. **DP&L's** EBITDA to Interest Expense ratio cannot be less than 2.50 to 1.00. As of December 31, 2014, this covenant was met with a ratio of 10.12 to 1.00.

Debt Ratings
During 2014, Moody's downgraded **DPL** and **DP&L's** credit and debt ratings. Standard & Poor's and Fitch's ratings did not change.

The following table outlines the debt ratings and outlook for **DPL** and **DP&L**, along with the effective dates of each rating.

	DPL	**DP&L**	Outlook	Effective
Fitch Ratings	BB	BBB	Stable	September 2014
Moody's Investors Service, Inc.	Ba3	Baa2	Stable	September 2014
Standard & Poor's Financial Services LLC	BB	BBB-	Stable	April 2014

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Credit Ratings

The following table outlines the credit ratings (issuer/corporate rating) and outlook for each company, along with the effective dates of each rating and outlook for **DPL** and **DP&L**.

	DPL	**DP&L**	Outlook	Effective
Fitch Ratings	B+	BB+	Stable	September 2014
Moody's Investors Service, Inc.	Ba3	Baa3	Stable	September 2014
Standard & Poor's Financial Services LLC	BB	BB	Stable	April 2014

On September 19, 2014, Moody's downgraded **DPL's** senior unsecured debt rating from Ba2 Stable to Ba3 Stable, and **DP&L's** senior unsecured credit rating from Baa2 Stable to Baa3 Stable. Moody's also downgraded **DP&L's** senior secured debt rating from Baa1 Stable to Baa2 Stable.

If the rating agencies were to reduce our debt or credit ratings further, our borrowing costs may increase, our potential pool of investors and funding resources may be reduced, and we may be required to post additional collateral under selected contracts. These events may have an adverse effect on our results of operations, financial condition and cash flows. In addition, any such reduction in our debt or credit ratings may adversely affect the trading price of our outstanding debt securities. Non-investment grade companies, such as **DPL**, may experience higher costs to issue new securities. **DP&L** is still considered investment grade by one of the three rating agencies above.

Off-Balance Sheet Arrangements

DPL – Guarantees

In the normal course of business, **DPL** enters into various agreements with its wholly-owned subsidiaries, DPLE and DPLER, and its wholly-owned subsidiary MC Squared, providing financial or performance assurance to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to these subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish these subsidiaries' intended commercial purposes. During the year ended December 31, 2014, **DPL** did not incur any losses related to the guarantees of these obligations and we believe it is unlikely that **DPL** would be required to perform or incur any losses in the future associated with any of the above guarantees.

At December 31, 2014, **DPL** had $20.5 million of guarantees to third parties for future financial or performance assurance under such agreements, on behalf of DPLER, DPLE and MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLER, DPLE and MC Squared to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $1.6 million at December 31, 2014 and $0.2 million at December 31, 2013.

DP&L owns a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. At December 31, 2014, **DP&L** could be responsible for the repayment of 4.9%, or $74.4 million, of a $1,517.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2015 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2014, we have no knowledge of such a default.

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Commercial Commitments and Contractual Obligations

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2014, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DPL:					
Long-term debt	$ 2,163.2	$ 20.1	$ 655.2	$ 260.2	$ 1,227.7
Interest payments	847.7	107.8	196.0	175.0	368.9
Pension and postretirement payments	280.2	26.6	54.3	56.1	143.2
Operating leases	0.6	0.4	0.2	-	-
Coal contracts (a)	486.2	255.6	161.2	69.4	-
Limestone contracts (a)	18.3	6.1	12.2	-	-
Purchase orders and other contractual obligations	72.4	39.2	17.3	15.9	-
Total contractual obligations	$ 3,868.6	$ 455.8	$ 1,096.4	$ 576.6	$ 1,739.8

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Long-term debt	$ 877.6	$ 0.1	$ 445.2	$ 0.2	$ 432.1
Interest payments	336.5	24.2	40.0	31.7	240.6
Pension and postretirement payments	280.2	26.6	54.3	56.1	143.2
Operating leases	0.6	0.4	0.2	-	-
Coal contracts (a)	486.2	255.6	161.2	69.4	-
Limestone contracts (a)	18.3	6.1	12.2	-	-
Purchase orders and other contractual obligations	72.4	39.2	17.3	15.9	-
Total contractual obligations	$ 2,071.8	$ 352.2	$ 730.4	$ 173.3	$ 815.9

(a) Total at **DP&L** operated units.

Long-term debt:

DPL's Long-term debt as of December 31, 2014 consists of **DPL's** unsecured notes and unsecured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds and the Wright-Patterson Air Force Base (WPAFB) note. These long-term debt amounts include current maturities but exclude unamortized debt discounts, premiums and fair value adjustments.

DP&L's Long-term debt as of December 31, 2014 consists of its first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 6 of the Notes to **DPL's** Consolidated Financial Statements and Note 5 of the Notes to **DP&L's** Financial Statements.

Interest payments:

Interest payments are associated with the long-term debt described above. The interest payments relating to variable-rate debt are projected using the interest rate prevailing at December 31, 2014.

Pension and postretirement payments:
As of December 31, 2014, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 8 of Notes to **DPL's** Consolidated Financial Statements and Note 7 of Notes to **DP&L's** Financial Statements. These estimated future benefit payments are projected through 2024.

Coal contracts:
DPL, through its principal subsidiary **DP&L**, has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:
DPL, through its principal subsidiary **DP&L**, has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:
As of December 31, 2014, **DPL** and **DP&L** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Reserve for uncertain tax positions:
Due to the uncertainty regarding the timing of future cash outflows associated with our unrecognized tax benefits of $3.0 million at December 31, 2014, we are unable to make a reliable estimate of the periods of cash settlement with the respective tax authorities and have not included such amounts in the contractual obligations table above.

MARKET RISK

We are subject to certain market risks including, but not limited to, changes in commodity prices for electricity, coal, environmental emission allowances, and changes in capacity prices and fluctuations in interest rates. We use various market risk-sensitive instruments, including derivative contracts, primarily to limit our exposure to fluctuations in commodity pricing. Our Commodity Risk Management Committee (CRMC), comprised of members of senior management, is responsible for establishing risk management policies and the monitoring and reporting of risk exposures related to our **DP&L** operated generation units. The CRMC meets on a regular basis with the objective of identifying, assessing and quantifying material risk issues and developing strategies to manage these risks.

Commodity Pricing Risk

Commodity pricing risk exposure includes the impacts of weather, market demand, increased competition and other economic conditions. To manage the volatility relating to these exposures at our **DP&L** operated generation stations, we use a variety of non-derivative and derivative instruments including forward contracts and futures contracts. These instruments are used principally for economic hedging purposes and none are held for trading purposes. Derivatives that fall within the scope of derivative accounting under GAAP must be recorded at their fair value and marked to market. MTM gains and losses on derivative instruments that qualify for cash flow hedge accounting are deferred in AOCI until the forecasted transactions occur. We adjust the derivative instruments that do not qualify for cash flow hedging to fair value on a monthly basis and where applicable, we recognize a corresponding regulatory asset for above-market costs or a regulatory liability for below-market costs in accordance with regulatory accounting under GAAP.

The coal market has increasingly been influenced by both international and domestic supply and consumption, making the price of coal more volatile than in the past, and while we have substantially all of the total expected coal volume needed to meet our retail and wholesale sales requirements for 2015 under contract, sales requirements may change, particularly for retail load. The majority of the contracted coal is purchased at fixed prices. Some contracts provide for periodic adjustments and some are priced based on market indices. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, the wholesale market price of power, certain provisions in coal contracts related to government imposed costs, counterparty performance and credit, scheduled outages and electric generation station mix. To the extent we are not able to hedge against price volatility or recover increases through our fuel and purchased power recovery rider that began in January 2010, our results of operations, financial condition or cash flows could be materially affected.

In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), signed into law in July 2010, contains significant requirements relating to derivatives, including, among others, a requirement that

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certain transactions be cleared on exchanges that would necessitate the posting of cash collateral for these transactions. We are considered an end-user under the Dodd-Frank Act and therefore are exempt from most of the collateral and margining requirements. We are required to report our bilateral derivative contracts, unless our counterparty is a major swap participant or has elected to report on our behalf. Even though we qualify for an exception from these requirements, our counterparties that do not qualify for the exception may pass along any increased costs incurred by them through higher prices and reductions in unsecured credit limits or be unable to enter into certain transactions with us.

For purposes of potential risk analysis, we use a sensitivity analysis to quantify potential impacts of market rate changes on the statements of results of operations. The sensitivity analysis represents hypothetical changes in market values that may or may not occur in the future.

Commodity derivatives

To minimize the risk of fluctuations in the market price of commodities, such as coal, power, and heating oil, we may enter into commodity forward and futures contracts to effectively hedge the cost/revenues of the commodity. Maturity dates of the contracts are scheduled to coincide with market purchases/sales of the commodity. Cash proceeds or payments between us and the counterparty at maturity of the contracts are recognized as an adjustment to the cost of the commodity purchased or sold. We generally do not enter into forward contracts beyond thirty-six months. As of December 31, 2014, there are no coal derivatives.

A 10% increase or decrease in the market price of our heating oil forwards at December 31, 2014 would not have a significant effect on Net income.

The following table provides information regarding the volume and average market price of our power forward derivative contracts at December 31, 2014 and the effect to Net income if the market price were to increase or decrease by 10%:

Power Forwards	Contract Volume (in millions of MWh)		Weighted Average Market Price per MWh		Increase / decrease in Net income (in millions)
2015 - Net purchase/(Sale) position	0.2	$	41.06	$	0.3
2016 - Net purchase/(Sale) position	(1.2)	$	40.31	$	(3.1)
2017 - Net purchase/(Sale) position	-	$	-	$	-

Wholesale revenues

Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins (**DP&L's** electric revenues in the wholesale market include sales to DPLER).

Approximately 17% of **DPL's** and 45% of **DP&L's** electric revenues for the year ended December 31, 2014 were from sales of excess energy and capacity in the wholesale market.

Approximately 16% of **DPL's** and 45% of **DP&L's** electric revenues for the year ended December 31, 2013 were from sales of excess energy and capacity in the wholesale market.

Approximately 11% of **DPL's** and 36% of **DP&L's** electric revenues for the year ended December 31, 2012 were from sales of excess energy and capacity in the wholesale market.

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The table below provides the effect on annual Net income (net of an estimated income tax at 35%) as of December 31, 2014 of a hypothetical increase or decrease of 10% in the price per megawatt hour of wholesale power (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER), including the impact of a corresponding 10% change in the portion of purchased power used as part of the sale (note the share of the internal generation used to meet the DPLER wholesale sale would not be affected by the 10% change in wholesale prices):

$ in millions	DPL	DP&L
Effect of 10% change in price per MWh	$ 10.1	$ 7.9

RPM Capacity revenues and costs

As a member of PJM, **DP&L** receives revenues from the RTO related to its transmission and generation assets and incurs costs associated with its load obligations for retail customers. PJM, which has a delivery year that runs from June 1 to May 31, has conducted auctions for capacity through the 2017/18 delivery year. The clearing prices for capacity during the PJM delivery periods from 2013/14 through 2017/18 are as follows:

($/MW-day)	PJM Delivery Year				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Capacity clearing price	$ 28	$ 126	$ 136	$ 59	$ 120

Our computed average capacity prices by calendar year are reflected in the table below:

	Calendar Year				
($/MW-day)	**2013**	**2014**	**2015**	**2016**	**2017**
Computed average capacity price	$ 23	$ 85	$ 132	$ 91	$ 95

Future RPM auction results are dependent on a number of factors, which include the overall supply and demand of generation and load, other state legislation or regulation, transmission congestion, and PJM's RPM business rules. The volatility in the RPM capacity auction pricing has had and will continue to have a significant impact on **DPL's** capacity revenues and costs. Although **DP&L** currently has an approved RPM rider in place to recover or repay any excess capacity costs or revenues, the RPM rider only applies to customers supplied under our SSO. Customer switching reduces the number of customers supplied under our SSO, causing more of the RPM capacity costs and revenues to be excluded from the RPM rider calculation.

The table below provides estimates of the effect on annual Net income (net of an estimated income tax of 35%) as of December 31, 2014 of a hypothetical increase or decrease of $10/MW-day in the RPM auction price. The table shows the impact resulting from capacity revenue changes. We did not include the impact of a change in the RPM capacity costs since these costs will either be recovered through the RPM rider for SSO retail customers or recovered through the development of our overall energy pricing for customers who do not fall under the SSO. These estimates include the impact of the RPM rider and are based on the levels of customer switching experienced through December 31, 2014. As of December 31, 2014, approximately 29% of **DP&L's** RPM capacity revenues and costs were recoverable from SSO retail customers through the RPM rider.

$ in millions	DPL	DP&L
Effect of $10/MW-day change in capacity auction pricing	$ 6.4	$ 5.1

Capacity revenues and costs are also impacted by, among other factors, the levels of customer switching, our generation capacity, the levels of wholesale revenues and our retail customer load. In determining the capacity price sensitivity above, we did not consider the impact that may arise from the variability of these other factors.

There are proposals from PJM pending before the FERC that would modify capacity markets including near-term modifications with respect to RPM and longer-term modifications that would phase-out RPM and replace it with a Capacity Performance ("CP") program. The final form of CP program has not been established and the effects on **DP&L** cannot be predicted. In concept, however, the CP program is intended to result in higher capacity prices paid to generators, paired with larger penalties for a generator's failure to perform during periods where electricity is in high demand. Future RPM or CP auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the capacity auctions.

Fuel and purchased power costs

DPL's and **DP&L's** fuel (including coal, gas, oil and emission allowances) and purchased power costs as a percentage of total operating costs in the years ended December 31, 2014, 2013 and 2012 were 42%, 45% and 39%, respectively. We have a significant portion of projected 2015 fuel needs under contract. The majority of our contracted coal is purchased at fixed prices although some contracts provide for periodic pricing adjustments. We may purchase SO_2 allowances for 2015; however, the exact consumption of SO_2 allowances will depend on market prices for power, availability of our generation units and the actual sulfur content of the coal burned. We may purchase some NO_x allowances for 2015 depending on NO_x emissions. Fuel costs are affected by changes in volume and price and are driven by a number of variables including weather, reliability of coal deliveries, scheduled outages and electric generation station mix.

Purchased power costs depend, in part, upon the timing and extent of planned and unplanned outages of our generating capacity as well as requirement to supply an increasing percentage of SSO load through the competitive bid auction. We will purchase power on a discretionary basis when wholesale market conditions provide opportunities to obtain power at a cost below our internal generation costs.

Beginning January 1, 2010, **DP&L** was allowed to recover its fuel and purchased power costs associated with supplying SSO load as part of the fuel rider approved by the PUCO. Since there has been an increase in customer switching, SSO customers currently represent approximately 29% of **DP&L's** total fuel costs. Beginning January 1, 2016, the fuel rider will no longer exist since SSO will at that time be supplied by 100% competitive bid.

The table below provides the effect on annual Net income (net of an estimated income tax at 35%) as of December 31, 2014, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 29% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 29.2	$ 29.5

Interest Rate Risk

As a result of our normal investing and borrowing activities, our financial results are exposed to fluctuations in interest rates, which we manage through our regular financing activities. We maintain both cash on deposit and investments in cash equivalents that may be affected by adverse interest rate fluctuations. **DPL** and **DP&L** have both fixed-rate and variable rate long-term debt. **DPL's** variable-rate debt consists of a $160 million unsecured term loan with a syndicated bank group. The term loan interest rate fluctuates with changes in an underlying interest rate index, typically LIBOR. **DP&L's** variable-rate debt is comprised of $100.0 million of publicly held pollution control bonds. The variable-rate bonds bear interest based on a prevailing rate that is reset weekly based on a comparable market index. Market indexes can be affected by market demand, supply, market interest rates and other economic conditions. See Note 6 of Notes to **DPL's** Consolidated Financial Statements and Note 5 of Notes to **DP&L's** Financial Statements.

We partially hedged against interest rate fluctuations by entering into interest rate swap agreements to limit the interest rate exposure on the underlying financing. These interest rate swap agreements had mandatory settlement dates of September 30, 2013 and were being used to limit our exposure to changes in interest rates and the effect this could have on our future borrowing costs. On September 16, 2013 and immediately after the sale of **DP&L's** new $445 million of First Mortgage Bonds, **DP&L** settled all of the above mentioned swap agreements at a total net settlement of $0. As of December 31, 2014, we do not have any interest rate hedging agreements still in place.

The carrying value of **DPL's** debt was $2,159.7 million at December 31, 2014, consisting of **DPL's** unsecured notes, unsecured term loan, Capital Trust II securities along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. All of **DPL's** debt was adjusted to fair value at the Merger date according to FASC 805. The fair value of this debt at December 31, 2014 was $2,204.8 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DPL's** debt obligations that are sensitive to interest rate changes:

Principal Payments and Interest Rate Detail by Contractual Maturity Date

DPL	Years ending December 31,						Principal amount at December 31,	Fair value at December 31,
$ in millions	2015	2016	2017	2018	2019	Thereafter	2014	2014
Long-term debt								
Variable-rate debt	$ 20.0	$ 40.0	$ 40.0	$ 60.0	$ -	$ 100.0	$ 260.0	$ 260.0
Average interest rate	2.4%	2.4%	2.4%	2.4%	0.0%	0.1%		
Fixed-rate debt	$ 0.1	$ 575.1	$ 0.1	$ 0.1	$ 200.1	$ 1,127.7	1,903.2	1,944.8
Average interest rate	4.2%	2.9%	4.2%	4.2%	6.7%	6.5%		
Total							$ 2,163.2	$ 2,204.8

The carrying value of **DP&L's** debt was $877.1 million at December 31, 2014, consisting of its first mortgage bonds, tax-exempt pollution control bonds and the WPAFB note. The fair value of this debt at December 31, 2014 was $882.5 million, based on current market prices or discounted cash flows using current rates for similar issues with similar terms and remaining maturities. The following table provides information about **DP&L's** debt *obligations that are sensitive to interest rate changes. The* **DP&L** *debt was not revalued using push-down* accounting as a result of the Merger.

Principal Payments and Interest Rate Detail by Contractual Maturity Date

DP&L	Years ending December 31,						Principal amount at December 31,	Fair value at December 31,
$ in millions	2015	2016	2017	2018	2019	Thereafter	2014	2014
Long-term debt								
Variable-rate debt	$ -	$ -	$ -	$ -	$ -	$ 100.0	$ 100.0	$ 100.0
Average interest rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		
Fixed-rate debt	$ 0.1	$ 445.1	$ 0.1	$ 0.1	$ 0.1	$ 332.1	777.6	782.5
Average interest rate	4.2%	1.9%	4.2%	4.2%	4.2%	4.8%		
Total							$ 877.6	$ 882.5

Long-term Debt Interest Rate Risk Sensitivity Analysis

Our estimate of market risk exposure is presented for our fixed-rate and variable-rate debt at December 31, 2014 and 2013 for which an immediate adverse market movement causes a potential material effect on our financial condition, results of operations, or the fair value of the debt. We believe that the adverse market movement represents the hypothetical loss to future earnings and does not represent the maximum possible loss nor any expected actual loss, even under adverse conditions, because actual adverse fluctuations would likely differ. As of December 31, 2014 and 2013, we did not hold any market risk sensitive instruments which were entered into for trading purposes.

Carrying value and fair value of debt with one percent interest rate risk

DPL

$ in millions	*Carrying value at December 31, 2014 (a)*	Fair value at December 31, 2014	*One Percent Interest Rate Risk*	*Carrying value at December 31, 2013 (a)*	Fair value at December 31, 2013	*One Percent Interest Rate Risk*
Long-term debt						
Variable-rate debt	$ 260.0	$ 260.0	$ 2.6	$ 290.0	$ 290.0	$ 2.9
Fixed-rate debt	1,899.7	1,944.8	19.4	2,004.4	2,044.6	20.4
Total	$ 2,159.7	$ 2,204.8	$ 22.0	$ 2,294.4	$ 2,334.6	$ 23.3

(a) Carrying value includes unamortized debt discounts and premiums.

DP&L

$ in millions	Carrying value at December 31, 2014 (a)	Fair value at December 31, 2014	One Percent Interest Rate Risk	Carrying value at December 31, 2013 (a)	Fair value at December 31, 2013	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 100.0	$ 100.0	$ 1.0	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	777.1	782.5	7.8	777.1	759.6	7.6
Total	$ 877.1	$ 882.5	$ 8.8	$ 877.1	$ 859.6	$ 8.6

(a) Carrying value includes unamortized debt discounts and premiums.

DPL's debt is comprised of both fixed-rate debt and variable-rate debt. In regard to fixed rate debt, the interest rate risk with respect to **DPL's** long-term debt primarily relates to the potential impact a decrease of one percentage point in interest rates has on the fair value of **DPL's** $1,944.8 million of fixed-rate debt and not on **DPL's** financial condition or results of operations. On the variable-rate debt, the interest rate risk with respect to **DPL's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DPL's** results of operations related to the fair value of **DPL's** $260.0 million variable-rate long-term debt outstanding as of December 31, 2014.

DP&L's interest rate risk with respect to **DP&L's** long-term debt primarily relates to the potential impact a decrease in interest rates of one percentage point has on the fair value of **DP&L's** $782.5 million of fixed-rate debt and not on **DP&L's** financial condition or **DP&L's** results of operations. On the variable-rate debt, the interest rate risk with respect to **DP&L's** long-term debt represents the potential impact an increase of one percentage point in the interest rate has on **DP&L's** results of operations related to the fair value of **DP&L's** $100.0 million variable-rate long-term debt outstanding as of December 31, 2014.

Equity Price Risk

As of December 31, 2014, approximately 18% of the defined benefit pension plan assets were comprised of investments in equity securities and 82% related to investments in fixed income securities, cash and cash equivalents, and alternative investments. The equity securities are carried at their market value of approximately $65.4 million at December 31, 2014. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $6.5 million reduction in fair value as of December 31, 2014 and approximately a $0.3 million increase to the 2015 pension expense.

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Credit Risk

Credit risk is the risk of an obligor's failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. We limit our credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and continue to evaluate their creditworthiness after transactions have been originated. We use the three leading corporate credit rating agencies and other current market-based qualitative and quantitative data to assess the financial strength of counterparties on an ongoing basis. We may require various forms of credit assurance from counterparties in order to mitigate credit risk.

Goodwill Impairments

During the first quarter of 2014, we performed an interim impairment test on the $135.8 million in goodwill at our DPLER reporting unit. The DPLER reporting unit was identified as being "at risk" during the fourth quarter of 2013. The impairment indicators arose based on market information available regarding actual and proposed sales of competitive retail marketers, which indicated a significant decline in valuations during the first quarter of 2014.

In Step 1 of the interim impairment test, the fair value of the reporting unit was determined to be less than its carrying amount under both the market approach and the income approach using a discounted cash flow valuation model. The significant assumptions included commodity price curves, estimated electricity to be demanded by its customers, changes in its customer base through attrition and expansion, discount rates, the assumed tax structure and the level of working capital required to run the business.

During the second quarter of 2014, we finalized the work to determine the implied fair value for the DPLER reporting unit. There were no further adjustments to the full impairment of $135.8 million recognized in the first quarter.

In the fourth quarter of 2013, **DPL** completed its annual October 1 goodwill impairment tests and recognized goodwill impairment expense of $306.3 million. The Company identified both the **DP&L** and DPLER reporting units as "at risk." A reporting unit is considered "at risk" when its fair value is not higher than its carrying amount by more than 10%. The Company monitors its reporting units at risk of step 1 failure on an ongoing basis. Since 2012, the **DP&L** reporting unit had been considered at risk subsequent to its goodwill impairments of $1,817.2 million recognized in 2012 and $306.3 million recognized in 2013. At December 31, 2014, goodwill at the **DP&L** reporting is not considered at risk. It is possible that we may incur goodwill impairment at the **DP&L** reporting unit in future periods if adverse changes in its business or operating environment occur. As of December 31, 2014, the DP&L reporting unit had goodwill of $317.0 million and the DPLER reporting unit had no goodwill.

See Note 5 of Notes to **DPL's** Consolidated Financial Statements for more information on the impairment of Goodwill.

Critical Accounting Estimates

DPL's Consolidated Financial Statements and **DP&L's** Financial Statements are prepared in accordance with GAAP. In connection with the preparation of these financial statements, our management is required to make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the related disclosure of contingent liabilities. These assumptions, estimates and judgments are based on our historical experience and assumptions that we believe to be reasonable at the time. However, because future events and their effects cannot be determined with certainty, the determination of estimates requires the exercise of judgment. Our critical accounting estimates are those which require assumptions to be made about matters that are highly uncertain.

Different estimates could have a material effect on our financial results. Judgments and uncertainties affecting the application of these policies and estimates may result in materially different amounts being reported under different conditions or circumstances. Historically, however, recorded estimates have not differed materially from actual results. Significant items subject to such judgments include: the carrying value of property, plant and equipment; the valuation of goodwill; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

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Impairments

In accordance with the provisions of GAAP relating to the accounting for goodwill, goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions; operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass its effect to customers; negative or declining cash flows; loss of a key contract or customer particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. See Note 5 of Notes to **DPL's** Consolidated Financial Statements discussing the impairment of goodwill at **DPL** in 2014, 2013 and 2012.

In accordance with the provisions of GAAP relating to the accounting for impairments, long-lived assets to be held and used are reviewed for impairment whenever events or circumstances indicate that the carrying amount may not be recoverable. When required, impairment losses on assets to be held and used are recognized based on the fair value of the asset. We determine the fair value of these assets based upon estimates of future cash flows, market value of similar assets, if available, or independent appraisals, if required. In analyzing the fair value and recoverability using future cash flows, we make projections based on a number of assumptions and estimates of growth rates, future economic conditions, assignment of discount rates and estimates of terminal values. An impairment loss is recognized if the carrying amount of the long-lived asset is not recoverable from its undiscounted cash flows. The measurement of impairment loss is the difference between the carrying amount and fair value of the asset. See Note 15 of Notes to Notes to **DPL's** Consolidated Financial Statements and Note 13 of Notes to **DP&L's** Financial Statements discussing the impairment of long-lived assets in 2014 and 2013.

Revenue Recognition (including Unbilled Revenue)

We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. The determination of the energy sales to customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. We recognize revenues using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, projected line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Given our estimation method and the fact that customers are billed monthly, we believe it is unlikely that materially different results will occur in future periods when these amounts are subsequently billed.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since taxing authorities may interpret them differently. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to Net income and cash flows and adjustments to tax-related assets and liabilities could be material. We have adopted the provisions of GAAP relating to the accounting for uncertainty in income taxes. Taking into consideration the uncertainty and judgment involved in the determination and filing of income taxes, these GAAP provisions establish standards for recognition and measurement in financial statements of positions taken, or expected to be taken, by an entity on its income tax returns. Positions taken by an entity on its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Deferred income tax assets and liabilities represent future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets.

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Regulatory Assets and Liabilities

Application of the provisions of GAAP relating to regulatory accounting requires us to reflect the effect of rate regulation in **DPL's** Consolidated Financial Statements and **DP&L's** Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, we defer these costs as Regulatory assets that otherwise would be expensed by nonregulated companies. Likewise, we recognize Regulatory liabilities when it is probable that regulators will require customer refunds through future rates and when revenue is collected from customers for expenses that are not yet incurred. Regulatory assets are amortized into expense and Regulatory liabilities are amortized into income over the recovery period authorized by the regulator.

We evaluate our Regulatory assets to determine whether or not they are probable of recovery through future rates and make various assumptions in our analyses. The expectations of future recovery are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period the assessment is made. We currently believe the recovery of our Regulatory assets is probable. See Note 3 of Notes to **DPL's** Consolidated Financial Statements and Note 3 of Notes to **DP&L's** Financial Statements.

AROs

In accordance with the provisions of GAAP relating to the accounting for AROs, legal obligations associated with the retirement of long-lived assets are required to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. These GAAP provisions also require that components of previously recorded depreciation related to the cost of removal of assets upon future retirement, whether legal AROs or not, must be removed from a company's accumulated depreciation reserve and be reclassified as a regulatory liability. We make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities and expenses as they relate to AROs. These assumptions and estimates are based on historical experience and assumptions that we believe to be reasonable at the time.

Insurance and Claims Costs

In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL,** provides insurance coverage solely to us, our subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017 and may or may not be renewed at that time. Insurance and Claims Costs on **DPL's** Consolidated Balance Sheets include estimated liabilities for insurance and claims costs of approximately $6.4 million and $6.7 million at December 31, 2014 and 2013, respectively. Furthermore, **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, **DP&L** has estimated liabilities for medical, life and disability claims costs below certain coverage thresholds of third-party providers. **DPL** and **DP&L** had recorded these additional insurance and claims liabilities of approximately $15.6 million and $18.8 million for 2014 and 2013, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for MVIC at **DPL** and the estimated liabilities for workers' compensation, medical, life and disability claims at **DP&L** are actuarially determined using certain assumptions. There is uncertainty associated with the loss estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

Pension and Postretirement Benefits

We account for and disclose pension and postemployment benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postemployment plans. These GAAP provisions require the use of assumptions, such as the discount rate for liabilities and long-term rate of return on assets, in determining the obligations, annual cost, and funding requirements of the plans.

For 2015, we are decreasing our long-term rate of asset return assumption to 6.50% from 6.75% for pension plan assets. In addition, we are decreasing our long-term rate of asset return assumption to 4.50% from 6.00% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes and will impact the expense determination starting in 2015. Also, for 2015, we have decreased our assumed discount rate to 4.02% from 4.86% for pension and to 3.71% from 4.58% for postemployment benefits expense to reflect current duration-based yield curve discount rates.

A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2015 pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.5 million to 2015 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.8 million to 2015 pension expense.

In future periods, differences in the actual return on pension and other post-employment benefit plan assets and assumed return, or changes in the discount rate, will affect the timing of contributions, if any to the plans. We provide postemployment health care benefits to employees who retired prior to 1987. A one percentage point change in the assumed health care cost trend rate would affect postemployment benefit costs by less than $1.0 million.

Contingent and Other Obligations
During the conduct of our business, we are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject us to environmental, litigation, insurance and other risks. We periodically evaluate our exposure to such risks and record estimated liabilities for those matters where a loss is considered probable and reasonably estimable in accordance with GAAP. In recording such estimated liabilities, we may make assumptions, estimates and judgments that affect the reported amounts of assets, liabilities and expenses as they relate to contingent and other obligations. These assumptions and estimates are based on historical experience and assumptions and may be subject to change. We, however, believe such estimates and assumptions are reasonable.

LEGAL AND OTHER MATTERS

A discussion of LEGAL AND OTHER MATTERS is described in Note 13 of Notes to **DPL's** Consolidated Financial Statements and Note 12 of Notes to **DP&L's** Financial Statements. A discussion of environmental matters and competition and regulation matters affecting both **DPL** and **DP&L** is described in Item 1 – Environmental Considerations and Item 1 – Competition and Regulation. Such discussions are incorporated by reference in this Management's Discussion and Analysis of Financial Condition and Results of Operations and made a part hereof.

Recently Issued Accounting Pronouncements
A discussion of recently issued accounting pronouncements is described in Note 1 of Notes to **DPL's** Consolidated Financial Statements and Note 1 of Notes to **DP&L's** Financial Statements and such discussion is incorporated by reference in this Management's Discussion and Analysis of Financial Condition and Results of Operations and made a part hereof.

Item 7A – Quantitative and Qualitative Disclosures about Market Risk

The information required by this item of Form 10-K is set forth in the Market Risk section under Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 8 – Financial Statements and Supplementary Data

This report includes the combined filing of **DPL** and **DP&L**. Throughout this report, the terms "we," "us," "our" and "ours" are used to refer to both **DPL** and **DP&L**, respectively and altogether, unless the context indicates otherwise. Discussions or areas of this report that apply only to **DPL** or **DP&L** will clearly be noted in the section.

FINANCIAL STATEMENTS

DPL INC.

Report of Independent Registered Public Accounting Firm

To the Board of Directors of DPL Inc.

We have audited the accompanying consolidated balance sheets of DPL Inc. as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income/(loss), cash flows, and shareholder's equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule "Schedule II – Valuation and Qualifying Accounts" for each of the three years in the period ended December 31, 2014. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of DPL Inc. at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
February 25, 2015
Indianapolis, Indiana

DPL INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

$ in millions	Year ended December 31, 2014	2013	2012
Revenues	$ 1,763.0	$ 1,636.9	$ 1,668.4
Cost of revenues:			
Fuel	304.5	366.7	361.9
Purchased power	592.6	389.0	342.1
Amortization of intangibles	1.2	7.1	95.1
Total cost of revenues	898.3	762.8	799.1
Gross margin	864.7	874.1	869.3
Operating expenses:			
Operation and maintenance	388.3	396.7	406.4
Depreciation and amortization	139.8	132.9	125.4
General taxes	91.7	80.9	79.5
Goodwill impairment	135.8	306.3	1,817.2
Fixed asset impairment	11.5	26.2	-
Other	(3.9)	2.5	0.2
Total operating expenses	763.2	945.5	2,428.7
Operating income / (loss)	101.5	(71.4)	(1,559.4)
Other income / (expense), net			
Investment income	0.9	1.4	2.5
Interest expense	(126.6)	(124.0)	(122.9)
Charge for early redemption of debt	(30.9)	(2.8)	-
Other deductions	(1.5)	(2.9)	(2.3)
Total other expense, net	(158.1)	(128.3)	(122.7)
Earnings (loss) from operations before income tax	(56.6)	(199.7)	(1,682.1)
Income tax expense	18.0	22.3	47.7
Net loss	$ (74.6)	$ (222.0)	$ (1,729.8)

See Notes to Consolidated Financial Statements.

DPL INC.
STATEMENTS OF COMPREHENSIVE LOSS

$ in millions	Year ended December 31, 2014	2013	2012
Net loss	$ (74.6)	$ (222.0)	$ (1,729.8)
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.2, $0.6 and $(0.2) for each respective period	(0.3)	(1.2)	0.5
Reclassification to earnings, net of income tax benefit / (expense) of $(0.2), $(0.7) and $0.0 for each respective period	0.2	1.4	(0.1)
Total change in fair value of available-for-sale	(0.1)	0.2	0.4
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of $10.3, $(10.6) and $1.4 for each respective period	(19.0)	19.7	(1.5)
Reclassification to earnings, net of income tax benefit / (expense) of $(9.5), $(2.3) and $0.4 for each respective period	16.9	3.4	(0.5)
Total change in fair value of derivatives	(2.1)	23.1	(2.0)
Pension and postretirement activity:			
Net loss for the period, net of income tax benefit / (expense) of $8.3, $(2.7) and $1.0 for each respective period	(14.9)	4.9	(1.9)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, $0.3 and $0.0 for each respective period	-	0.3	-
Total change in unfunded pension and postretirement	(14.9)	5.2	(1.9)
Other comprehensive income / (loss)	(17.1)	28.5	(3.5)
Net comprehensive loss	$ (91.7)	$ (193.5)	$ (1,733.3)

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions	Year ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net loss	$ (74.6)	$ (222.0)	$ (1,729.8)
Adjustments to reconcile Net loss to Net cash from operating activities			
Depreciation and amortization	139.8	132.9	125.4
Amortization of intangibles	1.2	7.1	95.1
Amortization of debt market value adjustments	0.3	(14.4)	(19.0)
Deferred income taxes	17.7	24.0	(4.2)
Charge for early redemption of debt	30.9	2.8	-
Goodwill impairment	135.8	306.3	1,817.2
Fixed asset impairment	11.5	26.2	-
Loss / (Gain) on asset disposal	(3.9)	2.5	0.2
Recognition of deferred SECA revenue	-	-	(17.8)
Changes in certain assets and liabilities:			
Accounts receivable	0.5	7.4	13.4
Inventories	(24.9)	27.4	15.6
Prepaid taxes	(0.9)	0.7	-
Taxes applicable to subsequent years	(7.1)	(1.4)	7.2
Deferred regulatory costs, net	5.4	7.6	(1.1)
Accounts payable	32.1	(5.8)	(16.2)
Accrued taxes payable	20.7	(5.5)	5.1
Accrued interest payable	(1.3)	(3.3)	1.5
Other current and deferred liabilities	(40.6)	1.5	(18.6)
Pension, retiree and other benefits	19.1	1.8	28.5
Unamortized investment tax credit	(0.5)	(0.5)	(0.3)
Insurance and claims costs	(0.2)	(4.8)	(2.8)
Other	(16.9)	12.3	(7.9)
Net cash from operating activities	244.1	302.8	291.5
Cash flows from investing activities:			
Capital expenditures	(118.1)	(124.4)	(198.1)
Proceeds from sale of property	10.7	0.8	1.1
Insurance proceeds	0.3	7.6	-
Purchase of renewable energy credits	(3.5)	(3.9)	(5.4)
Decrease / (increase) in restricted cash	(3.3)	(2.8)	2.9
Other investing activities, net	1.3	(1.2)	0.3
Net cash from investing activities	(112.6)	(123.9)	(199.2)

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

$ in millions	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012
Cash flows from financing activities:			
Deferred financing costs	**(3.6)**	(15.3)	(0.8)
Retirement of debt	**(335.0)**	(945.1)	(0.1)
Premium paid for early redemption of debt	**(29.1)**	(2.4)	-
Issuance of long-term debt	**200.0**	645.0	-
Borrowings from revolving credit facilities	**190.0**	50.0	-
Repayment of borrowings from revolving credit facilities	**(190.0)**	(50.0)	-
Dividends paid on common stock	**-**	-	(64.1)
Contributions of additional paid-in capital from parent	**-**	-	0.3
Payment to former warrant holders	**-**	-	(9.0)
Net cash from financing activities	**(167.7)**	(317.8)	(73.7)
Cash and cash equivalents:			
Net change	**(36.2)**	(138.9)	18.6
Balance at beginning of period	**53.2**	192.1	173.5
Cash and cash equivalents at end of period	**$ 17.0**	$ 53.2	$ 192.1
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	**$ 117.3**	$ 137.5	$ 136.9
Income taxes (refunded) / paid, net	**$ 0.7**	$ (5.2)	$ 47.6
Non-cash financing and investing activities:			
Accruals for capital expenditures	**$ 16.3**	$ 14.7	$ 16.7

See Notes to Consolidated Financial Statements.

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DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 17.0	$ 53.2
Restricted cash	16.8	13.5
Accounts receivable, net (Note 2)	200.9	203.3
Inventories (Note 2)	100.2	82.7
Taxes applicable to subsequent years	77.8	70.6
Regulatory assets, current (Note 3)	44.2	20.8
Other prepayments and current assets	41.8	35.1
Total current assets	498.7	479.2
Property, plant and equipment:		
Property, plant and equipment	2,759.3	2,677.0
Less: Accumulated depreciation and amortization	(318.4)	(206.7)
	2,440.9	2,470.3
Construction work in process	76.7	63.9
Total net property, plant and equipment	2,517.6	2,534.2
Other non-current assets:		
Regulatory assets, non-current (Note 3)	167.5	159.7
Goodwill (Note 5)	317.0	452.8
Intangible assets, net of amortization (Note 5)	37.4	42.8
Other deferred assets	39.6	52.8
Total other non-current assets	561.5	708.1
Total Assets	$ 3,577.8	$ 3,721.5

See Notes to Consolidated Financial Statements.

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DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	December 31, 2014	December 31, 2013
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 6)	$ 20.1	$ 10.2
Accounts payable	109.2	78.2
Accrued taxes	102.6	89.4
Accrued interest	27.2	28.5
Customer security deposits	14.4	13.9
Regulatory liabilities, current (Note 3)	4.4	-
Insurance and claims costs	6.4	6.7
Other current liabilities	48.7	64.2
Total current liabilities	333.0	291.1
Non-current liabilities:		
Long-term debt (Note 6)	2,139.6	2,284.2
Deferred taxes (Note 7)	587.3	564.3
Taxes payable	80.9	79.1
Regulatory liabilities, non-current (Note 3)	124.1	121.1
Pension, retiree and other benefits (Note 8)	95.9	51.6
Unamortized investment tax credit	2.2	2.8
Other deferred credits	48.2	69.4
Total non-current liabilities	3,078.2	3,172.5
Redeemable preferred stock of subsidiary (Note 11)	18.4	18.4
Commitments and contingencies (Note 13)		
Common shareholder's equity:		
Common stock:		
1,500 shares authorized; 1 share issued and outstanding at December 31, 2014 and 2013	-	-
Other paid-in capital	2,237.4	2,237.0
Accumulated other comprehensive income	7.5	24.6
Retained earnings / (deficit)	(2,096.7)	(2,022.1)
Total common shareholder's equity	148.2	239.5
Total Liabilities and Shareholder's Equity	$ 3,577.8	$ 3,721.5

See Notes to Consolidated Financial Statements.

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DPL INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

$ in millions (except Outstanding Shares)	Common Stock [a] Outstanding Shares	Common Stock [a] Amount	Other Paid-in Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings/ (Deficit)	Total
Year ended December 31, 2012						
Beginning balance $	1	-	2,237.3	(0.4)	(6.2)	2,230.7
Total comprehensive income (loss)				(3.5)	(1,729.8)	(1,733.3)
Common stock dividends [a]					(70.0)	(70.0)
Other			(0.6)			(0.6)
Ending balance	1		2,236.7	(3.9)	(1,806.0)	426.8
Year ended December 31, 2013						
Total comprehensive income (loss) $				28.5	(222.0)	(193.5)
Other [b]			0.3		5.9	6.2
Ending balance	1		2,237.0	24.6	(2,022.1)	239.5
Year ended December 31, 2014						
Total comprehensive income (loss)				(17.1)	(74.6)	(91.7)
Other			0.4		-	0.4
Ending balance $	1	$ -	$ 2,237.4	$ 7.5	$ (2,096.7)	$ 148.2

(a) 1,500 shares authorized

(b) $5.9 million of dividends declared in 2012 were reversed in 2013.

See Notes to Consolidated Financial Statements.

DPL Inc.
Notes to Consolidated Financial Statements
For the years ended December 31, 2014, 2013 and 2012

NOTE 1– OVERVIEW AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Business

DPL is a diversified regional energy company organized in 1985 under the laws of Ohio. **DPL's** two reportable segments are the Utility segment, comprised of its **DP&L** subsidiary, and the Competitive Retail segment, comprised of its DPLER subsidiary. See Note 14 for more information relating to these reportable segments. The terms "we," "us," "our" and "ours" are used to refer to **DPL** and its subsidiaries.

On November 28, 2011, **DPL** was acquired by AES in the Merger and **DPL** became a wholly-owned subsidiary of AES. Following the merger of **DPL** and Dolphin Subsidiary II, Inc., **DPL** became an indirectly wholly-owned subsidiary of AES.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail service are still regulated. **DP&L** has the exclusive right to provide such service to its approximately 516,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplies 100% of the generation for SSO customers and by January 2016, SSO will be 100% competitively bid. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. Comments and reply comments were filed. **DP&L** amended its application on February 25, 2014 and again on May 23, 2014. Additional comments and reply comments were filed. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014 the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation including transfer into a new unregulated affiliate of **DPL** or through a sale.

DPLER sells competitive retail electric service, under contract, to residential, commercial and industrial customers. DPLER's operations include those of its wholly-owned subsidiary MC Squared. DPLER has approximately 260,000 customers currently located throughout Ohio and Illinois. Approximately 131,000 of DPLER's customers are also electric distribution customers of **DP&L**. DPLER does not own any transmission or generation assets, and purchases all of its electric energy from **DP&L** to meet its sales obligations. DPLER's sales reflect the general economic conditions and seasonal weather patterns of the area.

DPL's other significant subsidiaries include DPLE, which owns and operates peaking generating facilities from which it makes wholesale sales of electricity and MVIC, our captive insurance company that provides insurance services to us and our other subsidiaries. All of **DPL's** subsidiaries are wholly-owned.

DPL also has a wholly-owned business trust, DPL Capital Trust II, formed for the purpose of issuing trust capital securities to investors.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DPL and its subsidiaries employed 1,182 people as of December 31, 2014, of which 1,130 were employed by **DP&L**. Approximately 61% of all **DPL** employees are under a collective bargaining agreement which expires on October 31, 2017.

Financial Statement Presentation

We prepare Consolidated Financial Statements for **DPL**. **DPL's** Consolidated Financial Statements include the accounts of **DPL** and its wholly-owned subsidiaries except for DPL Capital Trust II which is not consolidated, consistent with the provisions of GAAP. **DP&L's** undivided ownership interests in certain coal-fired generating stations are included in the financial statements at amortized cost, which was adjusted to fair value at the Merger date. Operating revenues and expenses are included on a pro rata basis in the corresponding lines in the Consolidated Statement of Operations. See Note 4 for more information.

Certain immaterial amounts from prior periods have been reclassified to conform to the current period presentation.

All material intercompany accounts and transactions are eliminated in consolidation.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; the valuation of goodwill; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; assets and liabilities related to employee benefits; goodwill; and intangibles.

Valuation of Goodwill

FASC 350, "Intangibles – Goodwill and Other", requires that goodwill be tested for impairment at the reporting unit level at least annually or more frequently if impairment indicators are present. In evaluating the potential impairment of goodwill, we make estimates and assumptions about revenue, operating cash flows, capital expenditures, growth rates and discount rates based on our budgets and long term forecasts, macroeconomic projections, and current market expectations of returns on similar assets. There are inherent uncertainties related to these factors and management's judgment in applying these factors. Generally, the fair value of a reporting unit is determined using a discounted cash flow valuation model. We could be required to evaluate the potential impairment of goodwill outside of the required annual assessment process if we experience situations, including but not limited to: deterioration in general economic conditions; operating or regulatory environment; increased competitive environment; increase in fuel costs particularly when we are unable to pass its effect to customers; negative or declining cash flows; loss of a key contract or customer particularly when we are unable to replace it on equally favorable terms; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. See Note 5 for information regarding the impairments of goodwill in 2014, 2013 and 2012.

Revenue Recognition

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. Energy sales to customers are based on the reading of their meters that occurs on a systematic basis throughout the month. We recognize the revenues on our statements of operations using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, estimated line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class.

All of the power produced at the generation stations is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. The power sales and purchases within **DP&L's** service territory are reported on a net hourly basis as revenues or purchased power on our Statements of Operations. We record expenses when purchased electricity is received and when expenses are incurred, with the exception of the ineffective portion of certain power purchase contracts that are derivatives and qualify for hedge accounting. We also have certain derivative contracts that do not qualify for hedge accounting, and their unrealized gains or losses are recorded prior to the receipt of electricity.

Allowance for Uncollectible Accounts

We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collections efforts have been exhausted.

Sale of Receivables

DPLER and its subsidiary MC Squared sell receivables from their customers. These sales are at face value for cash at the billed amounts for their customers' use of energy. Total receivables sold during the years ended December 31, 2014 and 2013 were $125.6 million and $96.1 million, respectively.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held stations as an asset in property, plant and equipment. New property, plant and equipment additions are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $1.5 million, $1.5 million and $4.0 million in the years ended December 31, 2014, 2013 and 2012, respectively.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Repairs and Maintenance

Costs associated with maintenance activities, primarily power station outages, are recognized at the time the work is performed. These costs, which include labor, materials and supplies, and outside services required to maintain equipment and facilities, are capitalized or expensed based on defined units of property.

Depreciation – Changes in Estimates

Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For **DPL's** generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates.

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at certain generating stations. See Note 15 for more information. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator.

For **DPL's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 5.3% in 2014, 5.8% in 2013 and 4.8% in 2012.

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2014 and 2013:

	December 31,			
$ in millions	**2014**	**Composite Rate**	2013	Composite Rate
Regulated:				
Transmission	$ 227.5	4.1%	$ 213.1	4.1%
Distribution	**1,011.7**	**5.4%**	970.1	5.6%
General	62.5	12.4%	56.8	12.1%
Non-depreciable	**61.6**	**N/A**	60.8	N/A
Total regulated	1,363.3		1,300.8	
Unregulated:				
Production / Generation	1,354.9	5.4%	1,340.8	6.2%
Other	**21.3**	**8.1%**	15.7	8.9%
Non-depreciable	19.8	N/A	19.7	N/A
Total unregulated	1,396.0		1,376.2	
Total property, plant and equipment in service	$ 2,759.3	5.3%	$ 2,677.0	5.8%

AROs

We recognize AROs in accordance with GAAP which requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the related asset. Our legal obligations associated with the retirement of our long-lived assets consists primarily of river intake and discharge structures, coal unloading facilities, loading docks, ice breakers and ash disposal facilities. Our generation AROs are recorded within Other deferred credits on the consolidated balance sheets.

Estimating the amount and timing of future expenditures of this type requires significant judgment. Management routinely updates these estimates as additional information becomes available.

Changes in the Liability for Generation AROs

$ in millions		
Balance at December 31, 2012	$	23.9
Calendar 2013		
Accretion expense		0.8
Settlements		(0.3)
Balance at December 31, 2013		24.4
Calendar 2014		
Additions		3.6
Accretion expense		0.9
Settlements		(2.0)
Balance at December 31, 2014	$	26.9

Asset Removal Costs

We continue to record costs of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $119.3 million and $115.0 million in estimated costs of removal at December 31, 2014 and 2013, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2012	$	112.1
Calendar 2013		
Additions		22.0
Settlements		(19.1)
Balance at December 31, 2013		115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014	$	119.3

Regulatory Accounting
As a regulated utility, we apply the provisions of FASC 980 *"Regulated Operations,"* which gives recognition to the ratemaking and accounting practices of the PUCO and the FERC. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory assets can also represent performance incentives permitted by the regulator. Regulatory assets have been included as allowable costs for ratemaking purposes, as authorized by the PUCO or established regulatory practices. Regulatory liabilities generally represent obligations to make refunds or future rate reductions to customers for previous over collections or the deferral of revenues collected for costs that **DPL** expects to incur in the future.

The deferral of costs (as regulatory assets) is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the PUCO or FERC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings. Our regulatory assets and liabilities have been created pursuant to a specific order of the PUCO or FERC or established regulatory practices, such as other utilities under the jurisdiction of the PUCO or FERC being granted recovery of similar costs. It is probable, but not certain, that these regulatory assets will be recoverable, subject to PUCO or FERC approval. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 3 for more information about Regulatory Assets and Liabilities.

Inventories
Inventories are carried at average cost and include coal, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations.

Intangibles
Intangibles include emission allowances, renewable energy credits, customer relationships, customer contracts and trademark/trade name. Emission allowances are carried on a first-in, first-out (FIFO) basis for purchased emission allowances. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized.

Customer relationships recognized as part of the purchase accounting are amortized over nine to fifteen years and customer contracts are amortized over the average length of the contracts. Emission allowances are amortized as they are used in our operations on a FIFO basis. Renewable energy credits are amortized as they are used or retired. Trademark/trade name have an indefinite life and accordingly are not amortized. See Note 5 for additional information.

Income Taxes
Income taxes are accounted in accordance with FASC 740, "Income Taxes", which requires an asset and liability approach for financial accounting and reporting of income taxes with tax effects of differences, based on currently enacted income tax rates, between the financial reporting and tax basis of accounting reported as deferred tax assets or liabilities in the balance sheets. Valuation allowances are provided against deferred tax assets unless it is more likely than not that the asset will be realized.

Investment tax credits, which have been used to reduce federal income taxes payable, are deferred for financial reporting purposes and are amortized over the useful lives of the property to which they relate. For rate-regulated operations, additional deferred income taxes and offsetting regulatory assets or liabilities are recorded to recognize that income taxes will be recoverable or refundable through future revenues.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. The consolidated tax liability is allocated to each subsidiary based on the separate return method which is specified in our tax allocation agreement and which provides a consistent, systematic and rational approach. See Note 7 for additional information.

Financial Instruments
We classify our investments in debt and equity financial instruments of publicly traded entities into different categories: held-to-maturity and available-for-sale. Available-for-sale securities are carried at fair value and unrealized gains and losses on those securities, net of deferred income taxes, are presented as a separate component of shareholders' equity. Other than temporary declines in value are recognized currently in earnings. Financial instruments classified as held-to-maturity are carried at amortized cost. The cost basis for public equity security and fixed maturity investments is average cost and amortized cost, respectively.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities
DP&L collects certain excise taxes levied by state or local governments from its customers. **DP&L's** excise taxes and certain other taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations. The amounts for the years ended December 31, 2014, 2013 and 2012, were $50.8 million, $50.5 million and $50.5 million, respectively.

Cash and Cash Equivalents
Cash and cash equivalents are stated at cost, which approximates fair value. All highly liquid short-term investments with original maturities of three months or less are considered cash equivalents.

Restricted Cash
Restricted cash includes cash which is restricted as to withdrawal or usage. The nature of the restrictions include restrictions imposed by agreements related to deposits held as collateral.

Financial Derivatives
All derivatives are recognized as either assets or liabilities in the balance sheets and are measured at fair value. Changes in the fair value are recorded in earnings unless the derivative is designated as a cash flow hedge of a forecasted transaction or it qualifies for the normal purchases and sales exception.

We use forward contracts to reduce our exposure to changes in energy and commodity prices and as a hedge against the risk of changes in cash flows associated with expected electricity purchases. These purchases are used to hedge our full load requirements. We also hold forward sales contracts that hedge against the risk of changes in cash flows associated with power sales during periods of projected generation facility availability. We use cash flow hedge accounting when the hedge or a portion of the hedge is deemed to be highly effective, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. We have elected not to offset net derivative positions in the financial statements. Accordingly, we do not offset such derivative positions against the fair value of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral under master netting agreements. See Note 10 for additional information.

Insurance and Claims Costs
In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL,** provides insurance coverage solely to us, our subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017 and may or may not be renewed at that time. **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, **DP&L** has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $15.6 million and $18.8 million at December 31, 2014 and 2013, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for workers' compensation, medical, life and disability costs at **DP&L** are actuarially determined using certain assumptions. There is uncertainty associated with these loss

estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

Pension and Postretirement Benefits
We account for and disclose pension and postemployment benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postemployment plans. These GAAP provisions require the use of assumptions, such as the discount rate for liabilities and long-term rate of return on assets, in determining the obligations, annual cost, and funding requirements of the plans.

Related Party Transactions
In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations. This includes ensuring that the regulated utilities served, including **DP&L**, are not subsidizing costs incurred for the benefit of non-regulated businesses.

The following table provides a summary of these transactions:

$ in millions	**For the year ended December 31, 2014**	For the year ended December 31, 2013
Transactions with the Service Company		
Charges for services provided	**$ 35.8**	$ -
Charges to the Service Company	**$ 0.1**	$ -

Transactions with the Service Company:	**At December 31, 2014**	At December 31, 2013
Net payable to the Service Company	**$ (4.7)**	$ -

DPL Capital Trust II
DPL has a wholly-owned business trust, DPL Capital Trust II (the Trust), formed for the purpose of issuing trust capital securities to third-party investors. Effective in 2003, **DPL** deconsolidated the Trust upon adoption of the accounting standards related to variable interest entities and currently treats the Trust as a nonconsolidated subsidiary. The Trust holds mandatorily redeemable trust capital securities. The investment in the Trust, which amounts to $0.3 million and $0.4 million at December 31, 2014 and 2013, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $14.9 million at December 31, 2014 and 2013, respectively that was established upon the Trust's deconsolidation in 2003. See Note 6 for additional information.

In addition to the obligations under the note payable mentioned above, **DPL** also agreed to a security obligation which represents a full and unconditional guarantee of payments to the capital security holders of the Trust.

Recently Adopted Accounting Standards

Discontinued Operations
The FASB recently issued ASU 2014-08 "Presentation of Financial Statements" (Topic 205) and "Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity" effective for annual and interim periods beginning after December 15, 2014. ASU 2014-08 updates the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have (or will have) a major effect on an entity's operations and financial results. In addition, an entity is required to expand disclosures for discontinued operations by providing more information about the assets, liabilities, revenues and expenses of discontinued operations both on the face of the financial statements and in the Notes. For the disposal of an individually significant component of an entity that does not qualify for discontinued operations reporting, an entity is required to disclose the pretax profit or loss of the component in the Notes. Our early adoption of ASU No. 2014-008 in the third quarter of 2014 did not have any impact on our overall results of operations, financial position or cash flows.

Recently Issued Accounting Standards

Going Concern

The FASB recently issued ASU 2014-15 "Presentation of Financial Statements – Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern)" effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. There are required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity's ability to continue as a going concern (before consideration of management's plans), management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, and management's plans that alleviated substantial doubt about the entity's ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

Revenue from Contracts with Customers

The FASB recently issued ASU 2014-09 "Revenue from Contracts with Customers" (Topic 606) effective for annual and interim periods beginning after December 15, 2016; with retrospective application. The core principle of the ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Because the guidance in this update is principles-based, it can be applied to all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Additionally, the guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. We have not yet determined the extent, if any, to which our overall results of operations, financial position or cash flows may be affected by the implementation of this ASU.

NOTE 2 – SUPPLEMENTAL FINANCIAL INFORMATION

	December 31,	
$ in millions	**2014**	2013
Accounts receivable, net		
Unbilled revenue	**$ 79.2**	$ 77.8
Customer receivables	**104.8**	102.7
Amounts due from partners in jointly-owned stations	**14.2**	15.8
Other	**4.0**	8.2
Provisions for uncollectible accounts	**(1.3)**	(1.2)
Total accounts receivable, net	**$ 200.9**	$ 203.3
Inventories		
Fuel and limestone	**$ 65.3**	$ 42.7
Plant materials and supplies	**33.5**	38.2
Other	**1.4**	1.8
Total inventories, at average cost	**$ 100.2**	$ 82.7

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Accumulated Other Comprehensive Income / (Loss)

The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2014, 2013 and 2012 are as follows:

Details about Accumulated Other Comprehensive Income / (Loss) Components	**Affected line item in the Consolidated Statements of Operations**	**Years ended December 31,**		
$ in millions		**2014**	*2013*	*2012*
Gains and losses on Available-for-sale securities activity (Note 9):				
	Other income / (deductions)	$ **0.4**	$ 2.1	$ (0.1)
	Total before income taxes	**0.4**	2.1	(0.1)
	Tax expense	**(0.2)**	(0.7)	-
	Net of income taxes	**0.2**	1.4	(0.1)
Gains and losses on cash flow hedges (Note 10):				
	Interest Expense	**(1.3)**	-	0.2
	Revenue	**28.4**	2.2	(0.1)
	Purchased power	**(0.7)**	3.5	(1.1)
	Total before income taxes	**26.4**	5.7	(1.0)
	Tax expense	**(9.5)**	(2.3)	0.5
	Net of income taxes	**16.9**	3.4	(0.5)
Amortization of defined benefit pension items (Note 8):				
	Tax benefit	**-**	0.3	-
	Net of income taxes	**-**	0.3	-
Total reclassifications for the period, net of income taxes		$ **17.1**	$ 5.1	$ (0.6)

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The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2014 and 2013 are as follows:

$ in millions	Gains / (losses) on available-for-sale securities	Gains / (losses) on cash flow hedges	Change in unfunded pension obligation	Total
Balance January 1, 2013	$ 0.4	$ (2.5)	$ (1.8)	$ (3.9)
Other comprehensive income / (loss) before reclassifications	(1.2)	19.7	4.9	23.4
Amounts reclassified from accumulated other comprehensive income / (loss)	1.4	3.4	0.3	5.1
Net current period other comprehensive income	0.2	23.1	5.2	28.5
Balance December 31, 2013	0.6	20.6	3.4	24.6
Other comprehensive loss before reclassifications	**(0.3)**	**(19.0)**	**(14.9)**	**(34.2)**
Amounts reclassified from accumulated other comprehensive income / (loss)	**0.2**	**16.9**	**-**	**17.1**
Net current period other comprehensive loss	**(0.1)**	**(2.1)**	**(14.9)**	**(17.1)**
Balance December 31, 2014	$ 0.5	$ 18.5	$ (11.5)	$ 7.5

NOTE 3 – REGULATORY MATTERS

In accordance with FASC 980, we have recognized total regulatory assets of $211.7 million and $180.5 million as of December 31, 2014 and 2013 and total regulatory liabilities of $128.5 million and $121.1 million as of December 31, 2014 and 2013. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 for accounting policies regarding Regulatory Assets and Liabilities.

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The following table presents **DPL's** Regulatory assets and liabilities:

$ in millions	Type of Recovery [a]	Amortization Through	December 31, 2014	December 31, 2013
Regulatory assets, current:				
Deferred storm costs	A	2015	$ **22.3**	$ -
Fuel and purchased power recovery costs	B	2015	**16.3**	6.3
Economic development costs	B	2015	**2.1**	7.7
Energy efficiency program	B	2015	**1.8**	-
Transmission costs	B	2015	**-**	2.6
Other miscellaneous	B	2015	**1.7**	4.2
Total regulatory assets, current			$ **44.2**	$ 20.8
Regulatory assets, non-current:				
Pension benefits	A	Ongoing	$ **99.6**	$ 77.1
Deferred recoverable income taxes	A/C	Ongoing	**43.1**	32.4
Unamortized loss on reacquired debt	A	Various	**9.9**	10.9
CCEM smart grid and advanced metering infrastructure costs	D	Undetermined	**6.6**	6.6
Retail settlement system costs	D	Undetermined	**3.1**	3.1
Consumer education campaign	D	Undetermined	**3.0**	3.0
Deferred storm costs	D	2015	**-**	25.6
Other miscellaneous	D	Undetermined	**2.2**	1.0
Total regulatory assets, non-current			$ **167.5**	$ 159.7
Regulatory liabilities, current:				
Transmission costs			$ **2.9**	$ -
Other miscellaneous			**1.5**	-
Total regulatory liabilities, current			$ **4.4**	$ -
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated property			$ **119.3**	$ 115.0
Postretirement benefits			**4.8**	5.6
Other miscellaneous			**-**	0.5
Total regulatory liabilities, non-current			$ **124.1**	$ 121.1

A – Recovery of incurred costs without a rate of return.
B – Recovery of incurred costs plus rate of return.
C – Balance has an offsetting liability resulting in no effect on rate base.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.

Regulatory Assets

Deferred storm costs represent costs incurred to repair the damage to **DP&L's** distribution equipment by major storms in 2008, 2011 and 2012. Such costs are included in "Regulatory Assets, non-current" on the accompanying Consolidated Balance Sheets as of December 31, 2013 and in "Regulatory Assets, current" as of December 31, 2014. **DP&L** filed an application with the PUCO in 2012 to recover these costs. On April 14, 2014, **DP&L** reached an agreement in principle whereby **DP&L** would recover storm costs of $22.3 million from all customers on a non-bypassable basis. As a result, using the best estimate of the amount that is probable of recovery, **DP&L** reduced the regulatory asset balance to $22.3 million. In accordance with FASC 980 "Regulated Operations", the reduction was recognized as a current period expense, which is included in Operation and maintenance and the corresponding adjustment to carrying costs which is included in interest expense on the accompanying Statements of Operations. In accordance with the agreement reached with the PUCO staff, a Stipulation was filed and a final order was issued on December 17, 2014 that approved the Stipulation covering this agreement in principle. Recovery will begin in January 2015 therefore this asset was reclassified to current.

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Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. As part of the PUCO approval process, an outside auditor reviews fuel costs and the fuel procurement process. An audit of 2012 fuel costs occurred in 2013, and on June 12, 2013 we received a report from the auditor recommending a pre-tax disallowance of $5.3 million. A reserve of $2.6 million was recorded against the regulatory asset. In August 2014, the PUCO issued an order, which overruled the auditor recommendation and instead included the disallowance of an immaterial amount of fuel costs. The impact of the order was a reversal in the third quarter of 2014 of the vast majority of the previously established $2.6 million reserve and a corresponding reduction to fuel expense. The 2013 audit was completed with no material disallowance of fuel expenses. The costs recovered through the fuel rider decrease each year as more SSO supply is provided through the competitive bid. The fuel rider will be completely phased out beginning January 1, 2016.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Energy efficiency program costs represent costs incurred to develop and implement various customer programs addressing energy efficiency. These costs are being recovered through an Energy Efficiency Rider (EER) that began July 1, 2009 and that is subject to an annual true-up for any over/under recovery of costs.

Transmission costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, retail rates are adjusted to true-up costs with recovery in rates.

Pension benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow-through items as the result of tax benefits previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. On October 19, 2010, **DP&L** elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Retail settlement system costs represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers with what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through a future **DP&L** rate proceeding.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

Regulatory Liabilities

Transmission Costs see "*Regulatory Assets – Transmission costs*" above.

Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

Postretirement benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

NOTE 4 – OWNERSHIP OF COAL-FIRED FACILITIES

DP&L and certain other Ohio utilities have undivided ownership interests in five coal-fired electric generating facilities and numerous transmission facilities. Certain expenses, primarily fuel costs for the generating units, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of December 31, 2014, **DP&L** had $25.0 million of construction work in process at such facilities. **DP&L's** share of the operating cost of such facilities is included within the corresponding line in the Statements of Operations, and **DP&L's** share of the investment in the facilities is included within Total net property, plant and equipment in the Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the jointly-owned station.

DP&L's undivided ownership interest in such facilities at December 31, 2014, is as follows:

	DP&L Share		**DPL** Carrying Value			
	Ownership (%)	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and in Service (Yes/No)
Jointly-owned production units						
Conesville - Unit 4	16.5	129	$ 24	$ 2	$ 1	Yes
Killen - Unit 2	67.0	402	308	19	2	Yes
Miami Fort - Units 7 and 8	36.0	368	214	23	2	Yes
Stuart - Units 1 through 4	35.0	808	219	16	14	Yes
Zimmer - Unit 1	28.1	371	182	35	6	Yes
Transmission (at varying percentages)			42	6	-	
Total		2,078	$ 989	$ 101	$ 25	

Beckjord Unit 6 was retired effective October 1, 2014 and **DP&L's** sale of its interest in East Bend closed on December 30, 2014.

NOTE 5 – GOODWILL AND OTHER INTANGIBLE ASSETS

Impairment of Goodwill

In connection with the acquisition of **DPL** by AES, **DPL** allocated the purchase price to goodwill for two reporting units, the DP&L reporting unit, which includes **DP&L** and other entities, and DPLER. Of the total goodwill, approximately $2.4 billion was allocated to the DP&L reporting unit and the remainder was allocated to DPLER. Goodwill represents the value assigned at the Merger date, as adjusted for subsequent changes in the purchase price allocation, less recognized impairments.

During the first quarter of 2014, we performed an interim impairment test on the $135.8 million in goodwill at our DPLER reporting unit. The DPLER reporting unit was identified as being "at risk" during the fourth quarter of 2013. The impairment indicators arose based on market information available regarding actual and proposed sales of competitive retail marketers, which indicated a significant decline in valuations during the first quarter of 2014. In Step 1 of the interim impairment test, the fair value of the reporting unit was determined to be less than its carrying amount under both the market approach and the income approach using a discounted cash flow valuation model. The significant assumptions included commodity price curves, estimated electricity to be demanded by its customers, changes in its customer base through attrition and expansion, discount rates, the assumed tax structure and the level of working capital required to run the business. During the second quarter of 2014, we finalized the work to determine the implied fair value for the DPLER reporting unit. There were no further adjustments to the full impairment of $135.8 million recognized in the first quarter.

As of October 1, 2013, **DPL** performed its annual goodwill impairment test and recognized a goodwill impairment at its DP&L reporting unit of $306.3 million. In performing the annual goodwill impairment test as of October 1, 2013, Step 1 of the test failed as the fair value of the reporting unit no longer exceeded its carrying amount due primarily to lower estimates of capacity prices in future years as well as lower dark spreads contributing to lower overall operating margins for the business. The fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The significant assumptions included within the discounted cash flow valuation model were capacity price curves, amount of the non-bypassable charge, *commodity price curves, dispatching, valuation of regulatory assets and liabilities, discount rates and deferred* income taxes. In Step 2, goodwill was determined to have an implied fair value of $317.0 million after the hypothetical purchase price allocation under the accounting guidance for business combinations.

DPL recognized a goodwill impairment expense of $1.817.2 million in 2012 at the DP&L reporting unit. During 2012, North American natural gas prices fell significantly compared to the previous year, which exerted downward pressure on wholesale power prices in the Ohio power market. These falling power prices compressed wholesale margins at **DP&L** and led to increased customer switching from **DP&L** to other CRES providers, including DPLER, who were offering retail prices lower than **DP&L's** standard service offer. In addition, several municipalities in **DP&L's** service territory passed ordinances allowing them to become government aggregators and contracted with CRES providers to provide generation service to the customers located within the municipal boundaries, further contributing to the switching trend. CRES providers also became more active in **DP&L's** service territory. These developments reduced **DP&L's** forecasted profitability, operating cash flows and liquidity. As a result, in September 2012, management lowered its previous forecasts of profitability and operating cash flows. Collectively, these events were considered an interim goodwill impairment indicator at the DP&L reporting unit. There were no interim impairment indicators identified for the goodwill at DPLER in 2012.

The goodwill associated with the Merger is not deductible for tax purposes. Accordingly, there is no cash or financial statement tax benefit related to the impairment. The Company's effective tax rates were impacted by the pretax impairment, however. The Company's effective tax rates were (31.8%), (11.2%) and (2.8%) for the years ended December 31, 2014, 2013 and 2012, respectively.

The following table summarizes the changes in Goodwill:

$ in millions	DP&L Reporting Unit	DPLER Reporting Unit	Total
Balance at December 31, 2012			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(1,817.2)	-	(1,817.2)
Net balance at December 31, 2012	$ 623.3	$ 135.8	$ 759.1
Goodwill impairments during 2013	$ (306.3)	$ -	$ (306.3)
Balance at December 31, 2013			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,123.5)	-	(2,123.5)
Net balance at December 31, 2013	$ 317.0	$ 135.8	$ 452.8
Goodwill impairments during 2014	$ -	$ (135.8)	$ (135.8)
Balance at December 31, 2014			
Goodwill	$ 2,440.5	$ 135.8	$ 2,576.3
Accumulated impairment losses	(2,123.5)	(135.8)	(2,259.3)
Net balance at December 31, 2014	$ 317.0	$ -	$ 317.0

The following tables summarize the balances comprising intangible assets as of December 31, 2014:

$ in millions	***December 31, 2014***			*December 31, 2013*		
	Gross Balance	**Accumulated Amortization**	**Net Balance**	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Customer Contracts [(a)]	$ 27.0	$ (27.0)	$ -	$ 27.0	$ (25.8)	$ [illegible]
Customer Relationships [(b)]	31.8	(6.9)	24.9	31.8	(4.6)	27.2
Other [(c)]	7.7	(1.3)	6.4	8.4	(0.1)	8.3
	66.5	(35.2)	31.3	67.2	(30.5)	35.5
Not subject to Amortization						
Trademark/Trade name [(d)]	6.1	-	6.1	6.1	-	6.1
Total intangibles	$ 72.6	$ (35.2)	$ 37.4	$ 73.3	$ (30.5)	$ 41.6

(a) Represents above market contracts that DPLER has with third-party customers existing as of the Merger date.

(b) Represents relationships DPLER has with third-party customers as of the Merger date, where DPLER has regular contact with the customer, and the customer has the ability to make direct contact with DPLER.

(c) Consists of various intangible assets including renewable energy credits, emission allowances, and other intangibles, none of which are individually significant.

(d) Trademark/Trade name represents the value assigned to the trade names of DPLER and MC Squared.

The following table summarizes, by category, intangible assets acquired during the period ended December 31, 2014:

$ in millions	Amount	Subject to Amortization/ Indefinite-lived	Weighted Average Amortization Period (years)	Amortization Method
Renewable Energy Certificates	$ 7.7	Subject to amortization	Various	As Utilized

The following table summarizes the amortization expense, broken down by intangible asset category for 2015 through 2019:

	Estimated amortization expense				
	Years ending December 31,				
$ in millions	2015	2016	2017	2018	2019
Customer relationships	$ 3.8	$ 3.1	$ 2.7	$ 2.3	$ 2.1
Renewable Energy Certificates	4.2	3.5	-	-	-
	$ 8.0	$ 6.6	$ 2.7	$ 2.3	$ 2.1

NOTE 6 – DEBT OBLIGATIONS

Long-term debt

$ in millions	**December 31, 2014**	December 31, 2013
First mortgage bonds due in September 2016 - 1.875%	**$ 445.0**	$ 445.0
Pollution control series due in January 2028 - 4.7%	**35.3**	35.3
Pollution control series due in January 2034 - 4.8%	**179.1**	179.1
Pollution control series due in September 2036 - 4.8%	**100.0**	100.0
Pollution control series due in November 2040 - variable rates: 0.04% - 0.15% and 0.04% - 0.26% (a)	**100.0**	100.0
U.S. Government note due in February 2061 - 4.2%	**18.1**	18.3
Unamortized debt discount	**(2.8)**	(3.1)
Total long-term debt at subsidiary	**874.7**	874.6
Bank term loan due in May 2018 - variable rates: 2.41% - 2.42% (a)	**140.0**	180.0
Senior unsecured bonds due in October 2016 - 6.50%	**130.0**	430.0
Senior unsecured bonds due in October 2019 - 6.75%	**200.0**	-
Senior unsecured bonds due in October 2021 - 7.25%	**780.0**	780.0
Note to DPL Capital Trust II due in September 2031 - 8.125%	**15.6**	20.6
Unamortized debt discount	**(0.7)**	(1.0)
Total long-term debt	**$ 2,139.6**	$ 2,284.2

(a) - range of interest rates for the twelve months ended December 31, 2014 and December 31, 2013, respectively

Current portion - long-term debt

$ in millions	December 31, 2014	December 31, 2013
Bank term loan due in May 2018 - variable rates: 2.41% - 2.42% (a)	$ 20.0	$ 10.0
U.S. Government note due in February 2061 - 4.2%	0.1	0.1
Capital lease obligations	-	0.1
Total current portion - long-term debt	$ 20.1	$ 10.2

(a) - range of interest rates for the twelve months ended December 31, 2014 and December 31, 2013, respectively

At December 31, 2014, maturities of long-term debt are summarized as follows:

Due within the twelve months ending December 31,

$ in millions	
2015	$ 20.1
2016	615.1
2017	40.1
2018	60.1
2019	200.1
Thereafter	1,227.7
	2,163.2
Unamortized discounts and premiums, net	(3.5)
Total long-term debt	$ 2,159.7

Premiums or discounts recognized at the Merger date are amortized over the life of the debt using the effective interest method.

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding first mortgage bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by a standby letter of credit issued by JPMorgan Chase Bank, N.A. This letter of credit facility, which expires in June 2018, is irrevocable and has no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the years ended December 31, 2014, 2013 and 2012.

On May 10, 2013, **DP&L** entered into a $300.0 million unsecured revolving credit agreement with a syndicated bank group. This $300.0 million facility has a five year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature which provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million. At December 31, 2014, there were two letters of credit in the amount of $0.7 million outstanding, with the remaining $299.3 million available to **DP&L**. Fees associated with this revolving credit facility were not material during the years ended December 31, 2014 or 2013.

DP&L's unsecured revolving credit agreement and **DP&L's** amended standby letters of credit have two financial covenants, the first being Total Debt to Total Capitalization and the second being EBITDA to Interest Expense. The EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base (WPAFB). **DP&L** financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On September 19, 2013, **DP&L** closed a $445.0 million issuance of senior secured first mortgage bonds. These new bonds mature on September 15, 2016, and are secured by **DP&L's** First & Refunding Mortgage. Substantially all property, plant and equipment of **DP&L** is subject to the lien of the First and Refunding Mortgage.

On May 10, 2013, **DPL** entered into a $200.0 million unsecured term loan agreement. This term loan has a five year term expiring on May 10, 2018; however, if **DPL** has not either: (a) prepaid the full $200.0 million term loan balance; or (b) refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this **DPL** term loan shall be July 15, 2016. This term loan amortizes at 5% of the original balance per quarter from September 2014 to maturity. As of December 31, 2014 there was $160 million outstanding on this Term Loan. Fees associated with this new term loan were not material during the years ended December 31, 2014 or 2013.

On May 10, 2013, **DPL** entered into a $100.0 million unsecured revolving credit facility. This facility has a $100.0 million letter of credit sublimit and a feature which provides **DPL** the ability to increase the size of the facility by an additional $50.0 million. This facility has a five year term expiring on May 10, 2018; however, if **DPL** has not refinanced its senior unsecured bonds due October 2016 before July 15, 2016, then the maturity of this **DPL** credit facility shall be July 15, 2016. As of December 31, 2014 there was one letter of credit issued in the amount of $2.3 million, with the remaining $97.7 million available to **DPL**. Fees associated with this revolving credit facility were not material during the years ended December 31, 2014 or 2013.

DPL's unsecured revolving credit agreement and unsecured term loan have two financial covenants. The first financial covenant, a Total Debt to EBITDA ratio, is calculated at the end of each fiscal quarter by dividing total debt at the end of the current quarter by consolidated EBITDA for the four prior fiscal quarters. The second financial covenant is an EBITDA to Interest Expense ratio that is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

DPL's unsecured revolving credit agreement and unsecured term loan restrict dividend payments from **DPL** to AES and adjust the cost of borrowing under the facilities under certain credit rating scenarios.

In connection with the closing of the Merger, **DPL** assumed $1,250.0 million of debt that Dolphin Subsidiary II, Inc., a subsidiary of AES, issued on October 3, 2011 to partially finance the Merger. The $1,250.0 million was issued in two tranches. The first tranche was $450.0 million of five year senior unsecured notes issued with a 6.50% coupon maturing on October 15, 2016. The second tranche was $800.0 million of ten year senior unsecured notes issued with a 7.25% coupon maturing on October 15, 2021. In December 2013, **DPL** executed an Open Market Repurchase Program and successfully bought back $20 million of the first tranche of five year senior unsecured notes issued with a 6.50% coupon and $20 million of the second tranche of ten year senior unsecured notes issued with a 7.25% coupon. Subsequent to repurchasing these bonds **DPL** immediately retired them.

On September 6, 2014, **DPL** announced its intent to purchase a maximum of $280.0 million of aggregate principal of the Senior Unsecured bonds maturing October 2016 through a tender offer. On October 6, 2014, **DPL** increased the maximum amount of the tender to $300.0 million and on October 20th the tender expired. **DPL** settled the $300.0 million on October 6th through (a) net proceeds from a $200.0 million Senior Unsecured note issuance (maturing October 2019 and priced at 6.75%); (b) a draw on the **DPL** revolving line of credit and (c) cash on hand.

In October 2014, **DPL** repaid $5.0 million of the note due to Capital Trust II, which used the funds to repurchase securities in the open market at a slight premium. Subsequent to repurchasing these securities Capital Trust II immediately retired them.

NOTE 7 – INCOME TAXES

DPL's components of income tax expense were as follows:

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Computation of tax expense			
Federal income tax expense / (benefit) [(a)]	$ **(19.8)**	$ (69.9)	$ (588.7)
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**1.2**	1.7	3.5
Depreciation of AFUDC - Equity	**(3.4)**	(3.2)	(2.4)
Investment tax credit amortized	**(0.5)**	(0.5)	(0.3)
Section 199 - domestic production deduction	**(1.1)**	(4.1)	(2.1)
Non-deductible merger-related compensation	**-**	-	0.6
Non-deductible goodwill impairment	**47.5**	107.2	636.0
Accrual (settlement) for open tax years	**(6.6)**	(8.8)	(0.1)
Other, net [(b)]	**0.7**	(0.1)	1.2
Total tax expense	$ **18.0**	$ 22.3	$ 47.7
Components of tax expense			
Federal - current	$ **(0.1)**	$ 1.8	$ 48.6
State and Local - current	**0.9**	0.7	1.2
Total current	**0.8**	2.5	49.8
Federal - deferred	**16.6**	18.1	(4.9)
State and local - deferred	**0.6**	1.7	2.8
Total deferred	**17.2**	19.8	(2.1)
Total tax expense	$ **18.0**	$ 22.3	$ 47.7

Components of Deferred Tax Assets and Liabilities

$ in millions	December 31, 2014	2013
Net non-current Assets / (Liabilities)		
Depreciation / property basis	$ **(548.2)**	$ (531.5)
Income taxes recoverable	**(14.8)**	(11.4)
Regulatory assets	**(18.0)**	(15.6)
Investment tax credit	**1.5**	1.0
Compensation and employee benefits	**3.2**	(3.9)
Intangibles	**(7.0)**	(2.0)
Long-term debt	**(1.5)**	(1.7)
Other (c)	**(2.5)**	0.8
Net non-current liabilities	$ **(587.3)**	$ (564.3)
Net current Assets / (Liabilities) (d)		
Other	$ **1.1**	$ (2.6)
Net current assets / (liabilities)	$ **1.1**	$ (2.6)

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes expense of $0.4 million, $0.0 million and benefits of $1.2 million in the years ended December 31, 2014 2013, and 2012, respectively, of income tax related to adjustments from prior years.
(c) The Other non-current liabilities caption includes deferred tax assets of $27.1 million in 2014 and $20.7 million in 2013 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $21.9 million in 2014 and $16.6 million in 2013. These net operating loss carryforwards expire from 2014 to 2027.
(d) Amounts are included within Other prepayments and current assets and Other current liabilities on the Consolidated Balance Sheets of DPL.

The following table presents the tax expense / (benefit) related to pensions, postemployment benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

$ in millions	Years ended December 31, 2014	2013	2012
Tax expense / (benefit)	$ **(9.1)**	$ 15.4	$ (2.5)

Accounting for Uncertainty in Income Taxes

We apply the provisions of GAAP relating to the accounting for uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

$ in millions	
Balance at December 31, 2012	$ 18.3
Calendar 2013	
Tax positions taken during prior period	(0.1)
Lapse of Statute of Limitations	(6.9)
Settlement with taxing authorities	(2.5)
Balance at December 31, 2013	8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Balance at December 31, 2014	$ 3.0

Of the December 31, 2014 balance of unrecognized tax benefits, $0.9 million is due to uncertainty in the timing of deductibility.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The amounts accrued as well as the expense / (benefit) recorded were not material for the years ended December 31, 2014, 2013 and 2012.

Following is a summary of the tax years open to examination by major tax jurisdiction:
U.S. Federal – 2010 and forward
State and Local – 2010 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statutes of limitations.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The results of the examination were approved by the Joint Committee on Taxation on January 18, 2013. As a result of the examination, **DPL** received a refund of $19.9 million and recorded a $1.2 million reduction to income tax expense.

NOTE 8 – PENSION AND POSTRETIREMENT BENEFITS

DP&L sponsors a traditional defined benefit pension plan for most of the employees of **DPL** and its subsidiaries. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees (management employees), the traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional pension plan was closed to new management employees. A participant is 100% vested in all amounts credited to his or her account upon the completion of five vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, **DPL** and **DP&L**. Employees that transferred from **DP&L** to the Service Company maintain their previous eligibility to participate in the **DP&L** pension plan.

Almost all management employees beginning employment on or after January 1, 2011 participate in a cash balance pension plan. Similar to the traditional pension plan for management employees, the cash balance benefits are based on compensation and years of service. A participant shall become 100% vested in all amounts credited to his or her account upon the completion of three vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. Vested benefits in the cash balance plan are fully portable upon termination of employment.

In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain retired key executives. The SERP has an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within Pension, retiree and other benefits on our Consolidated Balance Sheets.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions during the years ended December 31, 2014, 2013 and 2012.

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits until their death, while qualified employees who retired after 1987 are eligible for life insurance benefits and partially subsidized health care. The partially subsidized health care is at the election of the employee, who pays the majority of the cost, and is available only from their retirement until they are covered by Medicare. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

We recognize an asset for a plan's overfunded status and a liability for a plan's underfunded status and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. For the transmission and distribution areas of our electric business, these amounts are recorded as regulatory assets and liabilities which represent the regulated portion that would otherwise be charged or credited to AOCI. We have historically recorded these costs on the accrual basis and this is how these costs have been historically recovered through customer rates. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

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The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2014 and 2013. The amounts presented in the following tables for pension include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postemployment include both health and life insurance benefits.

$ in millions	Pension	
	Year ended December 31, 2014	Year ended December 31, 2013
Change in benefit obligation		
Benefit obligation at beginning of period	$ **370.5**	$ 395.6
Service cost	**5.9**	7.2
Interest cost	**17.5**	15.6
Plan amendments	**6.8**	-
Actuarial (gain) / loss	**67.3**	(26.5)
Benefits paid	**(24.2)**	(21.4)
Benefit obligation at end of period	**443.8**	370.5
Change in plan assets		
Fair value of plan assets at beginning of period	**349.1**	361.4
Actual return on plan assets	**46.4**	8.7
Contributions to plan assets	**0.4**	0.4
Benefits paid	**(24.2)**	(21.4)
Fair value of plan assets at end of period	**371.7**	349.1
Funded status of plan	$ **(72.1)**	$ (21.4)

$ in millions	Postretirement	
	Year ended December 31, 2014	Year ended December 31, 2013
Change in benefit obligation		
Benefit obligation at beginning of period	$ **19.7**	$ 22.4
Service cost	**0.2**	0.2
Interest cost	**0.8**	0.8
Actuarial (gain) / loss	**0.2**	(2.2)
Benefits paid	**(1.3)**	(1.5)
Benefit obligation at end of period	**19.6**	19.7
Change in plan assets		
Fair value of plan assets at beginning of period	**3.7**	4.2
Contributions to plan assets	**0.9**	1.0
Benefits paid	**(1.3)**	(1.5)
Fair value of plan assets at end of period	**3.3**	3.7
Funded status of plan	$ **(16.3)**	$ (16.0)

$ in millions	Pension		Postretirement	
	December 31,		December 31,	
	2014	2013	**2014**	2013
Amounts recognized in the Balance sheets				
Current liabilities	**$ (0.4)**	$ (0.4)	**$ (0.5)**	$ (0.5)
Non-current liabilities	**(71.7)**	(21.0)	**(15.8)**	(15.5)
Net liability at Year ended December 31,	**$ (72.1)**	$ (21.4)	**$ (16.3)**	$ (16.0)

Amounts recognized in Accumulated Other **Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax**				
Components:				
Prior service cost	**$ 14.1**	$ 8.8	**$ 0.4**	$ 0.5
Net actuarial loss / (gain)	**103.4**	63.0	**(5.0)**	(6.0)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 117.5**	$ 71.8	**$ (4.6)**	$ (5.5)
Recorded as:				
Regulatory asset	**$ 99.0**	$ 76.3	**$ 0.4**	$ 0.4
Regulatory liability	**-**	-	**(4.8)**	(5.6)
Accumulated other comprehensive income	**18.5**	(4.5)	**(0.2)**	(0.3)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 117.5**	$ 71.8	**$ (4.6)**	$ (5.5)

The accumulated benefit obligation for our defined benefit pension plans was $431.0 million and $359.8 million at December 31, 2014 and 2013, respectively.

The net periodic benefit cost (income) of the pension and postemployment benefit plans were:

Net Periodic Benefit Cost - Pension

$ in millions	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012
Service cost	**$ 5.9**	$ 7.2	$ 6.2
Interest cost	**17.5**	15.6	17.3
Expected return on assets [(a)]	**(22.9)**	(23.3)	(22.7)
Amortization of unrecognized:			
Actuarial gain	**3.4**	4.9	5.0
Prior service cost	**1.5**	1.5	1.5
Net periodic benefit cost	**$ 5.4**	$ 5.9	$ 7.3

Net Periodic Benefit Cost - Postretirement

$ in millions	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012
Service cost	**$ 0.2**	$ 0.2	$ 0.1
Interest cost	**0.8**	0.8	0.9
Expected return on assets [(a)]	**(0.2)**	(0.1)	(0.3)
Amortization of unrecognized:			
Actuarial loss	**(0.6)**	(0.5)	(0.6)
Net periodic benefit cost	**$ 0.2**	$ 0.4	$ 0.1

(a) For purposes of calculating the expected return on pension plan assets under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be amortized into the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets was approximately $361.0 million in 2014, $351.2 million in 2013, and $346.0 million in 2012.

Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

Pension

$ in millions	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012
Net actuarial loss / (gain)	**$ 43.8**	$ (12.0)	$ 5.5
Prior service cost	**6.8**	-	-
Reversal of amortization item:			
Net actuarial loss	**(3.4)**	(4.9)	(5.0)
Prior service cost	**(1.5)**	(1.5)	(1.5)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ 45.7**	$ (18.4)	$ (1.0)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	**$ 51.1**	$ (12.5)	$ 6.3

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Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities *(cont.)*

Postretirement

$ in millions	**Year ended December 31, 2014**	Year ended December 31, 2013	Year ended December 31, 2012
Net actuarial loss / (gain)	$ **0.4**	$ (2.0)	$ 1.0
Reversal of amortization item:			
Net actuarial gain	**0.6**	0.5	0.7
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.0**	$ (1.5)	$ 1.7
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.2**	$ (1.1)	$ -

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2015 are:

$ in millions	Pension	Postretirement
Net actuarial gain / (loss)	$ 5.8	$ (0.5)
Prior service cost	$ 2.0	$ -

Our expected return on plan asset assumptions, used to determine benefit obligations, are based on historical long-term rates of return on investments, which use the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors, such as inflation and interest rates, as well as asset diversification and portfolio rebalancing, are evaluated when long-term capital market assumptions are determined. Peer data and historical returns are reviewed to verify reasonableness and appropriateness.

For 2015, we are decreasing our expected long-term rate of return assumption to 6.50% from 6.75% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption from to 4.50% from 6.00% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. Also, for 2015, we have decreased our assumed discount rate to 4.02% from 4.86% for pension and to 3.71% from 4.58% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2015 pension expense of approximately $3.5 million. A 25 basis point increase in the discount rate for pension would result in a decrease of approximately $0.5 million to 2015 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.8 million to 2015 pension expense.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2014. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

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The weighted average assumptions used to determine benefit obligations at December 31, 2014, 2013 and 2012 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2014	2013	2012	**2014**	2013	2012
Discount rate for obligations	**4.02%**	4.86%	4.04%	**3.71%**	4.58%	3.75%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2014, 2013 and 2012 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2014	2013	2012	**2014**	2013	2012
Discount rate	**4.86%**	4.04%	4.88%	**4.51%**	4.58%	4.62%
Expected rate of return on plan assets	**6.75%**	6.75%	7.00%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2014, 2013 and 2012 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2014	2013	2012	**2014**	2013	2012
Pre - age 65						
Current health care cost trend rate	**7.75%**	8.00%	8.50%	**6.97%**	7.75%	8.00%
Year trend reaches ultimate	**2023**	2019	2019	**2029**	2023	2019
Post - age 65						
Current health care cost trend rate	**6.75%**	7.50%	8.00%	**6.97%**	6.75%	7.50%
Year trend reaches ultimate	**2021**	2018	2018	**2029**	2021	2018
Ultimate health care cost trend rate	**5.00%**	5.00%	5.00%	**4.50%**	5.00%	5.00%

The assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects on the net periodic postemployment benefit cost and the accumulated postemployment benefit obligation:

Effect of change in health care cost trend rate

$ in millions		One-percent increase		One-percent decrease
Service cost plus interest cost	$	0.1	$	-
Benefit obligation	$	1.0	$	(0.9)

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions due within the following years:		Pension		Postretirement
2015	$	24.8	$	1.9
2016	$	25.2	$	1.8
2017	$	25.7	$	1.7
2018	$	26.3	$	1.6
2019	$	26.7	$	1.5
2020 - 2024	$	137.0	$	6.1

We expect to make contributions of $0.4 million to our SERP in 2015 to cover benefit payments. We also expect to contribute $1.9 million to our other postemployment benefit plans in 2015 to cover benefit payments. We do not expect to make any contributions to our pension plan during 2015.

The Pension Protection Act of 2006 (the Act) contained new requirements for our single employer defined benefit pension plan. In addition to establishing a 100% funding target for plan years beginning after December 31, 2008, the Act also limits some benefits if the funded status of pension plans drops below certain thresholds. Among other restrictions under the Act, if the funded status of a plan falls below a predetermined ratio of 80%, lump-sum payments to new retirees are limited to 50% of amounts that otherwise would have been paid and new benefit improvements may not go into effect. For the 2014 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 113.86% and is estimated to be 113.86% until the 2015 status is certified in September 2015 for the 2015 plan year. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors certain relief from funding requirements and benefit restrictions of the Act.

Plan Assets

Plan assets are invested using a total return investment approach whereby a mix of equity securities, debt securities and other investments are used to preserve asset values, diversify risk and achieve our target investment return benchmark. Investment strategies and asset allocations are based on careful consideration of plan liabilities, the plan's funded status and our financial condition. Investment performance and asset allocation are measured and monitored on an ongoing basis.

Plan assets are managed in a balanced portfolio comprised of two major components: an equity portion and a fixed income portion. The expected role of plan equity investments is to maximize the long-term real growth of plan assets, while the role of fixed income investments is to generate current income, provide for more stable periodic returns and provide some protection against a prolonged decline in the market value of plan equity investments.

Long-term strategic asset allocation guidelines are determined by management and take into account the Plan's long-term objectives as well as its short-term constraints. The target allocations for plan assets are 2 – 41% for equity securities, 60 – 82% for fixed income securities and 8 – 16% for other investments. Equity securities include U.S. and international equity, while fixed income securities include long-duration and high-yield bond funds and emerging market debt funds. Other investments include hedge funds that follow several different strategies.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

The following table summarizes the Company's target pension plan allocation for 2014:

	Target Allocation
Equity Securities	19%
Debt Securities	69%
Real Estate	6%
Other	6%

The fair values of our pension plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2014

Asset Category $ in millions	**Market Value at December 31, 2014**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservable inputs** (Level 3)
Equity securities [(a)]				
Small/Mid cap equity	$ 10.6	$ 10.6	$ -	$ -
Large cap equity	22.2	22.2	-	-
International equity	18.2	18.2	-	-
Emerging markets equity	2.8	2.8	-	-
SIIT dynamic equity	11.6	11.6	-	-
Total equity securities	65.4	65.4	-	-
Debt securities [(b)]				
Emerging markets debt	6.0	6.0	-	-
High yield bond	6.5	6.5	-	-
Long duration fund	242.7	242.7	-	-
Total debt securities	255.2	255.2	-	-
Cash and cash equivalents [(c)]				
Cash	1.6	1.6	-	-
Other investments [(d)]				
Core property collective fund	26.3	-	26.3	-
Common collective fund	23.2	-	23.2	-
Total other investments	49.5	-	49.5	-
Total pension plan assets	$ 371.7	$ 322.2	$ 49.5	$ -

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries.
(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years.
(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.
(d) This category represents a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies.

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The fair values of our pension plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	Market Value at December 31, 2013	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Equity securities [a]				
Small/Mid cap equity	$ 10.5	$ 10.5	$ -	$ -
Large cap equity	20.8	20.8	-	-
International equity	20.3	20.3	-	-
Emerging markets equity	3.2	3.2	-	-
SIIT dynamic equity	10.5	10.5	-	-
Total equity securities	65.3	65.3	-	-
Debt securities [b]				
Emerging markets debt	6.6	6.6	-	-
High yield bond	6.9	6.9	-	-
Long duration fund	223.3	223.3	-	-
Total debt securities	236.8	236.8	-	-
Cash and cash equivalents [c]				
Cash	0.9	0.9	-	-
Other investments [d]				
Core property collective fund	23.5	-	23.5	-
Common collective fund	22.6	-	22.6	-
Total other investments	46.1	-	46.1	-
Total pension plan assets	$ 349.1	$ 303.0	$ 46.1	$ -

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries.

(b) This category includes investments in investment-grade fixed-income instruments that are designed to mirror the term of the pension assets and generally have a tenor between 10 and 30 years.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies.

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The fair values of our other postemployment benefit plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Postemployment Benefit Plan Assets at December 31, 2014

Asset Category $ in millions	**Market Value at December 31, 2014**	**Quoted prices in active markets for identical assets**	**Significant observable inputs**	**Significant unobservable inputs**
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund (a)	$ 3.2	$ 3.2	$ -	$ -

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

The fair values of our other postemployment benefit plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Postemployment Benefit Plan Assets at December 31, 2013

Asset Category $ in millions	Market Value at December 31, 2013	Quoted prices in active markets for identical assets	Significant observable inputs	Significant unobservable inputs
		(Level 1)	(Level 2)	(Level 3)
JP Morgan Core Bond Fund (a)	$ 3.7	$ 3.7	$ -	$ -

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

NOTE 9 – FAIR VALUE MEASUREMENTS

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The fair value of our financial instruments represents estimates of possible value that may or may not be realized in the future. The table below presents the fair value and cost of our non-derivative instruments at December 31, 2014 and 2013. See Note 10 for the fair values of our derivative instruments.

	December 31, 2014		December 31, 2013	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money market funds	$ 0.1	$ 0.1	$ 0.3	$ 0.3
Equity securities	2.7	3.7	3.3	4.4
Debt securities	4.7	4.7	5.4	5.5
Hedge Funds	0.8	0.8	0.9	0.9
Real Estate	0.4	0.4	0.4	0.4
Total assets	$ 8.7	$ 9.7	$ 10.3	$ 11.5
Liabilities				
Debt	$ 2,159.7	$ 2,204.8	$ 2,294.4	$ 2,334.6

Debt

Unrealized gains or losses are not recognized in the financial statements as debt is presented at the carrying value, net of unamortized premium or discount in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2016 to 2061.

Master Trust Assets

DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans. These assets are primarily comprised of open-ended mutual funds which are valued using the net asset value per unit. These investments are recorded at fair value within Other deferred assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DPL had $0.8 million ($0.5 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2014 and $0.9 million ($0.6 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2013.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the *past twelve months, $0.4 million ($0.2 million after tax) of unrealized gains were reversed into earnings.* Over the next twelve months, $0.4 million ($0.2 million after tax) of unrealized gains are expected to be reversed to earnings.

Fair Value Hierarchy
Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as:

- Level 1 (quoted prices in active markets for identical assets or liabilities);
- Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active);
- Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.

We did not have any transfers of the fair values of our financial instruments between Level 1 and Level 2 of the fair value hierarchy during the twelve months ended December 31, 2014 and 2013.

The fair value of assets and liabilities at December 31, 2014 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.1	$ 0.1	$ -	$ -
Equity securities	3.7	3.7	-	-
Debt securities	4.7	4.7	-	-
Hedge Funds	0.8	-	0.8	-
Real Estate	0.4	0.4	-	-
Total Master trust assets	9.7	8.9	0.8	-
Derivative assets				
Forward power contracts	14.9	-	13.7	1.2
Total derivative assets	14.9	-	13.7	1.2
Total assets	$ 24.6	$ 8.9	$ 14.5	$ 1.2
Liabilities				
FTRs	$ 0.6	$ -	$ -	$ 0.6
Heating oil futures	0.4	0.4	-	-
Natural gas futures	0.1	0.1	-	-
Forward power contracts	11.1	-	11.1	-
Total derivative liabilities	12.2	0.5	11.1	0.6
Long-term debt	2,204.8	-	2,186.6	18.2
Total liabilities	$ 2,217.0	$ 0.5	$ 2,197.7	$ 18.8

(a) Includes credit valuation adjustment.

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The fair value of assets and liabilities at December 31, 2013 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2013 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.3	$ 0.3	$ -	$ -
Equity securities	4.4	4.4	-	-
Debt securities	5.5	5.5	-	-
Hedge Funds	0.9	-	0.9	-
Real Estate	0.4	0.4	-	-
Total Master trust assets	11.5	10.6	0.9	-
Derivative assets				
FTRs	0.2	-	-	0.2
Heating oil futures	0.2	0.2	-	-
Forward power contracts	13.4	-	13.4	-
Total derivative assets	13.8	0.2	13.4	0.2
Total assets	$ 25.3	$ 10.8	$ 14.3	$ 0.2
Liabilities				
Forward power contracts	$ 10.6	$ -	$ 10.6	$ -
Total derivative liabilities	10.6	-	10.6	-
Long-term debt	2,334.6	-	2,316.1	18.5
Total liabilities	$ 2,345.2	$ -	$ 2,326.7	$ 18.5

(a) Includes credit valuation adjustment.

Our financial instruments are valued using the market approach in the following categories:

- Level 1 inputs are used for derivative contracts such as heating oil futures and for money market accounts that are considered cash equivalents. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions.
- Level 2 inputs are used to value derivatives such as forward power contracts and forward NYMEX-quality coal contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit; and interest rate hedges, which use observable inputs to populate a pricing model.
- Level 3 inputs such as financial transmission rights are considered a Level 3 input because the monthly auctions are considered inactive. Our Level 3 inputs are immaterial to our derivative balances as a whole and as such no further disclosures are presented.

Our debt is fair valued for disclosure purposes only and most of the fair values are determined using quoted market prices in inactive markets. These fair value inputs are considered Level 2 in the fair value hierarchy. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

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Approximately 97% of the inputs to the fair value of our derivative instruments are from quoted market prices.

Non-recurring Fair Value Measurements
We use the cost approach to determine the fair value of our AROs which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. In 2014, AROs for asbestos, landfills, and river structures decreased by $1.5 million ($1.0 million after tax) primarily due to the sale of a generation plant. The ARO for ash ponds was increased by $2.4 million ($1.6 million after tax) due to new rules issued by the USEPA in December 2014 that will be effective in June 2015. The December 2014 increase of the AROs for ash ponds was limited to the ponds located at plants which are no longer in operation. Additional ash pond AROs will be recorded in the first quarter of 2015 for the ponds located at plants which remain in operation. There were no additions to our AROs during the year ended December 31, 2013.

When evaluating impairment of goodwill and long-lived assets, we measure fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to the carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

$ in millions	**Year ended December 31, 2014**				
	Carrying Amount	**Fair Value Level 1**	**Fair Value Level 2**	**Fair Value Level 3**	**Gross Loss**
Assets					
Long-lived assets held and used [(a)]					
DP&L (East Bend)	$ 14.2	$ -	$ -	$ 2.7	$ 11.5
Goodwill [(b)]					
DPLER Reporting unit	$ 135.8	$ -	$ -	$ -	$ 135.8

$ in millions	Year ended December 31, 2013				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross Loss
Assets					
Long-lived assets held and used [(a)]					
DP&L (Conesville)	$ 26.2	$ -	$ -	$ -	$ 26.2
Goodwill [(b)]					
DP&L Reporting unit	$ 623.3	$ -	$ -	$ 317.0	$ 306.3

(a) See Note 15 for further information
(b) See Note 5 for further information

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets during the year ended December 31, 2014:

$ in millions	Fair Value	Valuation Technique	Unobservable input	Range (Weighted Average)
Long-lived assets held and used:				
DP&L (East Bend)	$ [illegible]	Discounted cash flows	Annual revenue growth	-31% to 18% (0%)
			Annual pretax operating margin	3% to 34% (15%)

NOTE 10 – DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

In the normal course of business, **DPL** enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and

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interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges or not designated as hedges for accounting purposes, which we refer to as mark to market.

At December 31, 2014, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	10.5	-	10.5
Heating Oil Futures	Mark to Market	Gallons	378.0	-	378.0
Natural Gas Futures	Mark to Market	Dths	200.0	-	200.0
Forward Power Contracts	Cash Flow Hedge	MWh	175.0	(2,991.0)	(2,816.0)
Forward Power Contracts	Mark to Market	MWh	1,725.2	(2,707.8)	(982.6)

At December 31, 2013, **DPL** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	-	7.1
Heating Oil Futures	Mark to Market	Gallons	1,428.0	-	1,428.0
Forward Power Contracts	Cash Flow Hedge	MWh	140.4	(4,705.7)	(4,565.3)
Forward Power Contracts	Mark to Market	MWh	3,177.8	(2,883.1)	294.7

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair values of cash flow hedges determined by current public market prices will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity and our sale of retail power to third parties through our subsidiary DPLER. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

We also entered into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. These interest rate derivative contracts were settled in the third quarter of 2013. We do not hedge all interest rate exposure. We reclassify gains and losses on interest rate derivative hedges out of AOCI and into earnings in those periods in which hedged interest payments occur.

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The following table provides information for **DPL** concerning gains or losses recognized in AOCI for the cash flow *hedges:*

$ in millions (net of tax)	**Year ended December 31, 2014** Power	**Year ended December 31, 2014** Interest Rate Hedges	Year ended December 31, 2013 Power	Year ended December 31, 2013 Interest Rate Hedges	Year ended December 31, 2012 Power	Year ended December 31, 2012 Interest Rate Hedges
Beginning accumulated derivative gain / (loss) in AOCI	$ **1.4**	$ **19.2**	$ (3.0)	$ 0.5	$ 0.3	$ (0.8)
Net gains / (losses) associated with current period hedging transactions	**(19.0)**	**-**	1.0	18.7	(2.6)	1.1
Net gains reclassified to earnings:						
Interest Expense	**-**	**(0.9)**	-	-	-	0.2
Revenues	**18.3**	**-**	2.1	-	(0.7)	-
Purchased Power	**(0.5)**	**-**	1.3	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	$ **0.2**	$ **18.3**	$ 1.4	$ 19.2	$ (3.0)	$ 0.5
Net gains / (losses) associated with the ineffective portion of the hedging transaction						
Interest Expense	$ **-**	$ **-**	$ -	$ 0.8	$ -	$ 0.2
Portion expected to be reclassified to earnings in the next twelve months (a)	$ **3.5**	$ **(0.9)**				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**24**	**0**				

(a) The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

Mark to Market Accounting

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchases and sales exceptions under FASC 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the consolidated statements of results of operations in the period in which the change occurred. This is commonly referred to as "MTM accounting." Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We mark to market FTRs, heating oil futures and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the consolidated statements of results of operations on an accrual basis.

Regulatory Assets and Liabilities
In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of **DP&L's** load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' portion of the heating oil futures are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the consolidated statements of results of operations or balance sheets of the gains and losses on **DPL's** derivatives not designated as hedging instruments for the years ended December 31, 2014, 2013 and 2012:

Year ended December 31, 2014

$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	(3.0)
Realized gain / (loss)	(0.1)	0.7	(3.6)	(0.1)	(3.1)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	(6.1)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ -	$ -	$ -	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Purchased Power	-	(0.1)	(5.1)	(0.2)	(5.4)
Fuel	(0.6)	-	-	-	(0.6)
Total	$ (0.7)	$ (0.1)	$ (5.1)	$ (0.2)	(6.1)

Year ended December 31, 2013

$ in millions	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments				
Change in unrealized gain	$ -	$ 0.3	$ 0.6	$ 0.9
Realized gain	0.1	1.2	1.1	2.4
Total	$ 0.1	$ 1.5	$ 1.7	$ 3.3
Recorded in Income Statement: gain / (loss)				
Revenue	$ -	$ -	$ -	$ -
Purchased Power	-	1.5	1.7	3.2
Fuel	0.1	-	-	0.1
O&M	-	-	-	-
Total	$ 0.1	$ 1.5	$ 1.7	$ 3.3

$ in millions	Year ended December 31, 2012 NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ 14.5	$ (1.6)	$ (0.2)	$ 4.3	$ 17.0
Realized gain / (loss)	(29.5)	1.9	0.5	(5.0)	(32.1)
Total	$ (15.0)	$ 0.3	$ 0.3	$ (0.7)	$ (15.1)
Recorded on Balance Sheet:					
Partners' share of gain	$ 4.2	$ -	$ -	$ -	$ 4.2
Regulatory (asset) / liability	1.0	(0.6)	-	-	0.4
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(5.1)	(5.1)
Purchased Power	-	-	0.3	4.4	4.7
Fuel	(20.2)	0.7	-	-	(19.5)
O&M	-	0.2	-	-	0.2
Total	$ (15.0)	$ 0.3	$ 0.3	$ (0.7)	$ (15.1)

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The following tables show the fair value and balance sheet classification of **DPL's** derivative instruments at December 31, 2014 and 2013.

Fair Values of Derivative Instruments
December 31, 2014

			Gross Amounts Not Offset in the Consolidated Balance Sheets		
$ in millions	Hedging Designation	Gross Fair Value as presented in the Consolidated Balance Sheets (a)	Financial Instruments with Same Counterparty in Offsetting Position	Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 5.6	$ (2.0)	$ -	$ 3.6
Forward power contracts	MTM	5.5	(3.4)	-	2.1
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	0.3	(0.3)	-	-
Forward power contracts	MTM	3.5	(0.9)	-	2.6
Total assets		$ 14.9	$ (6.6)	$ -	$ 8.3
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.1	$ (2.0)	$ -	$ 0.1
Forward power contracts	MTM	7.5	(3.4)	(4.1)	-
FTRs	MTM	0.6	-	-	0.6
Heating oil futures	MTM	0.4	-	(0.4)	-
Natural gas	MTM	0.1	-	(0.1)	-
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Cash Flow	0.6	(0.3)	(0.3)	-
Forward power contracts	MTM	0.9	(0.9)	-	-
Total liabilities		$ 12.2	$ (6.6)	$ (4.9)	$ 0.7

(a) Includes credit valuation adjustment.

As of December 31, 2014, the above table includes Forward power contracts in a short-term asset position of $11.1 million. This table does not include a short-term asset position of $0.1 million of Forward power contracts that had been, but no longer need to be, accounted for as derivatives at fair value that are to be amortized to earnings over the remaining term of the associated forward contract.

Fair Values of Derivative Instruments
December 31, 2013

$ in millions	Hedging Designation	Gross Fair Value as presented in the Consolidated Balance Sheets (a)	Gross Amounts Not Offset in the Consolidated Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Consolidated Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.2)	$ -	$ 0.3
Forward power contracts	MTM	4.9	(4.2)	-	0.7
FTRs	MTM	0.2	-	-	0.2
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	3.0	-	(3.0)	-
Forward power contracts	MTM	5.0	(0.3)	-	4.7
Total assets		$ 13.8	$ (4.7)	$ (3.2)	$ 5.9
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.7	$ (0.2)	$ (2.3)	$ 0.2
Forward power contracts	MTM	6.6	(4.2)	(2.3)	0.1
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	MTM	1.3	(0.3)	(1.0)	-
Total liabilities		$ 10.6	$ (4.7)	$ (5.6)	$ 0.3

(a) Includes credit valuation adjustment.

As of December 31, 2013, this table includes Forward power contracts in a short-term asset position of $5.4 million and a long-term asset position of $8.0 million. This table does not include a short-term asset position of $0.9 million or a long-term asset position of $0.1 million of Forward power contracts that had been, but no longer need to be, accounted for as derivatives at fair value that are to be amortized to earnings over the remaining term of the associated forward contract.

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. Since our debt has fallen below investment grade, we are in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. Since our debt has fallen below investment grade, some of our counterparties to the derivative instruments have requested collateralization of the MTM loss.

The aggregate fair value of **DPL's** derivative instruments that are in a MTM loss position at December 31, 2014 is $12.2 million. This amount is offset by $4.9 million of collateral posted directly with third parties and in a broker margin account which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $6.6 million. Since our debt is below investment grade, we could have to post collateral for the remaining $0.7 million.

NOTE 11 – REDEEMABLE PREFERRED STOCK

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2014. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2014. The table below details the preferred shares outstanding at December 31, 2014:

		December 31, 2014 and 2013		Carrying Value [(a)] ($ in millions)	
	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	December 31, 2014	December 31, 2013
DP&L Series A	3.75%	$ 102.50	93,280	$ 7.4	$ 7.4
DP&L Series B	3.75%	$ 103.00	69,398	5.6	5.6
DP&L Series C	3.90%	$ 101.00	65,830	5.4	5.4
Total			228,508	$ 18.4	$ 18.4

(a) Carrying value is fair value at the Merger date plus cumulative accrued dividends, of which there were none at December 31, 2014.

The **DP&L** preferred stock may be redeemed at **DP&L's** option as determined by its Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends, of which there were none as of December 31, 2014. In addition, **DP&L's** Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Since this potential redemption-triggering event is not solely within the control of **DP&L**, the preferred stock is presented on the Consolidated Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

As long as any **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not affected **DP&L's** ability to pay cash dividends and, as of December 31, 2014, **DP&L's** retained earnings of $381.8 million were all available for common stock dividends payable to **DPL**. We do not expect this restriction to have an effect on the payment of cash dividends in the future. **DPL** records dividends on preferred stock of **DP&L** within Interest expense on the Statements of Operations.

NOTE 12 – COMMON SHAREHOLDERS' EQUITY

Effective on the Merger date, **DPL** adopted Amended Articles of Incorporation providing for 1,500 authorized common shares, of which one share is outstanding at December 31, 2014.

As of December 31, 2014, there was no Event of Default - **DPL's** Articles generally define an "Event of Default" as either (i) a breach of a covenant or obligation under the Articles; (ii) the entering of an order of insolvency or bankruptcy by a court and that order remains in effect and unstayed for 180 days; or (iii) **DPL**, **DP&L** or one of its principal subsidiaries commences a voluntary case under bankruptcy or insolvency laws or consents to the appointment of a trustee, receiver or custodian to manage all of the assets of **DPL**, **DP&L** or one of its principal subsidiaries – but **DPL's** leverage ratio was at 0.93 to 1.00 and **DPL's** senior long-term debt rating from all three major credit rating agencies was below investment grade. As a result, as of December 31, 2014, **DPL** was prohibited under its Articles from making a distribution to its shareholder or making a loan to any of its affiliates (other than its subsidiaries).

NOTE13 – CONTRACTUAL OBLIGATIONS, COMMERCIAL COMMITMENTS AND CONTINGENCIES

DPL – Guarantees

In the normal course of business, **DPL** enters into various agreements with its wholly-owned subsidiaries, DPLE and DPLER and its wholly-owned subsidiary, MC Squared, providing financial or performance assurance to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to these subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish these subsidiaries' intended commercial purposes.

At December 31, 2014, **DPL** had $20.5 million of guarantees to third parties for future financial or performance assurance under such agreements, including $2.0 million of guarantees on behalf of DPLER, $18.3 million of guarantees on behalf of DPLE and $0.2 million of guarantees on behalf of MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLER, DPLE and MC Squared to such beneficiaries and are terminable at any time by **DPL** upon written notice to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $1.6 million and $0.2 million at December 31, 2014 and 2013, respectively.

To date, **DPL** has not incurred any losses related to the guarantees of DPLER's, DPLE's and MC Squared's obligations and we believe it is remote that **DPL** would be required to perform or incur any losses in the future associated with any of the above guarantees of DPLER's, DPLE's and MC Squared's obligations.

Equity Ownership Interest

DP&L has a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of December 31, 2014, **DP&L** could be responsible for the repayment of 4.9%, or $74.4 million, of a $1,517.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2015 and 2040. This would only happen if this electric generation company defaulted on its debt payments. At December 31, 2014, we have no knowledge of such a default.

Contractual Obligations and Commercial Commitments

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2014, these include:

	Payments due in:				
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DPL:					
Coal contracts [(a)]	486.2	255.6	161.2	69.4	-
Limestone contracts [(a)]	18.3	6.1	12.2	-	-
Purchase orders and other contractual obligations	72.4	39.2	17.3	15.9	-

(a) Total at **DP&L** operated units.

Coal contracts:

DPL, through its principal subsidiary **DP&L**, has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. As of December 31, 2014, 57% of our future committed coal obligations are with a single supplier. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:

DPL, through its principal subsidiary **DP&L**, has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:

As of December 31, 2014, **DPL** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

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Contingencies

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Consolidated Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2014, cannot be reasonably determined.

Environmental Matters

DPL's and **DP&L's** facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including SIPs) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and
- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $0.8 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable or a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to environmental matters quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations.

Environmental Matters Related to Air Quality

Clean Air Act Compliance

In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on how much of a pollutant can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

Clean Air Interstate Rule/Cross-State Air Pollution Rule

The USEPA promulgated CAIR on March 10, 2005, which required allowance surrender for SO_2 and NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. To implement the required emission reductions for this rule, the states were to establish emission-allowance-based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.

On July 7, 2011, the USEPA proposed CSAPR to replace CAIR. CSAPR required significant reductions in SO_2 and NOx emissions from covered sources, such as power stations in 28 eastern states including Ohio. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that the USEPA overstepped its regulatory authority by requiring states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR continued to serve as the governing program. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR, and on April 29, 2014, the U.S. Supreme Court reversed the 2012 decision by the D.C. Circuit Court, reinstating CSAPR, and remanded the case back to the D.C. Circuit Court for further proceedings consistent with the U. S. Supreme Court decision. On June 26, 2014, the U.S. Department of Justice, on behalf of the USEPA, filed a motion with the D.C. Circuit Court to lift the stay, and CSAPR was reinstated on October 23, 2014. The USEPA established new effective dates for compliance with the reduced emissions levels, beginning in 2015 with additional reductions in 2017. Oral arguments to address the remaining litigation regarding CSAPR are schedule for March 2015. At this time, it is not possible to predict with precision what impacts CSAPR may have on our consolidated financial condition, results of operations or cash flows, but we do not expect to have material capital costs to comply with CSAPR.

Mercury and Other Hazardous Air Pollutants
On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The USEPA Administrator signed the final rule, now called MATS, on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected EGUs must come into compliance with the new requirements by April 16, 2015. All of our operating EGUs are expected to be able to achieve compliance through control technologies that are currently in place.

On January 31, 2013, the USEPA finalized a rule regulating emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulation contains emissions limitations, operating limitations and other requirements. **DP&L** expects to be in compliance with this rule and the costs are not currently expected to be material to **DP&L's** operations.

National Ambient Air Quality Standards
On January 5, 2005, the USEPA published its final non-attainment designations for the National Ambient Air Quality Standard (NAAQS) for Fine Particulate Matter 2.5 (PM 2.5). These designations included counties and partial counties in which **DP&L** operates and/or owns generating facilities. On December 31, 2012, the USEPA re-designated Adams County, where the Stuart and Killen generating stations are located, to attainment status. On December 14, 2012, the USEPA tightened the PM 2.5 standard to 12.0 micrograms per cubic meter, and on December 18, 2014, issued a pre-publication version of the final attainment designations. No counties containing **DP&L** operated generating facilities were designated as non-attainment, however, several co-owned units are located in non-attainment counties. Attainment in those counties will be required by the end of 2021. We cannot predict the effect the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

The USEPA published the national ground level ozone standard on March 12, 2008, lowering the 8-hour level from 0.08 ppm to 0.075 ppm, which was upheld by the U.S. Circuit Court of Appeals in July 2013. No **DP&L** operations are currently located in non-attainment areas. On December 17, 2014, the USEPA published a proposed rule lowering the 8-hour ozone standard from 0.075 to a value between 0.065 and 0.070 ppm. The USEPA intends to finalize the rule regarding the ozone NAAQS by October 2015, with initial designations to be issued in October 2017. In addition, in December 2013, eight northeastern states petitioned the USEPA to add nine upwind states, including Ohio, to the Ozone Transport Region, a group of states required to impose enhanced restrictions on ozone emissions. If the petition is granted, our facilities could be subject to such enhanced requirements. We cannot predict the effect the revisions of the ozone standard will have on **DP&L's** financial condition or results of operations.

Effective April 12, 2010, the USEPA implemented revisions to its primary NAAQS for nitrogen dioxide. This change may affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and

Dayton after 2016. Several of our facilities or co-owned facilities are within this area. **DP&L** cannot determine the effect of this potential change, if any, on its operations.

Effective August 23, 2010, the USEPA implemented its revisions to its primary NAAQS for SO_2 replacing the previous 24-hour standard and annual standard with a one-hour standard. Initial non-attainment designations were made July 25, 2013, and Pierce Township in Clermont County, location of **DP&L's** co-owned unit Beckjord Unit 6, was the only area with **DP&L** operations designated as non-attainment. Beckjord Unit 6 was retired effective October 1, 2014. Non-attainment areas will be required to meet the 2010 standard by October 2018. On April 17, 2014, the USEPA proposed a data requirements rule for air agencies to ascertain attainment characterization more extensively across the country by additional modeling and/or monitoring requirements of areas with sources that exceed specified thresholds of SO_2 emissions. The rule, if finalized, could require the installation of monitors at one or more of **DP&L's** coal-fired power plants and result in additional non-attainment designations that could impact our operations. **DP&L** is unable to determine the effect of the proposed rule on its operations.

On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide and Other Greenhouse Gas Emissions
The USEPA began regulating GHG emissions from certain stationary sources in January 2011 under regulations referred to as the "Tailoring Rule." The regulations are implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing certain new construction or major modifications, the Prevention of Significant Deterioration, or PSD, program. Obligations relating to Title V permits include recordkeeping and monitoring requirements. Sources subject to PSD can be required to implement Best Available Control Technology, or BACT. In June 2014, the U.S. Supreme Court ruled that the USEPA had exceeded its statutory authority in issuing the Tailoring Rule under Section 165 of the CAA by regulating sources under the PSD program based solely on their GHG emissions. However, the U.S. Supreme Court also held that the USEPA could impose GHG BACT requirements for sources already required to implement PSD for certain other pollutants. Therefore, if future modifications to **DP&L's** sources require PSD review for other pollutants, it may also trigger GHG BACT requirements. The USEPA has issued guidance on what BACT entails for the control of GHG and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of the BACT requirements applicable to us on our operations cannot be determined at this time as **DP&L** will not be required to implement BACT until **DP&L** constructs a new major source or makes a major modification of an existing major source. However, the cost of compliance could be material.

In January 2014, the USEPA proposed revised GHG New Source Performance Standards for new EGUs under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. In addition, new natural gas-fired EGUs must meet a standard of no greater than 1,000 pounds of CO_2 per megawatt hour (if the rule is finalized in its current form). The rule is expected to be finalized this summer.

The USEPA issued proposed rules establishing GHG performance standards for existing power plants under CAA Section 111(d) on June 2, 2014. Under the proposed rule, called the Clean Power Plan, states would be judged against state-specific carbon dioxide emissions targets beginning in 2020, with expected total U.S. power section emissions reduction of 30% from 2005 levels by 2030. For Ohio specifically, the Clean Power Plan proposes an interim goal for 2020-2029 and a proposed 2030 final goal of 1,452 pounds of CO_2 per megawatt hour and 1,338 pounds of CO_2 per megawatt hour, respectively, a reduction of approximately 28% from 2012 levels. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one- or two-year extensions under certain circumstances. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one or two-year extensions under certain circumstances. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one- or two-year extensions under certain circumstances. The proposed rule was subject to a public comment process and the USEPA is expected to finalize it by the summer of 2015. Among other things, we could be required to make efficiency improvements to existing facilities. The USEPA also issued proposed carbon pollution standards for modified and reconstructed power plants on June 2, 2014, which are also expected to be finalized by the summer of 2015.

Various states and certain regulated entities have filed lawsuits challenging the Clean Power Plan. However, it is too soon to determine what the rule, and the corresponding SIPs affecting our operations, will require once they are finalized, whether they will survive judicial and other challenges, and if so, whether and when the rule and the corresponding SIP would materially impact our business, operations or financial condition.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. Further GHG legislation or regulation implemented at a future date could have a significant effect on **DP&L's** operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial effect that such legislation or regulation may have on **DP&L**.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Stations
As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, **DP&L** and the other owners of the Stuart generating station are subject to certain specified emission targets related to NO_x, SO_2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on **DP&L's** results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Units
In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and AEP Generation) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. **DP&L** cannot predict the outcome of this matter.

In December 2007, the Ohio EPA issued an NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) for alleged violations of the CAA. The NOV alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received an NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio SIP and permits for the station in areas including SO_2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, the USEPA issued an NOV to Zimmer for excess emissions. In addition, Zimmer received an NOV from the USEPA dated December 16, 2014 alleging violations in opacity on two dates in 2014. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. **DP&L** is unable to predict the outcome of these matters.

In January 2015, **DP&L** received NOVs from the USEPA alleging violations in opacity at the Stuart and Killen generating stations in 2014. **DP&L** is beginning the process of discussions with the USEPA on these NOVs. **DP&L** is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly-Owned Stations
On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the two projects described in the NOV were modifications subject to NSR. As a result of the cessation of operations of the six coal-fired units at the Hutchings Station, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake
On May 19, 2014, the USEPA finalized new regulations pursuant to the CWA governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of

organisms as a result of cooling water withdrawal. Although we do not yet know the full impact the final rules will have on our operations, the final rules may require material changes to the intake structure at Stuart Station to reduce impingement with the possibility of additional site specific requirements for reducing entrainment. We do not believe the final rules will have a material impact on operations at any of the other **DP&L**-operated facilities.

Clean Water Act – Regulation of Water Discharge
In December 2006, **DP&L** submitted a renewal application for the Stuart generating station NPDES permit that was due to expire on June 30, 2007. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In September 2010, the USEPA formally objected to the November 12, 2008 revised permit due to questions regarding the basis for the alternate thermal limitation. At **DP&L's** request, a public hearing was held on March 23, 2011, where **DP&L** presented its position on the issue and provided written comments. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA did not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit would pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012.

The draft permit required **DP&L,** over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. **DP&L** submitted comments to the draft permit. In November 2012, the Ohio EPA issued another draft which included a compliance schedule for performing a study to justify an alternate thermal limitation and to which **DP&L** submitted comments. In December 2012, the USEPA formally withdrew their objection to the permit. On January 7, 2013, the Ohio EPA issued a final permit. On February 1, 2013, **DP&L** appealed various aspects of the final permit to the Environmental Review Appeals Commission. A hearing before the Commission is scheduled for March 2015. Depending on the outcome of the appeal process, the effects on **DP&L's** operations could be material.

In September 2009, the USEPA announced that it would be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. The proposed rule was released on June 7, 2013. Under a consent decree, the USEPA is required to issue a final rule by September 2015. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

A final NPDES permit for Killen Station was issued on September 4, 2014. We do not expect the new permit to have a material impact on Killen's operations.

In January 2014, **DP&L** submitted an application for the renewal of the Hutchings Station NPDES permit which expired in July 2014. A final permit was issued on September 19, 2014 with an effective date of November 1, 2014. We do not expect the new permit to have a material impact on Hutchings' operations.

Regulation of Waste Disposal
In September 2002, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, **DP&L** and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, **DP&L** received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. On August 16, 2006, an Administrative Settlement Agreement and Order on Consent ("ASAOC") was executed and became effective among a group of PRPs, not including **DP&L**, and the USEPA. On August 25, 2009, the USEPA issued an Administrative Order requiring that access to **DP&L's** service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. **DP&L** granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against **DP&L** and numerous other defendants alleging that **DP&L** and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against **DP&L** that related to allegations that chemicals used by **DP&L** at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly directly

delivered by truck to the landfill. Discovery, including depositions of past and present **DP&L** employees, was conducted in 2012. On February 8, 2013, the Court granted **DP&L's** motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by the PRP group in performing an RI/FS under the August 15, 2006 ASAOC. That summary judgment ruling was appealed on March 4, 2013, and on July 14, 2014, a three-judge panel of the U.S. Court of Appeals for the 6th Circuit affirmed the lower Court's ruling and subsequently denied a request by the plaintiffs for rehearing. On November 14, 2014, the PRP group appealed the decision to the U.S. Supreme Court, but the writ of certiorari was denied by the Court on January 20, 2015. On January 14, 2015, the PRP group served **DP&L** and other defendants a request for production of documents related to any survey regarding waste management or waste disposal. Information responsive to this request was provided on February 17, 2015. In addition, on January 16, 2015, the USEPA issued a Special Notice Letter and Section 104(e) Information Request to **DP&L** and other defendants, requesting historical information related to waste management practices. **DP&L** is in the process of developing its response to the request which is due by March 20, 2015. **DP&L** is unable to predict the outcome of this action by the plaintiffs and USEPA. Additionally, the Court's 2013 ruling and the Court of Appeals' affirmation of that ruling in 2014 does not address future litigation that may arise with respect to actual remediation costs. While **DP&L** is unable to predict the outcome of these matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to **DP&L** does not demonstrate that it contributed hazardous substances to the site. While **DP&L** is unable to predict the outcome of this matter, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. A proposed rule is expected in mid-2015, with a final rule expected in 2016. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds
In March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and Stuart Stations. Subsequently, the USEPA collected similar information for the Hutchings Station.

In August 2010, the USEPA conducted an inspection of the Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the Hutchings Station ash ponds. **DP&L** is unable to predict whether there will be additional USEPA action relative to **DP&L's** proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen Station ash ponds. In May 2012, we received a draft report on the inspection. **DP&L** submitted comments on the draft report in June 2012. On March 14, 2013, **DP&L** received the final report on the inspection of the Killen Station ash pond inspection from the USEPA which included recommended actions. **DP&L** has submitted a response with its actions to the USEPA. **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion residuals (CCR) under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. The USEPA released its final rule on December 19, 2014, designating coal combustion residuals that are not beneficially reused as non-hazardous solid waste under RCRA Subtitle D. The rule becomes effective six months after publication of the rule in the Federal Register, expected in February 2015, and applies new detailed management practices to new and existing landfills and surface impoundments, including lateral expansions of such units. **DP&L** is currently reviewing the rule and assessing the impact on our operations. Our business, financial condition or operations could be materially and adversely affected by this regulation.

Notice of Violation Involving Co-Owned Units
On September 9, 2011, **DP&L** received an NOV from the USEPA with respect to its co-owned Stuart generating station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The

notice alleged non-compliance by **DP&L** with certain provisions of the RCRA, the CWA NPDES permit program and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flows.

Legal and Other Matters

In February 2007, **DP&L** filed a lawsuit in the United States District Court for Southern District of Ohio against Appalachian Fuels, LLC ("Appalachian") seeking damages incurred due to Appalachian's failure to supply approximately 1.5 million tons of coal to two commonly-owned stations under a coal supply agreement, of which *approximately 570 thousand tons was* ***DP&L's*** *share.* ***DP&L*** *obtained replacement coal to meet its needs.* Appalachian has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with **DP&L** and other utilities joining PJM, in 2006, the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, **DP&L** entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolved SECA claims against BP Energy Company ("BP") and **DP&L**, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries). On October 1, 2012, **DP&L** received the $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in other deferred credits related to SECA.

NOTE 14 – BUSINESS SEGMENTS

DPL operates through two segments consisting of the operations of two of its wholly-owned subsidiaries, **DP&L** (Utility segment) and DPLER (Competitive Retail segment which includes DPLER's wholly-owned subsidiary, MC Squared). This is how we view our business and make decisions on how to allocate resources and evaluate performance.

The Utility segment is comprised of **DP&L's** electric generation, transmission and distribution businesses which generate and deliver electricity to residential, commercial, industrial and governmental customers. **DP&L** generates electricity at five coal-fired electric generating stations and distributes electricity to more than 516,000 retail customers who are located in a 6,000 square mile area of West Central Ohio. **DP&L** also sells electricity to DPLER and any excess energy and capacity is sold into the wholesale market. **DP&L's** transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law.

The Competitive Retail segment is DPLER's competitive retail electric service businesses which sell retail electric energy under contract to residential, commercial, industrial and governmental customers who have selected DPLER or its subsidiary MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 260,000 customers currently located throughout Ohio and in Illinois. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L**. Intercompany sales from **DP&L** to DPLER are based on fixed-price contracts for each customer; the price approximates market prices for wholesale power at the inception of each customer's contract. **DP&L** started selling power to MC Squared during June 2012 and became their sole source of power in September 2012 under the same terms as above. The operations of the Competitive Retail segment are not subject to cost-of-service rate regulation by federal or state regulators.

Included within the "Other" column are other businesses that do not meet the GAAP requirements for disclosure as reportable segments as well as certain corporate costs which include interest expense on **DPL's** debt.

Management evaluates segment performance based on gross margin. The accounting policies of the reportable segments are the same as those described in Note 1 – Overview and Summary of Significant Accounting Policies. Intersegment sales and profits are eliminated in consolidation.

The following tables present financial information for each of **DPL's** reportable business segments:

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2014					
Revenues from external customers	$ 1,181.2	$ 533.6	$ 48.2	$ -	$ 1,763.0
Intersegment revenues	487.1	-	5.5	(492.6)	-
Total revenues	1,668.3	533.6	53.7	(492.6)	1,763.0
Fuel	314.9	-	(10.4)	-	304.5
Purchased power	582.4	491.8	7.5	(489.1)	592.6
Amortization of intangibles	-	-	1.2	-	1.2
Gross margin[(a)]	$ 771.0	$ 41.8	$ 55.4	$ (3.5)	$ 864.7
Depreciation and amortization	$ 144.8	$ 0.8	$ (5.8)	$ -	$ 139.8
Goodwill impairment (Note 5)	$ -	$ -	$ 135.8	$ -	$ 135.8
Fixed asset impairment	$ -	$ -	$ 11.5	$ -	$ 11.5
Interest expense	$ 33.9	$ 0.5	$ 92.9	$ (0.7)	$ 126.6
Income tax expense / (benefit)	$ 39.7	$ 2.0	$ (23.7)	$ -	$ 18.0
Net income / (loss)	$ 115.0	$ 3.2	$ (192.8)	$ -	$ (74.6)
Cash capital expenditures	$ 114.2	$ 2.5	$ 1.4	$ -	$ 118.1
Total assets (end of year)	$ 3,338.7	$ 94.9	$ 1,440.1	$ (1,295.9)	$ 3,577.8

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2013					
Revenues from external customers	$ 1,098.2	$ 511.6	$ 27.1	$ -	$ 1,636.9
Intersegment revenues	453.3	-	4.0	(457.3)	-
Total revenues	1,551.5	511.6	31.1	(457.3)	1,636.9
Fuel	362.5	-	4.2	-	366.7
Purchased power	381.9	459.7	1.1	(453.7)	389.0
Amortization of intangibles	-	-	7.1	-	7.1
Gross margin (a)	$ 807.1	$ 51.9	$ 18.7	$ (3.6)	$ 874.1
Depreciation and amortization	$ 140.2	$ 0.6	$ (7.9)	$ -	$ 132.9
Goodwill impairment (Note 5)	$ -	$ -	$ 306.3	$ -	$ 306.3
Fixed asset impairment	$ 86.0	$ -	$ (59.8)	$ -	$ 26.2
Interest expense	$ 37.2	$ 0.5	$ 86.9	$ (0.6)	$ 124.0
Income tax expense / (benefit)	$ 18.6	$ 4.2	$ (0.5)	$ -	$ 22.3
Net income / (loss)	$ 83.6	$ 6.6	$ (312.2)	$ -	$ (222.0)
Cash capital expenditures	$ 122.1	$ -	$ 2.3	$ -	$ 124.4
Total assets (end of year)	$ 3,313.1	$ 105.0	$ 1,675.8	$ (1,372.4)	$ 3,721.5

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

$ in millions	Utility	Competitive Retail	Other	Adjustments and Eliminations	DPL Consolidated
Year ended December 31, 2012					
Revenues from external customers	$ 1,138.4	$ 493.1	$ 36.9	$ -	$ 1,668.4
Intersegment revenues	393.4	-	3.4	(396.8)	-
Total revenues	1,531.8	493.1	40.3	(396.8)	1,668.4
Fuel	354.9	-	7.0	-	361.9
Purchased power	309.5	424.5	1.5	(393.4)	342.1
Amortization of intangibles	-	-	95.1	-	95.1
Gross margin (a)	$ 867.4	$ 68.6	$ (63.3)	$ (3.4)	$ 869.3
Depreciation and amortization	$ 141.3	$ 0.4	$ (16.3)	$ -	$ 125.4
Goodwill impairment (Note 5)	$ -	$ -	$ 1,817.2	$ -	$ 1,817.2
Fixed asset impairment	$ 80.8	$ -	$ (80.8)	$ -	$ -
Interest expense	$ 39.1	$ 0.6	$ 83.9	$ (0.7)	$ 122.9
Income tax expense / (benefit)	$ 55.1	$ 18.1	$ (25.5)	$ -	$ 47.7
Net income / (loss)	$ 91.2	$ 22.8	$ (1,725.4)	$ (118.4)	$ (1,729.8)
Cash capital expenditures	$ 195.5	$ -	$ 2.6	$ -	$ 198.1
Total assets (end of year)	$ 3,464.2	$ 99.2	$ 683.9	$ -	$ 4,247.3

(a) For purposes of discussing operating results, we present and discuss gross margins. This format is useful to investors because it allows analysis and comparability of operating trends and includes the same information that is used by management to make decisions regarding our financial performance.

NOTE 15 – FIXED-ASSET IMPAIRMENT

During the first quarter of 2014, **DP&L** tested the recoverability of long-lived assets at East Bend, a 186 MW coal-fired plant in Kentucky jointly-owned by **DP&L**. Indications during that quarter that the fair value of the asset group was less than its carrying amount were determined to be impairment indicators given how narrowly these long-lived assets had passed the recoverability test during the fourth quarter of 2013. **DP&L** performed a long-lived asset impairment test and determined that the carrying amount of the asset group was not recoverable. The East Bend asset group was determined to have a fair value of $2.7 million using the market approach. As a result, we recognized an asset impairment expense of $11.5 million. East Bend is reported in the Utility segment, however, this impairment is shown within Other in Business Segments (Note 14) due to acquisition adjustments at **DPL** which were not pushed down to the utility segment.. In May 2014, an agreement was signed for the sale of **DP&L's** interest in the generating assets at East Bend. This transaction closed on December 30, 2014.

During the fourth quarter of 2013, the Company tested the recoverability of the long-lived assets at Conesville, a 129 MW coal-fired station in Ohio jointly-owned by **DP&L.** Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit failing step 1 of the annual goodwill impairment test were determined to be an impairment indicator for long-lived assets. The Company performed a long-lived asset impairment test and determined that the carrying amount of the asset group was not recoverable. The long-lived asset group subject to the impairment evaluation was determined to be each individual station of **DP&L**. This determination was based on the assessment of the stations' ability to generate independent cash flows. The Conesville asset group was determined to have zero fair value using discounted cash flows under the income approach. As a result, the Company recognized an asset impairment expense of $26.2 million. Conesville is reported in the Utility segment.

FINANCIAL STATEMENTS

The Dayton Power and Light Company

Report of Independent Registered Public Accounting Firm

To the Board of Directors of The Dayton Power and Light Company

We have audited the accompanying balance sheets of The Dayton Power and Light Company (DP&L) as of December 31, 2014 and 2013, and the related statements of operations, comprehensive income, cash flows, and shareholder's equity for each of the three years in the period ended December 31, 2014. Our audit also included the financial statement schedule "Schedule II – Valuation and Qualifying Accounts" for each of the three years in the period ended December 31, 2014. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of DP&L at December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
February 25, 2015
Indianapolis, Indiana

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF OPERATIONS

$ in millions	Year ended December 31, 2014	2013	2012
Revenues	$ 1,668.3	$ 1,551.5	$ 1,531.8
Cost of revenues:			
Fuel	314.9	362.5	354.9
Purchased power	582.4	381.9	309.5
Total cost of revenues	897.3	744.4	664.4
Gross margin	771.0	807.1	867.4
Operating expenses:			
Operation and maintenance	353.2	362.1	385.9
Depreciation and amortization	144.8	140.2	141.3
General taxes	87.7	76.4	74.4
Fixed asset impairment	-	86.0	80.8
Other	(3.5)	2.5	0.2
Total operating expenses	582.2	667.2	682.6
Operating income	188.8	139.9	184.8
Other income / (expense), net			
Investment income	0.9	2.0	2.3
Interest expense	(33.9)	(37.2)	(39.1)
Other deductions	(1.1)	(2.5)	(1.7)
Total other expense, net	(34.1)	(37.7)	(38.5)
Earnings (loss) from operations before income tax	154.7	102.2	146.3
Income tax expense	39.7	18.6	55.1
Net income	115.0	83.6	91.2
Dividends on preferred stock	0.9	0.9	0.9
Earnings on common stock	$ 114.1	$ 82.7	$ 90.3

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

$ in millions	Year ended December 31, 2014	2013	2012
Net income	$ 115.0	$ 83.6	$ 91.2
Available-for-sale securities activity:			
Change in fair value of available-for-sale securities, net of income tax benefit / (expense) of $0.2, $0.9 and $(0.2) for each respective period	(0.3)	(1.6)	0.5
Reclassification to earnings, net of income tax benefit / (expense) of $(0.2), $(0.7) and $0.0 for each respective period	0.2	1.4	(0.1)
Total change in fair value of available-for-sale securities	(0.1)	(0.2)	0.4
Derivative activity:			
Change in derivative fair value, net of income tax benefit / (expense) of $10.5, $(0.6) and $1.6 for each respective period	(18.8)	1.0	(3.0)
Reclassification of earnings, net of income tax benefit / (expense) of $(11.5), $(2.5) and $0.5 for each respective period	15.4	2.6	(3.4)
Total change in fair value of derivatives	(3.4)	3.6	(6.4)
Pension and postretirement activity:			
Prior service cost for the period, net of income tax benefit / (expense) of $0.0, $(0.2) and $(0.5) for each respective period	-	0.5	0.8
Net loss for the period, net of income tax benefit / (expense) of $6.9, $(1.9) and $0.8 for each respective period	(12.1)	4.3	(1.5)
Reclassification to earnings, net of income tax benefit / (expense) of $0.0, $(1.9) and $(1.5) for each respective period	-	3.8	2.7
Total change in unfunded pension and postretirement obligation	(12.1)	8.6	2.0
Other comprehensive income / (loss)	(15.6)	12.0	(4.0)
Net comprehensive income	$ 99.4	$ 95.6	$ 87.2

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

	Year ended December 31,		
$ in millions	**2014**	2013	2012
Cash flows from operating activities:			
Net income	$ 115.0	$ 83.6	$ 91.2
Adjustments to reconcile Net income (loss) to Net cash from operating activities			
Depreciation and amortization	**144.8**	140.2	141.3
Deferred income taxes	**7.5**	(16.8)	3.6
Fixed asset impairment	**-**	86.0	80.8
Loss / (Gain) on asset disposal	**(3.5)**	2.5	0.2
Recognition of deferred SECA revenue	**-**	-	(17.8)
Changes in certain assets and liabilities:			
Accounts receivable	**(7.1)**	15.0	20.9
Inventories	**(24.6)**	27.2	14.2
Prepaid taxes	**(1.1)**	0.4	0.1
Taxes applicable to subsequent years	**(6.9)**	(1.8)	5.2
Deferred regulatory costs, net	**5.4**	7.8	(1.5)
Accounts payable	**32.4**	(5.9)	(15.3)
Accrued taxes payable	**9.0**	(9.1)	(8.5)
Accrued interest payable	**0.1**	(3.4)	5.2
Other current and deferred liabilities	**(18.1)**	5.9	(22.1)
Pension, retiree and other benefits	**19.1**	1.8	28.5
Unamortized investment tax credit	**(2.5)**	(2.5)	(2.5)
Other	**(17.8)**	4.4	16.3
Net cash from operating activities	**251.7**	335.3	339.8
Cash flows from investing activities:			
Capital expenditures	**(114.2)**	(122.1)	(195.5)
Decrease / (increase) in restricted cash	**(3.7)**	(2.3)	2.9
Purchase of renewable energy credits	**(3.5)**	(3.9)	(5.4)
Proceeds from sale of property	**10.7**	0.8	0.2
Insurance proceeds	**0.9**	14.2	-
Other investing activities, net	**1.3**	(1.2)	0.3
Net cash from investing activities	**(108.5)**	(114.5)	(197.5)

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS (continued)

$ in millions	Year ended December 31, 2014	2013	2012
Cash flows from financing activities			
Dividends paid on common stock to parent	**(159.0)**	(190.0)	(145.0)
Dividends paid on preferred stock	**(0.9)**	(0.9)	(0.9)
Retirement of long-term debt	**(0.1)**	(470.1)	(0.1)
Issuance of long-term debt	**-**	445.0	-
Deferred financing costs	**(0.7)**	(10.4)	-
Borrowings from related party	**15.0**	-	-
Repayment of borrowings from related party	**(15.0)**	-	-
Net cash from financing activities	**(160.7)**	(226.4)	(146.0)
Cash and cash equivalents:			
Net change	**(17.5)**	(5.6)	(3.7)
Balance at beginning of period	**22.9**	28.5	32.2
Cash and cash equivalents at end of period	**$ 5.4**	$ 22.9	$ 28.5
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	**$ 26.6**	$ 41.5	$ 35.1
Income taxes (refunded) / paid, net	**$ 0.7**	$ (20.3)	$ 61.9
Non-cash financing and investing activities:			
Accruals for capital expenditures	**$ 16.3**	$ 14.7	$ 16.7

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5.4	$ 22.9
Restricted cash	16.7	13.0
Accounts receivable, net (Note 2)	152.7	147.5
Inventories (Note 2)	99.0	81.7
Taxes applicable to subsequent years	75.4	68.5
Regulatory assets, current (Note 3)	44.2	20.8
Other prepayments and current assets	41.1	32.5
Total current assets	434.5	386.9
Property, plant and equipment:		
Property, plant and equipment	5,120.7	5,105.3
Less: Accumulated depreciation and amortization	(2,495.7)	(2,448.1)
	2,625.0	2,657.2
Construction work in process	75.4	60.9
Total net property, plant and equipment	2,700.4	2,718.1
Other non-current assets:		
Regulatory assets, non-current (Note 3)	167.5	159.7
Intangible assets, net of amortization (Note 1)	7.8	8.3
Other deferred assets	28.5	40.1
Total other non-current assets	203.8	208.1
Total Assets	$ 3,338.7	$ 3,313.1

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	**December 31, 2014**	December 31, 2013
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 5)	**$ 0.1**	$ 0.2
Accounts payable	**104.8**	73.9
Accrued taxes	**82.6**	81.0
Accrued interest	**9.8**	9.6
Customer security deposits	**34.5**	33.1
Regulatory liabilities, current (Note 3)	**4.4**	-
Other current liabilities	**44.8**	59.7
Total current liabilities	**281.0**	257.5
Non-current liabilities:		
Long-term debt (Note 5)	**877.0**	876.9
Deferred taxes (Note 6)	**650.0**	632.3
Taxes payable	**78.4**	76.5
Regulatory liabilities, non-current (Note 3)	**124.1**	121.1
Pension, retiree and other benefits (Note 7)	**95.9**	51.6
Unamortized investment tax credit	**22.4**	24.9
Other deferred credits	**43.6**	45.4
Total non-current liabilities	**1,891.4**	1,828.7
Redeemable preferred stock (Note 10)	**22.9**	22.9
Commitments and contingencies (Note 12)		
Common shareholder's equity:		
Common stock, par value of $0.01 per share	**0.4**	0.4
250,000,000 shares authorized, 41,172,173 shares issued and		
Other paid-in capital	**803.5**	803.5
Accumulated other comprehensive loss	**(42.3)**	(26.7)
Retained earnings	**381.8**	426.8
Total common shareholder's equity	**1,143.4**	1,204.0
Total Liabilities and Shareholder's Equity	**$ 3,338.7**	$ 3,313.1

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF SHAREHOLDER'S EQUITY

$ in millions (except Outstanding Shares)	Common Stock (a) Outstanding Shares	Common Stock (a) Amount	Other Paid-in Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings	Total
Beginning balance	41,172,173	$ 0.4	$ 803.2	$ (34.7)	$ 589.0	$ 1,357.9
Year ended December 31, 2012						
Total comprehensive income (loss)				(4.0)	91.2	87.2
Common stock dividends					(145.0)	(145.0)
Preferred stock dividends					(0.9)	(0.9)
Other			0.1		(0.2)	(0.1)
Ending balance	41,172,173	0.4	803.3	(38.7)	534.1	1,299.1
Year ended December 31, 2013						
Total comprehensive income (loss)				12.0	83.6	95.6
Common stock dividends					(190.0)	(190.0)
Preferred stock dividends					(0.9)	(0.9)
Other			0.2			0.2
Ending balance	41,172,173	0.4	803.5	(26.7)	426.8	1,204.0
Year ended December 31, 2014						
Total comprehensive income (loss)				**(15.6)**	**115.0**	**99.4**
Common stock dividends					**(159.0)**	**(159.0)**
Preferred stock dividends					**(0.9)**	**(0.9)**
Other					**(0.1)**	**(0.1)**
Ending balance	41,172,173	$ 0.4	$ 803.5	$ (42.3)	$ 381.8	$ 1,143.4

(a) $0.01 par value, 50,000,000 shares authorized.

See Notes to Financial Statements.

The Dayton Power and Light Company
Notes to Financial Statements
For the years ended December 31, 2014, 2013 and 2012

NOTE 1 – OVERVIEW AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Business

DP&L is a public utility incorporated in 1911 under the laws of Ohio. Beginning in 2001, Ohio law gave Ohio consumers the right to choose the electric generation supplier from whom they purchase retail generation service, however distribution and transmission retail service are still regulated. **DP&L** has the exclusive right to provide such service to its more than 516,000 customers located in West Central Ohio. Additionally, **DP&L** procures and provides retail SSO electric service to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio and generates electricity at five coal-fired power stations. Beginning in 2014, **DP&L** no longer supplies 100% of the generation for SSO customers and by January 2016, SSO will be 100% competitively bid. Principal industries located in **DP&L's** service territory include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions, seasonal weather patterns of the area and the market price of electricity. **DP&L** sells any excess energy and capacity into the wholesale market. **DP&L** also sells electricity to DPLER, an affiliate, to satisfy the electric requirements of its retail customers.

In accordance with the ESP Order, on December 30, 2013, **DP&L** filed an application with the PUCO stating its plan to transfer or sell its generation assets. Comments and reply comments were filed. **DP&L** amended its application on February 25, 2014 and again on May 23, 2014. Additional comments and reply comments were filed. On July 14, 2014, **DP&L** announced its decision to retain **DP&L's** generation assets. On September 17, 2014 the PUCO ordered that **DP&L's** application as amended and updated was approved. **DP&L** is required to sell or transfer its generation assets by January 1, 2017 and continues to look at multiple options to effectuate the separation including transfer into a new unregulated affiliate of **DPL** or through a sale.

On November 28, 2011, **DP&L's** parent company **DPL** was acquired by AES in the Merger and **DPL** became a wholly-owned subsidiary of AES. Following the Merger of **DPL** and Dolphin Subsidiary II, Inc., **DPL** became an indirectly wholly-owned subsidiary of AES.

DP&L's electric transmission and distribution businesses are subject to rate regulation by federal and state regulators while its generation business is deemed competitive under Ohio law. Accordingly, **DP&L** applies the accounting standards for regulated operations to its electric transmission and distribution businesses and records regulatory assets when incurred costs are expected to be recovered in future customer rates, and regulatory liabilities when current cost recoveries in customer rates relate to expected future costs.

DP&L employed 1,130 people as of December 31, 2014. Approximately 64% of all employees are under a collective bargaining agreement which expires on October 31, 2017.

Financial Statement Presentation

DP&L does not have any subsidiaries. **DP&L** has undivided ownership interests in five electric generating facilities and numerous transmission facilities. These undivided interests in jointly-owned facilities are accounted for on a pro rata basis in **DP&L's** Financial Statements.

Certain immaterial amounts from prior periods have been reclassified to conform to the current period presentation.

The preparation of financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the revenues and expenses of the periods reported. Actual results could differ from these estimates. Significant items subject to such estimates and judgments include: the carrying value of Property, plant and equipment; unbilled revenues; the valuation of derivative instruments; the valuation of insurance and claims liabilities; the valuation of allowances for receivables and deferred income taxes; Regulatory assets and liabilities; reserves recorded for income tax exposures; litigation; contingencies; the valuation of AROs; and assets and liabilities related to employee benefits.

Revenue Recognition

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We consider revenue realized, or realizable, and earned when persuasive evidence of an arrangement exists, the products or services have been provided to the customer, the sales price is fixed or determinable, and collection is reasonably assured. Energy sales to customers are based on the reading of their meters that occurs on a systematic basis throughout the month. We recognize the revenues on our statements of results of operations using an accrual method for retail and other energy sales that have not yet been billed, but where electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. At the end of each month, unbilled revenues are determined by the estimation of unbilled energy provided to customers since the date of the last meter reading, estimated line losses, the assignment of unbilled energy provided to customer classes and the average rate per customer class.

All of the power produced at the generation stations is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. The power sales and purchases within **DP&L's** service territory are reported on a net hourly basis as revenues or purchased power on our statements of results of operations. We record expenses when purchased electricity is received and when expenses are incurred, with the exception of the *ineffective portion of certain power purchase contracts that are derivatives and qualify for hedge accounting.* We also have certain derivative contracts that do not qualify for hedge accounting, and their unrealized gains or losses are recorded prior to the receipt of electricity.

Allowance for Uncollectible Accounts
We establish provisions for uncollectible accounts by using both historical average loss percentages to project future losses and by establishing specific provisions for known credit issues. Amounts are written off when reasonable collections efforts have been exhausted.

Property, Plant and Equipment
We record our ownership share of our undivided interest in jointly-held stations as an asset in property, plant and equipment. Property, plant and equipment are stated at cost. For regulated transmission and distribution property, cost includes direct labor and material, allocable overhead expenses and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds and equity used to finance regulated construction projects. For non-regulated property, cost also includes capitalized interest. Capitalization of AFUDC and interest ceases at either project completion or at the date specified by regulators. AFUDC and capitalized interest was $1.5 million, $1.5 million, and $4.0 million for the years ended December 31, 2014, 2013 and 2012, respectively.

For unregulated generation property, cost includes direct labor and material, allocable overhead expenses and interest capitalized during construction using the provisions of GAAP relating to the accounting for capitalized interest.

For substantially all depreciable property, when a unit of property is retired, the original cost of that property less any salvage value is charged to Accumulated depreciation and amortization.

Property is evaluated for impairment when events or changes in circumstances indicate that its carrying amount may not be recoverable.

Repairs and Maintenance
Costs associated with maintenance activities, primarily station outages, are recognized at the time the work is performed. These costs, which include labor, materials and supplies, and outside services required to maintain equipment and facilities, are capitalized or expensed based on defined units of property.

Depreciation – Changes in Estimates
Depreciation expense is calculated using the straight-line method, which allocates the cost of property over its estimated useful life. For **DP&L's** generation, transmission and distribution assets, straight-line depreciation is applied monthly on an average composite basis using group rates.

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at certain generating stations. See Note 13 for more information. Gradual decreases in power prices as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator.

In the third quarter of 2012, a series of events led **DP&L** management to conclude that there was impairment in the value of certain generating stations. See Note 13 for more information.

For **DP&L's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 2.8% in 2014, 4.4% in 2013 and 4.2% in 2012.

The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2014 and December 31, 2013:

	December 31,			
$ in millions	**2014**	**Composite Rate**	2013	Composite Rate
Regulated:				
Transmission	**$ 402.4**	**2.3%**	$ 388.3	2.3%
Distribution	**1,568.0**	**3.5%**	1,528.2	3.5%
General	**116.1**	**6.7%**	111.1	6.2%
Non-depreciable	**61.6**	**N/A**	60.8	N/A
Total regulated	**2,148.1**		2,088.4	
Unregulated:				
Production / Generation	**2,957.7**	**2.4%**	3,002.1	5.2%
Non-depreciable	**14.9**	**N/A**	14.8	N/A
Total unregulated	**2,972.6**		3,016.9	
Total property, plant and equipment in service	**$ 5,120.7**	**2.8%**	$ 5,105.3	4.4%

AROs

We recognize AROs in accordance with GAAP which requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time those obligations are incurred. Upon initial recognition of a legal liability, costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the related asset. Our legal obligations associated with the retirement of our long-lived assets consisted primarily of river intake and discharge structures, coal unloading facilities, loading docks, ice breakers and ash disposal facilities. Our generation AROs are recorded within other deferred credits on the balance sheets.

Estimating the amount and timing of future expenditures of this type requires significant judgment. Management routinely updates these estimates as additional information becomes available.

Changes in the Liability for Generation AROs

$ in millions		
Balance at December 31, 2012	$	19.2
Calendar 2013		
Accretion expense		1.0
Settlements		(0.3)
Balance at December 31, 2013		19.9
Calendar 2014		
Additions		3.6
Accretion expense		1.1
Settlements		(1.7)
Balance at December 31, 2014	$	22.9

Asset Removal Costs

We continue to record cost of removal for our regulated transmission and distribution assets through our depreciation rates and recover those amounts in rates charged to our customers. There are no known legal AROs associated with these assets. We have recorded $119.3 million and $115.0 million in estimated costs of removal at December 31, 2014 and 2013, respectively, as regulatory liabilities for our transmission and distribution property. These amounts represent the excess of the cumulative removal costs recorded through depreciation rates versus the cumulative removal costs actually incurred. See Note 3 for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
Balance at December 31, 2012	$	112.1
Calendar 2013		
Additions		22.0
Settlements		(19.1)
Balance at December 31, 2013		115.0
Calendar 2014		
Additions		19.6
Settlements		(15.3)
Balance at December 31, 2014	$	119.3

Regulatory Accounting

As a regulated utility, we apply the provisions of FASC 980 *"Regulated Operations,"* which gives recognition to the ratemaking and accounting practices of the PUCO and the FERC. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory assets can also represent performance incentives permitted by the regulator. Regulatory assets have been included as allowable costs for ratemaking purposes, as authorized by the PUCO or established regulatory practices. Regulatory liabilities generally represent obligations to make refunds or future rate reductions to customers for previous over collections or the deferral of revenues collected for costs that **DPL** expects to incur in the future.

The deferral of costs (as regulatory assets) is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the PUCO or FERC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings. Our regulatory assets and liabilities have been created pursuant to a specific order of the PUCO or FERC or established regulatory practices, such as other utilities under the jurisdiction of the PUCO or FERC being granted recovery of similar costs. It is probable, but not certain, that these regulatory assets will be recoverable, subject to PUCO or FERC approval. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 3 for more information about Regulatory Assets and Liabilities.

Inventories
Inventories are carried at average cost and include coal, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations.

Intangibles
Intangibles consist of emission allowances and renewable energy credits. Emission allowances are carried on a first-in, first out (FIFO) basis for purchased emission allowances. Net gains or losses on the sale of excess emission allowances, representing the difference between the sales proceeds and the cost of emission allowances, are recorded as a component of our fuel costs and are reflected in Operating income when realized. Part of the gains on emission allowances are used to reduce the overall fuel rider charged to our SSO retail customers. Emission allowances are amortized as they are used in our operations. Renewable energy credits are amortized as they are used or retired.

Income Taxes
Income taxes are accounted in accordance with FASC 740 which requires an asset and liability approach for financial accounting and reporting of income taxes with tax effects of differences, based on currently enacted income tax rates, between the financial reporting and tax basis of accounting reported as deferred tax assets or liabilities in the balance sheets. Valuation allowances are provided against deferred tax assets unless it is more likely than not that the asset will be realized.

Investment tax credits, which have been used to reduce federal income taxes payable, are deferred for financial reporting purposes and are amortized over the useful lives of the property to which they relate. For rate-regulated operations, additional deferred income taxes and offsetting regulatory assets or liabilities are recorded to recognize that income taxes will be recoverable or refundable through future revenues.

DPL and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. The consolidated tax liability is allocated to each subsidiary based on the separate return method which is specified in our tax allocation agreement and which provides a consistent, systematic and rational approach. See Note 6 for additional information.

Financial Instruments
We classify our investments in debt and equity financial instruments of publicly traded entities into different categories: available-for-sale and held-to-maturity. Available-for-sale securities are carried at fair value and unrealized gains and losses on those securities, net of deferred income taxes, are presented as a separate component of shareholders' equity. Other-than-temporary declines in value are recognized currently in earnings. Financial instruments classified as held-to-maturity are carried at amortized cost. The cost basis for public equity security and fixed maturity investments is average cost and amortized cost, respectively.

Accounting for Taxes Collected from Customers and Remitted to Governmental Authorities
DP&L collects certain excise taxes levied by state or local governments from its customers. **DP&L's** excise taxes are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Operations in accordance with AES policy. The amounts for the years ended December 31, 2014, 2013 and 2012 were $50.8 million, $50.5 million and $50.5 million, respectively.

Cash and Cash Equivalents
Cash and cash equivalents are stated at cost, which approximates fair value. All highly liquid short-term investments with original maturities of three months or less are considered cash equivalents.

Restricted Cash
Restricted cash includes cash which is restricted as to withdrawal or usage. The nature of the restrictions include restrictions imposed by agreements related to deposits held as collateral.

Financial Derivatives
All derivatives are recognized as either assets or liabilities in the balance sheets and are measured at fair value. Changes in the fair value are recorded in earnings unless they are designated as a cash flow hedge of a forecasted transaction or qualify for the normal purchases and sales exception.

We use forward contracts to reduce our exposure to changes in energy and commodity prices and as a hedge against the risk of changes in cash flows associated with expected electricity purchases. These purchases are used to hedge our full load requirements. We also hold forward sales contracts that hedge against the risk of changes in cash flows associated with power sales during periods of projected generation facility availability. We use cash flow hedge accounting when the hedge or a portion of the hedge is deemed to be highly effective, which results in changes in fair value being recorded within accumulated other comprehensive income, a component of shareholder's equity. We have elected not to offset net derivative positions in the financial statements. Accordingly, we do not offset such derivative positions against the fair value of amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral under master netting agreements. See Note 9 for additional information.

Insurance and Claims Costs
In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL,** provides insurance coverage solely to us, our subsidiaries and, in some cases, our partners in commonly-owned facilities we operate, for workers' compensation, general liability, and property damage on an ongoing basis. MVIC maintains an active run-off policy for directors' and officers' liability and fiduciary through their expiration in 2017 and may or may not be renewed at that time. **DP&L** is responsible for claim costs below certain coverage thresholds of MVIC for the insurance coverage noted above. In addition, **DP&L** has estimated liabilities for medical, life, and disability reserves for claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $15.6 million and $18.8 million at December 31, 2014 and 2013, respectively, within Other current liabilities and Other deferred credits on the balance sheets. The estimated liabilities for MVIC at **DPL** and the estimated liabilities for workers' compensation, medical, life and disability costs at **DP&L** are actuarially determined using certain assumptions. There is uncertainty associated with these loss estimates and actual results may differ from the estimates. Modification of these loss estimates based on experience and changed circumstances is reflected in the period in which the estimate is re-evaluated.

Pension and Postretirement Benefits
We account for and disclose pension and postemployment benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postemployment plans. These GAAP provisions require the use of assumptions, such as the discount rate for liabilities and long-term rate of return on assets, in determining the obligations, annual cost, and funding requirements of the plans.

Related Party Transactions
In the normal course of business, **DP&L** enters into transactions with other subsidiaries of **DPL**. All material intercompany accounts and transactions are eliminated in **DPL's** Consolidated Financial Statements.

In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including, among other companies, **DPL** and **DP&L**. The Service Company allocates the costs for these services based on cost drivers designed to result in fair and equitable allocations. This includes ensuring that the regulated utilities served, including **DP&L,** are not subsidizing costs incurred for the benefit of non-regulated businesses.

The following table provides a summary of these transactions:

$ in millions	Years ended December 31, 2014	2013	2012
DP&L revenues:			
Sales to DPLER (including MC Squared) [(a)]	$ 487.1	$ 453.9	$ 390.8
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC [(b)]	$ (2.9)	$ (2.9)	$ (2.6)
Expense recoveries for services provided to DPLER [(c)]	$ 2.2	$ 5.2	$ 4.0
DP&L Customer security deposits:			
Deposits received from DPLER [(d)]	$ 20.1	$ 19.2	$ 20.2
Transactions with the Service Company:			
Charges for services provided	$ 30.5	$ -	$ -
Charges to the Service Company	$ 0.1	$ -	$ -

Transactions with the Service Company:	At December 31, 2014	At December 31, 2013
Net payable to the Service Company	$ (4.7)	$ -

(a) **DP&L** sells power to DPLER and MC Squared to satisfy the electric requirements of their retail customers. The revenue dollars associated with sales to DPLER and MC Squared are recorded as wholesale revenues in **DP&L's** Financial Statements. **DP&L** started selling physical power to MC Squared during June 2012 and became their sole source of power in September 2012.

(b) MVIC, a wholly-owned captive insurance subsidiary of **DPL**, provides insurance coverage to **DP&L** and other **DPL** subsidiaries for workers' compensation, general liability, property damages and directors' and officers' liability. These amounts represent insurance premiums paid by **DP&L** to MVIC.

(c) In the normal course of business **DP&L** incurs and records expenses on behalf of DPLER. Such expenses include but are not limited to employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. **DP&L** subsequently charges these expenses to DPLER at **DP&L's** cost and credits the expense in which they were initially recorded.

(d) **DP&L** requires credit assurance from the CRES providers serving customers in its service territory because **DP&L** is the default energy provider should the CRES provider fail to fulfill its obligations to provide electricity. Due to **DPL's** credit downgrade, **DP&L** required cash collateral from DPLER.

Recently Adopted Accounting Standards

Discontinued Operations

The FASB recently issued ASU 2014-08 "Presentation of Financial Statements" (Topic 205) and "Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity" effective for annual and interim periods beginning after December 15, 2014. ASU 2014-08 updates the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have (or will have) a major effect on an entity's operations and financial results. In addition, an entity is required to expand disclosures for discontinued operations by providing more information about the assets, liabilities, revenues and expenses of discontinued operations both on the face of the financial statements and in the Notes. For the disposal of an individually significant component of an entity that does not qualify for discontinued operations reporting, an entity is required to disclose the pretax profit or loss of the component in the Notes. Our early adoption of ASU No. 2014-008 in the third quarter of 2014 did not have any impact on our overall results of operations, financial position or cash flows.

Recently Issued Accounting Standards

Going Concern

The FASB recently issued ASU 2014-15 "Presentation of Financial Statements – Going Concern (Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern)" effective for annual and interim periods ending after December 15, 2016. ASU 2014-15 requires management to evaluate whether there are conditions or events, considered in aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. There are

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required disclosures if substantial doubt is identified including documentation of: principal conditions or events that raised substantial doubt about the entity's ability to continue as a going concern (before consideration of management's plans), management's evaluation of the significance of those conditions or events in relation to the entity's ability to meet its obligations, and management's plans that alleviated substantial doubt about the entity's ability to continue as a going concern. This ASU is not expected to have any impact on our overall results of operations, financial position or cash flows.

Revenue from Contracts with Customers
The FASB recently issued ASU 2014-09 "Revenue from Contracts with Customers" (Topic 606) effective for annual and interim periods beginning after December 15, 2016; with retrospective application. The core principle of the ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Because the guidance in this update is principles-based, it can be applied to all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Additionally, the guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. We have not yet determined the extent, if any, to which our overall results of operations, financial position or cash flows may be affected by the implementation of this ASU.

NOTE 2 – SUPPLEMENTAL FINANCIAL INFORMATION

	December 31,	
$ in millions	**2014**	2013
Accounts receivable, net		
Unbilled revenue	$ **49.0**	$ 47.2
Customer receivables	**68.7**	58.2
Amounts due from partners in jointly-owned stations	**14.2**	15.8
Other	**21.7**	27.2
Provisions for uncollectible accounts	**(0.9)**	(0.9)
Total accounts receivable, net	$ **152.7**	$ 147.5
Inventories		
Fuel and limestone	$ **65.3**	$ 42.9
Plant materials and supplies	**32.3**	37.0
Other	**1.4**	1.8
Total inventories, at average cost	$ **99.0**	$ 81.7

Accumulated Other Comprehensive Income (Loss)

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The amounts reclassified out of Accumulated Other Comprehensive Income / (Loss) by component during the years ended December 31, 2014, 2013 and 2012 are as follows:

Details about Accumulated Other Comprehensive *Income / (Loss)* Components	***Affected line item in the Statements of* Operations**	**Years ended December 31,**		
$ in millions		**2014**	2013	2012
Gains and losses on Available-for-sale securities activity (Note 8):				
	Other income / (deductions)	$ **0.4**	$ 2.1	$ (0.1)
	Total before income taxes	**0.4**	2.1	(0.1)
	Tax expense	**(0.2)**	(0.7)	-
	Net of income taxes	**0.2**	1.4	(0.1)
Gains and losses on cash flow hedges (Note 9):				
	Interest expense	**(1.1)**	(2.1)	(2.5)
	Revenue	**28.4**	2.2	0.3
	Purchased power	**(0.4)**	5.0	(1.6)
	Total before income taxes	**26.9**	5.1	(3.8)
	Tax expense	**(11.5)**	(2.5)	0.4
	Net of income taxes	**15.4**	2.6	(3.4)
Amortization of defined benefit pension items (Note 7):				
	Reclassification to Other income / (deductions)	**-**	5.7	4.1
	Tax benefit	**-**	(1.9)	(1.4)
	Net of income taxes	**-**	3.8	2.7
Total reclassifications for the period, net of income taxes		$ **15.6**	$ 7.8	$ (0.8)

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The changes in the components of Accumulated Other Comprehensive Income / (Loss) during the years ended December 31, 2014 and 2013 are as follows:

$ in millions	Gains / (losses) on available-for-sale securities	Gains / (losses) on cash flow hedges	Change in unfunded pension obligation	Total
Balance January 1, 2013	$ 1.0	$ 2.6	$ (42.3)	$ (38.7)
Other comprehensive income / (loss) before reclassifications	(1.6)	1.0	4.8	4.2
Amounts reclassified from accumulated other comprehensive income / (loss)	1.4	2.6	3.8	7.8
Net current period other comprehensive income / (loss)	(0.2)	3.6	8.6	12.0
Balance December 31, 2013	0.8	6.2	(33.7)	(26.7)
Other comprehensive loss before reclassifications	**(0.3)**	**(18.8)**	**(12.1)**	**(31.2)**
Amounts reclassified from accumulated other comprehensive income / (loss)	**0.2**	**15.4**	**-**	**15.6**
Net current period other comprehensive loss	**(0.1)**	**(3.4)**	**(12.1)**	**(15.6)**
Balance December 31, 2014	**$ 0.7**	**$ 2.8**	**$ (45.8)**	**$ (42.3)**

NOTE 3 – REGULATORY MATTERS

In accordance with FASC 980, we have recognized total regulatory assets of $211.7 million and $180.5 million as of December 31, 2014 and 2013, respectively and total regulatory liabilities of $128.5 million and $121.1 million as of December 31, 2014 and 2013, respectively. Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. See Note 1 for accounting policies regarding Regulatory Assets and Liabilities.

The following table presents **DP&L's** Regulatory assets and liabilities:

$ in millions	Type of Recovery [(a)]	Amortization Through	December 31, 2014	December 31, 2013
Regulatory assets, current:				
Deferred storm costs	A	2015	$ 22.3	$ -
Fuel and purchased power recovery costs	B	2015	16.3	6.3
Economic development costs	B	2015	2.1	7.7
Energy efficiency program	B	2015	1.8	-
Transmission costs	B	2015	-	2.6
Other miscellaneous	B	2015	1.7	4.2
Total regulatory assets, current			$ 44.2	$ 20.8
Regulatory assets, non-current:				
Pension benefits	A	Ongoing	$ 99.6	$ 77.1
Deferred recoverable income taxes	A/C	Ongoing	43.1	32.4
Unamortized loss on reacquired debt	A	Various	9.9	10.9
CCEM smart grid and advanced metering infrastructure costs	D	Undetermined	6.6	6.6
Retail settlement system costs	D	Undetermined	3.1	3.1
Consumer education campaign	D	Undetermined	3.0	3.0
Deferred storm costs	D	2015	-	25.6
Other miscellaneous	D	Undetermined	2.2	1.0
Total regulatory assets, non-current			$ 167.5	$ 159.7
Regulatory liabilities, current:				
Transmission costs			$ 2.9	$ -
Other miscellaneous			1.5	-
Total regulatory liabilities, current			$ 4.4	$ -
Regulatory liabilities, non-current:				
Estimated costs of removal - regulated			$ 119.3	$ 115.0
Postretirement benefits			4.8	5.6
Other miscellaneous			-	0.5
Total regulatory liabilities, non-current			$ 124.1	$ 121.1

A – *Recovery of incurred costs without a rate of return.*
B – Recovery of incurred costs plus rate of return.
C – Balance has an offsetting liability resulting in no effect on rate base.
D – Recovery not yet determined, but is probable of occurring in future rate proceedings.

Regulatory Assets

Deferred storm costs represent costs incurred to repair the damage cause to **DP&L's** distribution equipment by major storms in 2008, 2011 and 2012. Such costs are included in Regulatory Assets, non-current on the accompanying Balance Sheets as of December 31, 2013 and in Regulatory Assets, current as of December 31, 2014. **DP&L** filed an application with the PUCO in 2012 to recover these costs. On April 14, 2014, **DP&L** reached an agreement in principle with the PUCO staff whereby **DP&L** would recover storm costs of $22.3 million from all customers on a non-bypassable basis. As a result, using the best estimate of the amount that is probable of recovery, **DP&L** reduced the regulatory asset balance to $22.3 million. In accordance with FASC 980 "Regulated Operations", the reduction was recognized as a current period expense, which is included in Operation and maintenance and the corresponding adjustment to carrying costs which is included in interest expense on the accompanying Statements of Operations. In accordance with the agreement reached with the PUCO staff, a stipulation was filed and a final order was issued on December 17, 2014 that approved the Stipulation. Recovery will begin in January 2015 therefore this asset was reclassified to current.

Fuel and purchased power recovery costs represent prudently incurred fuel, purchased power, derivative, emission and other related costs which will be recovered from or returned to customers in the future through the operation of the fuel and purchased power recovery rider. The fuel and purchased power recovery rider fluctuates based on actual costs and recoveries and is modified at the start of each seasonal quarter. As part of the PUCO approval process, an outside auditor reviews fuel costs and the fuel procurement process. An audit of 2012 fuel costs occurred in 2013, and on June 12, 2013 we received a report from the auditor recommending a pre-tax disallowance of $5.3 million. A reserve of $2.6 million was recorded against the regulatory asset. In August 2014, the PUCO issued an order, which overruled the auditor recommendation and instead included the disallowance of an immaterial amount of fuel costs. The impact of the order was a reversal in the third quarter of 2014 of the vast majority of the previously established $2.6 million reserve and a corresponding reduction to fuel expense. The 2013 audit was completed with no material disallowance of fuel expenses. The costs recovered through the fuel rider decrease each year as more SSO supply is provided through the competitive bid. The fuel rider will be completely phased out beginning January 1, 2016.

Economic development costs represent costs incurred to promote economic development within the State of Ohio. These costs are being recovered through an Economic Development Rider that is subject to a bi-annual true-up process for any over/under recovery of costs.

Energy efficiency program costs represent costs incurred to develop and implement various customer programs addressing energy efficiency. These costs are being recovered through an Energy Efficiency Rider (EER) that began July 1, 2009 and that is subject to an annual true-up for any over/under recovery of costs.

Transmission costs represent the costs related to transmission, ancillary service and other PJM-related charges that have been incurred as a member of PJM. On an annual basis, retail rates are adjusted to true-up costs with recovery in rates.

Pension benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" costs of our regulated operations that for ratemaking purposes are deferred for future recovery. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory asset represents the regulated portion that would otherwise be charged as a loss to OCI.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow-through items as the result of tax benefits previously provided to customers. This is the cumulative flow-through benefit given to regulated customers that will be collected from them in future years. Since currently existing temporary differences between the financial statements and the related tax basis of assets will reverse in subsequent periods, these deferred recoverable income taxes will decrease over time.

Unamortized loss on reacquired debt represents losses on long-term debt reacquired or redeemed in prior periods. These costs are being amortized over the lives of the original issues in accordance with FERC and PUCO rules.

CCEM smart grid and AMI costs represent costs incurred as a result of studying and developing distribution system upgrades and implementation of AMI. On October 19, 2010, **DP&L** elected to withdraw its case pertaining to the Smart Grid and AMI programs. The PUCO accepted the withdrawal in an order issued on January 5, 2011. The PUCO also indicated that it expects **DP&L** to continue to monitor other utilities' Smart Grid and AMI programs and to explore the potential benefits of investing in Smart Grid and AMI programs and that **DP&L** will, when appropriate, file new Smart Grid and/or AMI business cases in the future. We plan to file to recover these deferred costs in a future regulatory rate proceeding. Based on past PUCO precedent, we believe these costs are probable of future recovery in rates.

Retail settlement system costs represent costs to implement a retail settlement system that reconciles the energy a CRES supplier delivers to its customers with what its customers actually use. Based on case precedent in other utilities' cases, the costs are recoverable through a future **DP&L** rate proceeding.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation. **DP&L** will be seeking recovery of these costs as part of our next distribution rate case filing at the PUCO. The timing of such a filing has not yet been determined.

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Regulatory Liabilities

Transmission Costs see "*Regulatory Assets – Transmission costs*" above.

Estimated costs of removal – regulated property reflect an estimate of amounts collected in customer rates for costs that are expected to be incurred in the future to remove existing transmission and distribution property from service when the property is retired.

Postretirement benefits represent the qualifying FASC 715 "Compensation – Retirement Benefits" gains related to our regulated operations that, for ratemaking purposes, are probable of being reflected in future rates. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. This regulatory liability represents the regulated portion that would otherwise be reflected as a gain to OCI.

NOTE 4 – OWNERSHIP OF COAL-FIRED FACILITIES

DP&L and certain other Ohio utilities have undivided ownership interests in five coal-fired electric generating facilities and numerous transmission facilities. Certain expenses, primarily fuel costs for the generating units, are allocated to the owners based on their energy usage. The remaining expenses, investments in fuel inventory, plant materials and operating supplies, and capital additions are allocated to the owners in accordance with their respective ownership interests. As of December 31, 2014, **DP&L** had $25.0 million of construction work in process at such facilities. **DP&L's** share of the operating cost of such facilities is included within the corresponding line in the Statements of Operations and **DP&L's** share of the investment in the facilities is included within Total net property, plant and equipment in the Balance Sheets. Each joint owner provides their own financing for their share of the operations and capital expenditures of the jointly-owned station.

DP&L's undivided ownership interest in such facilities at December 31, 2014, is as follows:

	DP&L Share		**DP&L** Carrying Value			
	Ownership %	Summer Production Capacity (MW)	Gross Plant In Service ($ in millions)	Accumulated Depreciation ($ in millions)	Construction Work in Process ($ in millions)	SCR and FGD Equipment Installed and in Service (Yes/No)
Jointly-owned production units						
Conesville - Unit 4	16.5	129	$ 23	$ 4	$ 1	Yes
Killen - Unit 2	67.0	402	624	314	2	Yes
Miami Fort - Units 7 and 8	36.0	368	361	162	2	Yes
Stuart - Units 1 through 4	35.0	808	756	323	14	Yes
Zimmer - Unit 1	28.1	371	1,101	675	6	Yes
Transmission (at varying percentages)			98	62	-	
Total		2,078	$ 2,963	$ 1,540	$ 25	

Beckjord Unit 6 was retired effective October 1, 2014 and **DP&L** sold its interest in East Bend on December 30, 2014.

As part of the provisional **DPL** purchase accounting adjustments related to the Merger, four stations (Beckjord, Conesville, East Bend and Hutchings) had future expected cash flows that, when discounted, produced a fair market value different than **DP&L's** carrying value. Since **DP&L** did not apply push down accounting, this valuation did not affect the carrying value of these stations' valuation at **DP&L**. In the fourth quarter of 2013, **DP&L** performed an impairment review of its stations and recorded impairment expense of $86.0 million related to two of its stations, Conesville and East Bend. In addition, in the third quarter of 2012, **DP&L** recorded impairment expense of $80.8 million on its Conesville and Hutchings stations. See Note 13 for more information on these impairments.

NOTE 5 – DEBT OBLIGATIONS

Long-term debt is as follows:

Long-term debt

$ in millions	December 31, 2014	December 31, 2013
First mortgage bonds due in September 2016 - 1.875%	$ 445.0	$ 445.0
Pollution control series due in January 2028 - 4.7%	35.3	35.3
Pollution control series due in January 2034 - 4.8%	179.1	179.1
Pollution control series due in September 2036 - 4.8%	100.0	100.0
Pollution control series due in November 2040 - variable rates: 0.04% - 0.15% and 0.04% - 0.26% (a)	100.0	100.0
U.S. Government note due in February 2061 - 4.2%	18.1	18.2
Capital lease obligations	-	-
Unamortized debt discount	(0.5)	(0.7)
Total long-term debt	$ 877.0	$ 876.9

(a) - range of interest rates for the twelve months ended December 31, 2014 and December 31, 2013, respectively.

Current portion - long-term debt

$ in millions	December 31, 2014	December 31, 2013
U.S. Government note due in February 2061 - 4.2%	$ 0.1	$ 0.1
Capital lease obligations	-	0.1
Total current portion - long-term debt	$ 0.1	$ 0.2

(a) - range of interest rates for the twelve months ended December 31, 2014 and December 31, 2013, respectively.

At December 31, 2014, maturities of long-term debt are summarized as follows:

Due within the twelve months ending December 31,

$ in millions	
2015	$ 0.1
2016	445.1
2017	0.1
2018	0.1
2019	0.1
Thereafter	432.1
	877.6
Unamortized discount	(0.5)
Total long-term debt	$ 877.1

On December 4, 2008, the OAQDA issued $100.0 million of collateralized, variable rate Revenue Refunding Bonds Series A and B due November 1, 2040. In turn, **DP&L** borrowed these funds from the OAQDA and issued corresponding first mortgage bonds to support repayment of the funds. The payment of principal and interest on each series of the bonds when due is backed by two standby letters of credit issued by JPMorgan Chase Bank, N.A. **DP&L** amended these standby letters of credit on May 31, 2013 and extended the stated maturities to June 2018. These facilities are irrevocable and have no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the years ended December 31, 2014, 2013 or 2012.

On May 10, 2013, **DP&L** entered into a $300.0 million unsecured revolving credit agreement with a syndicated bank group. This new $300.0 million facility has a five year term expiring on May 10, 2018, a $100.0 million letter of credit sublimit and a feature which provides **DP&L** the ability to increase the size of the facility by an additional $100.0 million. At December 31, 2014, there were two letters of credit in the amount of $0.7 million outstanding,

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with the remaining $299.3 million available to **DP&L.** Fees associated with this revolving credit facility were not material during the years ended December 31, 2014 or 2013.

DP&L's unsecured revolving credit agreements and standby letters of credit have two financial covenants, the first measures Total Debt to Total Capitalization, the ratio is calculated, at the end of each fiscal quarter, by dividing total debt at the end of the quarter by total capitalization at the end of the quarter. The second financial covenant measures EBITDA to Interest Expense. EBITDA to Interest Expense ratio is calculated, at the end of each fiscal quarter, by dividing EBITDA for the four prior fiscal quarters by the consolidated interest charges for the same period.

On March 31, 2014, **DP&L** borrowed $15.0 million from **DPL** at an interest rate of LIBOR plus 2.0%. This note was due on or before April 30, 2014 and was repaid on April 30, 2014.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million of electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base (WPAFB). **DP&L** financed the acquisition of these assets with a note payable to the federal government that is payable monthly over 50 years and bears interest at 4.2% per annum.

On September 19, 2013, **DP&L** closed a $445.0 million issuance of senior secured first mortgage bonds. These new bonds mature on September 15, 2016, and are secured by **DP&L's** First & Refunding Mortgage.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the First and Refunding Mortgage.

NOTE 6 – INCOME TAXES

DP&L's components of income tax expense were as follows:

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Computation of tax expense			
Federal income tax expense / (benefit)[(a)]	$ **53.8**	$ 35.5	$ 50.9
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**1.2**	0.3	(2.0)
Depreciation of AFUDC - Equity	**(2.7)**	(2.5)	3.0
Investment tax credit amortized	**(2.5)**	(2.5)	(2.5)
Section 199 - domestic production deduction	**(4.6)**	(4.1)	(2.5)
Non-deductible merger-related compensation	**-**	-	0.6
Accrual (settlement) for open tax years	**(6.6)**	(8.8)	-
Other, net[(b)]	**1.1**	0.7	7.6
Total tax expense	$ **39.7**	$ 18.6	$ 55.1
Components of Tax Expense			
Federal - current	$ **34.1**	$ 38.6	$ 52.1
State and Local - current	**0.5**	(0.1)	1.0
Total current	**34.6**	38.5	53.1
Federal - deferred	**4.1**	(20.4)	4.7
State and local - deferred	**1.0**	0.5	(2.7)
Total deferred	**5.1**	(19.9)	2.0
Total tax expense	$ **39.7**	$ 18.6	$ 55.1

$ in millions	December 31, 2014	2013
Net non-current Assets / (Liabilities)		
Depreciation / property basis	$ **(618.8)**	$ (607.1)
Income taxes recoverable	**(14.8)**	(11.4)
Regulatory assets	**(18.0)**	(15.6)
Investment tax credit	**8.6**	8.8
Compensation and employee benefits	**5.2**	(0.2)
Other	**(12.2)**	(6.8)
Net non-current liabilities	$ **(650.0)**	$ (632.3)

	December 31, 2014	2013
Net current Assets / (Liabilities) [(c)]		
Other	$ **0.5**	$ (5.0)
Net current assets / (liabilities)	$ **0.5**	$ (5.0)

(a) The statutory tax rate of 35% was applied to pre-tax earnings.
(b) Includes expense of $0.7 million, $1.1 million and benefit of $7.6 million in the years ended December 31, 2014, 2013 and 2012, respectively, of income tax related to adjustments from prior years.
(c) Amounts are included within Other prepayments and current assets and Other current liabilities on the Balance Sheets of **DP&L**.

The following table presents the tax (benefit) / expense related to pensions, postemployment benefits, cash flow hedges and financial instruments that were credited to Accumulated other comprehensive loss.

$ in millions	Years ended December 31, 2014	2013	2012
Tax expense / (benefit)	$ **(6.0)**	$ 7.0	$ (0.8)

Accounting for Uncertainty in Income Taxes
We apply the provisions of GAAP relating to the accounting for uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits for **DP&L** is as follows:

$ in millions	
Balance at December 31, 2012	$ 18.3
Calendar 2013	
Tax positions taken during prior period	(0.1)
Lapse of Statute of Limitations	(6.9)
Settlement with taxing authorities	(2.5)
Balance at December 31, 2013	8.8
Calendar 2014	
Tax positions taken during prior period	2.8
Lapse of Statute of Limitations	(8.6)
Balance at December 31, 2014	$ 3.0

Of the December 31, 2014 balance of unrecognized tax benefits, $0.9 million is due to uncertainty in the timing of deductibility.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The amounts accrued and expense (benefit) recorded were not material for each period presented.

Following is a summary of the tax years open to examination by major tax jurisdiction:
U.S. Federal – 2010 and forward
State and Local – 2010 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months other than those subject to expiring statutes of limitations.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The results of the examination were approved by the Joint Committee on Taxation on January 18, 2013. As a result of the examination, **DPL** received a refund of $19.9 million and recorded a $1.2 million reduction to income tax expense.

NOTE 7 – PENSION AND POSTRETIREMENT BENEFITS

DP&L sponsors a traditional defined benefit pension plan for most of the employees of **DPL** and its subsidiaries. For collective bargaining employees, the defined benefits are based on a specific dollar amount per year of service. For all other employees (management employees), the traditional defined benefit pension plan is based primarily on compensation and years of service. As of December 31, 2010, this traditional pension plan was closed to new management employees. A participant is 100% vested in all amounts credited to his or her account upon the completion of five vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. In December 2013, an agreement was signed, effective January 1, 2014, whereby the Service Company began providing services including accounting, legal, human resources, information technology and other corporate services on behalf of companies that are part of the U.S. SBU, including among other companies, **DPL** and **DP&L**. Employees that transferred from **DP&L** to the Service Company maintain their previous eligibility to participate in the **DP&L** pension plan.

Almost all management employees beginning employment on or after January 1, 2011 participate in a cash balance pension plan. Similar to the traditional pension plan for management employees, the cash balance benefits are based on compensation and years of service. A participant shall become 100% vested in all amounts credited to his or her account upon the completion of three vesting years, as defined in The Dayton Power and Light Company Retirement Income Plan, or the participant's death or disability. If a participant's employment is terminated, other than by death or disability, prior to such participant becoming 100% vested in his or her account, the account shall be forfeited as of the date of termination. Vested benefits in the cash balance plan are fully portable upon termination of employment.

In addition, we have a Supplemental Executive Retirement Plan (SERP) for certain retired key executives as well as an immaterial unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. We also include our net liability to our partners related to our share of their pension costs within the Pension, retiree and other benefits on our Balance Sheets.

We generally fund pension plan benefits as accrued in accordance with the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and, in addition, make voluntary contributions from time to time. There were no contributions during the years ended December 31, 2014, 2013 and 2012.

Qualified employees who retired prior to 1987 and their dependents are eligible for health care and life insurance benefits until their death, while qualified employees who retired after 1987 are eligible for life insurance benefits and partially subsidized health care. The partially subsidized health care is at the election of the employee, who pays the majority of the cost, and is available only from their retirement until they are covered by Medicare. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

We recognize an asset for a plan's overfunded status and a liability for a plan's underfunded status and recognize, as a component of OCI, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. For the transmission and distribution areas of our electric business, these amounts are recorded as regulatory assets and liabilities which represent the regulated portion that would otherwise be charged or credited to AOCI. We have historically recorded these costs on the accrual basis and this is how these costs have been historically recovered through customer rates. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

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The following tables set forth the changes in our pension and postemployment benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2014 and 2013. The amounts presented in the following tables for pension include the collective bargaining plan formula, traditional management plan formula and cash balance plan formula and the SERP in the aggregate. The amounts presented for postemployment include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
	2014	2013
Change in benefit obligation		
Benefit obligation at beginning of period	$ **370.5**	$ 395.6
Service cost	**5.9**	7.2
Interest cost	**17.5**	15.6
Plan amendments	**6.8**	-
Actuarial (gain) / loss	**67.3**	(26.5)
Benefits paid	**(24.2)**	(21.4)
Benefit obligation at end of period	**443.8**	370.5
Change in plan assets		
Fair value of plan assets at beginning of period	**349.1**	361.4
Actual return on plan assets	**46.4**	8.7
Contributions to plan assets	**0.4**	0.4
Benefits paid	**(24.2)**	(21.4)
Fair value of plan assets at end of period	**371.7**	349.1
Funded status of plan	$ **(72.1)**	$ (21.4)

$ in millions	Postretirement	
	Years ended December 31,	
	2014	2013
Change in benefit obligation		
Benefit obligation at beginning of period	$ **19.7**	$ 22.4
Service cost	**0.2**	0.2
Interest cost	**0.8**	0.8
Actuarial (gain) / loss	**0.2**	(2.2)
Benefits paid	**(1.3)**	(1.5)
Benefit obligation at end of period	**19.6**	19.7
Change in plan assets		
Fair value of plan assets at beginning of period	**3.7**	4.2
Contributions to plan assets	**0.9**	1.0
Benefits paid	**(1.3)**	(1.5)
Fair value of plan assets at end of period	**3.3**	3.7
Funded status of plan	$ **(16.3)**	$ (16.0)

$ in millions	Pension		Postretirement	
	December 31,		December 31,	
	2014	2013	**2014**	2013
Amounts recognized in the Balance sheets				
Current liabilities	**$ (0.4)**	$ (0.4)	**$ (0.5)**	$ (0.5)
Non-current liabilities	**(71.7)**	(21.0)	**(15.8)**	(15.5)
Net liability at Year ended December 31,	**$ (72.1)**	$ (21.4)	**$ (16.3)**	$ (16.0)
Amounts recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost	**$ 20.3**	$ 16.3	**$ 0.6**	$ 0.7
Net actuarial loss / (gain)	**152.5**	115.1	**(5.8)**	(6.9)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 172.8**	$ 131.4	**$ (5.2)**	$ (6.2)
Recorded as:				
Regulatory asset	**$ 99.0**	$ 76.3	**$ -**	$ -
Regulatory liability	**-**	-	**(4.5)**	(5.2)
Accumulated other comprehensive income	**73.8**	55.1	**(0.7)**	(1.0)
Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax	**$ 172.8**	$ 131.4	**$ (5.2)**	$ (6.2)

The accumulated benefit obligation for our defined benefit pension plans was $431.0 million and $359.8 million at December 31, 2014 and 2013, respectively.

The net periodic benefit cost (income) of the pension and postemployment benefit plans were:

Net Periodic Benefit Cost - Pension

	Years ended December 31,		
$ in millions	**2014**	2013	2012
Service cost	**$ 5.9**	$ 7.2	$ 6.2
Interest cost	**17.5**	15.6	17.3
Expected return on assets [(a)]	**(22.9)**	(23.6)	(22.7)
Amortization of unrecognized:			
Actuarial gain	**6.4**	9.3	8.8
Prior service cost	**2.8**	2.8	2.8
Net periodic benefit cost before adjustments	**9.7**	11.3	12.4
Settlement Expense	**-**	-	0.6
Net periodic benefit cost after adjustments	**$ 9.7**	$ 11.3	$ 13.0

(a) For purposes of calculating the expected return on pension plan assets under GAAP, the market-related value of assets (MRVA) is used. GAAP requires that the difference between actual plan asset returns and estimated plan asset returns be amortized into the MRVA equally over a period not to exceed five years. We use a methodology under which we include the difference between actual and estimated asset returns in the MRVA equally over a three year period. The MRVA used in the calculation of expected return on pension plan assets was approximately $361.0 million in 2014, $351.2 million in 2013, and $346.0 million in 2012.

Net Periodic Benefit Cost / (Income) - Postretirement

$ in millions	Years ended December 31, 2014	2013	2012
Service cost	$ **0.2**	$ 0.2	$ 0.1
Interest cost	**0.8**	0.8	0.9
Expected return on assets	**(0.2)**	(0.2)	(0.3)
Amortization of unrecognized:			
Actuarial loss	**(0.8)**	(0.7)	(0.9)
Prior service credit	**0.1**	0.1	0.1
Net periodic benefit cost / (income)	$ **0.1**	$ 0.2	$ (0.1)

Other Changes in Plan Assets and Benefit Obligation Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

Pension

$ in millions	Years ended December 31, 2014	2013	2012
Net actuarial loss / (gain)	$ **43.8**	$ (11.7)	$ 5.2
Prior service cost	**6.8**	-	-
Reversal of amortization item:			
Net actuarial loss	**(6.4)**	(9.3)	(9.4)
Prior service cost	**(2.8)**	(2.8)	(2.8)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **41.4**	$ (23.8)	$ (7.0)
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **51.1**	$ (12.5)	$ 6.0

Postretirement

$ in millions	Years ended December 31, 2014	2013	2012
Net actuarial loss / (gain)	$ **0.4**	$ (1.9)	$ 1.1
Reversal of amortization item:			
Net actuarial gain	**0.8**	0.7	0.9
Prior service credit	**(0.1)**	(0.1)	(0.1)
Total recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.1**	$ (1.3)	$ 1.9
Total recognized in net periodic benefit cost and Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities	$ **1.2**	$ (1.1)	$ 1.8

Estimated amounts that will be amortized from AOCI, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2015 are:

$ in millions	Pension	Postretirement
Net actuarial gain / (loss)	$ 9.8	$ (0.7)
Prior service cost	$ 3.3	$ 0.1

Our expected return on plan asset assumptions, used to determine benefit obligations, are based on historical long-term rates of return on investments, which use the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors, such as inflation and interest rates, as well as asset diversification and portfolio rebalancing, are evaluated when long-term capital market assumptions are determined. Peer data and historical returns are reviewed to verify reasonableness and appropriateness.

For 2015, we are decreasing our expected long-term rate of return assumption to 6.50% from 6.75% for pension plan assets. In addition, we are decreasing our long-term rate of return assumption to 4.50% from 6.00% for other postemployment benefit plan assets. These rates of return represent our long-term assumptions based on our current portfolio mixes. Also, for 2015, we are decreasing our assumed discount rate to 4.02% from 4.86% for pension and to 3.71% from 4.58% for postemployment benefits expense to reflect current duration-based yield curve discount rates. A one percent change in the rate of return assumption for pension would result in an increase or decrease to the 2015 pension expense of approximately $3.5 million. A 25 basis point change in the discount rate for pension would result in a decrease of approximately $0.5 million to 2015 pension expense. A 25 basis point decrease in the discount rate for pension would result in an increase of approximately $0.8 million to 2015 pension expense.

In determining the discount rate to use for valuing liabilities, we used a market yield curve on high-quality fixed income investments as of December 31, 2014. We project the expected benefit payments under the plan based on participant data and based on certain assumptions concerning mortality, retirement rates, termination rates, etc. The expected benefit payments for each year are then discounted back to the measurement date using the appropriate spot rate for each half-year from the yield curve, thereby obtaining a present value of all expected future benefit payments using the yield curve. Finally, an equivalent single discount rate is determined which produces a present value equal to the present value determined using the full yield curve.

The weighted average assumptions used to determine benefit obligations during the years ended December 31, 2014, 2013 and 2012 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2014	2013	2012	**2014**	2013	2012
Discount rate for obligations	**4.02%**	4.86%	4.04%	**3.71%**	4.58%	3.75%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2014, 2013 and 2012 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2014	2013	2012	**2014**	2013	2012
Discount rate	**4.86%**	4.04%	4.88%	**4.51%**	4.58%	4.62%
Expected rate of return on plan assets	**6.75%**	6.75%	7.00%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	3.94%	3.94%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2014, 2013 and 2012 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligation		
	2014	2013	2012	**2014**	2013	2012
Pre - age 65						
Current health care cost trend rate	**7.75%**	8.00%	8.50%	**6.97%**	7.75%	8.00%
Year trend reaches ultimate	**2023**	2019	2019	**2029**	2023	2019
Post - age 65						
Current health care cost trend rate	**6.75%**	7.50%	8.00%	**6.97%**	6.75%	7.50%
Year trend reaches ultimate	**2021**	2018	2018	**2029**	2021	2018
Ultimate health care cost trend rate	**5.00%**	5.00%	5.00%	**4.50%**	5.00%	5.00%

The assumed health care cost trend rates have an effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects on the net periodic postemployment benefit cost and the accumulated postemployment benefit obligation:

Effect of change in health care cost trend rate

$ in millions		One-percent increase		One-percent decrease
Service cost plus interest cost	$	0.1	$	-
Benefit obligation	$	1.0	$	(0.9)

Benefit payments, which reflect future service, are expected to be paid as follows:

Estimated future benefit payments and Medicare Part D reimbursements

$ in millions due within the following years:		Pension		Postretirement
2015	$	24.8	$	1.9
2016	$	25.2	$	1.8
2017	$	25.7	$	1.7
2018	$	26.3	$	1.6
2019	$	26.7	$	1.5
2020 - 2024	$	137.0	$	6.1

We expect to make contributions of $0.4 million to our SERP in 2015 to cover benefit payments. We also expect to contribute $1.9 million to our other postemployment benefit plans in 2015 to cover benefit payments. We do not expect to make any contributions to our pension plan during 2015.

The Pension Protection Act of 2006 (the Act) contained new requirements for our single employer defined benefit pension plan. In addition to establishing a 100% funding target for plan years beginning after December 31, 2008, the Act also limits some benefits if the funded status of pension plans drops below certain thresholds. Among other restrictions under the Act, if the funded status of a plan falls below a predetermined ratio of 80%, lump-sum payments to new retirees are limited to 50% of amounts that otherwise would have been paid and new benefit improvements may not go into effect. For the 2014 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 113.86% and is estimated to be 113.86% until the 2015 status is certified in September 2015 for the 2015 plan year. The Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, grants plan sponsors certain relief from funding requirements and benefit restrictions of the Act.

Plan Assets

Plan assets are invested using a total return investment approach whereby a mix of equity securities, debt securities and other investments are used to preserve asset values, diversify risk and achieve our target investment return benchmark. Investment strategies and asset allocations are based on careful consideration of plan liabilities, the plan's funded status and our financial condition. Investment performance and asset allocation are measured and monitored on an ongoing basis.

Plan assets are managed in a balanced portfolio comprised of two major components: an equity portion and a fixed income portion. The expected role of plan equity investments is to maximize the long-term real growth of plan assets, while the role of fixed income investments is to generate current income, provide for more stable periodic returns and provide some protection against a prolonged decline in the market value of plan equity investments.

Long-term strategic asset allocation guidelines are determined by management and take into account the Plan's long-term objectives as well as its short-term constraints. The target allocations for plan assets are 2 – 41% for equity securities, 60 – 82% for fixed income securities and 8 – 16% for other investments. Equity securities include U.S. and international equity, while fixed income securities include long-duration and high-yield bond funds and emerging market debt funds. Other investments include hedge funds that follow several different strategies.

Most of our Plan assets are measured using quoted, observable prices which are considered Level One inputs in the Fair Value Hierarchy. The Core property collective fund and the Common collective fund are measured using Level Two inputs that are quoted prices for identical assets in markets that are less active.

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he following table summarizes the Company's target pension plan allocation for 2014:

	Target Allocation
Equity Securities	19%
Debt Securities	69%
Real Estate	6%
Other	6%

The fair values of our pension plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2014

Asset Category $ in millions	**Market Value at December 31, 2014**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservable inputs** (Level 3)
Equity securities [(a)]				
Small/Mid cap equity	$ 10.6	$ 10.6	$ -	$ -
Large cap equity	22.2	22.2	-	-
International equity	18.2	18.2	-	-
Emerging markets equity	2.8	2.8	-	-
SIIT dynamic equity	11.6	11.6	-	-
Total equity securities	65.4	65.4	-	-
Debt Securities [(b)]				
Emerging markets debt	6.0	6.0	-	-
High yield bond	6.5	6.5	-	-
Long duration fund	242.7	242.7	-	-
Total debt securities	255.2	255.2	-	-
Cash and cash equivalents [(c)]				
Cash	1.6	1.6	-	-
Other investments [(d)]				
Core property collective fund	26.3	-	26.3	-
Common collective fund	23.2	-	23.2	-
Total other investments	49.5	-	49.5	-
Total pension plan assets	$ 371.7	$ 322.2	$ 49.5	$ -

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the funds.

(b) This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a property fund that invests in commercial real estate and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

The fair values of our pension plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2013

Asset Category $ in millions	Market Value at December 31, 2013	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Equity securities [(a)]				
Small/Mid cap equity	$ 10.5	$ 10.5	$ -	$ -
Large cap equity	20.8	20.8	-	-
International equity	20.3	20.3	-	-
Emerging markets equity	3.2	3.2	-	-
SIIT dynamic equity	10.5	10.5	-	-
Total equity securities	65.3	65.3	-	-
Debt Securities [(b)]				
Emerging markets debt	6.6	6.6	-	-
High yield bond	6.9	6.9	-	-
Long duration fund	223.3	223.3	-	-
Total debt securities	236.8	236.8	-	-
Cash and cash equivalents [(c)]				
Cash	0.9	0.9	-	-
Other investments [(d)]				
Core property collective fund	23.5	-	23.5	-
Common collective fund	22.6	-	22.6	-
Total other investments	46.1	-	46.1	-
Total pension plan assets	$ 349.1	$ 303.0	$ 46.1	$ -

(a) This category includes investments in equity securities of large, small and medium sized companies and equity securities of foreign companies including those in developing countries. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund except for the **DPL** common stock which is valued using the closing price on the New York Stock Exchange.

(b) *This category includes investments in investment-grade fixed-income instruments, U.S. dollar-denominated debt securities of* emerging market issuers and high yield fixed-income securities that are rated below investment grade. The funds are valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

(c) This category comprises cash held to pay beneficiaries. The fair value of cash equals its book value.

(d) This category represents a property fund that invests in commercial real estate and a hedge fund of funds made up of 30+ different hedge fund managers diversified over eight different hedge strategies. The fair value of the hedge fund is valued using the net asset value method in which an average of the market prices for the underlying investments is used to value the fund.

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The fair values of our other postemployment benefit plan assets at December 31, 2014 by asset category are as follows:

Fair Value Measurements for Postemployment Benefit Plan Assets at December 31, 2014

Asset Category $ in millions	**Market Value at December 31, 2014**	**Quoted prices in active markets for identical assets** (Level 1)	**Significant observable inputs** (Level 2)	**Significant unobservable inputs** (Level 3)
JP Morgan Core Bond Fund [(a)]	$ 3.2	$ 3.2	$ -	$ -

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

The fair values of our other postemployment benefit plan assets at December 31, 2013 by asset category are as follows:

Fair Value Measurements for Postemployment Benefit Plan Assets at December 31, 2013

Asset Category $ in millions	Market Value at December 31, 2013	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
JP Morgan Core Bond Fund [(a)]	$ 3.7	$ 3.7	$ -	$ -

(a) This category includes investments in U.S. government obligations and mortgage-backed and asset-backed securities.

NOTE 8 – FAIR VALUE MEASUREMENTS

The fair values of our financial instruments are based on published sources for pricing when possible. We rely on valuation models only when no other method is available to us. The fair value of our financial instruments represents estimates of possible value that may or may not be realized in the future. The table below presents the fair value and cost of our non-derivative instruments at December 31, 2014 and 2013. See also Note 9 for the fair values of our derivative instruments.

	December 31, 2014		December 31, 2013	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
Assets				
Money market funds	$ 0.1	$ 0.1	$ 0.3	$ 0.3
Equity securities	2.7	3.7	3.3	4.4
Debt securities	4.7	4.7	5.4	5.5
Hedge Funds	0.8	0.8	0.9	0.9
Real Estate	0.4	0.4	0.4	0.4
Total assets	$ 8.7	$ 9.7	$ 10.3	$ 11.5
Liabilities				
Debt	$ 877.1	$ 882.5	$ 877.1	$ 859.6

Debt

The fair value of debt is based on current public market prices for disclosure purposes only. Unrealized gains or losses are not recognized in the financial statements as debt is presented at amortized cost in the financial statements. The debt amounts include the current portion payable in the next twelve months and have maturities that range from 2016 to 2061.

Master Trust Assets

DP&L established a Master Trust to hold assets that could be used for the benefit of employees participating in employee benefit plans and these assets are not used for general operating purposes. These assets are primarily comprised of open-ended mutual funds which are valued using the net asset value per unit. These investments are recorded at fair value within Other assets on the balance sheets and classified as available for sale. Any unrealized gains or losses are recorded in AOCI until the securities are sold.

DP&L had $1.1 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2014 and $1.2 million ($0.8 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2013.

Various investments were sold during the past twelve months to facilitate the distribution of benefits. During the past twelve months, $0.4 million ($0.2 million after tax) of unrealized gains were reversed into earnings. Over the next twelve months, $0.4 million ($0.2 million after tax) of unrealized gains are expected to be reversed to earnings.

Fair Value Hierarchy

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. These inputs are then categorized as:

- Level 1 (quoted prices in active markets for identical assets or liabilities);
- Level 2 (observable inputs such as quoted prices for similar assets or liabilities or quoted prices in markets that are not active);
- Level 3 (unobservable inputs).

Valuations of assets and liabilities reflect the value of the instrument including the values associated with counterparty risk. We include our own credit risk and our counterparty's credit risk in our calculation of fair value using global average default rates based on an annual study conducted by a large rating agency.

We did not have any transfers of the fair values of our financial instruments between Level 1 and Level 2 of the fair value hierarchy during the twelve months ended December 31, 2014 and 2013.

The fair value of assets and liabilities at December 31, 2014 and 2013 measured on a recurring basis and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

Assets and Liabilities at Fair Value

$ in millions	Fair Value at December 31, 2014 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.1	$ 0.1	$ -	$ -
Equity securities	3.7	3.7	-	-
Debt securities	4.7	4.7	-	-
Hedge Funds	0.8	-	0.8	-
Real Estate	0.4	0.4	-	-
Total Master trust assets	9.7	8.9	0.8	-
Derivative assets				
Forward power contracts	15.1	-	13.9	1.2
Total derivative assets	15.1	-	13.9	1.2
Total assets	$ 24.8	$ 8.9	$ 14.7	$ 1.2
Liabilities				
FTRs	$ 0.6	$ -	$ -	$ 0.6
Heating oil futures	0.4	0.4	-	-
Natural gas futures	0.1	0.1	-	-
Forward power contracts	11.2	-	11.2	-
Total derivative liabilities	12.3	0.5	11.2	0.6
Long-term debt	882.5	-	864.3	18.2
Total liabilities	$ 894.8	$ 0.5	$ 875.5	$ 18.8

(a) Includes credit valuation adjustment.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

$ in millions	Fair Value at December 31, 2013 (a)	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other observable inputs	Level 3 Unobservable inputs
Assets				
Master trust assets				
Money market funds	$ 0.3	$ 0.3	$ -	$ -
Equity securities	4.4	4.4	-	-
Debt securities	5.5	5.5	-	-
Hedge Funds	0.9	-	0.9	-
Real Estate	0.4	0.4	-	-
Total Master trust assets	11.5	10.6	0.9	-
Derivative assets				
Heating oil futures	0.2	0.2	-	-
FTRs	0.2	-	-	0.2
Forward power contracts	13.4	-	13.4	-
Total derivative assets	13.8	0.2	13.4	0.2
Total assets	$ 25.3	$ 10.8	$ 14.3	$ 0.2
Liabilities				
Forward power contracts	$ 10.6	$ -	$ 10.6	$ -
Total derivative liabilities	10.6	-	10.6	-
Long-term debt	859.6	-	841.1	18.5
Total liabilities	$ 870.2	$ -	$ 851.7	$ 18.5

(a) Includes credit valuation adjustment.

Our financial instruments are valued using the market approach in the following categories:

- Level 1 inputs are used for derivative contracts such as heating oil futures and for money market accounts that are considered cash equivalents. The fair value is determined by reference to quoted market prices and other relevant information generated by market transactions.
- Level 2 inputs are used to value derivatives such as forward power contracts and forward NYMEX-quality coal contracts (which are traded on the OTC market but which are valued using prices on the NYMEX for similar contracts on the OTC market). Other Level 2 assets include: open-ended mutual funds that are in the Master Trust, which are valued using the end of day NAV per unit; and interest rate hedges, which use observable inputs to populate a pricing model.
- Level 3 inputs such as financial transmission rights are considered a Level 3 input because the monthly auctions are considered inactive. Our Level 3 inputs are immaterial to our derivative balances as a whole and as such no further disclosures are presented.

Our debt is fair valued for disclosure purposes only and most of the fair values are determined using quoted market prices in inactive markets. These fair value inputs are considered Level 2 in the fair value hierarchy. The WPAFB note is not publicly traded. Fair value is assumed to equal carrying value. These fair value inputs are considered Level 3 in the fair value hierarchy as there are no observable inputs. Additional Level 3 disclosures were not presented since debt is not recorded at fair value.

Approximately 97% of the inputs to the fair value of our derivative instruments are from quoted market prices for **DP&L.**

Non-recurring Fair Value Measurements
We use the cost approach to determine the fair value of our AROs which are estimated by discounting expected cash outflows to their present value at the initial recording of the liability. Cash outflows are based on the approximate future disposal cost as determined by market information, historical information or other management estimates. These inputs to the fair value of the AROs would be considered Level 3 inputs under the fair value hierarchy. In 2014, AROs for asbestos, landfills, and river structures decreased by $1.5 million ($1.0 million after tax) primarily due to the sale of a generation plant. The ARO for ash ponds was increased by $2.4 million ($1.6 million after tax) due to new rules issued by the USEPA in December 2014 that will be effective in June 2015. The December 2014 increase of the AROs for ash ponds was limited to the ponds located at plants which are no longer in operation. Additional ash pond AROs will be recorded in the first quarter of 2015 for the ponds located at plants which remain in operation. There were no additions to our AROs during the year ended December 31, 2013.

When evaluating impairment of goodwill and long-lived assets, we measure fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to the carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

$ in millions	Year ended December 31, 2013				
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Gross Loss
Assets					
Long-lived assets held and used [(a)]					
Conesville	$ 30.0	$ -	$ -	$ 20.0	$ 10.0
East Bend	$ 76.0	$ -	$ -	$ -	$ 76.0

(a) See Note 13 for further information.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets during the year ended December 31, 2013:

$ in millions	Fair Value	Valuation Technique	Unobservable input	Range (Weighted Average)
Long-lived assets held and used:				
DP&L (Conesville)	$ -	Discounted cash flows	Annual revenue growth	-31% to 18% (0)

NOTE 9 – DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

In the normal course of business, **DP&L** enters into various financial instruments, including derivative financial instruments. We use derivatives principally to manage the risk of changes in market prices for commodities and interest rate risk associated with our long-term debt. The derivatives that we use to economically hedge these risks are governed by our risk management policies for forward and futures contracts. Our net positions are continually assessed within our structured hedging programs to determine whether new or offsetting transactions are required. The objective of the hedging program is to mitigate financial risks while ensuring that we have adequate resources to meet our requirements. We monitor and value derivative positions monthly as part of our risk management processes. We use published sources for pricing, when possible, to mark positions to market. All of our derivative instruments are used for risk management purposes and are designated as cash flow hedges or not designated as hedges for accounting purposes, which we refer to as mark to market.

At December 31, 2014, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	**Mark to Market**	**MWh**	**10.5**	**-**	**10.5**
Heating Oil Futures	**Mark to Market**	**Gallons**	**378.0**	**-**	**378.0**
Natural Gas	**Mark to Market**	**Dths**	**200.0**	**-**	**200.0**
Forward Power Contracts	**Cash Flow Hedge**	**MWh**	**175.0**	**(2,991.0)**	**(2,816.0)**
Forward Power Contracts	**Mark to Market**	**MWh**	**1,725.2**	**(2,804.0)**	**(1,078.8)**

At December 31, 2013, **DP&L** had the following outstanding derivative instruments:

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	-	7.1
Heating Oil Futures	Mark to Market	Gallons	1,428.0	-	1,428.0
Forward Power Contracts	Cash Flow Hedge	MWh	140.4	(4,705.7)	(4,565.3)
Forward Power Contracts	Mark to Market	MWh	3,172.4	(2,888.5)	283.9

Cash Flow Hedges

As part of our risk management processes, we identify the relationships between hedging instruments and hedged items, as well as the risk management objective and strategy for undertaking various hedge transactions. The fair values of cash flow hedges determined by current public market prices will continue to fluctuate with changes in market prices up to contract expiration. The effective portion of the hedging transaction is recognized in AOCI and transferred to earnings using specific identification of each contract when the forecasted hedged transaction takes place or when the forecasted hedged transaction is probable of not occurring. The ineffective portion of the cash flow hedge is recognized in earnings in the current period. All risk components were taken into account to determine the hedge effectiveness of the cash flow hedges.

We enter into forward power contracts to manage commodity price risk exposure related to our generation of electricity. We do not hedge all commodity price risk. We reclassify gains and losses on forward power contracts from AOCI into earnings in those periods in which the contracts settle.

The following table provides information for **DP&L** concerning gains or losses recognized in AOCI for the cash flow hedges:

$ in millions (net of tax)	**Year ended December 31, 2014** Power	**Year ended December 31, 2014** Interest Rate Hedge	Year ended December 31, 2013 Power	Year ended December 31, 2013 Interest Rate Hedge	Year ended December 31, 2012 Power	Year ended December 31, 2012 Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	$ 1.0	$ 5.2	$ (4.7)	$ 7.3	$ (0.8)	$ 9.8
Net gains / (losses) associated with current period hedging transactions	(18.8)	-	1.0	-	(3.0)	-
Net gains reclassified to earnings:						
Interest Expense	-	(2.6)	-	(2.1)	-	(2.5)
Revenues	18.2	-	1.4	-	(1.1)	-
Purchased Power	(0.2)	-	3.3	-	0.2	-
Ending accumulated derivative gain / (loss) in AOCI	$ 0.2	$ 2.6	$ 1.0	$ 5.2	$ (4.7)	$ 7.3

Net gains or losses associated with the ineffective portion of the hedging transactions were immaterial in the years ended December 31, 2014, 2013 and 2012.

	Power	Interest Rate Hedge
Portion expected to be reclassified to earnings in the next twelve months[(a)]	$ 3.5	$ (2.6)
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	24	0

(a) The actual amounts that we reclassify from AOCI to earnings related to power can differ from the estimate above due to market price changes.

Mark to Market Accounting

Certain derivative contracts are entered into on a regular basis as part of our risk management program but do not qualify for hedge accounting or the normal purchases and sales exceptions under FASC 815. Accordingly, such contracts are recorded at fair value with changes in the fair value charged or credited to the statements of results of operations in the period in which the change occurred. This is commonly referred to as "MTM accounting." Contracts we enter into as part of our risk management program may be settled financially, by physical delivery or net settled with the counterparty. We mark to market FTRs, heating oil futures, forward NYMEX-quality coal contracts and certain forward power contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided under GAAP. Derivative contracts that have been designated as normal purchases or normal sales under GAAP are not subject to MTM accounting treatment and are recognized in the statements of results of operations on an accrual basis.

Regulatory Assets and Liabilities

In accordance with regulatory accounting under GAAP, a cost that is probable of recovery in future rates should be deferred as a regulatory asset and a gain that is probable of being returned to customers should be deferred as a regulatory liability. Portions of the derivative contracts that are marked to market each reporting period and are related to the retail portion of **DP&L's** load requirements are included as part of the fuel and purchased power recovery rider approved by the PUCO which began January 1, 2010. Therefore, the Ohio retail customers' portion of the heating oil futures are deferred as a regulatory asset or liability until the contracts settle. If these unrealized gains and losses are no longer deemed to be probable of recovery through our rates, they will be reclassified into earnings in the period such determination is made.

The following tables show the amount and classification within the statements of results of operations or balance sheets of the gains and losses on **DP&L's** derivatives not designated as hedging instruments for the years ended December 31, 2014, 2013 and 2012.

Year ended December 31, 2014

$ in millions	Heating Oil	FTRs	Power	Natural Gas	Total
Derivatives not designated as hedging instruments					
Change in unrealized loss	$ (0.6)	$ (0.8)	$ (1.5)	$ (0.1)	$ (3.0)
Realized gain / (loss)	(0.1)	0.7	(3.0)	(0.1)	(2.5)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)
Recorded on Balance Sheet:					
Regulatory asset	$ (0.1)	$ -	$ -	$ -	$ (0.1)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	0.7	-	0.7
Purchased Power	-	(0.1)	(5.2)	(0.2)	(5.5)
Fuel	(0.6)	-	-	-	(0.6)
Total	$ (0.7)	$ (0.1)	$ (4.5)	$ (0.2)	$ (5.5)

Year ended December 31, 2013

$ in millions	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging				
Change in unrealized gain / (loss)	$ -	$ 0.3	$ (1.2)	$ (0.9)
Realized gain	0.1	1.2	1.6	2.9
Total	$ 0.1	$ 1.5	$ 0.4	$ 2.0
Recorded in Income Statement: gain /				
Revenue	$ -	$ -	$ 0.2	$ 0.2
Purchased Power	-	1.5	0.2	1.7
Fuel	0.1	-	-	0.1
Total	$ 0.1	$ 1.5	$ 0.4	$ 2.0

Year ended December 31, 2012					
$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Derivatives not designated as hedging instruments					
Change in unrealized gain / (loss)	$ 14.5	$ (1.6)	$ (0.2)	$ 3.0	$ 15.7
Realized gain / (loss)	(29.5)	1.9	0.5	4.9	(22.2)
Total	$ (15.0)	$ 0.3	$ 0.3	$ 7.9	$ (6.5)
Recorded on Balance Sheet:					
Partners' share of gain	$ 4.2	$ -	$ -	$ -	$ 4.2
Regulatory (asset) / liability	1.0	(0.6)	-	-	0.4
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	2.7	2.7
Purchased Power	-	-	0.3	5.2	5.5
Fuel	(20.2)	0.7	-	-	(19.5)
O&M	-	0.2	-	-	0.2
Total	$ (15.0)	$ 0.3	$ 0.3	$ 7.9	$ (6.5)

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The following tables show the fair value and balance sheet classification of **DP&L's** derivative instruments at December 31, 2014 and 2013.

Fair Values of Derivative Instruments
December 31, 2014

$ in millions	Hedging Designation	Gross Fair Value as presented in the Balance Sheets	Gross Amounts Not Offset in the Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 5.6	$ (2.0)	$ -	$ 3.6
Forward power contracts	MTM	5.6	(3.4)	-	2.2
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	0.3	(0.3)	-	-
Forward power contracts	MTM	3.6	(0.9)	-	2.7
Total assets		$ 15.1	$ (6.6)	$ -	$ 8.5
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.1	$ (2.0)	$ -	$ 0.1
Forward power contracts	MTM	7.5	(3.4)	(4.1)	-
FTRs	MTM	0.6	-	-	0.6
Heating oil futures	MTM	0.4	-	(0.4)	-
Natural gas futures	MTM	0.1	-	(0.1)	-
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	Cash Flow	0.6	(0.3)	(0.3)	-
Forward power contracts	MTM	1.0	(0.9)	-	0.1
Total liabilities		$ 12.3	$ (6.6)	$ (4.9)	$ 0.8

Fair Values of Derivative Instruments
December 31, 2013

$ in millions	Hedging Designation	Gross Fair Value as presented in the Balance Sheets	Gross Amounts Not Offset in the Balance Sheets: Financial Instruments with Same Counterparty in Offsetting Position	Gross Amounts Not Offset in the Balance Sheets: Cash Collateral	Net Amount
Assets					
Short-term derivative positions (presented in Other current assets)					
Forward power contracts	Cash Flow	$ 0.5	$ (0.2)	$ -	$ 0.3
Forward power contracts	MTM	4.9	(4.2)	-	0.7
FTRs	MTM	0.2	-	-	0.2
Heating oil futures	MTM	0.2	-	(0.2)	-
Long-term derivative positions (presented in Other deferred assets)					
Forward power contracts	Cash Flow	3.0	-	(3.0)	-
Forward power contracts	MTM	5.0	(0.3)	-	4.7
Total assets		$ 13.8	$ (4.7)	$ (3.2)	$ 5.9
Liabilities					
Short-term derivative positions (presented in Other current liabilities)					
Forward power contracts	Cash Flow	$ 2.7	$ (0.2)	$ (2.3)	$ 0.2
Forward power contracts	MTM	6.6	(4.2)	(2.3)	0.1
Long-term derivative positions (presented in Other deferred liabilities)					
Forward power contracts	MTM	1.3	(0.3)	(1.0)	-
Total liabilities		$ 10.6	$ (4.7)	$ (5.6)	$ 0.3

Certain of our OTC commodity derivative contracts are under master netting agreements that contain provisions that require our debt to maintain an investment grade credit rating from credit rating agencies. Since our debt has fallen below investment grade, we are in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization of the MTM loss. Since our debt has fallen below investment grade, some of our counterparties to the derivative instruments have requested collateralization of the MTM loss.

The aggregate fair value of **DP&L's** derivative instruments that are in a MTM loss position at December 31, 2014 is $12.3 million. This amount is offset by $4.9 million in a broker margin account and with other counterparties which offsets our loss positions on the forward contracts. This liability position is further offset by the asset position of counterparties with master netting agreements of $6.6 million. If **DP&L** debt were to fall below investment grade, **DP&L** could be required to post collateral for the remaining $0.8 million.

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NOTE 10 – REDEEMABLE PREFERRED STOCK

DP&L has $100 par value preferred stock, 4,000,000 shares authorized, of which 228,508 were outstanding as of December 31, 2014. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2014. The table below details the preferred shares outstanding at December 31, 2014 and 2013:

		December 31, 2014 and 2013		Par Value ($ in millions)	
$ in millions except per share amounts	Preferred Stock Rate	Redemption price ($ per share)	Shares Outstanding	December 31, 2014	December 31, 2013
DP&L Series A	3.75%	$ 102.50	93,280	$ 9.3	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	7.0	7.0
DP&L Series C	3.90%	$ 101.00	65,830	6.6	6.6
Total			228,508	$ 22.9	$ 22.9

The **DP&L** preferred stock may be redeemed at **DP&L's** option as determined by its Board of Directors at the per-share redemption prices indicated above, plus cumulative accrued dividends, of which there were none at December 31, 2014. In addition, **DP&L's** Amended Articles of Incorporation contain provisions that permit preferred stockholders to elect members of the Board of Directors in the event that cumulative dividends on the preferred stock are in arrears in an aggregate amount equivalent to at least four full quarterly dividends. Since this potential redemption-triggering event is not solely within the control of **DP&L**, the preferred stock is presented on the Balance Sheets as "Redeemable Preferred Stock" in a manner consistent with temporary equity.

As long as any **DP&L** preferred stock is outstanding, **DP&L's** Amended Articles of Incorporation also contain provisions restricting the payment of cash dividends on any of its common stock if, after giving effect to such dividend, the aggregate of all such dividends distributed subsequent to December 31, 1946 exceeds the net income of **DP&L** available for dividends on its common stock subsequent to December 31, 1946, plus $1.2 million. This dividend restriction has historically not impacted **DP&L's** ability to pay cash dividends and, as of December 31, 2014, **DP&L's** retained earnings of $381.8 million were all available for common stock dividends payable to **DPL**. We do not expect this restriction to have an effect on the payment of cash dividends in the future.

NOTE 11 – COMMON SHAREHOLDERS' EQUITY

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2014. All common shares are held by **DP&L's** parent, **DPL**.

As part of the PUCO's approval of the Merger, **DP&L** agreed to maintain a capital structure that includes an equity ratio of at least 50 percent and not to have a negative retained earnings balance.

NOTE 12 – CONTRACTUAL OBLIGATIONS, COMMERCIAL COMMITMENTS AND CONTINGENCIES

DP&L – Equity Ownership Interest

DP&L has a 4.9% equity ownership interest in an electric generation company which is recorded using the cost method of accounting under GAAP. As of December 31, 2014, **DP&L** could be responsible for the repayment of 4.9%, or $74.4 million, of a $1,517.9 million debt obligation comprised of both fixed and variable rate securities with maturities between 2015 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2014, we have no knowledge of such a default.

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Contractual Obligations and Commercial Commitments

We enter into various contractual obligations and other commercial commitments that may affect the liquidity of our operations. At December 31, 2014, these include:

		Payments due in:			
$ in millions	Total	Less than 1 year	2 - 3 years	4 - 5 years	More than 5 years
DP&L:					
Coal contracts [(a)]	486.2	255.6	161.2	69.4	-
Limestone contracts [(a)]	18.3	6.1	12.2	-	-
Purchase orders and other contractual obligations	72.4	39.2	17.3	15.9	-

(a) Total at **DP&L** operated units.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating stations it operates. As of December 31, 2014, 57% of our future committed coal obligations are with a single supplier. Some contract prices are subject to periodic adjustment and have features that limit price escalation in any given year.

Limestone contracts:
DP&L has entered into various limestone contracts to supply limestone used in the operation of FGD equipment at its generating facilities.

Purchase orders and other contractual obligations:
As of December 31, 2014, **DP&L** had various other contractual obligations including non-cancelable contracts to purchase goods and services with various terms and expiration dates.

Contingencies

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in our Financial Statements, as prescribed by GAAP, are adequate in light of the probable and estimable contingencies. However, there can be no assurances that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims, tax examinations, and other matters, including the matters discussed below, and to comply with applicable laws and regulations, will not exceed the amounts reflected in our Financial Statements. As such, costs, if any, that may be incurred in excess of those amounts provided as of December 31, 2014, cannot be reasonably determined.

Environmental Matters

DPL's and **DP&L's** facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. The environmental issues that may affect us include:

- The federal CAA and state laws and regulations (including SIPs) which require compliance, obtaining permits and reporting as to air emissions,
- Litigation with federal and certain state governments and certain special interest groups regarding whether modifications to or maintenance of certain coal-fired generating stations require additional permitting or pollution control technology, or whether emissions from coal-fired generating stations cause or contribute to global climate changes,
- Rules and future rules issued by the USEPA and the Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NO_x, and other air emissions. **DP&L** has installed emission control technology and is taking other measures to comply with required and anticipated reductions,
- Rules and future rules issued by the USEPA and the Ohio EPA that require reporting and reductions of GHGs,
- Rules and future rules issued by the USEPA associated with the federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and

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- Solid and hazardous waste laws and regulations, which govern the management and disposal of certain waste. The majority of solid waste created from the combustion of coal and fossil fuels is fly ash and other coal combustion by-products.

In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. In the normal course of business, we have investigatory and remedial activities underway at our facilities to comply, or to determine compliance, with such regulations. We record liabilities for loss contingencies related to environmental matters when a loss is probable of occurring and can be reasonably estimated in accordance with the provisions of GAAP. Accordingly, we have accruals for loss contingencies of approximately $0.8 million for environmental matters. We also have a number of environmental matters for which we have not accrued loss contingencies because the risk of loss is not probable or a loss cannot be reasonably estimated, which are disclosed in the paragraphs below. We evaluate the potential liability related to environmental matters quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material adverse effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our coal-fired generation units. Some of these matters could have material adverse impacts on the operation of the power stations.

Environmental Matters Related to Air Quality

Clean Air Act Compliance
In 1990, the federal government amended the CAA to further regulate air pollution. Under the CAA, the USEPA sets limits on how much of a pollutant can be in the ambient air anywhere in the United States. The CAA allows individual states to have stronger pollution controls than those set under the CAA, but states are not allowed to have weaker pollution controls than those set for the whole country. The CAA has a material effect on our operations and such effects are detailed below with respect to certain programs under the CAA.

Clean Air Interstate Rule/Cross-State Air Pollution Rule
The USEPA promulgated CAIR on March 10, 2005, which required allowance surrender for SO_2 and NO_x emissions from existing power stations located in 27 eastern states and the District of Columbia. To implement the required emission reductions for this rule, the states were to establish emission-allowance-based "cap-and-trade" programs. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the USEPA.

On July 7, 2011, the USEPA proposed CSAPR to replace CAIR. CSAPR required significant reductions in SO_2 and NOx emissions from covered sources, such as power stations in 28 eastern states including Ohio. On August 21, 2012, a three-judge panel of the D.C. Circuit Court vacated CSAPR, ruling that the USEPA overstepped its regulatory authority by requiring states to make reductions beyond the levels required in the CAA and failed to provide states an initial opportunity to adopt their own measures for achieving federal compliance. As a result of this ruling, the surviving provisions of CAIR continued to serve as the governing program. On June 24, 2013, the U.S. Supreme Court agreed to review the D.C. Circuit Court's decision to vacate CSAPR, and on April 29, 2014, the U.S. Supreme Court reversed the 2012 decision by the D.C. Circuit Court, reinstating CSAPR, and remanded the case back to the D.C. Circuit Court for further proceedings consistent with the U. S. Supreme Court decision. On June 26, 2014, the U.S. Department of Justice, on behalf of the USEPA, filed a motion with the D.C. Circuit Court to lift the stay, and CSAPR was reinstated on October 23, 2014. The USEPA established new effective dates for compliance with the reduced emissions levels, beginning in 2015 with additional reductions in 2017. Oral arguments to address the remaining litigation regarding CSAPR are schedule for March 2015. At this time, it is not possible to predict with precision what impacts CSAPR may have on our consolidated financial condition, results of operations or cash flows, but we do not expect to have material capital costs to comply with CSAPR.

Mercury and Other Hazardous Air Pollutants
On May 3, 2011, the USEPA published proposed Maximum Achievable Control Technology (MACT) standards for coal- and oil-fired electric generating units. The standards include new requirements for emissions of mercury and a number of other heavy metals. The USEPA Administrator signed the final rule, now called MATS, on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Our affected EGUs must come into compliance with the new requirements by April 16, 2015. All of our operating EGUs are expected to be able to achieve compliance through control technologies that are currently in place.

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On January 31, 2013, the USEPA finalized a rule regulating emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulation contains emissions limitations, operating limitations and other requirements. **DP&L** expects to be in compliance with this rule and the costs are not currently expected to be material to **DP&L's** operations.

National Ambient Air Quality Standards
On January 5, 2005, the USEPA published its final non-attainment designations for the National Ambient Air Quality Standard (NAAQS) for Fine Particulate Matter 2.5 (PM 2.5). These designations included counties and partial counties in which **DP&L** operates and/or owns generating facilities. On December 31, 2012, the USEPA re-designated Adams County, where the Stuart and Killen generating stations are located, to attainment status. On December 14, 2012, the USEPA tightened the PM 2.5 standard to 12.0 micrograms per cubic meter, and on December 18, 2014, issued a pre-publication version of the final attainment designations. No counties containing **DP&L** operated generating facilities were designated as non-attainment, however, several co-owned units are located in non-attainment counties. Attainment in those counties will be required by the end of 2021. We cannot predict the effect the revisions to the PM 2.5 standard will have on **DP&L's** financial condition or results of operations.

The USEPA published the national ground level ozone standard on March 12, 2008, lowering the 8-hour level from 0.08 ppm to 0.075 ppm, which was upheld by the U.S. Circuit Court of Appeals in July 2013. No **DP&L** operations are currently located in non-attainment areas. On December 17, 2014, the USEPA published a proposed rule lowering the 8-hour ozone standard from 0.075 to a value between 0.065 and 0.070 ppm. The USEPA intends to finalize the rule regarding the ozone NAAQS by October 2015, with initial designations to be issued in October 2017. In addition, in December 2013, eight northeastern states petitioned the USEPA to add nine upwind states, including Ohio, to the Ozone Transport Region, a group of states required to impose enhanced restrictions on ozone emissions. If the petition is granted, our facilities could be subject to such enhanced requirements. We cannot predict the effect the revisions of the ozone standard will have on **DP&L's** financial condition or results of operations.

Effective April 12, 2010, the USEPA implemented revisions to its primary NAAQS for nitrogen dioxide. This change may affect certain emission sources in heavy traffic areas like the I-75 corridor between Cincinnati and Dayton after 2016. Several of our facilities or co-owned facilities are within this area. **DP&L** cannot determine the effect of this potential change, if any, on its operations.

Effective August 23, 2010, the USEPA implemented its revisions to its primary NAAQS for SO_2 replacing the previous 24-hour standard and annual standard with a one-hour standard. Initial non-attainment designations were made July 25, 2013, and Pierce Township in Clermont County, location of **DP&L's** co-owned unit Beckjord Unit 6, was the only area with **DP&L** operations designated as non-attainment. Beckjord Unit 6 was retired effective October 1, 2014. Non-attainment areas will be required to meet the 2010 standard by October 2018. On April 17, 2014, the USEPA proposed a data requirements rule for air agencies to ascertain attainment characterization more extensively across the country by additional modeling and/or monitoring requirements of areas with sources that exceed specified thresholds of SO_2 emissions. The rule, if finalized, could require the installation of monitors at one or more of **DP&L's** coal-fired power plants and result in additional non-attainment designations that could impact our operations. **DP&L** is unable to determine the effect of the proposed rule on its operations.

On May 5, 2004, the USEPA issued its proposed regional haze rule, which addresses how states should determine the Best Available Retrofit Technology (BART) for sources covered under the regional haze rule. Final rules were published July 6, 2005, providing states with several options for determining whether sources in the state should be subject to BART. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the impact until Ohio determines how BART will be implemented.

Carbon Dioxide and Other Greenhouse Gas Emissions
The USEPA began regulating GHG emissions from certain stationary sources in January 2011 under regulations referred to as the "Tailoring Rule." The regulations are implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing certain new construction or major modifications, the Prevention of Significant Deterioration, or PSD, program. Obligations relating to Title V permits include recordkeeping and monitoring requirements. Sources subject to PSD can be required to implement Best Available Control Technology, or BACT. In June 2014, the U.S. Supreme Court ruled that the USEPA had exceeded its statutory authority in issuing the Tailoring Rule under Section 165 of the CAA by regulating sources under the PSD program based solely on their GHG emissions. However, the U.S. Supreme Court also held that

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the USEPA could impose GHG BACT requirements for sources already required to implement PSD for certain other pollutants. Therefore, if future modifications to **DP&L's** sources require PSD review for other pollutants, it may also trigger GHG BACT requirements. The USEPA has issued guidance on what BACT entails for the control of GHG and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of the BACT requirements applicable to us on our operations cannot be determined at this time as **DP&L** will not be required to implement BACT until **DP&L** constructs a new major source or makes a major modification of an existing major source. However, the cost of compliance could be material.

In January 2014, the USEPA proposed revised GHG New Source Performance Standards for new EGUs under CAA subsection 111(b), which would require new EGUs to limit the amount of CO_2 emitted per megawatt-hour. The proposal anticipates that affected coal-fired units would need to rely upon partial implementation of carbon capture and storage or other expensive CO_2 emission control technology to meet the standard. In addition, new natural gas-fired EGUs must meet a standard of no greater than 1,000 pounds of CO_2 per megawatt hour (if the rule is finalized in its current form). The rule is expected to be finalized this summer.

The USEPA issued proposed rules establishing GHG performance standards for existing power plants under CAA Section 111(d) on June 2, 2014. Under the proposed rule, called the Clean Power Plan, states would be judged against state-specific carbon dioxide emissions targets beginning in 2020, with expected total U.S. power section emissions reduction of 30% from 2005 levels by 2030. For Ohio specifically, the Clean Power Plan proposes an interim goal for 2020-2029 and a proposed 2030 final goal of 1,452 pounds of CO_2 per megawatt hour and 1,338 pounds of CO_2 per megawatt hour, respectively, a reduction of approximately 28% from 2012 levels. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one or two-year extensions under certain circumstances. The proposed rule requires states to submit SIPs to meet the standards set forth in the rule by June 30, 2016, with the possibility of one- or two-year extensions under certain circumstances. The proposed rule was subject to a public comment process and the USEPA is expected to finalize it by the summer of 2015. Among other things, we could be required to make efficiency improvements to existing facilities. The USEPA also issued proposed carbon pollution standards for modified and reconstructed power plants on June 2, 2014, which are also expected to be finalized by the summer of 2015. Various states and certain regulated entities have filed lawsuits challenging the Clean Power Plan. However, it is too soon to determine what the rule, and the corresponding SIPs affecting our operations, will require once they are finalized, whether they will survive judicial and other challenges, and if so, whether and when the rule and the corresponding SIP would materially impact our business, operations or financial condition.

Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of CO_2 emissions at generating stations we own and co-own is approximately 14 million tons annually. Further GHG legislation or regulation implemented at a future date could have a significant effect on **DP&L's** operations and costs, which could adversely affect our net income, cash flows and financial condition. However, due to the uncertainty associated with such legislation or regulation, we cannot predict the final outcome or the financial effect that such legislation or regulation may have on **DP&L**.

Litigation, Notices of Violation and Other Matters Related to Air Quality

Litigation Involving Co-Owned Stations

As a result of a 2008 consent decree entered into with the Sierra Club and approved by the U.S. District Court for the Southern District of Ohio, **DP&L** and the other owners of the Stuart generating station are subject to certain specified emission targets related to NO_x, SO_2 and particulate matter. The consent decree also includes commitments for energy efficiency and renewable energy activities. An amendment to the consent decree was entered into and approved in 2010 to clarify how emissions would be computed during malfunctions. Continued compliance with the consent decree, as amended, is not expected to have a material effect on **DP&L's** results of operations, financial condition or cash flows in the future.

Notices of Violation Involving Co-Owned Units

In June 2000, the USEPA issued an NOV to the **DP&L**-operated Stuart generating station (co-owned by **DP&L**, Duke Energy and AEP Generation) for alleged violations of the CAA. The NOV contained allegations consistent with NOVs and complaints that the USEPA had brought against numerous other coal-fired utilities in the Midwest. The NOV indicated the USEPA may: (1) issue an order requiring compliance with the requirements of the Ohio SIP; or (2) bring a civil action seeking injunctive relief and civil penalties of up to $27,500 per day for each violation. To date, neither action has been taken. **DP&L** cannot predict the outcome of this matter.

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In December 2007, the Ohio EPA issued an NOV to the **DP&L**-operated Killen generating station (co-owned by **DP&L** and Duke Energy) for alleged violations of the CAA. The NOV alleged deficiencies in the continuous monitoring of opacity. We submitted a compliance plan to the Ohio EPA on December 19, 2007. To date, no further actions have been taken by the Ohio EPA.

On March 13, 2008, Duke Energy, the operator of the Zimmer generating station, received an NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio SIP and permits for the station in areas including SO_2, opacity and increased heat input. A second NOV and FOV with similar allegations was issued on November 4, 2010. Also in 2010, the USEPA issued an NOV to Zimmer for excess emissions. In addition, Zimmer received an NOV from the USEPA dated December 16, 2014 alleging violations in opacity on two dates in 2014. **DP&L** is a co-owner of the Zimmer generating station and could be affected by the eventual resolution of these matters. Duke Energy is expected to act on behalf of itself and the co-owners with respect to these matters. **DP&L** is unable to predict the outcome of these matters.

In January 2015, **DP&L** received NOVs from the USEPA alleging violations in opacity at the Stuart and Killen generating stations in 2014. **DP&L** is beginning the process of discussions with the USEPA on these NOVs. **DP&L** is unable to predict the outcome of these matters.

Notices of Violation Involving Wholly-Owned Stations
On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the two projects described in the NOV were modifications subject to NSR. As a result of the cessation of operations of the six coal-fired units at the Hutchings Station, **DP&L** believes that the USEPA is unlikely to pursue the NSR complaint.

Environmental Matters Related to Water Quality, Waste Disposal and Ash Ponds

Clean Water Act – Regulation of Water Intake
On May 19, 2014, the USEPA finalized new regulations pursuant to the CWA governing existing facilities that have cooling water intake structures. The rules require an assessment of impingement and/or entrainment of organisms as a result of cooling water withdrawal. Although we do not yet know the full impact the final rules will have on our operations, the final rules may require material changes to the intake structure at Stuart Station to reduce impingement with the possibility of additional site specific requirements for reducing entrainment. We do not believe the final rules will have a material impact on operations at any of the other **DP&L**-operated facilities.

Clean Water Act – Regulation of Water Discharge
In December 2006, **DP&L** submitted a renewal application for the Stuart generating station NPDES permit that was due to expire on June 30, 2007. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In September 2010, the USEPA formally objected to the November 12, 2008 revised permit due to questions regarding the basis for the alternate thermal limitation. At **DP&L's** request, a public hearing was held on March 23, 2011, where **DP&L** presented its position on the issue and provided written comments. In a letter to the Ohio EPA dated September 28, 2011, the USEPA reaffirmed its objection to the revised permit as previously drafted by the Ohio EPA. This reaffirmation stipulated that if the Ohio EPA did not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit would pass to the USEPA. The Ohio EPA issued another draft permit in December 2011 and a public hearing was held on February 2, 2012.

The draft permit required **DP&L,** over the 54 months following issuance of a final permit, to take undefined actions to lower the temperature of its discharged water to a level unachievable by the station under its current design or alternatively make other significant modifications to the cooling water system. **DP&L** submitted comments to the draft permit. In November 2012, the Ohio EPA issued another draft which included a compliance schedule for performing a study to justify an alternate thermal limitation and to which **DP&L** submitted comments. In December 2012, the USEPA formally withdrew their objection to the permit. On January 7, 2013, the Ohio EPA issued a final permit. On February 1, 2013, **DP&L** appealed various aspects of the final permit to the Environmental Review Appeals Commission. A hearing before the Commission is scheduled for March 2015. Depending on the outcome of the appeal process, the effects on **DP&L's** operations could be material.

In September 2009, the USEPA announced that it would be revising technology-based regulations governing water discharges from steam electric generating facilities. The rulemaking included the collection of information via an industry-wide questionnaire as well as targeted water sampling efforts at selected facilities. The proposed rule was released on June 7, 2013. Under a consent decree, the USEPA is required to issue a final rule by September 2015. At present, **DP&L** is unable to predict the impact this rulemaking will have on its operations.

A final NPDES permit for Killen Station was issued on September 4, 2014. We do not expect the new permit to have a material impact on Killen's operations.

In January 2014, **DP&L** submitted an application for the renewal of the Hutchings Station NPDES permit which expired in July 2014. A final permit was issued on September 19, 2014 with an effective date of November 1, 2014. We do not expect the new permit to have a material impact on Hutchings' operations.

Regulation of Waste Disposal
In September 2002, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the South Dayton Dump landfill site. In August 2005, **DP&L** and other parties received a general notice regarding the performance of a Remedial Investigation and Feasibility Study (RI/FS) under a Superfund Alternative Approach. In October 2005, **DP&L** received a special notice letter inviting it to enter into negotiations with the USEPA to conduct the RI/FS. No recent activity has occurred with respect to that notice or PRP status. On August 16, 2006, an Administrative Settlement Agreement and Order on Consent ("ASAOC") was executed and became effective among a group of PRPs, not including **DP&L**, and the USEPA. On August 25, 2009, the USEPA issued an Administrative Order requiring that access to **DP&L's** service center building site, which is across the street from the landfill site, be given to the USEPA and the existing PRP group to help determine the extent of the landfill site's contamination as well as to assess whether certain chemicals used at the service center building site might have migrated through groundwater to the landfill site. **DP&L** granted such access and drilling of soil borings and installation of monitoring wells occurred in late 2009 and early 2010. On May 24, 2010, three members of the existing PRP group, Hobart Corporation, Kelsey-Hayes Company and NCR Corporation, filed a civil complaint in the United States District Court for the Southern District of Ohio against **DP&L** and numerous other defendants alleging that **DP&L** and the other defendants contributed to the contamination at the South Dayton Dump landfill site and seeking reimbursement of the PRP group's costs associated with the investigation and remediation of the site. On February 10, 2011, the Court dismissed claims against **DP&L** that related to allegations that chemicals used by **DP&L** at its service center contributed to the landfill site's contamination. The Court, however, did not dismiss claims alleging financial responsibility for remediation costs based on hazardous substances from **DP&L** that were allegedly directly delivered by truck to the landfill. Discovery, including depositions of past and present **DP&L** employees, was conducted in 2012. On February 8, 2013, the Court granted **DP&L's** motion for summary judgment on statute of limitations grounds with respect to claims seeking a contribution toward the costs that are expected to be incurred by the PRP group in performing an RI/FS under the August 15, 2006 ASAOC. That summary judgment ruling was appealed on March 4, 2013, and on July 14, 2014, a three-judge panel of the U.S. Court of Appeals for the 6th Circuit affirmed the lower Court's ruling and subsequently denied a request by the plaintiffs for rehearing. On November 14, 2014, the PRP group appealed the decision to the U.S. Supreme Court, but the writ of certiorari was denied by the Court on January 20, 2015. On January 14, 2015, the PRP group served **DP&L** and other defendants a request for production of documents related to any survey regarding waste management or waste disposal. Information responsive to this request was provided on February 17, 2015. In addition, on January 16, 2015, the USEPA issued a Special Notice Letter and Section 104(e) Information Request to **DP&L** and other defendants, requesting historical information related to waste management practices. **DP&L** is in the process of developing its response to the request which is due by March 20, 2015. **DP&L** is unable to predict the outcome of this action by the plaintiffs and USEPA. Additionally, the Court's 2013 ruling and the Court of Appeals' affirmation of that ruling in 2014 does not address future litigation that may arise with respect to actual remediation costs. While **DP&L** is unable to predict the outcome of these matters, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

In December 2003, **DP&L** and other parties received a special notice that the USEPA considers us to be a PRP for the clean-up of hazardous substances at the Tremont City landfill site. Information available to **DP&L** does not demonstrate that it contributed hazardous substances to the site. While **DP&L** is unable to predict the outcome of this matter, if **DP&L** were required to contribute to the clean-up of the site, it could have a material adverse effect on its operations.

On April 7, 2010, the USEPA published an Advance Notice of Proposed Rulemaking announcing that it is reassessing existing regulations governing the use and distribution in commerce of polychlorinated biphenyls (PCBs). While this reassessment is in the early stages and the USEPA is seeking information from potentially affected parties on how it should proceed, the outcome may have a material effect on **DP&L**. A proposed rule is expected in mid-2015, with a final rule expected in 2016. At present, **DP&L** is unable to predict the impact this initiative will have on its operations.

Regulation of Ash Ponds
In March 2009, the USEPA, through a formal Information Collection Request, collected information on ash pond facilities across the country, including those at Killen and Stuart Stations. Subsequently, the USEPA collected similar information for the Hutchings Station.

In August 2010, the USEPA conducted an inspection of the Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the Hutchings Station ash ponds. **DP&L** is unable to predict whether there will be additional USEPA action relative to **DP&L's** proposed plan or the effect on operations that might arise under a different plan.

In June 2011, the USEPA conducted an inspection of the Killen Station ash ponds. In May 2012, we received a draft report on the inspection. **DP&L** submitted comments on the draft report in June 2012. On March 14, 2013, **DP&L** received the final report on the inspection of the Killen Station ash pond inspection from the USEPA which included recommended actions. **DP&L** has submitted a response with its actions to the USEPA. **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion residuals (CCR) under the Resource Conservation Recovery Act (RCRA). On June 21, 2010, the USEPA published a proposed rule seeking comments on two options under consideration for the regulation of coal combustion byproducts including regulating the material as a hazardous waste under RCRA Subtitle C or as a solid waste under RCRA Subtitle D. The USEPA released its final rule on December 19, 2014 designating coal combustion residuals that are not beneficially reused as non-hazardous solid waste under RCRA Subtitle D. The rule becomes effective six months after publication of the rule in the Federal Register, expected in February 2015, and applies new detailed management practices to new and existing landfills and surface impoundments, including lateral expansions of such units. **DP&L** is currently reviewing the rule and assessing the impact on our operations. Our business, financial condition or operations could be materially and adversely affected by this regulation.

Notice of Violation Involving Co-Owned Units
On September 9, 2011, **DP&L** received an NOV from the USEPA with respect to its co-owned Stuart generating station based on a compliance evaluation inspection conducted by the USEPA and Ohio EPA in 2009. The notice alleged non-compliance by **DP&L** with certain provisions of the RCRA, the CWA NPDES permit program, and the station's storm water pollution prevention plan. The notice requested that **DP&L** respond with the actions it has subsequently taken or plans to take to remedy the USEPA's findings and ensure that further violations will not occur. Based on its review of the findings, although there can be no assurance, we believe that the notice will not result in any material effect on **DP&L's** results of operations, financial condition or cash flows.

Legal and Other Matters

In February 2007, **DP&L** filed a lawsuit against a coal supplier seeking damages incurred due to the supplier's failure to supply approximately 1.5 million tons of coal to two commonly-owned stations under a coal supply agreement, of which approximately 570 thousand tons was **DP&L's** share. **DP&L** obtained replacement coal to meet its needs. The supplier has denied liability, and is currently in federal bankruptcy proceedings in which **DP&L** is participating as an unsecured creditor. **DP&L** is unable to determine the ultimate resolution of this matter. **DP&L** has not recorded any assets relating to possible recovery of costs in this lawsuit.

In connection with **DP&L** and other utilities joining PJM, in 2006 the FERC ordered utilities to eliminate certain charges to implement transitional payments, known as SECA, effective December 1, 2004 through March 31, 2006, subject to refund. Through this proceeding, **DP&L** was obligated to pay SECA charges to other utilities, but received a net benefit from these transitional payments. A hearing was held and an initial decision was issued in August 2006. A final FERC order on this issue was issued on May 21, 2010 that substantially supports **DP&L's** and other utilities' position that SECA obligations should be paid by parties that used the transmission system during the timeframe stated above. Prior to this final order being issued, **DP&L** entered into a significant number of bilateral settlement agreements with certain parties to resolve the matter, which by design will be unaffected by the final decision. On July 5, 2012, a Stipulation was executed and filed with the FERC that resolves SECA claims against BP Energy Company ("BP") and **DP&L**, AEP (and its subsidiaries) and Exelon Corporation (and its subsidiaries). On October 1, 2012, **DP&L** received $14.6 million (including interest income of $1.8 million) from BP and recorded the settlement in the third quarter; at December 31, 2012, there is no remaining balance in other deferred credits related to SECA.

NOTE 13 – FIXED-ASSET IMPAIRMENT

During the fourth quarter of 2013, the Company tested the recoverability of long-lived assets at Conesville, a 129 MW coal-fired station in Ohio, and East Bend, a 186 MW coal-fired station in Kentucky jointly-owned by **DP&L**. Gradual decreases in power prices, as well as lower estimates of future capacity prices in conjunction with the DP&L reporting unit of **DPL** failing step 1 of the annual goodwill impairment test were collectively determined to be an impairment indicator for the **DP&L** long-lived assets. The Company performed a long-lived asset impairment test and determined that the carrying amounts of the asset groups were not recoverable. The long-lived asset group subject to the impairment evaluation was determined to be each individual station of **DP&L**. This determination was based on the assessment of the stations' ability to generate independent cash flows. The Conesville and East Bend asset groups were each determined to have a zero fair value using discounted cash flows under the income approach. As a result, the Company recognized an asset impairment expense of $10.0 million and $76.0 million for Conesville and East Bend, respectively.

On October 5, 2012, **DP&L** filed for approval an ESP with the PUCO which reflected a shift in our outlook for the regulatory environment. Within the ESP filing, **DP&L** agreed to request a separation of its generation assets from its transmission and distribution assets in recognition that a restructuring of **DP&L** operations will be necessary, in compliance with Ohio law. Also, during 2012, North American natural gas prices fell significantly from the previous year, exerting downward pressure on wholesale electricity prices in the Ohio power market. Falling power prices compressed wholesale margins at **DP&L's** generating stations. Furthermore, these lower power prices led to increased customer switching from **DP&L** to CRES providers, who were offering retail prices lower than **DP&L's** standard service offer. Also, several municipalities in **DP&L's** service territory have passed ordinances allowing them to become government aggregators with some having already contracted with CRES providers, further contributing to the switching trend. In September 2012, management revised its cash flow forecasts based on these developments as part of its annual budgeting process and forecasted lower operating cash flows than in prior reporting periods. Collectively, in the third quarter of 2012, these events were considered to be an impairment indicator for the long-lived asset group as management believed that these developments represent a significant adverse change in the business climate that could affect the value of the long-lived asset group.

The long-lived asset group subject to the impairment evaluation was determined to be each individual station of **DP&L**. This determination was based on the assessment of the stations' ability to generate independent cash flows. When the recoverability test of the long-lived asset group was performed, management concluded that, on an undiscounted cash flow basis, the carrying amount of two stations, Conesville and Hutchings, were not recoverable.

The fair value using the income approach was considered the most appropriate and resulted in a $25.0 million fair value for the Conesville Station. The carrying value of the Conesville station prior to the impairment was $97.5 million. Accordingly, the Conesville station was considered impaired and $72.5 million of impairment expense was recognized in the third quarter of 2012.

The fair value using the income approach was considered the most appropriate and resulted in a zero fair value for the Hutchings Station. The carrying value of the Hutchings Station prior to the impairment was $8.3 million. Accordingly, the Hutchings Station was considered impaired and $8.3 million of impairment expense was recognized in the third quarter of 2012.

Item 9 – Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A – Controls and Procedures

Disclosure Controls and Procedures

Our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) are responsible for establishing and maintaining our disclosure controls and procedures. These controls and procedures were designed to ensure that material information relating to us and our subsidiaries are communicated to the CEO and CFO. We evaluated these disclosure controls and procedures as of the end of the period covered by this report with the participation of our CEO and CFO. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2014 our disclosure controls and procedures were not effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, as evidenced by the material weakness described below.

As a result of the material weakness described below, the Company performed additional analysis and other post-closing procedures in order to ensure the proper preparation of the financial statements in accordance with generally accepted accounting principles in the United States of America. This material weakness did not result in any misstatements in the Company's audited financial statements. Accordingly, management believes that the financial statements included in this 2014 Form 10-K fairly present, in all material respects, our financial condition, results of operations and cash flows for the periods presented.

On May 14, 2013, The Committee of Sponsoring Organizations of the Treadway Commission ("COSO") issued an updated version of its Internal Control - Integrated Framework (the "2013 Framework"). Originally issued in 1992 (the "1992 Framework"), the 2013 Framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. We have reviewed the 2013 Framework and integrated the changes into the Company's internal controls over financial reporting. Management's assessment of the overall effectiveness of our internal controls over financial reporting for the year ending December 31, 2014 is based on the 2013 Framework and the change was not significant to our overall control structure over financial reporting. There was no change in our internal control over financial reporting during the quarter ended December 31, 2014, other than the identified material weakness described below, that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Following is our report on internal control over financial reporting as of December 31, 2014.

Management's Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations ("COSO") in 2013. Management determined that a material weakness in internal control over financial reporting existed as of December 31, 2014 as a result of an incorrect formula within the spreadsheet used to support an account balance, creating an understatement of earnings. The Company determined that sufficient controls did not exist to identify this error in a timely manner; therefore this deficiency could have led to a material error in the financial statements. As evidenced by this material weakness, management has concluded that, as of December 31, 2014, the Company did not maintain effective internal control over financial reporting. Management is currently developing a corrective action plan related to the operating effectiveness of the control described above. Management and our Board of Directors are committed to the remediation of this material weakness as well as the continued improvement of the Company's overall system of internal control over financial reporting.

Item 9B – Other Information

None.

PART III

Item 10 – Directors, Executive Officers and Corporate Governance

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 11 – Executive Compensation

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 12 – Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 13 – Certain Relationships and Related Transactions, and Director Independence

Not applicable pursuant to General Instruction I of the Form 10-K.

Item 14 – Principal Accountant Fees and Services

Accountant Fees and Services

The following table presents the aggregate fees billed for professional services rendered to **DPL** and **DP&L** by Ernst & Young LLP for 2014 and 2013. Other than as set forth below, no professional services were rendered or fees billed by Ernst & Young LLP during 2014 and 2013.

	2014 fees billed	2013 fees billed
Audit fees [(a)]	$ 1,523,700	$ 1,368,500
Audit-related Fees [(b)]	146,025	461,000
Tax Fees [(c)]	-	-
All Other Fees	-	14,600
Total	$ 1,669,725	$ 1,844,100

(a) Audit fees relate to professional services rendered for the audit of our annual financial statements and the reviews of our quarterly financial statements and other services that are normally provided in connection with regulatory filing or engagements and services rendered under an agreed upon procedure engagement related to environmental studies.
(b) Audit-related fees relate to services rendered to us for assurance and related services.
(c) *Tax fees consisted principally of tax compliance services.*

The Boards of Directors of DPL Inc. and The Dayton Power and Light Company (collectively, the "Board") pre-approve all audit and permitted non-audit services, including engagement fees and terms for such services in accordance with Section 10A of the Securities Exchange Act of 1934, as amended. The Board will generally pre-approve a listing of specific services and categories of services, including audit, audit-related and other services, for the upcoming or current fiscal year, subject to a specified cost level. Any material service not included in the pre-approved list of services must be separately pre-approved by the Board. In addition, all audit and permissible non-audit services in excess of the pre-approved cost level, whether or not such services are included on the pre-approved list of services, must be separately pre-approved by the Board.

PART IV

Item 15 – Exhibits, Financial Statements and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements

2. Financial Statement Schedules

For each of the three years in the period ended December 31, 2014:

The information required to be submitted in Schedules I, III, IV and V is omitted as not applicable or not required under rules of Regulation S-X.

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Exhibits

DPL and **DP&L** exhibits are incorporated by reference as described unless otherwise filed as set forth herein.

The exhibits filed as part of **DPL's** and **DP&L's** Annual Report on Form 10-K, respectively, are:

DPL.	DP&L	Exhibit Number	Exhibit	Location
X		2(a)	Agreement and Plan of Merger, dated as of April 19, 2011, by and among DPL Inc., The AES Corporation and Dolphin Sub, Inc.	Exhibit 2.1 to Report on Form 8-K filed April 20, 2011 (File No. 1-9052)
X		3(a)	Amended Articles of Incorporation of DPL Inc., as amended through January 6, 2012	Exhibit 3(a) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
X		3(b)	Amended Regulations of DPL Inc., as amended through November 28, 2011	Exhibit 3.2 to Report on Form 8-K filed November 28, 2011 (File No. 1-9052)
	X	3(c)	Amended Articles of Incorporation of The Dayton Power and Light Company, as of January 4, 1991	Exhibit 3(b) to Report on Form 10-K/A for the year ended December 31, 1991 (File No. 1-2385)
	X	3(d)	Regulations of The Dayton Power and Light Company, as of April 9, 1981	Exhibit 3(a) to Report on Form 8-K filed on May 3, 2004 (File No. 1-2385)
X	X	4(a)	Composite Indenture dated as of October 1, 1935, between The Dayton Power and Light Company and Irving Trust Company, Trustee with all amendments through the Twenty-Ninth Supplemental Indenture	Exhibit 4(a) to Report on Form 10-K for the year ended December 31, 1985 (File No. 1-2385)
X	X	4(b)	Forty-First Supplemental Indenture dated as of February 1, 1999, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(m) to Report on Form 10-K for the year ended December 31, 1998 (File No. 1-2385)
X	X	4(c)	Forty-Second Supplemental Indenture dated as of September 1, 2003, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4(r) to Report on Form 10-K for the year ended December 31, 2003 (File No. 1-9052)
X	X	4(d)	Forty-Third Supplemental Indenture dated as of August 1, 2005, between The Dayton Power and Light Company and The Bank of New York, Trustee	Exhibit 4.4 to Report on Form 8-K filed August 24, 2005 (File No. 1-2385)
X		4(e)	Indenture dated as of August 31, 2001 between DPL Inc. and The Bank of New York, Trustee	Exhibit 4(a) to Registration Statement No. 333-74630

DPL	DP&L	Exhibit Number	Exhibit	Location
X		4(f)	First Supplemental Indenture dated as of August 31, 2001 between DPL Inc. and The Bank of New York, as Trustee	Exhibit 4(b) to Registration Statement No. 333-74630
X		4(g)	Amended and Restated Trust Agreement dated as of August 31, 2001 among DPL Inc., The Bank of New York, The Bank of New York (Delaware), the administrative trustees named therein, and several Holders as defined therein	Exhibit 4(c) to Registration Statement No. 333-74630
X	X	4(h)	Forty-Fourth Supplemental Indenture dated as of September 1, 2006 between the Bank of New York, Trustee and The Dayton Power and Light Company	Exhibit 4(s) to Report on Form 10-K for the year ended December 31, 2009 (File No. 1-2385)
X	X	4(i)	Forty-Sixth Supplemental Indenture dated as of December 1, 2008 between The Bank of New York Mellon, Trustee and The Dayton Power and Light Company	Exhibit 4(x) to Report on Form 10-K for the year ended December 31, 2008 (File No. 1-2385)
X		4(j)	Indenture, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Wells Fargo Bank, National Association	Exhibit 4.1 to Report on Form 8-K filed October 5, 2011 by The AES Corporation (File No. 1-12291)
X		4(k)	Supplemental Indenture, dated as of November 28, 2011, between DPL Inc. and Wells Fargo Bank, National Association	Exhibit 4(k) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
X		4(l)	Registration Rights Agreement, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Merrill Lynch Pierce Fenner & Smith Incorporated and each of the initial purchasers named therein	Exhibit 4(l) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-2385)
	X	4(m)	Registration Rights Agreement, dated as of September 19, 2013, by and between Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers	Exhibit 4.1 to Report on Form 8-K filed September 25, 2013 (File No. 1-2385)
	X	4(n)	47th Supplemental Indenture to the First and Refunding Mortgage, dated as of September 1, 2013, by and between the Bank of New York Mellon, as Trustee, and The Dayton Power and Light Company	Exhibit 4.2 to Report on Form 8-K filed September 25, 2013 (File No. 1-2385)
X		4(o)	Indenture, dated October 6, 2014, between DPL Inc. and U.S. Bank National Association.	Exhibit 4.1 to Report on Form 8-K filed October 10, 2014 (File No. 1-9052)
X		4(p)	Registration Rights Agreement, dated as of October 6, 2014, by and between DPL Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers.	Exhibit 4.1 to Report on Form 8-K filed October 10, 2014 (File No. 1-9052)

DPL	DP&L	Exhibit Number	Exhibit	Location
X		10(h)	Credit Agreement, dated as of May 10, 2013, among DPL Inc., U.S. Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Fifth Third Bank and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the other lenders party to the Credit Agreement	Exhibit 10.2 to Report on Form 8-K filed May 16, 2013 (File No. 1-2385)
X		10(i)	Credit Agreement, dated as of May 10, 2013, among The Dayton Power and Light Company, Fifth Third Bank, as Administrative Agent, Swing Line Lender and an L/C Issuer, U.S. Bank, National Association and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the other lenders party to the Credit Agreement	Exhibit 10.3 to Report on Form 8-K filed May 16, 2013 (File No. 1-2385)
X		31(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(a)
X		31(b)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(b)
	X	31(c)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(c)
	X	31(d)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 31(d)
X		32(a)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(a)
X		32(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(b)
	X	32(c)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(c)
	X	32(d)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith as Exhibit 32(d)

DPL	DP&L	Exhibit Number	Exhibit	Location
X	X	101.INS	XBRL Instance	Furnished herewith as Exhibit 101.INS
X	X	101.SCH	XBRL Taxonomy Extension Schema	Furnished herewith as Exhibit 101.SCH
X	X	101.CAL	XBRL Taxonomy Extension Calculation Linkbase	Furnished herewith as Exhibit 101.CAL
X	X	101.DEF	XBRL Taxonomy Extension Definition Linkbase	Furnished herewith as Exhibit 101.DEF
X	X	101.LAB	XBRL Taxonomy Extension Label Linkbase	Furnished herewith as Exhibit 101.LAB
X	X	101.PRE	XBRL Taxonomy Extension Presentation Linkbase	Furnished herewith as Exhibit 101.PRE

Exhibits referencing File No. 1-9052 have been filed by DPL Inc. and those referencing File No. 1-2385 have been filed by The Dayton Power and Light Company.

Pursuant to paragraph (b)(4)(iii)(A) of Item 601 of Regulation S-K, we have not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt if the total amount of securities authorized thereunder does not exceed 10% of the total assets of us and our subsidiaries on a consolidated basis, but we hereby agree to furnish to the SEC on request any such instruments.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, DPL Inc. and The Dayton Power and Light Company have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized

DPL Inc.

February 25, 2015	By:	/s/ Kenneth J. Zagzebski (Kenneth J. Zagzebski) President and Chief Executive Officer (principal executive officer)

The Dayton Power and Light Company

February 25, 2015	By:	/s/ Thomas A. Raga (Thomas A. Raga) President and Chief Executive Officer (principal executive officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of **DPL Inc.** and in the capacities and on the dates indicated.

/s/ Brian Miller (Brian Miller)	Director and Chairman	February 25, 2015
/s/ Elizabeth Hackenson (Elizabeth Hackenson)	Director	February 25, 2015
/s/ Michael S. Mizell (Michael S. Mizell)	Director	February 25, 2015
/s/ Kazi K. Hasan (Kazi K. Hasan)	Director	February 25, 2015
/s/ Sharon A. Virag (Sharon A. Virag)	Director	February 25, 2015
(Mary Stawikey)	Director	February 25, 2015
/s/ Kenneth J. Zagzebski (Kenneth J. Zagzebski)	Director, President and Chief Executive Officer (principal executive officer)	February 25, 2015
/s/ Craig L. Jackson (Craig L. Jackson)	Chief Financial Officer (principal financial officer)	February 25, 2015
/s/ Kurt A. Tornquist (Kurt A. Tornquist)	Controller (principal accounting officer)	February 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of **The Dayton Power and Light Company** and in the capacities and on the dates indicated.

/s/ Brian Miller (Brian Miller)	Director and Chairman	February 25, 2015
/s/ Ken Zagzebski (Ken Zagzebski)	Director	February 25, 2015
/s/ Elizabeth Hackenson (Elizabeth Hackenson)	Director	February 25, 2015
/s/ Michael S. Mizell (Michael S. Mizell)	Director	February 25, 2015
/s/ Kazi K. Hasan (Kazi K. Hasan)	Director	February 25, 2015
/s/ Sharon A. Virag (Sharon A. Virag)	Director	February 25, 2015
/s/ Paul L. Freedman (Paul L. Freedman)	Director	February 25, 2015
/s/ Margaret A. Tigre (Margaret A. Tigre)	Director	February 25, 2015
/s/ Thomas A. Raga (Thomas A. Raga)	Director, President and Chief Executive Officer (principal executive *officer)*	February 25, 2015
/s/ Craig L. Jackson (Craig L. Jackson)	Chief Financial Officer (principal financial officer)	February 25, 2015
/s/ Kurt A. Tornquist (Kurt A. Tornquist)	Controller (principal accounting officer)	February 25, 2015

Schedule II

DPL Inc.
VALUATION AND QUALIFYING ACCOUNTS
For each of the three years ended December 31, 2012 - 2014

$ in thousands

Description		Balance at Beginning of Period		Additions		Deductions [(a)]		Balance at End of Period
Year ended December 31, 2014								
Deducted from accounts receivable - Provision for uncollectible accounts	$	1,160	$	7,644	$	7,537	$	1,267
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$	13,721	$	5,179	$	-	$	18,900
Year ended December 31, 2013								
Deducted from accounts receivable - Provision for uncollectible accounts	$	1,084	$	6,156	$	6,080	$	1,160
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$	12,349	$	2,159	$	787	$	13,721
Year ended December 31, 2012								
Deducted from accounts receivable - Provision for uncollectible accounts	$	1,136	$	5,902	$	5,954	$	1,084
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$	6,702	$	6,747	$	1,100	$	12,349

[(a)] Amounts written off, net of recoveries of accounts previously written off.

THE DAYTON POWER AND LIGHT COMPANY
VALUATION AND QUALIFYING ACCOUNTS
For each of the three years ended December 31, 2012 - 2014

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions [a]	Balance at End of Period
Year ended December 31, 2014				
Deducted from accounts receivable -				
Provision for uncollectible accounts	$ 909	$ 4,011	$ 4,023	$ 897
Year ended December 31, 2013				
Deducted from accounts receivable -				
Provision for uncollectible accounts	$ 923	$ 4,924	$ 4,938	$ 909
Year ended December 31, 2012				
Deducted from accounts receivable -				
Provision for uncollectible accounts	$ 941	$ 5,393	$ 5,411	$ 923

[a] Amounts written off, net of recoveries of accounts previously written off.