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 7 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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		OAC 4901-7 Appendix A, Chapter II, (B) Supplemental Filing Requirements		
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1	1	Appendix A, Chapter II, (B)(2)(a)-(c) Appendix A, Chapter II, (B)(3)(a)-(d)	S-2	Most recent 5 year financial forecast and support for the underlying assumptions.
1	1	Appendix A ,Chapter II, (B)(7)	S-3	A proposed notice for newspaper publication.
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1	2-3	Appendix A, Chapter II, (B)(9)	S-4.2	An executive summary of applicant utility's management policies, practices, and organization.
		OAC 4901-7 Appendix A, Chapter II, (C) Supplemental Information Provided at Filing		
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1	3	Appendix A, Chapter II, (C)(2)	Supplemental	Prospectuses of current stock and/or bond offering of the applicant, and/or of parent company.
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1	9-12	Appendix A, Chapter II, (C)(4)	Supplemental	The most recent SEC Form 10-K, 10-Q, and 8-K of the applicant, and/or parent company.
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K/A
(Amendment No. 1)

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

For the fiscal year ended **December 31, 2011**

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 [X]
The Dayton Power and Light Company	Yes [ ]	No [X]

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 [X]	No [ ]
The Dayton Power and Light Company	Yes [X]	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 [X]
The Dayton Power and Light Company	Yes [ ]	No [X]

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate Web site, 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 [X]	No [ ]
The Dayton Power and Light Company	Yes [X]	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.	[X]
The Dayton Power and Light Company	[X]

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.	[ ]	[ ]	[X]	[ ]
The Dayton Power and Light Company	[ ]	[ ]	[X]	[ ]

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 [X]
The Dayton Power and Light Company	Yes [ ]	No [X]

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, 2011, 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.

Explanatory Note

We are filing this Amendment No. 1 ("Form 10-K/A") to our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, as filed with the Securities and Exchange Commission (the "SEC") on March 28, 2012 (the "Form 10-K"), in order to file the interactive data files in eXtensible Business Language (XBRL) format required by Rule 405 of Regulation S-T and Item 601 of Regulation S-K. These XBRL documents did not attach properly to the initial Form 10-K filing.

In accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended, each item of the Form 10-K that is amended by this Form 10-K/A is restated in its entirety, and this Form 10-K/A is accompanied by currently dated certifications on Exhibits 31(a) – (d) and Exhibits 32(a) – (d) by our Chief Executive Officer and Chief Financial Officer.

Except as described above, no other changes have been made to the Form 10-K and we are not amending any other part of, or updating any other disclosures made in, the Form 10-K.

DPL Inc. and The Dayton Power and Light Company

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Fiscal Year Ended December 31, 2011

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
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
CSAPR	Cross-State Air Pollution Rule
CSP	Columbus Southern Power Company, 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
CO_2	Carbon Dioxide
CCEM	Customer Conservation and Energy Management
CRES	Competitive Retail Electric Service
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
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
Duke Energy	Duke Energy Ohio, Inc., formerly The Cincinnati Gas & Electric Company (CG&E)
EIR	Environmental Investment Rider
EPS	Earnings Per Share
ESOP	Employee Stock Ownership Plan
ESP	Electric Security Plans, filed with the PUCO, pursuant to Ohio law
ESP Stipulation	A Stipulation and Recommendation filed by **DP&L** with the PUCO on February 24, 2009 regarding **DP&L's** ESP filing pursuant to SB 221. The Stipulation was signed by the Staff of the PUCO, the Office of the Ohio Consumers' Counsel and various intervening parties. The PUCO approved the Stipulation on June 24, 2009.
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
FTRs	Financial Transmission Rights

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
kWh	Kilowatt hours
MC Squared	MC Squared Energy Services, LLC, a retail electricity supplier wholly-owned by DPLER which was purchased by DPLER on February 28, 2011
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**, The AES Corporation, ("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.
MISO	Midwest Independent Transmission System Operator, Inc., a regional transmission organization
MRO	Market Rate Option, a plan available to be filed with PUCO 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**
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
NYMEX	New York Mercantile Exchange
OAQDA	Ohio Air Quality Development Authority
OCC	Ohio Consumers' Counsel
ODT	Ohio Department of Taxation
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, a regional transmission organization
Predecessor	**DPL** prior to November 28, 2011, the date AES acquired **DPL**.
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RSU	Restricted Stock Units
RTO	Regional Transmission Organization

GLOSSARY OF TERMS (cont.)

Abbreviation or Acronym	Definition
RPM	Reliability Pricing Model
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
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SSO	Standard Service Offer which represents the regulated rates, authorized by the PUCO, charged to retail customers within **DP&L's** service territory.
Successor	**DPL** after its acquisition by AES.
TCRR	Transmission Cost Recovery Rider
USEPA	U.S. Environmental Protection Agency
USF	Universal Service Fund
VRDN	Variable Rate Demand Note

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 emissions, 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; 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 **DPL's** operating subsidiary (**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; the outcomes of litigation and regulatory investigations, proceedings or inquiries; general economic conditions; costs related to the Merger and the effects of any disruption from the Merger that may make it more difficult to maintain relationships with employees, customers, other business partners or government entities; 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 organized 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 is a wholly-owned, indirect subsidiary of AES.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** sells electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic, manufacturing and defense. **DP&L's** sales reflect the general economic conditions and seasonal weather patterns of the area. **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.

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, which was purchased on February 28, 2011. DPLER has approximately 40,000 customers currently located throughout Ohio and Illinois. DPLER does not have any transmission or generation assets and all of DPLER's electric energy was purchased from **DP&L** or PJM 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 us 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 1,510 employees as of December 31, 2011, of which 1,338 were full-time and 172 were part-time. At that date, 1,297 of these full-time employees and substantially all of the part-time employees were employed by **DP&L**. Approximately 53% of the employees are under a collective bargaining agreement which expires on October 31, 2014.

ELECTRIC OPERATIONS AND FUEL SUPPLY

(Amounts in MWs)	2011 Summer Generating Capacity Coal Fired	Solar, Combustion Turbines and Peaking Units	Total
DPL	2,830	988	3,818
DP&L	2,830	432	3,262

DPL's present summer generating capacity, including peaking units, is approximately 3,818 MW. Of this capacity, approximately 2,830 MW, or 74%, is derived from coal-fired steam generating stations and the balance of approximately 988 MW, or 26%, consists of solar, combustion turbine and diesel peaking units.

DP&L's present summer generating capacity, including peaking units, is approximately 3,262 MW. Of this capacity, approximately 2,830 MW, or 87%, is derived from coal-fired steam generating stations and the balance of approximately 432 MW, or 13%, consists of solar, combustion turbine and diesel peaking units.

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

Approximately 87% of the existing steam generating capacity is provided by certain generating units owned as tenants in common with Duke Energy and CSP. 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. **DP&L's** remaining steam generating capacity (approximately 365 MW) is derived from a generating station owned solely by **DP&L**. Additionally, **DP&L,** Duke Energy and CSP 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.

In 2011, we generated 98.3% of our electric output from coal-fired units and 1.7% 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*	Operating Company	Location	DP&L Portion	Total
Coal Units					
Hutchings	W	DP&L	Miamisburg, OH	365	365
Killen	C	DP&L	Wrightsville, OH	402	600
Stuart	C	DP&L	Aberdeen, OH	808	2,308
Conesville-Unit 4	C	CSP	Conesville, OH	129	780
Beckjord-Unit 6	C	Duke Energy	New Richmond, OH	207	414
Miami Fort-Units 7 & 8	C	Duke Energy	North Bend, OH	368	1,020
East Bend-Unit 2	C	Duke Energy	Rabbit Hash, KY	186	600
Zimmer	C	Duke Energy	Moscow, OH	365	1,300
Solar, Combustion Turbines or Diesel					
Hutchings	W	DP&L	Miamisburg, OH	25	25
Yankee Street	W	DP&L	Centerville, OH	101	101
Yankee Solar	W	DP&L	Centerville, OH	1	1
Monument	W	DP&L	Dayton, OH	12	12
Tait Diesels	W	DP&L	Dayton, OH	10	10
Sidney	W	DP&L	Sidney, OH	12	12
Tait Units 1-3	W	DP&L	Moraine, OH	256	256
Killen	C	DP&L	Wrightsville, OH	12	18
Stuart	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				3,818	8,388

*W = Wholly-Owned
C = Commonly-Owned

In addition to the above, **DP&L** also owns a 4.9% equity ownership interest in OVEC, an electric generating company. OVEC has two plants located in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,265 MW. **DP&L's** share of this generation capacity is approximately 111 MW.

We have substantially all of the total expected coal volume needed to meet our retail and firm wholesale sales requirements for 2012 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 outages and generation plant 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 a balanced SO_2 and NOx position for 2012.

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

	Average Cost of Fuel Consumed (¢/kWh)		
	2011	2010	2009
DPL	**2.76**	2.42	2.39
DP&L	**2.71**	2.37	2.36

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 as 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. **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 retail rates charged by public utilities. Regulation of retail rates encompasses the timing of applications, the effective date of rate increases, the recoverable 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. See Note 4 of Notes to **DPL's** Consolidated Financial Statements and Note 4 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.

On May 1, 2008, substitute SB 221, an Ohio electric energy bill, was signed by the Governor and went into effect July 31, 2008. This law required that all Ohio distribution utilities file either an ESP or MRO to establish rates for SSO service. 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 cost-based 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 option involve a "significantly excessive earnings test" based on the earnings of comparable companies with similar business and financial risks. **DP&L's** current SSO rates were established under an ESP that ends December 31, 2012. **DP&L** is in the process of developing an SSO filing that will be the basis for rates effective January 1, 2013 using either an ESP or MRO case. This case is scheduled to be filed on March 30, 2012.

SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, 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. **DP&L** is currently meeting its renewable requirements and expects to remain in compliance. The PUCO found that both **DP&L** and DPLER met the renewable targets in 2009, and the PUCO Staff recommended that the Commission find that they both met the renewable targets for 2010.

On May 19, 2010 the Commission approved in part and denied in part **DP&L's** request that the PUCO find that it met the 2009 energy efficiency portfolio requirements and directed **DP&L** to file a measurement and verification plan as well as a market potential study. We made this filing and settled the case through a stipulation that was approved in April 2011. The next energy efficiency portfolio plan is due to be filed in April 2013.

We are unable to predict how the PUCO will respond to many of the filings discussed above, but believe that the outcome for the non-ESP/MRO filings will not be material to our financial condition or results of operations. However, as the energy efficiency and alternative energy targets get increasingly larger over time, the costs of complying with SB 221 and the PUCO's implementing rules or the results of our ESP/MRO filing on March 30, 2012 could have a material effect on our financial condition or results of operations.

The ESP Stipulation also provided for the establishment of a fuel and purchased power recovery rider beginning 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 was hired in 2011 to review fuel costs and the fuel procurement process for 2010. **DP&L** and all of the active participants in this proceeding reached a Stipulation and Recommendation which was approved by the PUCO on November 9, 2011. In November 2011, **DP&L** recorded a $25 million pretax ($16 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 fuel costs is currently ongoing. The outcome of that audit is uncertain.

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. SB 221 included 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. Both the TCRR 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's** annual true-up of these two riders was approved by the PUCO by an order dated April 27, 2011 and its 2012 filing is still pending.

On September 9, 2009, the PUCO issued an order establishing a significantly excessive earnings test (SEET) proceeding pursuant to provisions contained in SB 221. A question and answer session was held before the Commission on April 1, 2010 to allow the Commission to gain a better understanding of the issues. The PUCO issued an order on June 30, 2010 to establish general rules for calculating the earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings. The other three Ohio utilities were required to make their SEET determinations in 2011 and 2010. Pursuant to the ESP Stipulation, **DP&L** becomes subject to the SEET in 2013 based on 2012 earnings results and the SEET may have a material effect on operations.

On August 28, 2009, **DP&L** filed its application to establish reliability targets consistent with the most recent PUCO Electric Service and Safety Standards (ESSS). On March 29, 2010, **DP&L** entered into a settlement establishing the new reliability targets. This settlement was approved on July 29, 2010. According to the ESSS rules, all Ohio utilities are subject to financial penalties if the established targets are not met for two consecutive years.

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 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 within **DP&L's** service territory, have led and may continue to lead to the entrance of additional competitors in our service territory. At December 31, 2011, there were fourteen CRES providers in **DP&L's** service territory. DPLER, an affiliated company and one of the fourteen registered CRES providers, has been marketing supply services to **DP&L** customers. During 2011, DPLER accounted for approximately 5,731 million kWh of the total 6,593 million kWh supplied by CRES providers within **DP&L's** service territory. Also during 2011, 27,812 customers with an annual energy usage of 862 million kWh were supplied by other CRES providers within **DP&L's** service territory. The volume supplied by DPLER represents approximately 41% of **DP&L's** total distribution sales volume during 2011. The reduction to gross margin in 2011 as a result of customers switching to DPLER and other CRES providers was approximately $58 million and $104 million, for **DPL** and **DP&L**, 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.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering alternative electric generation supplies to their citizens. To date, nine organizations have filed with the PUCO to initiate aggregation programs. If these nine organizations move forward with aggregation, it could have a material effect on our earnings. See Item 1A – Risk Factors for more information.

In 2010, DPLER began providing CRES services to business customers in Ohio who are not in **DP&L's** service territory. The incremental costs and revenues have not had a material effect on our results of operations, financial condition or cash flows.

DP&L entered into an economic development arrangement with its single largest electricity consumer. This arrangement was approved by the PUCO on June 8, 2011 and became effective in July 2011. Under Ohio law, **DP&L** is permitted to seek recovery of costs associated with economic development programs including foregone revenues from all customers. On October 26, 2011, the PUCO approved our Economic Development Rider, as filed, which is designed to recover costs associated with this and other economic development contracts and programs.

Federal Matters

Like other electric utilities and energy marketers, **DP&L** and DPLE may sell or purchase electric products on 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 are required to join a 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 2014/2015 period cleared at a per megawatt price of $126/day for our RTO area. The per megawatt prices for the periods 2013/2014, 2012/2013 and 2011/2012 were $28/day, $16/day and $110/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. Increases in customer switching causes 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 if the current auction price is not sustained, our future results of operations, financial condition and cash flows could be materially adversely impacted.

As a member of PJM, **DP&L** is also subject to charges and costs associated with PJM operations as approved by the FERC. FERC orders issued in 2007 and thereafter regarding the allocation of costs of large transmission facilities within PJM which would result in additional costs being allocated to **DP&L** that, over time and depending on final costs and how quickly the facilities are constructed, could become material. **DP&L** filed a notice of appeal to the U.S. Court of Appeals, D.C. Circuit, which was consolidated with other appeals taken by other interested parties of the same FERC orders and the consolidated cases were assigned to the 7th Circuit. On August 6, 2009, the 7th Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method it had approved. Rehearings were filed by other interested litigants and denied by the Court, which then remanded the matter to the FERC for further proceedings. On January 21, 2010, the FERC issued a procedural order on remand establishing a paper hearing process under which PJM will make an informational filing. Subsequently, PJM and other parties, including **DP&L**, filed initial comments, testimony and recommendations and reply comments. FERC did not establish a deadline for its issuance of a substantive order and the matter is still pending. **DP&L** cannot predict the timing or the likely outcome of the proceeding. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. Although we continue to maintain that these costs should be borne by the beneficiaries of these projects and that **DP&L** is not one of these beneficiaries, any new credits or additional costs resulting from the ultimate outcome of this proceeding will be reflected in **DP&L's** TCRR rider which already includes these costs.

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 June 2009, Reliability First Corporation (RFC), with responsibilities assigned to it by NERC over the reliability region that includes **DP&L**, commenced a routine audit of **DP&L's** operations. The audit, which was for the period June 18, 2007 to June 25, 2009, evaluated **DP&L's** compliance with 42 requirements in 18 NERC-reliability standards. **DP&L** is currently subject to a compliance audit at a minimum of once every three years as provided by the NERC Rules of Procedure. This audit was concluded in June 2009 and its findings revealed that **DP&L** had some Possible Alleged Violations (PAVs) associated with five NERC reliability requirements of various Standards. In response to the report, **DP&L** filed mitigation plans with RFC/NERC to address the PAVs. These mitigation plans were accepted by RFC/NERC. In July 2010, **DP&L** negotiated a settlement with NERC under which **DP&L** agreed to pay an immaterial amount in exchange for a resolution of all issues and obligations relating to the aforementioned PAVs. The settlement was approved on January 21, 2011 by the FERC.

ENVIRONMENTAL CONSIDERATIONS

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 effect us include:

- The Federal CAA and state laws and regulations (including State Implementation Plans) 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 plants require additional permitting or pollution control technology, or whether emissions from coal-fired generating plants cause or contribute to global climate changes.
- Rules and future rules issued by the USEPA and Ohio EPA that require substantial reductions in SO_2, particulates, mercury, acid gases, NOx, 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 Ohio EPA that require reporting and may require 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.
- 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. The EPA has previously determined that fly ash and other coal combustion byproducts are not hazardous waste subject to the Resource Conservation and Recovery

Act (RCRA), but the EPA is reconsidering that determination. A change in determination or other additional regulation of fly ash or other coal combustion byproducts could significantly increase the costs of disposing of such ash byproducts.

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 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 estimated accruals for loss contingencies of approximately $3.4 million for environmental matters. We also have a number of unrecognized loss contingencies related to environmental matters that 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 other pending environmental matters associated with our coal-fired generation units. Together, these could result in significant capital and operations and maintenance expenditures for our coal-fired generation plants, and could result in the early retirement of our generation units that do not have SCR and FGD equipment installed. Currently, our coal-fired generation units at Hutchings and Beckjord do not have this emission-control equipment installed. **DP&L** owns 100% of the Hutchings plant and has a 50% interest in Beckjord Unit 6. In addition to environmental matters, the operation of our coal-fired generation plants could be affected by a multitude of other factors, including forecasted power, capacity and commodity prices, competition and the levels of customer switching, current and forecasted customer demand, cost of capital and regulatory and legislative developments, any of which could pose a potential triggering event for an impairment of our investments in the Hutchings and Beckjord units. On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our commonly owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals or impairment charges are needed related to the Hutchings Station.

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.

Cross-State Air Pollution Rule
The Clean Air Interstate Rule (CAIR) final rules were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO_2. Litigation brought by entities not including **DP&L** resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 2008 decision.

In an attempt to conform to the Court's decision, on July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR). These rules were finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011, but subsequent litigation has resulted in their implementation being delayed indefinitely. CSAPR creates four separate trading programs: two SO_2 areas (Group 1 and Group 2); and two NOx reduction requirements (annual and ozone season). Group 1 states (16 states including Ohio) will have to meet a 2012 cap and additional reductions in 2014. Group 2 states (7 states) will only have to meet the 2012 cap. We do not believe the rule will have a material effect on our operations in 2012. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If CSAPR becomes effective, it is expected to institute a federal implementation plan (FIP) in lieu of state SIPs and allow for the states to develop SIPs for approval as early as 2013. **DP&L** is unable to estimate the impact of the new requirements; however, CSAPR could have a material effect on our operations.

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 (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. **DP&L** is evaluating the costs that may be incurred to comply with the new requirement; however, MATS could have a material adverse effect on our results of operations and result in material compliance costs.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. In December 2011, the USEPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the National Emissions Standards for Hazardous Air Pollutants for compression ignition (CI) reciprocating internal combustion engines (RICE) became effective. The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs for **DP&L's** operations are not expected to be material.

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. As of December 31, 2011, **DP&L's** Stuart, Killen and Hutchings Stations were located in non-attainment areas for the annual PM 2.5 standard. There is a possibility that these areas will be re-designated as "attainment" for PM 2.5 within the next few calendar quarters and that the NAAQS for PM 2.5 will become more stringent. 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.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. **DP&L** cannot determine the effect of this potential change, if any, on its 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 revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. **DP&L** cannot determine the effect of this potential change, if any, 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. In the final rule, the USEPA made the determination that CAIR achieves greater progress than BART and may be used by states as a BART substitute and USEPA subsequently determined that if CSAPR becomes effective, it may be used to comply with BART requirements. 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 Emissions and Other Greenhouse Gases
In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders carbon dioxide and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to **DP&L** cannot be determined at this time, but the cost of compliance could be material.

The USEPA plans to propose GHG standards for new and modified electric generating units (EGUs) under CAA subsection 111(b) – and propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d) during 2012. These rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

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 16 million tons annually. Further GHG legislation or regulation finalized 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**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of CO_2, including electric generating units. **DP&L's** first report to the USEPA was submitted prior to the September 30, 2011 due date for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. **DP&L** does not anticipate that this reporting rule will result in any significant cost or other effect on current operations.

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

Litigation Involving Co-Owned Plants
On June 20, 2011, the U.S. Supreme Court ruled that the USEPA regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including **DP&L**. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

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 J.M. Stuart generating station are subject to certain specified emission targets related to NOx, 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 Plants
In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued a NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy and CSP) 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 a 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 a NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (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, USEPA issued an NOV to Zimmer for excess emissions. **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.

Notices of Violation Involving Wholly-Owned Plants
In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the O.H. Hutchings Station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the O.H. 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. **DP&L** is engaged in discussions with the USEPA and Justice Department to resolve these matters, but **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

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

Clean Water Act – Regulation of Water Intake
On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act 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. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA released new proposed regulations on March 28, 2011, which were published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. The final rules are expected to be in place by mid-2012. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, we submitted an application for the renewal of the Stuart Station NPDES Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, **DP&L** and the Ohio EPA reached an agreement to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. The Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by

Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. 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 does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will 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 would require **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 and is considering legal options. Depending on the outcome of the process, the effects could be material on **DP&L's** operation.

In September 2009, the USEPA announced that it will 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. Subsequent to the information collection effort, it is anticipated that the USEPA will release a proposed rule by mid-2012 with a final regulation in place by early 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its 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. However, 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, is ongoing. 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 us.

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 us.

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**. The USEPA has indicated that a proposed rule will be released in late 2012. 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 J.M. Stuart Stations. Subsequently, the USEPA collected similar information for O.H. Hutchings Station.

In August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the O.H. 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. **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts 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 anticipates issuing a final rule on this topic in late 2012. **DP&L** is unable to predict the financial effect of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on **DP&L's** operations.

Notice of Violation Involving Co-Owned Plants

On September 9, 2011, **DP&L** received a notice of violation from the USEPA with respect to its co-owned J.M. 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 Clean Water Act National Pollutant Discharge Elimination System 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 flow.

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 plants 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. With respect to unsettled claims, **DP&L** management has deferred $17.8 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, as Other deferred credits representing the amount of unearned income where the earnings process is not complete. The amount at December 31, 2011 includes estimated earnings and interest of $5.2 million. On September 30, 2011, the FERC issued two SECA-related orders that affirmed an earlier order issued in 2010 by denying the rehearing requests that a number of different parties, including **DP&L**, had filed. These orders are now final, subject to possible appellate court review. These orders do not affect prior settlements that had been reached with other parties that owed SECA revenues to **DP&L** or were recipients of amounts paid by **DP&L**. For other parties that had not previously settled with **DP&L**, the exact timing and amounts of any payments that would be made or received by **DP&L** under these orders is still uncertain.

Also refer to Notes 2 and 18 of Notes to **DPL's** Consolidated Financial Statements for additional information surrounding the merger and certain related legal matters.

Capital Expenditures for Environmental Matters

DP&L's environmental capital expenditures are approximately $12 million, $12 million and $21 million in 2011, 2010 and 2009, respectively. **DP&L** has budgeted $15 million in environmental related capital expenditures for 2012.

ELECTRIC SALES AND REVENUES

The following table sets forth **DPL's** electric sales and revenues for the period November 28, 2011 (the Merger date) through December 31, 2011 (Successor), the period January 1, 2011 through November 27, 2011 and the years ended December 31, 2010 and 2009 (Predecessor), respectively.

In the following table, we have included the combined Predecessor and Successor statistical information and results of operations. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2011 operating and financial performance to 2010 and 2009, and because the core operations of **DPL** have not changed as a result of the Merger.

	DPL				
	Combined	Successor	Predecessor		
	Year ended December 31, 2011	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31, 2010	2009
Electric sales (millions of kWh)					
Residential	5,257	506	4,751	5,522	5,120
Commercial	3,956	343	3,613	3,842	3,678
Industrial	3,482	271	3,211	3,605	3,353
Other retail	1,410	116	1,294	1,437	1,386
Total retail	14,105	1,236	12,869	14,406	13,537
Wholesale	2,277	125	2,152	2,831	3,130
Total	16,382	1,361	15,021	17,237	16,667
Operating revenues ($ in thousands)					
Residential	$ 671,301	$ 64,672	$ 606,629	$ 662,507	$ 536,123
Commercial	375,781	32,544	343,237	369,934	318,502
Industrial	256,270	19,055	237,215	252,361	220,701
Other retail	108,391	8,061	100,330	110,150	95,459
Other miscellaneous revenues	17,295	2,020	15,275	9,815	8,766
Total retail	1,429,038	126,352	1,302,686	1,404,767	1,179,551
Wholesale	129,669	8,371	121,298	142,149	122,519
RTO revenues	261,368	20,430	240,938	272,832	225,677
Other revenues	7,768	1,775	5,993	11,697	11,689
Total	$ 1,827,843	$ 156,928	$ 1,670,915	$ 1,831,445	$ 1,539,436
Electric customers at end of period					
Residential	454,697			455,572	456,144
Commercial	53,341			50,764	50,141
Industrial	1,906			1,800	1,773
Other	6,943			6,742	6,577
Total	516,887			514,878	514,635

DPL is structured in two operating segments, **DP&L** and DPLER. See Note 19 of Notes to **DPL's** Consolidated Financial Statements for more information on **DPL's** segments. The following tables set forth **DP&L's** and DPLER's electric sales and revenues for the years ended December 31, 2011, 2010 and 2009, respectively.

	DP&L (a)		
	2011	2010	2009
Electric sales (millions of kWh)			
Residential	**5,257**	5,522	5,120
Commercial	**3,208**	3,741	3,678
Industrial	**3,313**	3,582	3,353
Other retail	**1,381**	1,432	1,386
Total retail	**13,159**	14,277	13,537
Wholesale	**2,440**	2,806	3,053
Total	**15,599**	17,083	16,590
Operating revenues ($ in thousands)			
Residential	$ **662,919**	$ 662,466	$ 536,116
Commercial	**204,465**	289,628	314,697
Industrial	**66,556**	110,115	178,534
Other retail	**55,694**	60,840	79,424
Other miscellaneous revenues	**17,744**	10,723	8,954
Total retail	**1,007,378**	1,133,772	1,117,725
Wholesale	**441,199**	365,798	181,871
RTO revenues	**229,143**	239,274	201,254
Other revenues	-	-	-
Total	$ **1,677,720**	$ 1,738,844	$ 1,500,850
Electric customers at end of period			
Residential	**454,697**	455,572	456,144
Commercial	**50,123**	50,155	50,141
Industrial	**1,757**	1,769	1,773
Other	**6,806**	6,739	6,577
Total	**513,383**	514,235	514,635

	DPLER (b)		
	2011	2010	2009
Electric sales (millions of kWh)			
Residential	**113**	1	-
Commercial	**2,579**	1,194	68
Industrial	**3,102**	2,476	983
Other retail	**883**	875	413
Total retail	**6,677**	4,546	1,464
Wholesale	-	-	-
Total	**6,677**	4,546	1,464
Operating revenues ($ in thousands)			
Residential	$ **8,381**	$ 41	$ -
Commercial	**171,316**	80,307	3,802
Industrial	**189,715**	142,246	42,165
Other retail	**56,344**	52,811	18,871
Other miscellaneous revenues	**252**	57	-
Total retail	**426,008**	275,462	64,838
Wholesale	**65**	-	-
RTO revenues	**2,407**	1,503	615
Other (mark-to-market gains / (losses))	**(3,068)**	27	95
Total	$ **425,412**	$ 276,992	$ 65,548
Electric customers at end of period			
Residential	**22,314**	33	-
Commercial	**14,321**	7,205	223
Industrial	**772**	564	44
Other	**2,764**	1,200	123
Total	**40,171**	9,002	390

(a) ***DP&L*** *sold 5,731 million kWh, 4,417 million kWh and 1,464 million kWh of power to DPLER (a subsidiary of* ***DPL****) for the years ended December 31, 2011, December 31, 2010 and 2009, respectively, which are not included in* ***DP&L*** *wholesale sales volumes in the chart above. These kWh sales also relate to* ***DP&L*** *retail customers within the* ***DP&L*** *service territory for distribution services and their inclusion in wholesale sales would result in a double counting of kWh volume. The dollars of operating revenues associated with these sales are classified as wholesale revenues on* ***DP&L's*** *Financial Statements and retail revenues on* ***DPL's*** *Consolidated Financial Statements.*

(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.

Our customers have the opportunity to select alternative electric generation service providers, as permitted by Ohio legislation.

Customers can elect to buy transmission and 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 could have a material adverse effect on our results of operations, financial condition and cash flows. 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, and additional CRES providers entering our territory.
- We could 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.

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.

<u>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 procedure of the PUCO.</u>

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 approved **DP&L's** filed ESP on June 24, 2009. **DP&L's** ESP provides, among other things, that **DP&L's** existing rate plan structure will continue through the end of 2012; that **DP&L** may seek recovery for adjustments to its existing rate plan structure for costs associated with storm damage, regulatory and tax changes, new climate change or carbon regulations, fuel and purchased power and certain other costs; and that SB 221's significantly excessive earnings test will apply in 2013 based upon **DP&L's** 2012 earnings. **DP&L** faces regulatory uncertainty from its next ESP or MRO filing which is scheduled to be filed on March 30, 2012 to be effective January 1, 2013. The filing may result in changes to the current rate structure and riders that could adversely 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 addition, as the local distribution utility, **DP&L** has an obligation to serve customers within its certified territory and under the terms of its ESP Stipulation, as it is the provider of last resort (POLR) for standard offer service. **DP&L's** current rate structure provides for a nonbypassable charge to compensate **DP&L** for this POLR obligation. The PUCO may decrease or discontinue this rate charge at some time in the future.

While 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 or 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. Certain of our cost recovery riders are also bypassable by some of our customers who switched to a CRES provider. Accordingly, the revenue **DP&L** receives may or may not match its expenses at any given time. Therefore, **DP&L** could be 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 and POLR service; changes in **DP&L's** rate structure and its ability to recover amounts for environmental compliance, POLR obligations, 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; 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.

<u>Our increased costs due to advanced energy and energy efficiency requirements may not be fully recoverable in the future.</u>

SB 221 contains targets relating to advanced energy, renewable energy, peak demand reduction and energy efficiency standards. The standards require that, by the year 2025 and each year thereafter, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources, which include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including solar energy. Annual renewable energy standards began in 2009 with increases in required percentages each year through 2024. The advanced energy standard must be met by 2025 and each year thereafter. 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 advanced energy and renewable energy standards have increased our power supply costs and are expected to continue to increase (and could materially increase) these costs. Pursuant to **DP&L's** approved ESP, **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, 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, **DPL** has substantially all of the total expected coal volume needed to meet its retail and firm wholesale sales requirements for 2012 under contract. In 2011, approximately 84% of **DP&L's** coal was provided by four suppliers, three of which were under long-term contracts with **DP&L**. 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. Pursuant to its ESP for SSO retail customers, **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. 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.

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 impacted 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, we use a variety of non-derivative and derivative instruments, such as swaps, futures and forwards, to manage our market risks. We also use 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. The Dodd-Frank Act provides a potential exception from these clearing and cash collateral requirements for commercial end-users. The Dodd-Frank Act requires the CFTC to establish rules to implement the Dodd-Frank Act's requirements and exceptions. Requirements to post collateral could reduce the cost effectiveness of entering into derivative transactions to reduce commodity price and interest rate volatility or could increase the demands on our liquidity or require us to increase our levels of debt to enter into such derivative transactions. Even if we were to 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.

We are subject to numerous environmental laws and regulations that require capital expenditures, increase our cost of operations and may expose us to environmental liabilities.

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 NOx, 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 greenhouse gas emissions as discussed in more detail in the next risk factor). With respect to our largest generation station, the J.M. Stuart Station, we are also subject to continuing compliance requirements related to NOx, 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** has an EIR in place as part of its existing rate plan structure, the last increase of which occurred in 2010 and remains at that level through 2012. In addition, **DP&L's** ESP permits it to seek recovery for costs associated with new climate change or carbon regulations. While we expect to recover certain environmental costs and expenditures from customers, if in the future we are unable to fully recover our costs in a timely manner or the SSO retail riders are bypassable or additional customer switching occurs, we could have a material adverse effect to our results of operations, financial condition and cash flows. 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 liability 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.

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 on-going 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 and litigation, including regulation of GHG emissions by the USEPA. 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 carbon 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.

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. During 2010 and 2009, **DP&L** realized net gains from these sales. 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 cause 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 NOx 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 available for sale and changes to the regulatory environment, including the implemention of CSAPR and CAIR. These factors could cause the amount and price of excess emission allowances **DP&L** sells to fluctuate, which could cause 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 NOx 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.

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 over 50% 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. We have constructed and placed into service FGD facilities at most of 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, at other stations, it may require us to burn more expensive types of coal or utilize 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.

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.

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 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 as 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 under its ESP, 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.

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 if auction prices are at low levels, our results of operations, financial condition and cash flows could have a material adverse effect.

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. While PJM transmission rates were initially designed to be revenue neutral, various proposals and proceedings currently taking place at 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, most if not all of the above costs are currently being recovered through our SSO retail rates. If in the future, however, we are unable to recover all of these costs in a timely manner, or the SSO retail riders are bypassable or additional customer switching occurs, our results of operations, financial condition and cash flows could have a material adverse effect.

As members of PJM, **DP&L** and DPLE are also subject to certain additional risks including those associated with the allocation among PJM members of losses caused by unreimbursed defaults of other participants in PJM markets 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.

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. FERC orders issued in 2007 and thereafter modified the traditional method of allocating costs associated with new high-voltage planned transmission facilities. FERC ordered that the cost of new high-voltage facilities be socialized across the PJM region. Various parties, including **DP&L**, challenged this allocation method and in 2009, the U.S. Court of Appeals, Seventh Circuit ruled that the FERC had failed to provide a reasoned basis for the allocation method and remanded the case to the FERC for further proceedings. Until such time as FERC may act to approve a change in methodology, PJM will continue to apply the allocation methodology that had been approved by FERC in 2007. The overall impact of FERC's allocation methodology cannot be definitively assessed because not all new planned construction is likely to happen. To date, the additional costs charged to **DP&L** for new large transmission approved projects has 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. Although we continue to maintain that the costs of these projects should be borne by the direct beneficiaries of the projects and that **DP&L** is not one of these beneficiaries, **DP&L** is recovering the Ohio retail jurisdictional share of these allocated costs from its SSO retail customers through the TCRR 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.

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 of our 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 currently maintain both cash on deposit and investments in cash equivalents 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, our credit ratings were reduced, resulting in increased borrowing costs and causing us to post cash collateral with certain of our counterparties. If the rating agencies were to reduce 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.

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 postretirement 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 postretirement benefit plan assets will increase the funding requirements under our pension and postretirement 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 postretirement 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 postretirement 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 be materially adversely effected.

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.

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.

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 International Financial Reporting Standards (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 expects to make a determination in 2012 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.

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

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 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, our results of operations, financial condition and cash flows could have a material adverse effect. 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, 2014. 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 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 business.

We operate in a highly regulated industry that requires the continued operation of sophisticated systems and network infrastructure at our generation plants, fuel storage facilities, 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 or 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 attempt to impose 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.

We will be subject to business uncertainties during the integration process with respect to the Merger with The AES Corporation that could adversely affect our financial results.
Uncertainty about the effect of the Merger on **DPL** and **DP&L**, their employees, customers and suppliers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties could cause customers, suppliers and others that deal with us to seek to change existing business relationships.

The success of our business will depend on **DPL's** and **DP&L's**,ability to realize anticipated benefits from the integration into AES. Certain risks to achieving these benefits include:

- the ability to successfully integrate into AES;
- on-going operating performance;
- the adaptability to changes resulting from the Merger; and
- continued employee retention and recruitment after the Merger.

We expect that matters relating to the Merger and integration-related issues will place a significant burden on management, employees and internal resources, which could otherwise have been devoted to other business opportunities. The diversion of management time on Merger integration-related issues could affect our financial results.

Lawsuits have been filed and several other lawsuits may be filed against DPL, its former directors, AES and Dolphin Sub, Inc. challenging the Merger Agreement, and an adverse judgment in such lawsuits may cause us to pay damages.
DPL and its directors have been named and AES and Dolphin Sub, Inc. have also been named, as defendants in purported class action and derivative action lawsuits filed by certain of our shareholders challenging the Merger and seeking, among other things, to rescind the Merger and to recover an unspecified amount of damages and costs. We could also be subject to additional litigation related to the Merger. While we currently believe that any such litigation is without merit, defending such matters could be costly and distracting to management and an adverse judgment in such lawsuits could affect the Merger or cause us to pay damages and costs.

Push-down accounting adjustments in connection with the Merger may have a material effect on DPL's future financial results.
Under U.S. GAAP, pursuant to FASC No. 805 and SEC Staff Accounting Bulletin Topic 5.J. "New Basis of Accounting Required in Certain Circumstances", when an acquisition results in an entity becoming substantially wholly-owned, push-down accounting is applied in the acquired entity's separate financial statements. Push-down accounting requires that the fair value adjustments and goodwill or negative goodwill identified by the acquiring entity be pushed down and reflected in the financial statements of the acquired entity. As a result, following the completion by AES of its purchase price allocation. In connection with the merger, the cost basis of certain of **DPL's** assets and liabilities has been and will continue to be adjusted and any resulting goodwill will be allocated and pushed down to **DPL**. AES is still in the preliminary stages of determining the adjustments, which are based on preliminary purchase price allocations and preliminary valuations of **DPL's** assets and liabilities (and will be subject to change within the applicable measurement period). These adjustments could have a material effect on **DPL's** future financial condition and results of operations, including but not limited to increased depreciation, amortization, impairment and other non-cash charges. As a result, **DPL's** actual future results may not be comparable with results in prior periods.

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. As a result of the push-down of purchase accounting to **DPL** from the acquisition of **DPL** by AES in November 2011, we had $2.5 billion of goodwill at December 31, 2011, which represented approximately 41% of total assets.

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.

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

Substantially all property and plants of **DP&L** are subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated as of October 1, 1935, as amended with the Bank of New York Mellon, as Trustee (Mortgage).

Item 3 - Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We are also from time to time involved in other reviews, investigations and proceedings by governmental and regulatory agencies regarding our business, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. We believe the amounts provided in our Consolidated Financial Statements, as prescribed by GAAP, for these matters 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 and other matters (including those matters noted 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, 2011, cannot be reasonably determined.

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 – Note 18 of Notes to the **DPL's** Consolidated 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 indirectly by AES and directly by an AES wholly-owned subsidiary, and as a result 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 period November 28, 2011 through December 31, 2011 (Successor), **DPL** paid dividends of $0.54 per share of **DPL** common stock that were declared during November 2011. In addition, during the period January 1, 2011 through November 27, 2011 (Predecessor), **DPL** declared dividends of $1.54 per share of common stock. During the years ended December 31, 2010 and 2009, **DPL** declared and paid dividends per share of common stock of $1.21 and $1.14, respectively. **DP&L** declares and pays dividends to its parent **DPL** from time to time as declared by the **DPL** board. Dividends in the amount of $220.0 million, $300.0 million and $325.0 million were paid in the years ended December 31, 2011, 2010 and 2009, respectively.

DPL's Amended Articles of Incorporation contain provisions restricting the payment of distributions to its shareholder and the making of loans to its affiliates (other than its subsidiaries). **DPL** may not make a distribution to its shareholder if, after giving effect to the distribution, **DPL** would be unable to pay its debts as they become due or **DPL's** total assets would be less than its total liabilities. In addition, **DPL** may not make a distribution to its shareholder or a loan to any of its affiliates (other than its subsidiaries), unless generally: (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 (b) at the time and as a result of the distribution or loan, **DPL's** leverage and interest coverage ratios are within certain parameters as set forth in the Articles and is noted below or, 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. The restrictions in the immediately preceding sentence will 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 the restrictions.

The parameters under **DPL's** Amended Articles of Incorporation for the leverage and interest ratios noted above are:, **DPL's** leverage ratio is not to exceed 0.67:1.00 and **DPL's** interest coverage ratio is not to be less than 2.5:1.0. At December 31, 2011, the leverage ratio was 0.55:1.00 and the interest coverage ratio was 7.5:1.0.

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, 2011, **DP&L's** retained earnings of $589.1 million were all available for **DP&L** common stock dividends payable to **DPL**.

DPL did not repurchase any of its common stock during the twelve months ended December 31, 2011.

Item 6 – Selected Financial Data

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** is a wholly-owned, indirect subsidiary of AES and therefore 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.

($ in millions except per share amounts or as indicated)	Successor (a) November 28, 2011 through December 31, 2011	Predecessor (a) January 1, 2011 through November 27, 2011	Predecessor (a) Years ended December 31, 2010	2009	2008	2007
DPL						
Basic earnings per share of common stock:						
Continuing operations (b)	N/A	$ 1.31	$ 2.51	$ 2.03	$ 2.22	$ 1.97
Discontinued operations	N/A	$ -	$ -	$ -	$ -	$ 0.09
Total basic earnings per common share	N/A	$ 1.31	$ 2.51	$ 2.03	$ 2.22	$ 2.06
Diluted earnings per share of common stock:						
Continuing operations (b)	N/A	$ 1.31	$ 2.50	$ 2.01	$ 2.12	$ 1.80
Discontinued operations	N/A	$ -	$ -	$ -	$ -	$ 0.08
Total diluted earnings per common share	N/A	$ 1.31	$ 2.50	$ 2.01	$ 2.12	$ 1.88
Dividends declared per share (e)	N/A	$ 1.54	$ 1.21	$ 1.14	$ 1.10	$ 1.04
Dividend payout ratio (e)	N/A	117.6%	48.2%	56.2%	49.5%	50.5%
Total electric sales (millions of kWh)	1,361	15,021	17,237	16,667	17,172	18,598
Results of operations:						
Revenues	$ 156.9	$ 1,670.9	$ 1,831.4	$ 1,539.4	$ 1,549.2	$ 1,462.5
Earnings (loss) from continuing operations, net of tax (b)	$ (6.2)	$ 150.5	$ 290.3	$ 229.1	$ 244.5	$ 211.8
Earnings from discontinued operations, net of tax	$ -	$ -	$ -	$ -	$ -	$ 10.0
Net income (loss)	$ (6.2)	$ 150.5	$ 290.3	$ 229.1	$ 244.5	$ 221.8
Financial position items at December 31:						
Total assets	$ 6,107.5	N/A	$ 3,813.3	$ 3,641.7	$ 3,637.0	$ 3,566.6
Long-term debt (d)	$ 2,628.9	N/A	$ 1,026.6	$ 1,223.5	$ 1,376.1	$ 1,541.5
Total construction additions	$ 201.0	N/A	$ 151.4	$ 145.3	$ 227.8	$ 346.7
Redeemable preferred stock of subsidiary	$ 18.4	N/A	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Senior unsecured debt ratings at December 31:						
Fitch Ratings	BB+	BBB+	A-	A-	BBB+	BBB+
Moody's Investors Service	Ba1	Baa1	Baa1	Baa1	Baa2	Baa2
Standard & Poor's Corporation	BB+	BB+	BBB+	BBB+	BBB-	BBB-
Number of shareholders - common stock	1	18,488	19,877	20,888	21,628	22,771

($ in millions except per share amounts or as indicated)	For the years ended December 31, 2011	2010	2009	2008	2007
DP&L					
Total electric sales (millions of kWh)	15,599	17,083	16,590	17,105	18,598
Results of operations:					
Revenues	$ 1,677.7	$ 1,738.8	$ 1,500.8	$ 1,520.5	$ 1,454.2
Earnings on common stock (c)	$ 192.3	$ 276.8	$ 258.0	$ 284.9	$ 270.7
Financial position items at December 31:					
Total assets	$ 3,525.7	$ 3,475.4	$ 3,457.4	$ 3,397.7	$ 3,276.7
Long-term debt (d)	$ 903.0	$ 884.0	$ 783.7	$ 884.0	$ 874.6
Redeemable preferred stock	$ 22.9	$ 22.9	$ 22.9	$ 22.9	$ 22.9
Senior secured debt ratings at December 31:					
Fitch Ratings	BBB+	AA-	AA-	A+	A+
Moody's Investors Service	A3	Aa3	Aa3	A2	A2
Standard & Poor's Corporation	BBB+	A	A	A-	BBB+
Number of shareholders - preferred stock	223	234	242	256	281

(a) *"Predecessor" refers to the operations of **DPL** and its subsidiaries prior to the consummation of the Merger. "Successor" refers to the operations of **DPL** and its subsidiaries subsequent to the Merger. See Note 2 of Notes to **DPL's** Consolidated Financial Statements for a description of this transaction. As of the Merger date, the disclosure of per share amounts no longer applies.*

(b) ***DPL** incurred merger-related costs of $37.9 million ($24.6 million net of tax) and a $15.7 million ($10.2 million net of tax) in the Predecessor and Successor periods, respectively, and had a $25.1 million ($16.3 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO.*

(c) ***DP&L** incurred merger-related costs of $19.4 million ($12.6 net of tax) and had a $25.1 million ($16.3 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO.*

(d) *Excludes current maturities of long-term debt.*

(e) *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.*

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.

The following discussion and analysis should be read in conjunction with our audited Consolidated Financial Statements and the 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, LLC. Refer to Note 19 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.* **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 power plant 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 power plants 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 Statement 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 The AES Corporation, a Delaware corporation ("AES") pursuant to the Agreement and Plan of Merger (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," and Note 2 of Notes to **DPL's** Consolidated Financial Statements 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 (see Note 2 of Notes to **DPL's** Consolidated Financial Statements). 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 and will have a material effect on **DPL's** cash requirements.

As a result of the Merger, including the assumption of merger-related debt, **DPL** and **DP&L** were downgraded by all three major credit rating agencies. We do not anticipate that these reduced ratings will have a significant effect on our liquidity; however, we expect that our cost of capital will increase. See Note 7 of Notes to **DPL's** Consolidated Financial Statements for more information. It is important for us to maintain our credit ratings and have access to the capital markets in order to reliably serve our customers, invest in capital improvements and prepare for our customer's future energy needs. As discussed in Note 2 of Notes to **DPL's** Consolidated Financial Statements and Item 1A – Risk Factors, further credit rating downgrades could also require us to post additional credit assurances for commodity derivatives as certain derivative instruments require us to post collateral or provide other credit assurances based on our credit ratings.

DPL incurred merger transaction costs consisting primarily of banker's fees, legal fees and change of control costs of approximately $53.6 million pre-tax during 2011. Other than these costs, interest on the additional debt and other items noted above, **DPL** and **DP&L** do not expect the Merger to have a significant effect on their sources of liquidity during 2012.

Predecessor and Successor Financial Presentation
DPL's financial statements and related financial and operating data include the periods before and after the Merger with AES on November 28, 2011, and are labeled as Predecessor and Successor, respectively. In accordance with GAAP, **DPL** applied push-down accounting to account for the merger. For accounting purposes only, push-down accounting created a new cost basis assigned to assets, liabilities and equity as of the Merger date. Such adjustments are subject to change as AES finalizes its purchase price allocation during the applicable measurement period. Consequently, **DPL's** results of operations and cash flows for the Predecessor and Successor periods in 2011 are not presented on a comparable basis and therefore are shown separately, rather than combined, in its audited financial statements.

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2011 operating and financial performance to 2010 and 2009, and because the core operations of **DPL** have not changed as a result of the merger.

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 Emissions and Other Greenhouse Gases**
  There is an 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. In 2007, a U.S. Supreme Court decision upheld that the USEPA has the authority to regulate GHG emissions under the CAA. In April 2009, the USEPA issued a proposed endangerment finding under the CAA. The proposed finding determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This endangerment finding became effective in January 2010. Numerous affected parties have asked the USEPA Administrator to reconsider this decision. As a result of this endangerment finding and other USEPA regulations, emissions of, CO_2 and other GHGs from electric generating units and other stationary sources are subject to regulation. Increased pressure for GHG emissions reduction is also coming from investor organizations and the international community. Environmental advocacy groups are also focusing considerable attention on GHG emissions from power generation facilities and their potential role in climate change. Approximately 99% of the energy we produce is generated by coal. **DP&L's** share of GHG emissions at generating stations we own and co-own is approximately 16 million tons annually. If we are required to implement of CO_2 and other GHGs at generation facilities, the cost to **DPL** and **DP&L** of such reductions could be material.

- **SB 221 Requirements**

SB 221 and the implementation rules contain targets relating to advanced energy portfolio standards, renewable energy, demand reduction and energy efficiency standards. The standards require that, by the year 2025, 25% of the total number of kWh of electricity sold by the utility to retail electric consumers must come from alternative energy resources, which include "advanced energy resources" such as distributed generation, clean coal, advanced nuclear, energy efficiency and fuel cell technology; and "renewable energy resources" such as solar, hydro, wind, geothermal and biomass. At least half of the 25% must be generated from renewable energy resources, including 0.5% from solar energy. 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. Pursuant to the ESP Stipulation, **DP&L** becomes subject to the SEET in 2013 based on 2012 earnings results and the SEET may have a material effect on our results of operations, financial condition and cash flows.

SB 221 also requires 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 MRO and ESP options involve a "significantly excessive earnings test" based on the earnings of comparable companies with similar business and financial risks. **DPL** will have a second opportunity to elect either an MRO or an ESP approach in a filing required to be made by March 30, 2012. The outcome of this filing could have a significant effect on the revenue we collect from our customers.

- **NOx and SO_2 Emissions – CSAPR**

  The Clean Air Interstate Rule (CAIR) final rules were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO_2. Litigation brought by entities not including **DP&L** resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 2008 decision.

  In an attempt to conform to the Court's decision, on July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR). These rules were finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011, but subsequent litigation has resulted in their implementation being delayed indefinitely. CSAPR creates four separate trading programs: two SO_2 areas (Group 1 and Group 2); and two NOx reduction requirements (annual and ozone season). Group 1 states (16 states including Ohio) will have to meet a 2012 cap and additional reductions in 2014. Group 2 states (7 states) will only have to meet the 2012 cap. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If CSAPR becomes effective, it is expected to institute a Federal Implementation Plan (FIP) in lieu of state SIPs and allow for the states to develop SIPs for approval as early as 2013. We do not believe the rule will have a material effect on our operations in 2012, but until the CSAPR becomes effective, **DP&L** is unable to estimate the impact of the new requirements in future years.

COMPETITION AND PJM PRICING

- **RPM Capacity Auction Price**
  The PJM RPM capacity base residual auction for the 2014/2015 period cleared at a per megawatt price of \$126/day for our RTO area. The per megawatt prices for the periods 2013/2014, 2012/2013, and 2011/2012 were \$28/day, \$16/day, and \$110/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 causes 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 2011, we estimate that a hypothetical increase or decrease of \$10 in the capacity auction price would result in an annual impact to net income of approximately \$5.2 million and \$3.9 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 supply 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.

  Lower market prices for power have resulted in increased levels of competition to provide transmission and generation services. This in turn has led to approximately 47% of **DP&L's** customers to switch their retail electric services to CRES providers. DPLER, an affiliated company and one of the registered CRES providers, has been marketing transmission and 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, 2011, 2010 and 2009:

	Year Ended December 31, 2011		Year Ended December 31, 2010		Year Ended December 31, 2009	
	Electric Customers	**Sales (in Millions of kWh)**	Electric Customers	Sales (in Millions of kWh)	Electric Customers	Sales (in Millions of kWh)
Supplied by DPLER						
Residential	**22,314**	**113**	33	1	-	-
Commercial	**10,485**	**1,830**	6,521	1,094	221	983
Industrial	**623**	**2,933**	533	2,453	44	68
Other	**3,245**	**855**	1,272	869	125	413
Supplied by DPLER	**36,667**	**5,731**	8,359	4,417	390	1,464
Supplied by non-affiliated CRES providers						
Residential	**21,261**	**97**	35	-	-	-
Commercial	**5,706**	**492**	722	67	11	3
Industrial	**321**	**232**	59	73	15	13
Other	**524**	**41**	35	5	18	-
Supplied by non-affiliated CRES providers	**27,812**	**862**	851	145	44	16
Total supplied in our service territory by DPLER and other CRES providers						
Residential	**43,575**	**210**	68	1	-	-
Commercial	**16,191**	**2,322**	7,243	1,161	232	986
Industrial	**944**	**3,165**	592	2,526	59	81
Other	**3,769**	**896**	1,307	874	143	413
Total supplied in our service territory by DPLER and other CRES providers	**64,479**	**6,593**	9,210	4,562	434	1,480
Distribution sales by DP&L in our service territory (a)						
Residential	**454,697**	**5,354**	455,572	5,522	456,144	5,120
Commercial	**50,123**	**3,700**	50,155	3,741	50,141	3,678
Industrial	**1,757**	**3,545**	1,769	3,582	1,773	3,353
Other	**6,804**	**1,423**	6,725	1,432	6,562	1,386
Distribution sales by DP&L in our service territory (a)	**513,381**	**14,022**	514,221	14,277	514,620	13,537

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

The volumes supplied by DPLER represent approximately 41%, 31% and 11% of **DP&L's** total distribution volumes during the years ended December 31, 2011, 2010 and 2009, 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.

As of December 31, 2011, Approximately 47% of **DP&L's** load has switched to CRES providers with DPLER acquiring 87% of the switched load. For the calendar year 2011, customer switching negatively affected **DPL's** gross margin by approximately $58 million compared to the 2010 effect of approximately $17 million. For the calendar year 2011, customer switching negatively affected **DP&L's** gross margin by approximately $104 million compared to the 2010 effect of approximately $53 million.

Several communities in **DP&L's** service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering alternative electric generation supplies to their citizens. To date, nine organizations have filed with the PUCO to initiate aggregation programs. If these nine organizations move forward with aggregation, it could have a material effect on our earnings. See Item 1A – Risk Factors for more information.

In 2010, DPLER began providing CRES services to customers in Ohio who are not in **DP&L's** service territory. The incremental costs and revenues have not had a material effect on our results of operations, financial condition or cash flows.

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. For the year ending December 31, 2012, we have hedged substantially all our coal requirements to meet our committed sales. We may not be able to hedge the entire exposure of our operations from commodity price volatility. 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.

  Effective January 2010, the SSO retail customer portion of fuel price changes, including coal requirements and purchased power costs, was reflected in the implementation of the fuel and purchased power recovery rider, subject to PUCO review. An audit of 2010 fuel costs occurred in 2011 and issues raised were resolved by a Stipulation approved by the PUCO in November 2011. As a result of this approval, **DP&L** recorded a $25 million pretax ($16 million net of tax) adjustment. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 fuel costs is currently ongoing.

FINANCIAL OVERVIEW

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2011 operating and financial performance to 2010 and 2009, and because the core operations of **DPL** have not changed as a result of the merger.

For the year ended December 31, 2011, Net income for **DPL** was $144.3 million, compared to Net income of $290.3 million for the same period in 2010. 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** net income for the years ended December 31, 2011 (Combined), 2010 and 2009:

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	 2009
Total operating revenues	$ 1,827.8	$ 156.9	$ 1,670.9	$ 1,831.4	$ 1,539.4
Total cost of fuel	391.6	35.8	355.8	383.9	330.4
Net purchased power	441.3	36.7	404.6	387.4	260.2
Amortization of intangibles	11.6	11.6	-	-	-
Total cost of revenues	844.5	84.1	760.4	771.3	590.6
Total gross margin (a)	983.3	72.8	910.5	1,060.1	948.8
Operating expenses					
Operation and maintenance	425.3	47.5	377.8	340.6	306.5
Depreciation and amortization	141.0	11.6	129.4	139.4	145.5
General taxes	83.1	7.6	75.5	75.7	68.6
Total operating expense	649.4	66.7	582.7	555.7	520.6
Operating income	333.9	6.1	327.8	504.4	428.2
Investment income / (expense)	0.5	0.1	0.4	1.8	(0.6)
Interest expense	(85.5)	(11.5)	(74.0)	(70.6)	(83.0)
Other income / (expense), net	(2.0)	(0.3)	(1.7)	(2.3)	(3.0)
Income / (loss) before income taxes	246.9	(5.6)	252.5	433.3	341.6
Income tax expense	102.6	0.6	102.0	143.0	112.5
Net income / (loss)	$ 144.3	$ (6.2)	$ 150.5	$ 290.3	$ 229.1

(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.*

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.

In the Management's Discussion and Analysis of Results of Operations and Financial Condition, we have included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such combined presentation is considered to be a non-GAAP disclosure. We have included such disclosure because we believe it facilitates the comparison of 2011 operating and financial performance to 2010 and 2009, and because the core operations of **DPL** have not changed as a result of the merger.

Income Statement Highlights – DPL

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Revenues:					
Retail	$ 1,429.0	$ 126.3	$ 1,302.7	$ 1,404.8	$ 1,179.5
Wholesale	129.7	8.4	121.3	142.2	122.7
RTO revenues	81.7	6.6	75.1	86.6	89.4
RTO capacity revenues	179.7	13.9	165.8	186.2	136.3
Other revenues	10.8	0.9	9.9	11.5	11.7
Mark-to-market gains / (losses)	(3.1)	0.8	(3.9)	0.1	(0.2)
Total revenues	1,827.8	156.9	1,670.9	1,831.4	1,539.4
Cost of revenues:					
Fuel costs	381.2	34.8	346.4	399.5	391.7
Gains from sale of coal	(8.8)	(0.6)	(8.2)	(4.1)	(56.3)
Gains from sale of emission allowances	-	-	-	(0.8)	(5.0)
Mark-to-market (gains) / losses	19.2	1.6	17.6	(10.7)	-
Net fuel	391.6	35.8	355.8	383.9	330.4
Purchased power	156.2	12.9	143.3	81.5	46.9
RTO charges	115.1	9.2	105.9	113.4	100.9
RTO capacity charges	172.9	13.1	159.8	191.9	112.4
Mark-to-market (gains) / losses	(2.9)	1.5	(4.4)	0.6	-
Net purchased power	441.3	36.7	404.6	387.4	260.2
Amortization of intangibles	11.6	11.6	-	-	-
Total cost of revenues	844.5	84.1	760.4	771.3	590.6
Gross margins (a)	$ 983.3	$ 72.8	$ 910.5	$ 1,060.1	$ 948.8
Gross margin as a percentage of revenues	53.8%	46.4%	54.5%	57.9%	61.6%
Operating income	333.9	6.1	327.8	504.4	428.2

(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.*

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.

Number of days	Years ended December 31, **2011**	2010	2009
Heating degree days (a)	**5,368**	5,636	5,561
Cooling degree days (a)	**1,160**	1,245	734

(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. 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 our retail customers' needs first, increases in 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 impacting 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 plants' and other utility plants' 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	2011 vs. 2010	2010 vs. 2009
Retail		
Rate	$ 45.9	$ 149.0
Volume	(29.1)	75.2
Other	6.7	0.9
Total retail change	23.5	225.1
Wholesale		
Rate	15.3	31.2
Volume	(27.8)	(11.7)
Total wholesale change	(12.5)	19.5
RTO capacity and other		
RTO capacity and other revenues	(11.4)	47.1
Other		
Unrealized MTM	(3.2)	0.3
Total revenues change	$ (3.6)	$ 292.0

For the year ended December 31, 2011, Revenues decreased $3.6 million to $1,827.8 million from $1,831.4 million in the same period of the prior year. This decrease was primarily the result of decreased retail and wholesale volumes, decreased RTO capacity and other revenues, offset by increased retail and wholesale rates and increased other miscellaneous retail revenues. The revenue components for the year ended December 31, 2011 are further discussed below:

- Retail revenues increased $23.5 million resulting primarily from a 3.4% increase in average retail rates due largely to the implementation of the fuel and energy efficiency riders, an increase in the TCRR and RPM riders, combined with the incremental effect of the recovery of costs under the EIR, as well as improved economic conditions. This increase in the average retail rates was partially offset by the effect of lower revenues due to customer switching which has resulted from increased levels of competition to provide transmission and generation services in our service territory. Retail sales volume experienced a 2.1% decrease compared to the prior year period largely due to unfavorable weather. The unfavorable weather conditions resulted in a 6% decrease in the number of cooling degree days to 1,160 days from 1,245 days in 2010. The above resulted in a favorable $45.9 million retail price variance and an unfavorable $29.1 million retail sales volume variance.
- Wholesale revenues decreased $12.5 million primarily as a result of a 19.6% decrease in wholesale sales volume which was largely a result of lower generation by our power plants, partially offset by a 13.4% increase in wholesale average prices. This resulted in an unfavorable $27.8 million wholesale sales volume variance partially offset by a favorable wholesale price variance of $15.3 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 $11.4 million compared to the same period in 2010. This decrease in RTO capacity and other revenues was primarily the result of a $6.5 million decrease in revenues realized from the PJM capacity auction, including a $4.9 million decrease in transmission, congestion and other revenues.

For the year ended December 31, 2010, Revenues increased $292.0 million, or 19%, to $1,831.4 million from $1,539.4 million in the same period of the prior year. This increase was primarily the result of higher average retail and wholesale rates, higher retail sales volume, and increased RTO capacity and other revenues, partially offset by lower wholesale sales volume. The revenue components for the year ended December 31, 2010 are further discussed below:

- Retail revenues increased $225.1 million resulting primarily from a 12% increase in average retail rates due largely to the implementation of the fuel and energy efficiency riders, an increase in the TCRR and RPM riders, combined with the incremental effect of the recovery of costs under the EIR. This increase in the average retail rates was partially offset by the effect of lower revenues due to customer switching which has resulted from increased levels of competition to provide transmission and generation services in our service territory. Retail sales volume had a 6% increase compared to those in the prior year period largely due to more favorable weather and improved economic conditions. The favorable weather conditions resulted in a 70% increase in the number of cooling degree days to 1,245 days from 734 days in 2009. The above resulted in a favorable $149.0 million retail price variance and a favorable $75.2 million retail sales volume variance.
- Wholesale revenues increased $19.5 million primarily as a result of a 28% increase in wholesale average prices, partially offset by a 10% decrease in wholesale sales volume which was largely a result of lower generation by our power plants and increased retail sales volume. This resulted in a favorable $31.2 million wholesale price variance partially offset by an unfavorable wholesale sales volume variance of $11.7 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 $47.1 million compared to the same period in 2009. This increase in RTO capacity and other revenues was primarily the result of a $49.9 million increase in revenues realized from the PJM capacity auction, partially offset by a $2.8 million decrease in transmission, congestion and other revenues.

DPL – Cost of Revenues
For the year ended December 31, 2011:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $7.7 million, or 2%, compared to 2010, primarily due to increased mark-to-market losses on coal contracts partially offset by decreased fuel costs. During the year ended December 31, 2011, **DP&L** realized $8.8 million in gains from the sale of coal, compared to $4.1 million realized during the same period in 2010. In addition to these gains, there was a 12% decrease in the volume of generation at our plants. Also offsetting the increase in fuel costs was a $15 million decrease due to an adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules.
- Net purchased power increased $53.9 million, or 14%, compared to the same period in 2010 due largely to an increase of $74.7 million in purchased power partially offset by a decrease of $17.3 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This increase included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. The increase in purchased power of $74.7 million was comprised of a $100.3 million increase associated with higher purchased power volumes due to lower internal generation partially offset by a $25.6 million decrease related to lower 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.

For the year ended December 31, 2010:

- Net fuel costs, which include coal, gas, oil and emission allowance costs, increased $53.5 million, or 16%, compared to 2009, primarily due to the impact of lower gains realized from the sale of **DP&L's** coal and excess emission allowances. During the year ended December 31, 2010, **DP&L** realized $4.1 million and $0.8 million in gains from the sale of coal and excess emission allowances, respectively, compared to $56.3 million and $5.0 million, respectively, realized during the same period in 2009. The effect of these lower gains was partially offset by the impact of a 2% decrease in the volume of generation by our plants.
- Net purchased power increased $127.2 million, or 49%, compared to the same period in 2009 due largely to an increase of $92.0 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This increase included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Also contributing to the increase in net purchased power was a $37.7 million increase related to higher average market prices for purchased power, partially offset by a $2.5 million decrease associated with lower purchased power volumes. 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.

DPL - Operation and Maintenance

$ in millions	2011 vs. 2010
Merger related costs	$ 53.6
Low-income payment program (1)	14.6
Generating facilities operating and maintenance expenses	12.9
Maintenance of overhead transmission and distribution lines	9.1
Competitive retail operations	7.6
Insurance settlement, net	3.4
Health insurance / long-term disability	(6.2)
Pension expense	(3.3)
Other, net	(7.0)
Total operation and maintenance expense	$ 84.7

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

During the year ended December 31, 2011, Operation and maintenance expense increased $84.7 million, or 25%, compared to the same period in 2010. This variance was primarily the result of:

- increased costs related to the Merger with AES,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly-owned production units relative to the same period in 2010,
- increased expenses related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011,
- 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
- a prior year insurance settlement that reimbursed us for legal costs associated with our litigation against certain former executives.

These increases were partially offset by:

- lower health insurance and disability costs primarily due to fewer employees going onto long-term disability during the current year as compared to the same period in 2010, and
- lower pension expenses primarily related to a $40 million contribution to the pension plan during 2011.

$ in millions	2010 vs. 2009
Energy efficiency programs (1)	$ 11.1
Health insurance / long-term disability	8.9
Low-income payment program (1)	5.2
Pension	4.0
Generating facilities operating and maintenance expenses	3.8
Insurance settlement, net	(3.4)
Other, net	4.5
Total operation and maintenance expense	$ 34.1

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

During the year ended December 31, 2010, Operation and maintenance expense increased $34.1 million, or 11%, compared to the same period in 2009. This variance was primarily the result of:

- higher expenses relating to energy efficiency programs that were put in place for our customers during 2009 and 2010,
- increased health insurance and disability costs primarily due to a number of employees going on long-term disability,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased pension costs due largely to a decline in the values of pension plan assets during 2008 and increased benefit costs, and
- increased expenses for generating facilities largely due to unplanned outages at jointly-owned production units.

These increases were partially offset by:

- an insurance settlement that reimbursed us for legal costs associated with our litigation against certain former executives.

DPL – Depreciation and Amortization

During the year ended December 31, 2011, Depreciation and amortization expense increased $1.6 million, or 1%, as compared to 2010. The increase primarily reflects the effect of investments in fixed assets partially offset by the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by approximately $4.8 million during the year ended December 31, 2011 compared to the year ended December 31, 2010. Amortization expense increased $11.6 million in 2011, primarily due to the amortization of intangibles acquired in the merger.

During the year ended December 31, 2010, Depreciation and amortization expense decreased $6.1 million, or 4%, as compared to 2009. The decrease primarily reflects the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by approximately $4.8 million during the year ended December 31, 2010.

DPL – General Taxes

During the year ended December 31, 2011, General taxes increased $7.4 million, or 10%, as compared to 2010. This increase was primarily the result of higher property tax accruals in 2011 compared to 2010 and an unfavorable determination of $4.5 million from the Ohio gross receipts tax audit. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues. All prior periods have been reclassified for comparability purposes.

During the year ended December 31, 2010, General taxes increased $7.1 million, or 10%, as compared to 2009. This increase was primarily the result of higher property tax accruals in 2010 compared to 2009 and an adjustment to future credits against state gross receipts taxes. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues.

DPL – Investment Income (Loss)

During the year ended December 31, 2011, Investment income (loss) decreased $1.3 million as compared to 2010 primarily as a result of lower average cash and short-term investment balances in 2011 compared to 2010.

During the year ended December 31, 2010, Investment income (loss) increased $2.4 million as compared to 2009 primarily as a result of $1.4 million of expense incurred in 2009 related to the early redemption of debt. In addition, **DPL** had higher cash and short-term investment balances in 2010 compared to 2009 which resulted in higher investment income.

DPL – Interest Expense
During the year ended December 31, 2011, Interest expense and charge for early redemption of debt increased $14.9 million, or 21%, as compared to 2010 due primarily to a $15.3 million charge for the early redemption of DPL *Capital Trust II securities in February 2011 and higher interest cost subsequent to the* Merger as a result of the $1.25 billion of debt that was assumed by **DPL** in connection with the AES Merger.

During the year ended December 31, 2010, Interest expense decreased $12.4 million, or 15%, as compared to 2009 primarily due to the early redemption in December 2009 of $52.4 million of the $195 million 8.125% Note to DPL Capital Trust II and the redemption of **DPL's** $175 million 8.00% Senior Notes in March 2009. A premium of $3.7 million was incurred as an expense in 2009 upon the early debt redemption of $52.4 million referred to above.

DPL – Income Tax Expense
During the year ended December 31, 2011, Income tax expense decreased $40.4 million, or 28%, as compared to 2010 primarily due to decreases in pre-tax income partially offset by non-deductible expenses related to the Merger, non-deductible compensation related to the Merger, a reduction in Internal Revenue Code Section 199 tax benefits and a write-off of a deferred tax asset on the termination of the ESOP.

During the year ended December 31, 2010, Income tax expense increased $30.5 million, or 27%, as compared to 2009 primarily due to increases in pre-tax income.

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 sell electricity to residential, commercial, industrial and governmental customers.* Electricity for the segment's 24-county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 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 rates for its generation business are deemed competitive under Ohio law.

Competitive Retail Segment
The Competitive Retail segment is DPLER's and MC Squared'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 MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 40,000 customers currently located throughout Ohio and Illinois. MC Squared, a Chicago-based retail electricity supplier, serves approximately 3,200 customers in Northern Illinois. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. 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. In the discussions that follow, we have not provided extensive discussions of the results of operations related to 2009 for the Competitive Retail segment because we believe that financial information is not comparable to the 2010 financial information. We have, however, included brief descriptions of the Competitive Retail segment's financial results for 2009 for informational purposes as required by GAAP following the Income Statement Highlights table below.

See Note 19 of Notes to **DPL's** Consolidated Financial Statements for further discussion of **DPL's** reportable segments.

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

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Utility	$ 895.5	$ 78.5	$ 817.0	$ 983.4	$ 918.0
Competitive Retail	61.5	4.8	56.7	38.5	0.7
Other	30.4	(10.1)	40.5	42.7	33.7
Adjustments and Eliminations	(4.1)	(0.4)	(3.7)	(4.5)	(3.6)
Total consolidated	*$ 983.3*	*$ 72.8*	*$ 910.5*	*$ 1,060.1*	*$ 948.8*

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

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Revenues:					
Retail	$ 426.1	$ 37.1	$ 389.0	$ 275.5	$ 64.8
RTO and other	(0.7)	1.1	(1.8)	1.5	0.7
	425.4	38.2	387.2	277.0	65.5
Cost of revenues:					
Purchased power	363.9	33.4	330.5	238.5	64.8
Gross margins (a)	61.5	4.8	56.7	38.5	0.7
Operation and maintenance expense	15.4	1.7	13.7	7.8	2.7
Other expenses (income), net	2.5	0.3	2.2	1.4	1.5
Total expenses, net	17.9	2.0	15.9	9.2	4.2
Earnings (loss) from continuing operations before income tax	43.6	2.8	40.8	29.3	(3.5)
Income tax expense (benefit)	17.8	1.1	16.7	10.5	(0.8)
Net income (loss)	$ 25.8	$ 1.7	$ 24.1	$ 18.8	$ (2.7)
Gross margin as a percentage of revenues	14.5%	12.6%	14.6%	13.9%	1.1%

(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
For the year ended December 31, 2011, the segment's retail revenues increased $150.6 million, or 54.7%, as compared to 2010. The increase was primarily driven by increased levels of competition in the competitive retail electric service business in the state of Ohio which in turn has resulted in a significant number of **DP&L's** retail customers switching their retail electric service to DPLER or other CRES providers. Also contributing to the year over year increase is $41.7 million of retail revenue from MC Squared which was purchased on February 28, 2011. Primarily as a result of the customer switching discussed above, the Competitive Retail segment sold approximately 6,677 million kWh of power to 40,171 customers in 2011 compared to 4,546 million kWh of power to 9,002 customers during 2010.

For the year ended December 31, 2010, the segment's retail revenues increased $210.7 million, or 325%, as compared to 2009. The increase was primarily driven by increased levels of competition in the competitive retail electric service business in the state of Ohio which in turn has resulted in a significant number of **DP&L's** retail customers switching their retail electric service to DPLER. Primarily as a result of the customer switching discussed above, the Competitive Retail segment sold approximately 4,546 million kWh of power to 9,002 customers during 2010 compared to 1,464 million kWh to 390 customers during 2009.

Competitive Retail Segment – Purchased Power
During the year ended December 31, 2011, the Competitive Retail segment purchased power increased $125.4 million, or 52.6%, as compared to 2010 primarily due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching and also $36.9 million relating to MC Squared customers as MC Squared was acquired on February 28, 2011. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. Intercompany sales from **DP&L** to DPLER are based on fixed-price contracts for each DPLER customers which approximate market prices for wholesale power at the inception of each customer's contract.

During the year ended December 31, 2010, the Competitive Retail segment purchased power increased $173.7 million, or 268%, as compared to 2009 primarily due to higher purchased power volumes required to satisfy an increase in customer base resulting from customer switching. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on fixed-price contracts which approximated market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers at the date of the agreement.

Competitive Retail Segment – Operation and Maintenance
DPLER's operation and maintenance expenses include employee-related expenses, accounting, information technology, payroll, legal and other administration expenses. The higher operation and maintenance expense in 2011 as compared to 2010 and 2009 is reflective of increased marketing and customer maintenance costs associated with the increased sales volume and number of customers and the purchase of MC Squared.

RESULTS OF OPERATIONS – The Dayton Power and Light Company (DP&L)

Income Statement Highlights – DP&L

$ in millions	Years ended December 31, 2011	2010	2009
Revenues:			
Retail	**$ 1,007.4**	$ 1,133.7	$ 1,117.6
Wholesale	**441.2**	365.6	182.1
RTO revenues	**76.7**	81.7	86.1
RTO capacity revenues	**152.4**	157.6	115.2
Mark-to-market gains / (losses)	**-**	0.2	(0.2)
Total revenues	**1,677.7**	1,738.8	1,500.8
Cost of revenues:			
Fuel costs	**370.2**	387.5	384.9
Gains from sale of coal	**(8.8)**	(4.1)	(56.3)
Gains from sale of emission allowances	**-**	(0.8)	(5.0)
Mark-to-market (gains) / losses	**19.2**	(10.7)	-
Net fuel	**380.6**	371.9	323.6
Purchased power	**121.5**	81.3	46.9
RTO charges	**114.9**	109.7	99.9
RTO capacity charges	**165.4**	191.9	112.4
Mark-to-market (gains) / losses	**(0.2)**	0.6	-
Net purchased power	**401.6**	383.5	259.2
Total cost of revenues	**782.2**	755.4	582.8
Gross margins (a)	**$ 895.5**	$ 983.4	$ 918.0
Gross margin as a percentage of revenues	**53.4%**	56.6%	61.2%
Operating income	**319.9**	450.2	421.9

(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.*

DP&L – Revenues

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

$ in millions	2011 vs. 2010	2010 vs. 2009
Retail		
Rate	$ (45.5)	$ (46.4)
Volume	(87.9)	60.7
Other	7.1	1.8
Total retail change	(126.3)	16.1
Wholesale		
Volume	48.0	109.1
Rate	27.6	74.4
Total wholesale change	75.6	183.5
RTO capacity and other		
RTO capacity and other revenues	(10.2)	38.0
Other		
Unrealized MTM	(0.2)	0.4
Total revenues change	$ (61.1)	$ 238.0

For the year ended December 31, 2011, Revenues decreased $61.1 million, or 3.5%, to $1,677.7 million from $1,738.8 million in the prior year. This decrease was primarily the result of lower average retail rates, retail sales volumes and decreased RTO capacity and other revenues, partially offset by higher wholesale sales volumes and higher average wholesale prices. The revenue components for the year ended December 31, 2011 are further discussed below:

- Retail revenues decreased $126.3 million primarily as a result of an 8% decrease in retail sales volumes compared to those in the prior year largely due to unfavorable weather conditions. The unfavorable weather conditions resulted in a 7% decrease in the number of cooling degree days to 1,160 days from 1,245 days in 2010. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory. The average retail rates decreased 4% overall primarily as a result of customers switching from **DP&L** to DPLER. The remaining distribution services provided by **DP&L** were billed at a lower rate resulting in a reduction of total average retail rates. The decrease in average retail rates resulting from customers switching was partially offset by the implementation of the fuel and energy efficiency riders, increased TCRR and RPM riders, and the incremental effect of the recovery of costs under the EIR. The above resulted in an unfavorable $87.9 million retail sales volume variance and an unfavorable $45.5 million retail price variance.
- Wholesale revenues increased $75.6 million primarily as a result of a 7% increase in average wholesale prices combined with a 13% increase in wholesale sales volume due in large part to the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. This resulted in a favorable $48.0 million wholesale volume variance and a $27.6 million favorable 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 $10.2 million compared to the same period in 2010. This decrease in RTO capacity and other revenues was primarily the result of a $5.2 million decrease in revenues realized from the PJM capacity auction, including a decrease of $5.0 million in transmission and congestion revenues.

For the year ended December 31, 2010, Revenues increased $238.0 million, or 16%, to $1,738.8 million from $1,500.8 million in the prior year. This increase was primarily the result of higher retail and wholesale sales volumes, higher average wholesale prices as well as increased RTO capacity and other revenues, partially offset by lower average retail rates. The revenue components for the year ended December 31, 2010 are further discussed below:

- Retail revenues increased $16.1 million primarily as a result of a 6% increase in retail sales volumes compared to those in the prior year period largely due to more favorable weather and improved economic conditions. The favorable weather conditions resulted in a 70% increase in the number of cooling degree days to 1,245 days from 734 days in 2009. Although **DP&L** had a number of customers that switched their retail electric service from **DP&L** to DPLER, an affiliated CRES provider, **DP&L** continued to provide distribution services to those customers within its service territory. The average retail rates decreased 4% overall primarily as a result of customers switching from **DP&L** to DPLER. The remaining distribution services provided by **DP&L** were billed at a lower rate resulting in a reduction of total average retail rates. The decrease in average retail rates resulting from customers switching was partially offset by the implementation of the fuel and energy efficiency riders, increased TCRR and RPM riders, and the incremental effect of the recovery of costs under the EIR. The above resulted in a favorable $60.7 million retail sales volume variance and an unfavorable $46.4 million retail price variance.
- Wholesale revenues increased $183.5 million primarily as a result of a 26% increase in average wholesale prices combined with a 60% increase in wholesale sales volume due in large part to the effect of customer switching discussed in the immediately preceding paragraph. **DP&L** records wholesale revenues from its sale of transmission and generation services to DPLER associated with these switched customers. This resulted in a favorable $109.1 million wholesale sales volume variance and a favorable wholesale price variance of $74.4 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 $38.0 million compared to the same period in 2009. This increase in RTO capacity and other revenues was primarily the result of a $42.4 million increase in revenues realized from the PJM capacity auction partially offset by a decrease of $4.4 million in transmission and congestion revenues.

DP&L – Cost of Revenues

For the year ended December 31, 2011:

- Net fuel costs, which include coal, gas, oil, and emission allowance costs, increased $8.7 million, or 2%, compared to 2010, primarily due to the impact of mark-to-market losses on coal contracts in 2011 compared to gains in 2010, partially offset by a reduction in fuel costs and an increase in gains on the sale of coal. Also offsetting the increase in fuel costs was a $15 million adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules.
- Net purchased power increased $18.1 million, or 5%, compared to 2010, due largely to an increase of $40.2 million in purchased power costs partially offset by a decrease of $21.3 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This decrease included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Also contributing to the increase in net purchased power was a $54.6 million increase associated with higher purchased power volumes, partially offset by a $14.4 million decrease related to lower 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.

For the year ended December 31, 2010:

- Net fuel costs, which include coal, gas, oil, and emission allowance costs, increased $48.3 million, or 15%, compared to 2009, primarily due to the impact of lower gains realized from the sale of **DP&L's** coal and excess emission allowances. During the year ended December 31, 2010, **DP&L** realized $4.1 million and $0.8 million in gains from the sale of coal and excess emission allowances, respectively, compared to $56.3 million and $5.0 million, respectively, during 2009. The effect of these lower gains was partially offset by the impact of a 3% decrease in the volume of generation by our plants.
- Net purchased power increased $124.3 million, or 48%, compared to 2009, due largely to an increase of $89.3 million in RTO capacity and other charges which were incurred as a member of PJM, including costs associated with **DP&L's** load obligations for retail customers. This increase included the net impact of the deferral and recovery of **DP&L's** transmission, capacity and other PJM-related charges. Also contributing to the increase in net purchased power was a $37.6 million increase related to higher average market prices for purchased power, partially offset by a $2.5 million decrease associated with lower purchased power volumes. 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.

DP&L – Operation and Maintenance

$ in millions	2011 vs. 2010
Merger related costs	$ 19.4
Low-income payment program [1]	14.6
Generating facilities operating and maintenance expenses	12.8
Maintenance of overhead transmission and distribution lines	9.1
Health insurance / long-term disability	(6.3)
Pension expenses	(3.3)
Other, net	(11.6)
Total operation and maintenance expense	$ 34.7

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

During the year ended December 31, 2011, Operation and maintenance expense increased $34.7 million, or 11%, compared to 2010. This variance was primarily the result of:

- increased costs related to the Merger with AES,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased expenses for generating facilities largely due to the length and timing of planned outages at jointly-owned production units relative to the same period in 2010, and
- increased expenses related to the maintenance of overhead transmission and distribution lines primarily as a result of storms, including a significant ice storm in February 2011.

These increases were partially offset by:

- lower health insurance and disability costs primarily due to fewer employees going onto long-term disability during the current year as compared to the same period in 2010, and
- lower pension expenses primarily related to a $40 million contribution to the pension plan during 2011.

$ in millions		2010 vs. 2009
Energy efficiency programs [(1)]	$	11.1
Health insurance / long-term disability		8.9
Low-income payment program [(1)]		5.1
Pension		4.0
Generating facilities operating and maintenance expenses		3.6
Other, net		4.0
Total operation and maintenance expense	$	36.7

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

During the year ended December 31, 2010, Operation and maintenance expense increased $36.7 million, or 13%, compared to 2009. This variance was primarily the result of:

- higher expenses relating to energy efficiency programs that were put in place for our customers during 2009 and 2010,
- increased health insurance and disability costs primarily due to a number of employees going on long-term disability,
- increased assistance for low-income retail customers which is funded by the USF revenue rate rider,
- increased pension costs due largely to a decline in the values of pension plan assets during 2008 and increased benefit costs, and
- increased expenses for generating facilities largely due to unplanned outages at jointly-owned production units.

DP&L – Depreciation and Amortization
During the year ended December 31, 2011, Depreciation and amortization expense increased $4.2 million as compared to 2010. The increase primarily reflected the impact of investments in plant and equipment partially offset by the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by $3.4 million during the year ended December 31, 2011 compared to the year ended December 31, 2010.

During the year ended December 31, 2010, Depreciation and amortization expense decreased $4.8 million as compared to 2009. The decrease primarily reflected the impact of a depreciation study which resulted in lower depreciation rates on generation property which were implemented on July 1, 2010, reducing the expense by $3.4 million during the year ended December 31, 2010.

DP&L – General Taxes
During the year ended December 31, 2011, General taxes increased $3.5 million to $75.9 million compared to 2010. This increase was primarily the result of higher property tax accruals in 2011 compared to 2010. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues. All prior periods have been reclassified for comparability purposes.

During the year ended December 31, 2010, General taxes increased $5.2 million to $72.4 million compared to 2009. This increase was primarily the result of higher property tax accruals in 2010 compared to 2009. Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues.

DP&L – Investment Income
Investment income realized during 2011 increased $15.6 million over 2010 primarily as a result of the sale of the DPL Inc. stock held by the Master Trust.

Investment income realized during 2010 did not fluctuate significantly from that realized during 2009.

DP&L – Interest Expense
Interest expense recorded during 2011 did not fluctuate significantly from that recorded in 2010.

Interest expense recorded during 2010 did not fluctuate significantly from that recorded in 2009.

DP&L – Income Tax Expense
During the year ended December 31, 2011, Income tax expense decreased $31.0 million compared to 2010 primarily due to decreases in pre-tax income offset by non-deductible compensation expenses related to the Merger, a reduction in Internal Revenue Code Section 199 tax benefits and a write-off of a deferred tax asset on the termination of the ESOP.

During the year ended December 31, 2010, Income tax expense increased $10.7 million compared to 2009 primarily due to increases in pre-tax income.

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

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Net cash provided by operating activities	$ 324.6	$ (0.9)	$ 325.5	$ 464.2	$ 524.7
Net cash used for investing activities	(142.7)	(30.9)	(111.8)	(220.6)	(164.7)
Net cash used for financing activities	(151.6)	88.9	(240.5)	(194.5)	(347.6)
Net change	30.3	57.1	(26.8)	49.1	12.4
Assumption of cash at acquisition	19.2	19.2	-	-	-
Cash and cash equivalents at beginning of period	124.0	97.2	124.0	74.9	62.5
Cash and cash equivalents at end of period	$ 173.5	$ 173.5	$ 97.2	$ 124.0	$ 74.9

DP&L

$ in millions	Years ended December 31, 2011	2010	2009
Net cash provided by operating activities	$ 355.8	$ 446.4	$ 513.7
Net cash used for investing activities	(176.6)	(148.6)	(166.0)
Net cash used for financing activities	(201.0)	(300.9)	(311.4)
Net change	(21.8)	(3.1)	36.3
Cash and cash equivalents at beginning of period	54.0	57.1	20.8
Cash and cash equivalents at end of period	$ 32.2	$ 54.0	$ 57.1

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

DPL's Net cash provided by operating activities for the years ended December 31, 2011, 2010 and 2009 can be summarized as follows:

	Combined	Successor	Predecessor		
	Year ended	November 28, 2011 through	January 1, 2011 through	Years ended December 31,	
$ in millions	December 31, 2011	December 31, 2011	November 27, 2011	2010	2009
Earnings from continuing operations	$ 144.3	$ (6.2)	$ 150.5	$ 290.3	$ 229.1
Depreciation and amortization	152.6	23.2	129.4	139.4	145.5
Deferred income taxes	65.6	0.1	65.5	59.9	201.6
Charge for early redemption of debt	15.3	-	15.3	-	-
Contribution to pension plan	(40.0)	-	(40.0)	(40.0)	-
Deferred regulatory costs, net	(14.3)	0.1	(14.4)	21.8	(23.6)
Cash settlement of interest rate hedges, net of tax	(31.3)	-	(31.3)	-	-
Other	32.4	(18.1)	50.5	(7.2)	(27.9)
Net cash provided by operating activities	$ 324.6	$ (0.9)	$ 325.5	$ 464.2	$ 524.7

For the year ended December 31, 2011, Net cash provided by operating activities was primarily a result of Earnings from continuing operations adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $65.6 million increase to Deferred income taxes primarily results from changes related to pension contributions, depreciation expense and repair expense.
- A $15.3 million charge for the early redemption of DPL Capital Trust II securities.
- **DP&L** made discretionary contributions of $40.0 million to the defined benefit pension plan in 2011.
- **DPL** made a cash payment of $48.1 million ($31.3 million net of the tax effect) related to interest rate hedge contracts that settled during the period.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

For the year ended December 31, 2010, Net cash provided by operating activities was primarily a result of Earnings from continuing operations adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $59.9 million increase to Deferred income taxes primarily results from changes related to pension contributions, depreciation expense and repair expense.
- **DP&L** made discretionary contributions of $40.0 million to the defined benefit pension plan in 2010.
- $21.8 million of cash collected to pay for fuel, purchased power and other fuel related costs and transmission, capacity and other PJM-related costs incurred during 2010, in excess of cash expenditures. These costs reduced the Regulatory asset in accordance with the provisions of GAAP relating to regulatory accounting (see Note 4 of Notes to **DPL's** Consolidated Financial Statements) and are expected to reduce the amount to be collected from customers in future periods.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

For the year ended December 31, 2009, Net cash provided by operating activities was primarily a result of Earnings from continuing operations adjusted for noncash depreciation and amortization, combined with the following significant transactions:

- The $201.6 million increase to Deferred income taxes primarily results from the recognition of certain tax benefits for 2008 and 2009 relating to a change in the tax accounting method for deductions pertaining to repairs, depreciation and mixed service costs. Primarily due to the recognition of these benefits during 2009, **DPL** received a net cash refund of state and federal income taxes totaling $94.6 million and, in addition, was able to offset $69.0 million of these benefits against income tax liabilities accrued in 2009.
- $23.6 million of cash used primarily to pay for transmission, capacity and other PJM-related costs incurred during 2009, net of recoveries. These costs were recorded as a Regulatory asset in accordance with the provisions of GAAP relating to regulatory accounting (see Note 4 of Notes to **DPL's** Consolidated Financial Statements) and are expected to be collected from customers during future years.
- Other represents items that had a current period cash flow impact and includes changes in working capital and other future rights or obligations to receive or to pay cash. These items are primarily impacted by, among other factors, the timing of when cash payments are made for fuel, purchased power, operating costs, interest and taxes, and when cash is received from our utility customers and from the sales of coal and excess emission allowances.

DP&L – *Net Cash provided by Operating Activities*
DP&L's Net cash provided by operating activities for the years ended December 31, 2011, 2010 and 2009 are summarized as follows:

$ in millions	**2011**	2010	2009
Net income	**$ 193.2**	$ 277.7	$ 258.9
Depreciation and amortization	**134.9**	130.7	135.5
Deferred income taxes	**50.7**	54.3	200.1
Contribution to pension plan	**(40.0)**	(40.0)	-
Deferred regulatory costs, net	**(12.6)**	21.8	(23.6)
Other	**29.6**	1.9	(57.2)
Net cash provided by operating activities	**$ 355.8**	$ 446.4	$ 513.7

For the years ended December 31, 2011, 2010 and 2009, the significant components of **DP&L's** Net cash provided by operating activities are similar to those discussed under **DPL's** Net cash provided by operating activities above.

DPL – Net Cash used for Investing Activities
DPL's Net cash used for investing activities for the years ended December 31, 2011, 2010 and 2009 are summarized as follows:

	Combined	Successor	Predecessor		
		November 28, 2011	January 1, 2011		
	Year ended	through	through	Years ended December 31,	
$ in millions	December 31, 2011	December 31, 2011	November 27, 2011	2010	2009
Environmental and renewable energy capital expenditures	**$ (11.8)**	**$ -**	**$ (11.8)**	$ (11.9)	$ (21.2)
Other plant-related asset acquisitions	**(192.9)**	**(30.5)**	**(162.4)**	(140.8)	(151.1)
Purchase of MC Squared	**(8.3)**	**-**	**(8.3)**	-	-
Sales / (purchases) of short-term investments	**69.2**	**-**	**69.2**	(69.3)	5.0
Other	**1.1**	**(0.4)**	**1.5**	1.4	2.6
DPL's net cash used for investing activities	**$ (142.7)**	**$ (30.9)**	**$ (111.8)**	$ (220.6)	$ (164.7)

For the year ended December 31, 2011, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation plants. Additionally, **DPL**, on behalf of DPLER, made a cash payment of approximately $8.3 million to acquire MC Squared (see Note 19 of Notes to **DPL's** Consolidated Financial Statements). Additionally, **DPL** redeemed $70.9 million of short-term investments mostly comprised of VRDN securities and purchased an additional $1.7 million of short-term investments during the same period. The VRDN securities have variable coupon rates that are typically re-set weekly relative to various short-term rate indices. **DPL** can tender these securities for sale upon notice to the broker and receive payment for the tendered securities within seven days.

For the year ended December 31, 2010, **DP&L** continued to see reductions in its environmental capital expenditures due to the completion of FGD and SCR projects including the FGD and SCR equipment completed and placed into service at Conesville during the fourth quarter of 2009. Approximately $4.2 million of the environmental capital expenditures incurred during 2010 relate to the construction of a solar energy facility at Yankee station. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment. Additionally, **DPL** purchased $54.2 million of VRDN securities, net of redemptions from various institutional securities brokers as well as $15.1 million of investment-grade fixed income corporate bonds. The VRDN securities are backed by irrevocable letters of credit. These securities have variable coupon rates that are typically re-set weekly relative to various short-term rate indices. **DPL** can tender these VRDN securities for sale upon notice to the broker and receive payment for the tendered securities within seven days.

For the year ended December 31, 2009, **DP&L** continued to see reductions in its environmental-related capital expenditures due to the completion of FGD and SCR projects. The expenditures in 2009 relate to the construction of FGD and SCR equipment at the Conesville generation station which was substantially completed and placed into service during the fourth quarter of 2009. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment.

DP&L – Net Cash used for Investing Activities

DP&L's Net cash used for investing activities for the years ended December 31, 2011, 2010 and 2009 are summarized as follows:

$ in millions	**2011**	2010	2009
Environmental and renewable energy capital expenditures	**$ (11.8)**	$ (11.9)	$ (21.2)
Other plant-related asset acquisitions	**(192.7)**	(138.1)	(146.2)
Proceeds from liquidation of **DPL** *stock, held in trust*	**26.9**	-	-
Other	**1.0**	1.4	1.4
DP&L's *net cash used for investing activities*	**$ (176.6)**	$ (148.6)	$ (166.0)

For the year ended December 31, 2011, **DP&L's** environmental expenditures were primarily related to pollution control devices at our generation plants. Additionally, **DP&L** received proceeds of $26.9 million related to the liquidation of **DPL** stock held in the Master Trust.

For the year ended December 31, 2010, **DP&L** continued to see reductions in its environmental capital expenditures due to the completion of FGD and SCR projects including the FGD and SCR equipment completed and placed into service at Conesville during the fourth quarter of 2009. Approximately $4.2 million of the environmental capital expenditures incurred during 2010 relate to the construction of a solar energy facility at Yankee station. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment.

For the year ended December 31, 2009, **DP&L** continued to see reductions in its environmental-related capital expenditures due to the completion of FGD and SCR projects. The expenditures in 2009 relate to the construction of FGD and SCR equipment at the Conesville generation station which was substantially completed and placed into service during the fourth quarter of 2009. **DP&L** also continued to make upgrades and other investments in other generation, transmission and distribution equipment.

DPL – Net Cash used for Financing Activities
DPL's Net cash used for financing activities for the years ended December 31, 2011, 2010 and 2009 can be summarized as follows:

$ in millions	Combined Year ended December 31, 2011	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Dividends paid on common stock	$ (176.0)	$ (63.0)	$ (113.0)	$ (139.7)	$ (128.8)
Retirement of long-term debt	(297.5)	-	(297.5)	-	(175.0)
Early redemption of long-term debt, including premium	(134.2)	-	(134.2)	-	(56.1)
Payment of MC Squared debt	(13.5)	-	(13.5)	-	-
Repurchase of DPL common stock	-	-	-	(56.4)	(64.4)
Repurchase of warrants	-	-	-	-	(25.2)
Issuance of long-term debt	425.0	125.0	300.0	-	-
Proceeds from liquidation of DPL stock, held in trust	26.9	26.9	-	-	-
Proceeds from exercise of warrants	14.7	-	14.7	-	77.7
Cash withdrawn from restricted funds	-	-	-	-	14.5
Other	3.0	-	3.0	1.6	9.7
Net cash used for financing activities	$ (151.6)	$ 88.9	$ (240.5)	$ (194.5)	$ (347.6)

For the year ended December 31, 2011, **DPL** paid common stock dividends of $176.0 million and retired long-term debt of $297.5 million. Additionally, **DPL** paid $134.2 million for its purchase of a portion of the DPL Capital Trust II capital securities, of which $122.0 million related to the capital securities and an additional $12.2 million related to the premium paid on the purchase. **DPL** also paid down the debt of MC Squared which was acquired in February 2011 (see Note 19 of Notes to **DPL's** Consolidated Financial Statements). **DPL** received $425.0 million from the issuance of additional debt. **DPL** received $26.9 million upon the liquidation of **DPL** stock held in the **DP&L** Master Trust and $14.7 million from the exercise of 700,000 warrants.

For the year ended December 31, 2010, **DPL** paid common stock dividends of $139.7 million. In addition, under the stock repurchase programs approved by the Board of Directors in October 2009 and October 2010 (see Note 14 of Notes to **DPL's** Consolidated Financial Statements), **DPL** repurchased approximately 2.18 million **DPL** common shares for $56.4 million.

For the year ended December 31, 2009, **DPL** redeemed long-term debt totaling $227.4 million and paid common stock dividends of $128.8 million. Under a stock repurchase program approved by the Board of Directors in October 2009 (see Note 14 of Notes to **DPL's** Consolidated Financial Statements), **DPL** repurchased approximately 2.4 million **DPL** common shares for $64.4 million. In addition, **DPL** repurchased 8.6 million warrants for $25.2 million. **DPL's** cash inflows during the period include $77.7 million received from the cash exercise of 3.7 million warrants and the withdrawal of the remaining balance of restricted funds of $14.5 million which was used primarily to fund the construction of FGD equipment at the Conesville generation station. **DPL** also received $9.0 million from option holders who exercised stock options.

DP&L – Net Cash used for Financing Activities
DP&L's Net cash used for financing activities for the years ended December 31, 2011, 2010 and 2009 can be summarized as follows:

$ in millions	**2011**	2010	2009
Dividends paid on common stock to parent	**$ (220.0)**	$ (300.0)	$ (325.0)
Cash contribution from parent	**20.0**	-	-
Cash withdrawn from restricted funds	-	-	14.5
Other	**(1.0)**	(0.9)	(0.9)
Net cash used for financing activities	**$ (201.0)**	$ (300.9)	$ (311.4)

For the year ended December 31, 2011, **DP&L's** Net cash used for financing activities primarily relates to $220 million in dividends offset by $20 million of additional capital contributed by **DPL**.

For the year ended December 31, 2010, **DP&L's** *Net cash used for financing activities primarily relates to* $300 million in dividends.

For the year ended December 31, 2009, **DP&L** paid $325 million in dividends to **DPL** and withdrew the remaining balance of $14.5 million from restricted funds to pay for the Conesville FGD and SCR projects.

Liquidity

We expect our existing sources of liquidity to remain sufficient to meet our anticipated obligations. Our business is capital intensive, requiring significant resources to fund operating expenses, construction expenditures, scheduled debt maturities, taxes, interest and dividend payments. For 2012 and subsequent years, we expect to satisfy these requirements with a combination of cash from operations and funds from the capital markets as our internal liquidity needs and market conditions warrant. We also expect that the borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

At the *filing date of this annual report on Form* 10-K, **DP&L** has access to $400 *million of short-term financing* under two revolving credit facilities. The first facility, established in August 2011, is for $200 million and expires in August 2015 and has eight participating banks, with no bank having more than 22% of the total commitment. **DP&L** also has the option to increase the borrowing under the first facility by $50 million. The second facility, established in April 2010, is for $200 million and expires in April 2013. A total of five banks participate in this facility, with no bank having more than 35% of the total commitment. **DP&L** also has the option to increase the borrowing under the second facility by $50 million.

At the filing date of this annual report on Form 10-K, **DPL** has access to $125 million of short-term financing under a revolving credit *facility established in* August 2011. *This facility expires in August* 2014, and has seven participating banks with, no bank having more than 32% of the total commitment. In addition, **DPL** entered into a $425 million unsecured term loan agreement with a syndicated bank group in August 2011. This agreement is for a three year term expiring on August 24, 2014. The entire $425 million has been drawn under this facility.

$ in millions	Type	Maturity	Commitment	Amounts available as of December 31, 2011
DP&L	Revolving	August 2015	$ 200.0	$ 200.0
DP&L	Revolving	April 2013	200.0	200.0
DPL Inc.	Revolving	August 2014	125.0	125.0
			$ 525.0	$ 525.0

Each **DP&L** revolving credit facility has a $50 million letter of credit sublimit. The entire **DPL** revolving credit *facility amount is available for letter of credit issuances.* As of December 31, 2011 and through the date of filing this annual report on Form 10-K, there were no letters of credit issued and outstanding on the revolving credit facilities.

Cash and cash equivalents for **DPL** and **DP&L** amounted to $173.5 million and $32.2 million, respectively, at December 31, 2011. At that date, neither **DPL** nor **DP&L** had short-term investments.

On February 23, 2011, **DPL** purchased $122.0 million principal amount of DPL Capital Trust II 8.125% trust preferred securities. As part of this transaction, **DPL** paid a $12.2 million, or 10%, premium. Debt issuance costs *and unamortized debt discount associated with this transaction, totaling* $3.1 *million, were also recognized in* February 2011.

Capital Requirements

CONSTRUCTION ADDITIONS

$ in millions	Actual 2009	Actual 2010	Actual 2011	Projected 2012	Projected 2013	Projected 2014
DPL	$ 145	$ 151	$ 201	$ 240	$ 220	$ 240
DP&L	$ 144	$ 148	$ 199	$ 235	$ 215	$ 235

Planned construction additions for 2012 relate primarily to new investments in and upgrades to **DP&L's** power plant 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.

DPL, through its subsidiary **DP&L**, is projecting to spend an estimated $700.0 million in capital projects for the period 2012 through 2014. Approximately $13.0 million of this projected amount is to enable **DP&L** to meet the recently revised reliability standards of NERC. **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 $47.0 million within the next 5 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

As mentioned above, **DPL** has access to $125 million of short-term financing under its revolving credit facility and has borrowed $425 million under its term loan facility. Each of these facilities has two financial covenants. The first financial covenant requires **DPL's** total debt to total capitalization ratio to not exceed 0.70 to 1.00. The second financial covenant requires **DPL's** consolidated earnings before interest, taxes, depreciation and amortization (EBITDA) to consolidated interest charge ratio to be not less than 2.50 to 1.00. As of December 31, 2011 the first covenant was met with a ratio of 0.55 to 1.00, and the second covenant was met with a ratio of 7.54 to 1.00. The debt to capitalization ratio is calculated as the sum of **DPL's** current and long-term portion of debt, including its guaranty obligations, divided by the total of **DPL's** shareholders' equity and total debt including guaranty obligations. The consolidated interest rate coverage 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.

Also mentioned above, **DP&L** has access to $400 million of short-term financing under its two revolving credit facilities. The following financial covenant is contained in each revolving credit facility: **DP&L's** total debt to total capitalization ratio is not to exceed 0.65 to 1.00. As of December 31, 2011, this covenant was met with a ratio of 0.41 to 1.00. The above ratio is calculated as the sum of **DP&L's** current and long-term portion of debt, including its guaranty obligations, divided by the total of **DP&L's** shareholders' equity and total debt including guaranty obligations.

Credit Ratings

Out cost of capital, access to capital markets and various provisions in our organizational and financing documents are tied to **DPL's** and **DP&L's** credit ratings. Downgrades in **DPL's** or **DP&L's** credit ratings could have an adverse effect on our cost of capital and could result in a requirement for us to post additional credit assurances for commodity derivatives as certain derivative instruments require us to post collateral or provide other credit assurances based on credit ratings.

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

	DPL *(a)*	**DP&L** *(b)*	Outlook	Effective
Fitch Ratings	BB+	BBB+	Stable	November 2011
Moody's Investors Service	Ba1	A3	Stable	November 2011
Standard & Poor's Corp.	BB+	BBB+	Stable	November 2011

(a) Credit rating relates to ***DPL's*** *Senior Unsecured debt.*
(b) Credit rating relates to ***DP&L's*** *Senior Secured debt.*

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, 2011, **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, 2011, **DPL** had $54.4 million of guarantees to third parties for future financial or performance assurance under such agreements, on behalf of DPLE, DPLER and MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover present and future obligations of DPLE, DPLER 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 $0.1 million at December 31, 2011 and $1.7 million at December 31, 2010.

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. As of December 31, 2011, **DP&L** could be responsible for the repayment of 4.9%, or $65.3 million, of a $1,332.3 million debt obligation that matures in 2026. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2011, we have no knowledge of such a default.

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, 2011, these include:

		Payment Due			
$ in millions	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
DPL:					
Long-term debt	$ 2,599.1	$ 0.4	$ 895.6	$ 450.2	$ 1,252.9
Interest payments	1,171.2	138.6	243.9	203.5	585.2
Pension and postretirement payments	261.1	25.6	50.8	52.1	132.6
Capital leases	0.7	0.3	0.4	-	-
Operating leases	1.5	0.5	0.8	0.2	-
Coal contracts (a)	818.6	233.4	265.6	162.6	157.0
Limestone contracts (a)	34.8	5.8	11.6	11.6	5.8
Purchase orders and other contractual obligations	71.3	57.5	7.8	6.0	-
Total contractual obligations	$ 4,958.3	$ 462.1	$ 1,476.5	$ 886.2	$ 2,133.5
DP&L:					
Long-term debt	$ 903.7	$ 0.4	$ 470.8	$ 0.2	$ 432.3
Interest payments	404.3	39.9	49.9	31.8	282.7
Pension and postretirement payments	261.1	25.6	50.8	52.1	132.6
Capital leases	0.7	0.3	0.4	-	-
Operating leases	1.5	0.5	0.8	0.2	-
Coal contracts (a)	818.6	233.4	265.6	162.6	157.0
Limestone contracts (a)	34.8	5.8	11.6	11.6	5.8
Purchase orders and other contractual obligations	71.3	57.5	7.8	6.0	-
Total contractual obligations	$ 2,496.0	$ 363.4	$ 857.7	$ 264.5	$ 1,010.4

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

Long-term debt:

DPL's Long-term debt as of December 31, 2011, consists of **DPL's** unsecured notes and unsecured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the Wright-Patterson Air Force Base debt facility. These long-term debt amounts include current maturities but exclude unamortized debt discounts and fair value adjustments.

DP&L's Long-term debt as of December 31, 2011, consists of its first mortgage bonds, tax-exempt pollution control bonds, capital leases and the Wright-Patterson Air Force Base debt facility. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 7 of Notes to **DPL's** Consolidated 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, 2011.

Pension and postretirement payments:

As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 9 of Notes to **DPL's** Consolidated Financial Statements. These estimated future benefit payments are projected through 2020.

Capital leases:

As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:

As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had several immaterial operating leases with various terms and expiration dates.

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 plants 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, 2011, **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 $25.0 million at December 31, 2011, 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 emissions and gas, 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 units, 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 unless they qualify for cash flow hedge accounting. 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 firm wholesale sales requirements for 2012 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 generation plant 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 certain transactions be cleared on exchanges that would necessitate the posting of cash collateral for these transactions. The Dodd-Frank Act provides a potential exception from these clearing and cash collateral requirements for commercial end-users. The Dodd-Frank Act requires the Commodity Futures Trading Commission to establish rules to implement the Dodd-Frank Act's requirements and exceptions. Requirements to post collateral could reduce the cost effectiveness of entering into derivative transactions to reduce commodity price and interest rate volatility or could increase the demands on our liquidity or require us to increase our levels of debt to enter into such derivative transactions. Even if we were to 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 counter-party 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.

A 10% increase or decrease in the market price of our wholesale power forward contracts and heating oil forwards at December 31, 2011 would not have a significant effect on Net income.

The following table provides information regarding the volume and average market price of our NYMEX coal forward derivative contracts at December 31, 2011 and the effect to Net income if the market price were to increase or decrease by 10%:

NYMEX Coal Forwards	Contract Volume (in millions of Tons)	Weighted Average Market Price (per Ton)	Increase / Decrease in Net Income (in millions) (a)
2012-Purchase	1.4	$ 70.37	$ 3.2
2013-Purchase	0.2	$ 70.37	$ 0.7
2014-Purchase	0.5	$ 74.11	$ 2.2

(a) The Net Income effect of a 10% change in the market price of NYMEX Coal has been partially off-set by our partners' share of the gain or loss associated with the jointly-owned power plants and also by the retail customers' share of the gain or loss which is deferred on the balance sheet in conjunction with the fuel and purchased power recovery rider.

Wholesale Revenues

Approximately 17% of **DPL's** and 35% of **DP&L's** electric revenues for the year ended December 31, 2011 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 18% of **DPL's** and 30% of **DP&L's** electric revenues for the year ended December 31, 2010 were from sales of excess energy and capacity in the wholesale market (**DP&L's** electric revenues in the wholesale market are reduced for sales to DPLER). Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

Approximately 17% of **DPL's** and 20% of **DP&L's** electric revenues for the year ended December 31, 2009 were from sales of excess energy and capacity in the wholesale market. Energy in excess of the needs of existing retail customers is sold in the wholesale market when we can identify opportunities with positive margins.

The table below provides the effect on annual Net income as of December 31, 2011, 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	$ 7.6	$ 6.6

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 which runs from June 1 to May 31, has conducted auctions for capacity through the 2014/15 delivery year. The clearing prices for capacity during the PJM delivery periods from 2010/11 through 2014/15 are as follows:

	PJM Delivery Year				
	2010/11	2011/12	2012/13	2013/14	2014/15
Capacity clearing price ($/MW-day)	$ 174	$ 110	$ 16	$ 28	$ 126

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

	Calendar Year				
	2010	2011	2012	2013	2014
Computed average capacity price ($/MW-day)	$ 144	$ 137	$ 55	$ 23	$ 85

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 as of December 31, 2011 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, 2011. As of December 31, 2011, approximately 43% 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 a $10/MW-day change in capacity auction pricing	$ 5.2	$ 3.9

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.

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, 2011 and 2010 were 37% and 43%, respectively. We have a significant portion of projected 2012 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 2012; 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 NOx allowances for 2012 depending on NOx 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 generation plant mix.

Purchased power costs depend, in part, upon the timing and extent of planned and unplanned outages of our generating capacity. 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.

Effective January 1, 2010, **DP&L** was allowed to recover its SSO retail customers' share of fuel and purchased power costs as part of the fuel rider approved by the PUCO. Since there has been an increase in customer switching, SSO customers currently represent approximately 43% of **DP&L's** total fuel costs. The table below provides the effect on annual net income as of December 31, 2011, of a hypothetical increase or decrease of 10% in the prices of fuel and purchased power, adjusted for the approximate 43% recovery:

$ in millions	DPL	DP&L
Effect of 10% change in fuel and purchased power	$ 19.9	$ 18.2

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 $425 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 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 7 and Note 18 of Notes to **DPL's** Consolidated Financial Statements.

We partially hedge against interest rate fluctuations by entering into interest rate swap agreements to limit the interest rate exposure on the underlying financing. As of December 31, 2011, we have entered into interest rate hedging relationships with an aggregate notional amount of $160 million related to planned future borrowing activities in calendar year 2013. The average interest rate associated with the $160 million aggregate notional amount interest rate hedging relationships is 3.8%. We are limiting our exposure to changes in interest rates since we believe the market interest rates at which we will be able to borrow in the future may increase.

As a result of the Merger with AES and the assumption by **DPL** of Merger-related debt, **DPL** and **DP&L's** credit ratings were downgraded by all three of the major credit rating agencies. We do not anticipate these reduced ratings having a significant impact on our liquidity; however, our cost of capital will increase.

The carrying value of **DPL's** debt was $2,629.3 million at December 31, 2011, consisting of **DPL's** unsecured notes and unsecured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the Wright-Patterson Air Force Base debt facility. 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, 2011 was $2,710.6 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 $ in millions	Years ending December 31, 2012	2013	2014	2015	2016	Thereafter	Carrying value at December 31, 2011 [(a)]	Fair value at December 31, 2011 [(a)]
Long-term debt								
Variable-rate debt	$ -	$ -	$ 425.0	$ -	$ -	$ 100.0	$ 525.0	$ 525.0
Average interest rate	0.0%	0.0%	2.3%	0.0%	0.0%	0.1%		
Fixed-rate debt	$ 0.4	$ 470.4	$ 0.2	$ 0.1	$ 450.1	$ 1,183.1	$ 2,104.3	$ 2,185.6
Average interest rate	4.9%	5.1%	5.2%	4.2%	6.5%	6.6%		
Total							$ 2,629.3	$ 2,710.6

[(a)] *Fixed rate debt totals include unamortized debt discounts.*

The carrying value of **DP&L's** debt was $903.4 million at December 31, 2011, consisting of its first mortgage bonds, tax-exempt pollution control bonds capital leases and the Wright-Patterson Air Force Base debt facility. The fair value of this debt was $934.5 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. Note that 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 $ in millions	Years ending December 31, 2012	2013	2014	2015	2016	Thereafter	Carrying value at December 31, 2011 [(a)]	Fair value at December 31, 2011 [(a)]
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%	0.1%		
Fixed-rate debt	$ 0.4	$ 470.4	$ 0.2	$ 0.1	$ 0.1	$ 332.2	$ 803.4	$ 834.5
Average interest rate	4.9%	5.1%	5.2%	4.2%	4.2%	4.8%		
Total							$ 903.4	$ 934.5

[(a)] *Fixed rate debt totals include unamortized debt discounts.*

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, 2011 and 2010 for which an immediate adverse market movement causes a potential material impact 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, 2011 and 2010, we did not hold any market risk sensitive instruments which were entered into for trading purposes.

DPL $ in millions	Carrying value at December 31, 2011	Fair value at December 31, 2011	One Percent Interest Rate Risk	Carrying value at December 31, 2010	Fair value at December 31, 2010	One Percent Interest Rate Risk
Long-term debt						
Variable-rate debt	$ 525.0	$ 525.0	$ 5.3	$ 100.0	$ 100.0	$ 1.0
Fixed-rate debt	2,104.3	2,185.6	21.9	1,224.1	1,207.5	12.1
Total	$ 2,629.3	$ 2,710.6	$ 27.2	$ 1,324.1	$ 1,307.5	$ 13.1

DP&L $ in millions	Carrying value at December 31, 2011	Fair value at December 31, 2011	One Percent Interest Rate Risk	Carrying value at December 31, 2010	Fair value at December 31, 2010	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	803.4	834.5	8.4	784.1	750.6	7.5
Total	$ 903.4	$ 934.5	$ 9.4	$ 884.1	$ 850.6	$ 8.5

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** $2,185.6 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 **DPL's** $525 million variable-rate long-term debt outstanding as of December 31, 2011.

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** $834.5 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 **DP&L's** $100.0 million variable-rate long-term debt outstanding as of December 31, 2011.

Equity Price Risk

As of December 31, 2011, approximately 30% of the defined benefit pension plan assets were comprised of investments in equity securities and 40% 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 $101.8 million at December 31, 2011. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $10.2 million reduction in fair value as of December 31, 2011 and approximately a $0.7 million increase to the 2011 pension expense.

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.

CRITICAL ACCOUNTING ESTIMATES

DPL's Consolidated Financial Statements and **DP&L's** Financial Statements are prepared in accordance with U.S. 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; 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.

Impairments and Assets Held for Sale: 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.

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.

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.

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 4 of Notes to **DPL's** Consolidated 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, property damage, and directors' and officers' liability. Insurance and Claims Costs on **DPL's** Consolidated Balance Sheets of **DPL** include estimated liabilities for insurance and claims costs of approximately $14.2 million and $10.1 million for 2011 and 2010, 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** record these additional insurance and claims costs of approximately $18.9 million and $19.0 million for 2011 and 2010, 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 based on a reasonable estimation of insured events occurring. 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 postretirement benefits in accordance with the provisions of GAAP relating to the accounting for pension and other postretirement 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 the Successor period in 2011 and continuing for 2012, we have decreased our long-term rate of return assumption from 8.00% to 7.00% for pension plan assets. We are maintaining our long-term rate of return assumption of 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 the Successor period and for 2012, we have decreased our assumed discount rate to 4.88% from 5.31% for pension and to 4.14% from 4.96% for postretirement 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 2012 pension expense of approximately $3.4 million. A one percent change in the discount rate for pension would result in an increase or decrease to the 2012 pension expense of approximately $1.2 million.

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 to the plans, if any. We provide postretirement 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 postretirement 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 18 of the DPL Inc. Notes to Consolidated 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 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.

Report of Independent Registered Public Accounting Firm

To the Board of Directors of DPL Inc.:

We have audited the accompanying Consolidated Balance Sheet of DPL Inc. as of December 31, 2011, and the related Consolidated Statements of Operations, Cash Flows, and Shareholders' Equity for the period from November 28, 2011 through December 31, 2011. Our audit also included the consolidated financial statement schedule listed in the index at Item 15(a). These consolidated financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and schedule based on our audit.

We conducted our audit 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 audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of DPL Inc. at December 31, 2011 and the consolidated results of its operations and its cash flows for the period from November 28, 2011 through December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
Cincinnati, Ohio
March 27, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors
DPL Inc.:

We have audited the accompanying consolidated balance sheet of DPL Inc. and its subsidiaries (DPL) as of December 31, 2010, and the related consolidated statements of results of operations, shareholders' equity and cash flows for each of the years ended December 31, 2010 and 2009, and the consolidated statements of results of operations, shareholders' equity and cash flows for the period from January 1, 2011 through November 27, 2011. In connection with our audits of the financial statements, we also have audited the financial statement schedule, "Schedule II – Valuation and Qualifying Accounts" for each of the years ended December 31, 2010 and 2009 and for the period from January 1, 2011 through November 27, 2011. These financial statements are the responsibility of DPL's management. Our responsibility is to express an opinion on these financial statements 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of DPL as of December 31, 2010, and the results of its operations and its cash flows for each of the years ended December 31, 2010 and 2009 and for the period from January 1, 2011 through November 27, 2011, 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/ KPMG LLP

Philadelphia, Pennsylvania
March 27, 2012

DPL INC.
CONSOLIDATED STATEMENTS OF RESULTS OF OPERATIONS

$ in millions except per share amounts	Successor: November 28, 2011 through December 31, 2011	Predecessor: January 1, 2011 through November 27, 2011	Predecessor: Years ended December 31, 2010	Predecessor: Years ended December 31, 2009
Revenues	$ 156.9	$ 1,670.9	$ 1,831.4	$ 1,539.4
Cost of revenues:				
Fuel	35.8	355.8	383.9	330.4
Purchased power	36.7	404.6	387.4	260.2
Amortization of intangibles	11.6	-	-	-
Total cost of revenues	84.1	760.4	771.3	590.6
Gross margin	72.8	910.5	1,060.1	948.8
Operating expenses:				
Operation and maintenance	47.5	377.8	340.6	306.5
Depreciation and amortization	11.6	129.4	139.4	145.5
General taxes	7.6	75.5	75.7	68.6
Total operating expenses	66.7	582.7	555.7	520.6
Operating income	6.1	327.8	504.4	428.2
Other income / (expense), net				
Investment income (loss)	0.1	0.4	1.8	(0.6)
Interest expense	(11.5)	(58.7)	(70.6)	(83.0)
Charge for early redemption of debt	-	(15.3)	-	-
Other income / (deductions)	(0.3)	(1.7)	(2.3)	(3.0)
Total other income / (expense), net	(11.7)	(75.3)	(71.1)	(86.6)
Earnings (loss) from operations before income tax	(5.6)	252.5	433.3	341.6
Income tax expense	0.6	102.0	143.0	112.5
Net income (loss)	$ (6.2)	$ 150.5	$ 290.3	$ 229.1
Average number of common shares outstanding (millions):				
Basic	N/A	114.5	115.6	112.9
Diluted	N/A	115.1	116.1	114.2
Earnings per share of common stock:				
Basic	N/A	$ 1.31	$ 2.51	$ 2.03
Diluted	N/A	$ 1.31	$ 2.50	$ 2.01
Dividends declared per share of common stock	N/A	$ 1.54	$ 1.21	$ 1.14

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

$ in millions except per share amounts	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Cash flows from operating activities:				
Net income / (loss)	$ (6.2)	$ 150.5	$ 290.3	$ 229.1
Adjustments to reconcile Net income to Net cash provided by operating activities:				
Depreciation and amortization	11.6	129.4	139.4	145.5
Amortization of other assets	11.6	-	-	-
Deferred income taxes	0.1	65.5	59.9	201.6
Charge for early redemption of debt	-	15.3	-	-
Changes in certain assets and liabilities:				
Accounts receivable	(12.3)	14.6	(1.5)	39.3
Inventories	(2.5)	(11.5)	10.4	(20.6)
Prepaid taxes	0.6	7.1	(9.0)	-
Taxes applicable to subsequent years	(71.2)	58.4	(4.1)	(1.5)
Deferred regulatory costs, net	0.1	(14.4)	21.8	(23.6)
Accounts payable	6.6	(0.6)	17.8	(65.0)
Accrued taxes payable	78.5	(58.6)	1.2	(2.4)
Accrued interest payable	6.4	(8.1)	(5.1)	(1.5)
Pension, retiree and other benefits	10.2	(34.2)	(58.2)	15.2
Unamortized investment tax credit	(0.2)	(2.3)	(2.8)	(2.8)
Insurance and claims costs	(0.1)	4.3	(6.1)	(1.4)
Other deferred debits, DPL stock held in trust	(26.9)	-	-	-
Other	(7.2)	10.1	10.2	12.8
Net cash provided by (used for) operating activities	(0.9)	325.5	464.2	524.7
Cash flows from investing activities:				
Capital expenditures	(30.5)	(174.2)	(152.7)	(172.3)
Proceeds from sale of property - other	-	-	-	1.2
Purchase of MC Squared	-	(8.3)	-	-
Purchases of short-term investments and securities	-	(1.7)	(86.4)	(20.7)
Sales of short-term investments and securities	-	70.9	17.1	25.7
Other investing activities, net	(0.4)	1.5	1.4	1.4
Net cash used for investing activities	(30.9)	(111.8)	(220.6)	(164.7)
Cash flows from financing activities:				
Dividends paid on common stock	(63.0)	(113.0)	(139.7)	(128.8)
Repurchase of DPL common stock	-	-	(56.4)	(64.4)
Repurchase of warrants	-	-	-	(25.2)
Proceeds from exercise of warrants	-	14.7	-	77.7
Proceeds from liquidation of DPL stock, held in trust	26.9	-	-	-
Retirement of long-term debt	-	(297.5)	-	(175.0)
Early redemption of Capital Trust II notes	-	(122.0)	-	(52.4)
Premium paid for early redemption of debt	-	(12.2)	-	(3.7)
Issuance of long-term debt	125.0	300.0	-	-
Payment of MC Squared debt	-	(13.5)	-	-
Withdrawal of restricted funds held in trust, net	-	-	-	14.5
Withdrawals from revolving credit facilities	-	50.0	-	260.0
Repayment of borrowings from revolving credit facilities	-	(50.0)	-	(260.0)
Exercise of stock options	-	1.6	1.4	9.0
Tax impact related to exercise of stock options	-	1.4	0.2	0.7
Net cash provided by (used for) financing activities	88.9	(240.5)	(194.5)	(347.6)
Cash and cash equivalents:				
Net change	57.1	(26.8)	49.1	12.4
Assumption of cash at acquisition	19.2	-	-	-
Balance at beginning of period	97.2	124.0	74.9	62.5
Cash and cash equivalents at end of period	$ 173.5	$ 97.2	$ 124.0	$ 74.9
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	6.0	62.0	77.1	84.3
Income taxes (refunded) / paid, net	-	25.6	87.1	(94.6)
Non-cash financing and investing activities:				
Accruals for capital expenditures	7.6	18.9	23.2	20.8
Long-term liability incurred for the purchase of plant assets	-	18.7	-	-
Assumption of debt with acquisition	1,250.0	-	-	-

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	Successor December 31, 2011	Predecessor December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 173.5	$ 124.0
Short-term investments	-	69.3
Accounts receivable, net (Note 3)	219.1	215.5
Inventories (Note 3)	125.8	112.6
Taxes applicable to subsequent years	76.5	63.7
Regulatory assets, current (Note 4)	20.2	22.0
Other prepayments and current assets	36.2	40.6
Total current assets	651.3	647.7
Property, plant and equipment:		
Property, plant and equipment	2,431.0	5,353.6
Less: Accumulated depreciation and amortization	(7.5)	(2,555.2)
	2,423.5	2,798.4
Construction work in process	152.3	119.7
Total net property, plant and equipment	2,575.8	2,918.1
Other non-current assets:		
Regulatory assets, non-current (Note 4)	177.8	167.0
Goodwill	2,489.3	-
Intangible assets, net of amortization (Note 6)	161.5	2.7
Other deferred assets	51.8	77.8
Total other non-current assets	2,880.4	247.5
Total Assets	$ 6,107.5	$ 3,813.3

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED BALANCE SHEETS

$ in millions	Successor December 31, 2011	Predecessor December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 7)	$ 0.4	$ 297.5
Accounts payable	111.1	98.7
Accrued taxes	76.3	68.1
Accrued interest	30.2	18.4
Customer security deposits	15.9	18.7
Regulatory liabilities, current (Note 4)	0.6	10.0
Other current liabilities	56.1	43.2
Total current liabilities	290.6	554.6
Non-current liabilities:		
Long-term debt (Note 7)	2,628.9	1,026.6
Deferred taxes (Note 8)	549.4	623.1
Regulatory liabilities, non-current (Note 4)	118.6	114.0
Pension, retiree and other benefits	47.5	64.9
Unamortized investment tax credit	3.6	32.4
Insurance and claims costs	14.2	10.1
Other deferred credits	205.6	146.2
Total non-current liabilities	3,567.8	2,017.3
Redeemable preferred stock of subsidiary	18.4	22.9
Commitments and contingencies (Note 18)		
Common shareholders' equity:		
Common stock:		

	Successor No par value December 2011	Predecessor Par value $0.01 December 2010
Shares authorized	1,500	250,000,000
Shares issued	1	163,724,211
Shares outstanding	1	116,924,844

	Successor December 31, 2011	Predecessor December 31, 2010
Common stock	-	1.2
Other paid-in capital	2,237.3	-
Warrants	-	2.7
Common stock held by employee plans	-	(12.5)
Accumulated other comprehensive loss	(0.4)	(18.9)
Retained earnings / (deficit)	(6.2)	1,246.0
Total common shareholders' equity	2,230.7	1,218.5
Total Liabilities and Shareholders' Equity	$ 6,107.5	$ 3,813.3

See Notes to Consolidated Financial Statements.

DPL INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

in millions (except Outstanding Shares)	Common Stock (b) Outstanding Shares	Common Stock (b) Amount	Warrants	Common Stock Held by Employee Plans	Accumulated Other Comprehensive Income / (Loss)	Other Paid-in Capital	Retained Earnings	Total
Beginning balance	115,961,880	$ 1.2	$ 31.0	$ (27.6)	$ (23.1)	$ -	$ 1,015.6	$ 997.1
2009 (Predecessor):								
Net income							229.1	
Change in unrealized gains (losses) on financial instruments, net of tax					0.5			
Change in deferred gains (losses) on cash flow hedges, net of tax					(3.7)			
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					(2.7)			
Total comprehensive income								223.2
Common stock dividends (a)							(128.8)	(128.8)
Repurchase of warrants			(13.6)				(11.6)	(25.2)
Exercise of warrants	4,973,629		(14.5)				92.2	77.7
Treasury stock purchased	(2,388,391)						(64.4)	(64.4)
Treasury stock reissued	419,649						10.1	10.1
Tax effects to equity							0.8	0.8
Employee / Director stock plans				8.3			0.5	8.8
Other							0.6	0.6
Ending balance	118,966,767	$ 1.2	$ 2.9	$ (19.3)	$ (29.0)	$ -	$ 1,144.1	$ 1,099.9
2010 (Predecessor):								
Net income							290.3	
Change in unrealized gains (losses) on financial instruments, net of tax					0.4			
Change in deferred gains (losses) on cash flow hedges, net of tax					6.4			
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					3.3			
Total comprehensive income								300.4
Common stock dividends (a)							(139.7)	(139.7)
Repurchase of warrants			(0.2)					(0.2)
Exercise of warrants	18,288							-
Treasury stock purchased	(2,182,751)						(56.4)	(56.4)
Treasury stock reissued	122,540						2.4	2.4
Tax effects to equity							0.2	0.2
Employee / Director stock plans				6.8			5.1	11.9
Ending balance	116,924,844	$ 1.2	$ 2.7	$ (12.5)	$ (18.9)	$ -	$ 1,246.0	$ 1,218.5
January 1, 2011 through November 27, 2011 (Predecessor):								
Net income							150.5	
Change in unrealized gains (losses) on financial instruments, net of tax								
Change in deferred gains (losses) on cash flow hedges, net of tax					(58.5)			
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					3.2			
Total comprehensive income								95.2
Common stock dividends (a)							(176.0)	(176.0)
Repurchase of warrants			(1.1)					(1.1)
Exercise of warrants								
Treasury stock reissued	805,150						18.2	18.2
Tax effects to equity							1.4	1.4
Employee / Director stock plans				12.7			1.8	14.5
Other					(0.1)		(0.1)	(0.2)
Ending balance	117,729,994	$ 1.2	$ 1.6	$ 0.2	$ (74.3)	$ -	$ 1,241.8	$ 1,170.5
November 28, 2011 through December 31, 2011 (Successor):								
Capitalization at merger	1					$ 2,235.6	$ -	$ 2,235.6
Net income							(6.2)	
Change in unrealized gains (losses) on financial instruments, net of tax								
Change in deferred gains (losses) on cash flow hedges, net of tax					(0.5)			
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax					0.1			
Total comprehensive income								(6.6)
Contribution from Parent						1.7		1.7
Ending balance	1	$ -	$ -	$ -	$ (0.4)	$ 2,237.3	$ (6.2)	$ 2,230.7

(a) Common stock dividends per share were $1.14 in 2009, $1.21 per share in 2010 and $1.54 per share in 2011.
(b) $0.01 par value, 250,000,000 shares authorized.

See Notes to Consolidated Financial Statements.

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. Refer to Note 18 for more information relating to these reportable segments.

On November 28, 2011, **DPL** was acquired by AES in the Merger and **DPL** became a wholly-owned subsidiary of AES. See Note 2.

DP&L is a public utility incorporated in 1911 under the laws of Ohio. **DP&L** is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

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, which was acquired on February 28, 2011. DPLER has approximately 40,000 customers currently located throughout Ohio and Illinois. DPLER does not own any transmission or generation assets, and all of DPLER's electric energy was purchased from **DP&L** or PJM 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 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 1,510 people as of December 31, 2011, of which 1,468 employees were employed by **DP&L**. Approximately 53% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

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 plants 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 5 for more information.

Certain excise taxes collected from customers have been reclassified out of revenue and operating expenses in the 2010 and 2009 presentation to conform to AES' presentation of these items. Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

Deferred SECA revenue of $15.4 million at December 31, 2010 was reclassified from Regulatory liabilities to Other deferred credits. The balance of deferred SECA revenue at December 31, 2011 and 2010 was $17.8 million and $15.4 million, respectively. The amount at December 31, 2011 includes interest of $5.2 million. The FERC-approved SECA billings are unearned revenue where the earnings process is not complete and do not represent a potential overpayment by retail ratepayers or potential refunds of costs that had been previously charged to retail ratepayers through rates. Therefore, any amounts that are ultimately collected related to these charges would not be a reduction to future rates charged to retail ratepayers and therefore do not meet the criteria for recording as a regulatory liability under GAAP.

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; 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.

On November 28, 2011, AES completed the Merger with **DPL**. As a result of the Merger, **DPL** is a wholly-owned, subsidiary of AES. **DPL's** basis of accounting incorporates the application of FASC 805, "Business Combinations" (FASC 805) as of the date of the Merger. FASC 805 requires the acquirer to recognize and measure identifiable assets acquired and liabilities assumed at fair value as of the Merger date. **DPL's** Consolidated Financial Statements and accompanying footnotes have been segregated to present pre-merger activity as the "Predecessor" Company and post-merger activity as the "Successor" Company. Purchase accounting impacts, including goodwill recognition, have been "pushed down" to **DPL**, resulting in the assets and liabilities of **DPL** being recorded at their respective fair values as of November 28, 2011 (see Note 2). These adjustments are subject to change as AES finalizes its purchase price allocation during the applicable measurement period.

As a result of the push down accounting, **DPL's** Consolidated Statements of Operations subsequent to the Merger include amortization expense relating to purchase accounting adjustments and depreciation of fixed assets based upon their fair value. Therefore, the **DPL** financial data prior to the Merger will not generally be comparable to its financial data subsequent to the Merger. See Note 2 for additional information.

DPL remeasured the carrying amount of all of its assets and liabilities to fair value, which resulted in the recognition of approximately $2,489.3 million 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.

As part of the purchase accounting, values were assigned to various intangible assets, including customer relationships, customer contracts and the value of our electric security plan. See Note 6 for more information.

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 plants is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. These power sales and purchases 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.

Property, Plant and Equipment
We record our ownership share of our undivided interest in jointly-held plants 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 $0.5 million, $3.9 million, $3.4 million and $3.1 million in the period from November 28, 2011 through December 31, 2011, the period January 1, 2011 through November 27, 2011, and the years ended December 31, 2010 and 2009, 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 plant 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 Study – Change in Estimate
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. In July 2010, **DPL** completed a depreciation rate study for non-regulated generation property based on its property, plant and equipment balances at December 31, 2009, with certain adjustments for subsequent property additions. The results of the depreciation study concluded that many of **DPL's** composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. **DPL** adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net reduction of depreciation expense. For the year ended December 31, 2011, the net reduction in depreciation expense amounted to $4.8 million ($3.1 million net of tax) compared to the prior year. On an annualized basis, the net reduction in depreciation expense is projected to be approximately $9.6 million ($6.2 million net of tax).

For **DPL's** generation, transmission, and distribution assets, straight-line depreciation is applied on an average annual composite basis using group rates that approximated 5.8% in 2011, 2.6% in 2010 and 2.7% in 2009.

The following is a summary of **DPL's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2011 and 2010:

	Successor		**Predecessor**	
$ in millions	**2011**	**Composite Rate**	2010	Composite Rate
Regulated:				
Transmission	**$ 189.5**	**4.8%**	$ 360.6	2.5%
Distribution	**803.0**	**5.8%**	1,256.5	3.4%
General	**26.3**	**13.1%**	79.6	3.7%
Non-depreciable	**59.7**	**N/A**	58.6	N/A
Total regulated	**$ 1,078.5**		$ 1,755.3	
Unregulated:				
Production / Generation	**$ 1,318.7**	**6.0%**	$ 3,543.6	2.3%
Other	**14.4**	**10.1%**	36.1	3.6%
Non-depreciable	**19.4**	**N/A**	18.6	N/A
Total unregulated	**$ 1,352.5**		$ 3,598.3	
Total property, plant and equipment in service	**$ 2,431.0**	**5.8%**	$ 5,353.6	2.6%

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 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.

The balance at November 28, 2011 has been adjusted to reflect the effect of the purchase accounting.

Changes in the Liability for Generation AROs

$ in millions		
2010 (Predecessor):		
Balance at January 1, 2010	$	16.2
Accretion expense		0.2
Additions		0.8
Settlements		(0.3)
Estimated cash flow revisions		0.6
Balance at December 31, 2010		17.5
January 1, 2011 through November 27, 2011 (Predecessor):		
Accretion expense		0.8
Additions		-
Settlements		(0.4)
Estimated cash flow revisions		0.9
Balance at November 27, 2011	$	18.8
November 28, 2011 through December 31, 2011 (Successor):		
Balance at November 28, 2011	$	23.6
Accretion expense		-
Additions		-
Settlements		(0.1)
Estimated cash flow revisions		0.1
Balance at December 31, 2011	$	23.6

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 $112.4 million and $107.9 million in estimated costs of removal at December 31, 2011 and 2010, 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 4 for additional information.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

$ in millions		
2010 (Predecessor):		
Balance at January 1, 2010	$	99.1
Additions		11.2
Settlements		(2.4)
Balance at December 31, 2010		107.9
January 1, 2011 through November 27, 2011 (Predecessor):		
Additions		8.6
Settlements		(4.3)
Balance at November 27, 2011	$	112.2
November 28, 2011 through December 31, 2011 (Successor):		
Balance at November 28, 2011	$	112.2
Additions		0.8
Settlements		(0.6)
Balance at December 31, 2011	$	112.4

Regulatory Accounting
In accordance with GAAP, Regulatory assets and liabilities are recorded in the balance sheets for our regulated transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and Regulatory liabilities represent current recovery of expected future costs.

We evaluate our Regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain Regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator. If we were required to terminate application of these GAAP provisions for all of our regulated operations, we would have to write off the amounts of all Regulatory assets and liabilities to the Statements of Results of Operations at that time. See Note 4.

Effective November 28, 2011, Regulatory assets and liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of 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 the value of our ESP. Emission allowances are carried on a first-in, first-out (FIFO) basis for purchased emission allowances. In addition, we recorded emission allowances at their fair value as of the Merger date. 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. During the years ended December 31, 2010 and 2009, **DP&L** recognized gains from the sale of emission allowances in the amounts of $0.8 million and $5.0 million, respectively. There were no gains in 2011. Beginning in January 2010, part of the gains on emission allowances were used to reduce the overall fuel rider charged to our SSO retail customers.

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. The ESP is amortized over one year on a straight-line basis. 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. See Note 6 for additional information.

Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy. The amounts for 2010 have been reclassified to reflect this change in presentation.

Income Taxes
GAAP 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. Deferred tax assets are recognized for deductible temporary differences. 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.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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 8 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.

Short-Term Investments
DPL, from time to time, utilizes VRDNs as part of its short-term investment strategy. The VRDNs are of high credit quality and are secured by irrevocable letters of credit from major financial institutions. VRDN investments have variable rates tied to short-term interest rates. Interest rates are reset every seven days and these VRDNs can be tendered for sale back to the financial institution upon notice. Although **DPL's** VRDN investments have original maturities over one year, they are frequently re-priced and trade at par. We account for these VRDNs as available-for-sale securities and record them as short-term investments at fair value, which approximates cost, since they are highly liquid and are readily available to support **DPL's** current operating needs.

DPL also utilizes investment-grade fixed income corporate securities in its short-term investment portfolio. These securities are accounted for as held-to-maturity investments.

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 Results of Operations.

Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, these taxes are accounted for on a net basis and recorded as a reduction in revenues. The amounts for the period November 28, 2011 through December 31, 2011, the period January 1, 2011 through December 31, 2011, and the years ended December 31, 2010 and 2009, $4.3 million, $49.4 million, $51.7 million and $49.5 million, respectively, were reclassified to conform to this presentation.

Share-Based Compensation
We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair-value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair-value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the Statements of Cash Flows within Cash flows from financing activities. See Note 12 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2011.

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.

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 and MTM accounting when the hedge or a portion of the hedge is not effective. See Note 11 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 to us, our subsidiaries and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. Insurance and claims costs on the Consolidated Balance Sheets of **DPL** include estimated liabilities for insurance and claims costs of approximately $14.2 million and $10.1 million for 2011 and 2010, 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 reserves for claims costs below certain coverage thresholds of third-party providers. We record these additional insurance and claims costs of approximately $18.9 million and $19.0 million for 2011 and 2010, 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 based on a reasonable estimation of insured events occurring and any payments related to those events. 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.

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 $0.5 million and $3.6 million at December 31, 2011 and 2010, respectively, is included in Other deferred assets within Other noncurrent assets. **DPL** also has a note payable to the Trust amounting to $19.5 million and $142.6 million at December 31, 2011 and 2010 that was established upon the Trust's deconsolidation in 2003. See Note 7 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

There were no newly adopted accounting standards during 2011.

Recently Issued Accounting Standards

Fair Value Disclosures
In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income
In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Goodwill Impairment
In September 2011, the FASB issued ASU 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 350, "Intangibles-Goodwill and Other." ASU 2011-08 allows an entity to first test Goodwill using qualitative factors to determine if it is more likely than not that the fair value of a reporting unit

has been impaired, then the two-step impairment test is not performed. We will incorporate these new requirements in any future goodwill impairment testing.

2. Business Combination

On November 28, 2011, AES completed its acquisition of **DPL**. AES paid cash consideration of approximately $3,483.6 million. The allocation of the purchase price was based on the estimated fair value of assets acquired and liabilities assumed. In addition, Dolphin Subsidiary II, Inc. (a wholly-owned subsidiary of AES) issued $1,250.0 million of debt, which, as a result of the merger of **DPL** and Dolphin Subsidiary II, Inc. was assumed by **DPL**.

Following is a summary of estimated fair value of assets acquired and liabilities assumed as of November 28, 2011 measured in accordance with FASC 805.

$ in millions	Fair value of assets acquired and liabilities assumed
Cash	$ 116.4
Accounts receivable	277.6
Inventory	123.7
Other current assets	41.0
Property, plant and equipment	2,548.5
Intangible assets subject to amortization	166.3
Intangible assets - indefinite-lived	5.0
Regulatory assets	201.1
Other non-current assets	58.3
Current liabilities	(400.2)
Debt	(1,255.1)
Deferred taxes	(558.2)
Regulatory liabilities	(117.0)
Other non-current liabilities	(194.7)
Redeemable preferred stock	(18.4)
Net identifiable assets acquired	994.3
Goodwill	2,489.3
Net assets acquired	$ 3,483.6

The carrying values of the majority of regulated assets and liabilities were determined to be stated at their estimate fair values at the Merger date based on a conclusion that individual assets are subject to regulation by the PUCO and the FERC. As a result, the future cash flows associated with the assets are limited to the carrying value plus a return, and management believes that a market participant would not expect to recover any more or less than the carrying value. Furthermore, management believes that the current rate of return on regulated assets is consistent with an amount that market participants would expect. FASC 805 requires that the beginning balance of fixed depreciable assets be shown net, with no accumulated amortization recorded, at the date of the Merger.

Property, plant and equipment were valued based on the discounted value of the estimated future cash flows to be generated from such assets.

Intangible assets include the fair value of customer relationships, customer contracts and **DP&L's** ESP based on a combination of the income approach, the market based approach and the cost approach.

The fair value of inventory consists primarily of two components: materials and supplies; and fuel and limestone. The estimated fair value at the Merger date was established using a variety of approaches to estimate the market price. The carrying value of fuel inventory was adjusted to its fair value by applying market cost at the Merger date.

Energy derivative contracts were reassessed and revalued at the Merger date based on forward market prices and forecasted energy requirements. The fair value assigned to the power contracts was determined using an income approach comparing the contract rate to the market rate for power over the remaining period of the contracts incorporating nonperformance risk. Management also incorporated certain assumptions related to quantities and market presentation that it believes market participants would make in the valuation. The fair value of the power contracts will be amortized as the contracts settle.

Other regulatory assets are costs that are being recovered or will be recovered through the ratemaking process and are valued at their expected recoverable amount.

The fair value assigned to long-term debt was determined by a third party pricing service's quoted price.

Redeemable preferred stock was valued based on the last price paid by a third party.

The Merger triggered a new basis of accounting for **DPL** for the postretirement benefit plans sponsored by **DPL** under FASC 805 which required remeasuring plan liabilities without the five year smoothing of market-related asset gains and losses.

During the periods January 1, 2011 through November 27, 2011 and November 28, 2011 through December 31, 2011, **DPL** incurred pre-tax merger costs of $37.9 million and $15.7 million, respectively, primarily related to legal fees, transaction advisory services and change of control provisions. **DPL** does not anticipate significant merger related costs in 2012.

As a result of the Merger, **DPL** reclassified emission allowances and renewable energy credits to intangible assets and records certain excise and other taxes net as a reduction of revenue, consistent with AES' policies. All material prior period amounts have been reclassified to conform to this presentation.

3. Supplemental Financial Information

DPL Inc. $ in millions	**Successor** **At December 31, 2011**	**Predecessor** At December 31, 2010
Accounts receivable, net:		
Unbilled revenue	**$ 72.4**	$ 84.5
Customer receivables	**113.2**	113.9
Amounts due from partners in jointly-owned plants	**29.2**	7.0
Coal sales	**1.0**	4.0
Other	**4.4**	7.0
Provision for uncollectible accounts	**(1.1)**	(0.9)
Total accounts receivable, net	**$ 219.1**	$ 215.5
Inventories, at average cost:		
Fuel and limestone	**$ 84.2**	$ 73.2
Plant materials and supplies	**39.8**	38.8
Other	**1.8**	0.6
Total inventories, at average cost	**$ 125.8**	$ 112.6

4. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the consolidated balance sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery being reflected in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities are classified as current or non-current based on the term in which recovery is expected. Amounts at December 31, 2010 were reclassified to conform to the 2011 presentation.

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

$ in millions	Type of Recovery (a)	Amortization Through	Successor December 31, 2011	Predecessor December 31, 2010
Current Regulatory Assets:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	$ 4.7	$ 14.5
Power plant emission fees	C	Ongoing	4.8	6.6
Electric Choice systems costs	F	2011	-	0.9
Fuel and purchased power recovery costs	C	Ongoing	10.7	-
Total current regulatory assets			$ 20.2	$ 22.0
Non-current Regulatory Assets:				
Deferred recoverable income taxes	B/C	Ongoing	$ 24.1	$ 29.9
Pension benefits	C	Ongoing	92.1	81.1
Unamortized loss on reacquired debt	C	Ongoing	13.0	14.3
Regional transmission organization costs	D	2014	4.1	5.5
Deferred storm costs - 2008	D		17.9	16.9
CCEM smart grid and advanced metering infrastructure costs	D		6.6	6.6
CCEM energy efficiency program costs	F	Ongoing	8.8	4.8
Consumer education campaign	D		3.0	3.0
Retail settlement system costs	D		3.1	3.1
Other costs			5.1	1.8
Total non-current regulatory assets			$ 177.8	$ 167.0
Current Regulatory Liabilities:				
Fuel and purchased power recovery costs	C	Ongoing	-	10.0
Other	C	Ongoing	0.6	-
Total current regulatory liabilities			$ 0.6	$ 10.0
Non-current Regulatory Liabilities:				
Estimated costs of removal - regulated property			$ 112.4	$ 107.9
Postretirement benefits			6.2	6.1
Total non-current regulatory liabilities			$ 118.6	$ 114.0

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

Regulatory Assets

TCRR, transmission, ancillary and other PJM-related 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.

Power plant emission fees represent costs paid to the State of Ohio since 2002. As part of the fuel factor settlement agreement in November 2011, these costs are being recovered through the fuel factor.

Electric Choice systems costs represent costs incurred to modify the customer billing system for unbundled customer rates and electric choice utility bills relative to other generation suppliers and information reports provided to the state administrator of the low-income payment program. In March 2006, the PUCO issued an order that approved our tariff as filed. We began collecting this rider immediately and have recovered all costs.

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. **DP&L** implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. On October 6, 2011, **DP&L** and all of the active participants in this proceeding reached a Stipulation and Recommendation that resolves the majority of the issues raised related to the fuel audit. In November 2011, **DP&L** recorded a $25 million pretax ($16 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 costs is currently ongoing. The outcome of that audit is uncertain.

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.

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 other comprehensive income (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.

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.

Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case. In accordance with FERC precedence, we are amortizing these costs over a 10-year period that began in 2004 when we joined the PJM RTO.

Deferred storm costs – 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted **DP&L** the authority to defer these costs with a return until such time that **DP&L** seeks recovery in a future rate proceeding.

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.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs. The two-year true-up was approved by the PUCO and a new rate was set.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation and its related rate case.

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

Other costs primarily include RPM capacity, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

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.

5. *Ownership of Coal-fired Facilities*

DP&L and certain other Ohio utilities have undivided ownership interests in seven 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, 2011, **DP&L** had $48.0 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 Results 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 plant.

DP&L's undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings plant at December 31, 2011, is as follows:

	DP&L Share		**DP&L** Investment (adjusted to fair value at Merger date)			
	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)
Production Units:						
Beckjord Unit 6	50.0	207	$ -	$ -	$ -	No
Conesville Unit 4	16.5	129	-	-	2	Yes
East Bend Station	31.0	186	-	-	2	Yes
Killen Station	67.0	402	331	-	4	Yes
Miami Fort Units 7 and 8	36.0	368	239	1	2	Yes
Stuart Station	35.0	808	181	1	14	Yes
Zimmer Station	28.1	365	161	2	24	Yes
Transmission (at varying percentages)			34	-	-	
Total		2,465	$ 946	$ 4	$ 48	
Wholly-owned production unit:						
Hutchings Station	100.0	365	$ -	$ -	$ 2	No

Currently, our coal-fired generation units at Hutchings and Beckjord do not have the SCR and FGD emission-control equipment installed. **DP&L** owns 100% of the Hutchings plant and has a 50% interest in Beckjord Unit 6. On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2015. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. Beckjord Unit 6 was valued at zero at the

Merger date. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals are needed related to the Hutchings Station.

DPL revalued **DP&L's** investment in the above plants at the estimated fair value for each plant at the Merger date.

6. Goodwill and Other Intangible Assets

Goodwill at November 28, 2011 represents the value assigned at the Merger date. **DPL** had no goodwill recorded at December 31, 2010 and during the January 1, 2011 through November 27, 2011 predecessor period. Goodwill as of November 28, 2011 and December 31, 2011 was $2,489.3 million. **DPL** did not recognize any impairment losses related to goodwill during 2011.

The following tables summarize the balances comprising Intangible assets as of December 31, 2011:

$ in millions	December 31, 2011		
	Gross Balance	**Accumulated Amortization**	**Net Balance**
Subject to Amortization			
Electric Security Plan [a]	$ 88.0	$ (8.6)	$ 79.4
Customer contracts [b]	45.0	(3.0)	42.0
Customer relationships [c]	31.8	(0.5)	31.3
Other [d]	5.0	(1.2)	3.8
	169.8	(13.3)	156.5
Not subject to Amortization			
Tradmark/Trade name [e]	5.0	-	5.0
Total intangibles	$ 174.8	$ (13.3)	$ 161.5

The following table summarizes, by category, intangible assets acquired during the year ended December 31, 2011:

$ in millions	**Amount**	**Subject to Amortization/ Indefinite-lived**	**Weighted Average Amortization Period (years)**	**Amortization Method**
Electric security plan [a][f]	$ 88.0	Subject to amortization	1	Other
Customer contracts [b][f]	45.0	Subject to amortization	3	Other
Customer relationships [c]	31.8	Subject to amortization	12	Straight line
Other	2.3	Subject to amortization	Various	As Utilized
Trademark/Trade name [e]	5.0	Indefinite-lived	N/A	N/A
	$ 172.1			

(a) Represents the value of **DP&L's** Electric Security Plan which is a rate plan for the supply and pricing of electric generation services. It provides a level of price stability to consumers of electricity compared to market-based electricity prices.
(b) Represents above market contracts that DPLER has with third party customers existing as of the Merger date.
(c) 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 contract with DPLER.
(d) Consists of various intangible assets including renewable energy credits, emission allowances, and other intangibles, none of which are individually significant.
(e) Trademark/Trade name represents the value assigned to the trade name of DPLER.
(f) The amortization method used reflects the pattern in which the economic benefits of the intangible asset are consumed. Amortization of these intangible assets is shown as a reduction within gross margin on our Consolidated Statements of Results of Operations.

Most of the intangible assets acquired during the period disclosed above arose from the acquisition of **DPL** by AES (see Note 2 for more information). An immaterial amount of intangible assets was acquired by **DPL** through the acquisition of MC Squared Energy Services on February 28, 2011.

The following table summarizes the amortization expense, broken down by intangible asset category for 2012 through 2016:

	Estimated amortization expense				
$ in millions	2012	2013	2014	2015	2016
Electric security plan	$ 79.4	$ -	$ -	$ -	$ -
Customer contracts	32.0	8.6	1.4	-	-
Customer relationships	3.0	3.0	3.0	3.0	2.7
Other	-	0.3	0.2	0.2	-
	$ 114.4	$ 11.9	$ 4.6	$ 3.2	$ 2.7

7. Debt Obligations

Long-term Debt	**Successor**	**Predecessor**
$ in millions	**December 31, 2011**	December 31, 2010
First mortgage bonds maturing in October 2013 - 5.125%	**$ 503.6**	$ 470.0
Pollution control series maturing in January 2028 - 4.70%	**36.1**	35.3
Pollution control series maturing in January 2034 - 4.80%	**179.6**	179.1
Pollution control series maturing in September 2036 - 4.80%	**96.2**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.06% - 0.32% and 0.16% - 0.36% (a)	**100.0**	100.0
U.S. Government note maturing in February 2061 - 4.20%	**18.5**	-
	934.0	884.4
Obligation for capital lease	**0.4**	0.1
Unamortized debt discount	**-**	(0.5)
Total long-term debt at subsidiary	**934.4**	884.0
Bank Term Loan - variable rates: 1.48% - 4.25% (b)	**425.0**	-
Senior unsecured bonds maturing October 2016 - 6.50%	**450.0**	-
Senior unsecured bonds maturing October 2021 - 7.25%	**800.0**	-
Note to DPL Capital Trust II maturing in September 2031 - 8.125%	**19.5**	142.6
Total long-term debt	**$ 2,628.9**	$ 1,026.6

Current portion - Long-term Debt	**Successor**	**Predecessor**
$ in millions	**December 31, 2011**	December 31, 2010
U.S. Government note maturing in February 2061 - 4.20%	**$ 0.1**	$ -
Obligation for capital lease	**0.3**	0.1
Total current portion - long-term debt at subsidiary	**0.4**	0.1
Senior notes maturing in September 2011 - 6.875%	**-**	297.4
Total current portion - long-term debt	**$ 0.4**	$ 297.5

(a) *Range of interest rates for the twelve months ended December 31, 2011 and December 31, 2010, respectively.*

(b) *Range of interest rates since the loan was drawn in August 2011.*

The presentation above for the Successor is based on the revaluation of the debt at the Merger date.

At December 31, 2011, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	DPL
Due within one year	$ 0.4
Due within two years	470.4
Due within three years	425.2
Due within four years	0.1
Due within five years	450.1
Thereafter	1,252.9
	2,599.1
Unamortized adjustments to market value from purchase accounting	30.2
Total long-term debt	$ 2,629.3

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

On November 21, 2006, **DP&L** entered into a $220 million unsecured revolving credit agreement. This agreement was terminated by **DP&L** on August 29, 2011.

On December 4, 2008, the OAQDA issued $100 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 December 2013, 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, 2011 and 2010, respectively.

On April 20, 2010, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the period between April 20, 2010 and December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, **DP&L** had no outstanding letters of credit against the facility.

On February 23, 2011, **DPL** purchased $122.0 million principal amount of DPL Capital Trust II 8.125% capital securities in a privately negotiated transaction. As part of this transaction, **DPL** paid a $12.2 million, or 10%, premium. Debt issuance costs and unamortized debt discount totaling $3.1 million were also recognized in February 2011 associated with this transaction.

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. **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 August 24, 2011, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the five months ended December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, **DP&L** had no outstanding letters of credit against the facility.

On August 24, 2011, **DPL** entered into a $125 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on August 24, 2014. **DPL** had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the five months ended December 31, 2011. This facility may also be used to issue letters of credit up to the $125 million limit. As of December 31, 2011, **DPL** had no outstanding letters of credit against the facility.

On August 24, 2011, **DPL** entered into a $425 million unsecured term loan agreement with a syndicated bank group. This agreement is for a three year term expiring on August 24, 2014. **DPL** has borrowed the entire $425 million available under the facility at December 31, 2011. Fees associated with this term loan were not material during the five months ended December 31, 2011.

On September 1, 2011 **DPL** retired $297.4 million of 6.875% senior unsecured notes that had matured.

In connection with the closing of the Merger (see Note 2), **DPL** assumed $1.25 billion of debt that Dolphin Subsidiary II, Inc., a subsidiary of AES, issued on October 3, 2011 to finance a portion of the merger. The $1.25 *billion was issued in two tranches. The first tranche was $450 million of five year senior unsecured notes issued* at 6.50% maturing on October 15, 2016. The second tranche was $800 million of ten year senior unsecured notes issued at 7.25% maturing on October 15, 2021.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

8. Income Taxes

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

$ in millions	Successor November 28, 2011 through December 31, 2011	Predecessor January 1, 2011 through November 27, 2011	Predecessor Years ended December 31, 2010	Predecessor Years ended December 31, 2009
Computation of Tax Expense				
Federal income tax expense / (benefit) (a)	$ (2.0)	$ 88.4	$ 151.7	$ 119.9
Increases (decreases) in tax resulting from:				
State income taxes, net of federal effect	0.1	3.8	2.4	0.9
Depreciation of AFUDC - Equity	(0.3)	(2.9)	(2.2)	(2.0)
Investment tax credit amortized	(0.2)	(2.3)	(2.8)	(2.8)
Section 199 - domestic production deduction	-	(3.6)	(9.1)	(4.6)
Non-deductible merger costs	0.1	6.0	-	-
Non-deductible merger-related compensation	3.5	-	-	-
Derivatives	(0.1)	-	-	-
Compensation and benefits	-	13.8	0.4	(0.7)
Income not subject to tax	(0.6)	-	-	-
Other, net (b)	0.1	(1.2)	2.6	1.8
Total tax expense	$ 0.6	$ 102.0	$ 143.0	$ 112.5
Components of Tax Expense				
Federal - Current	$ 0.4	$ 53.2	$ 84.8	$ (84.4)
State and Local - Current	0.4	0.9	1.1	(1.8)
Total Current	$ 0.8	$ 54.1	$ 85.9	$ (86.2)
Federal - Deferred	$ (0.2)	$ 43.2	$ 55.9	$ 196.0
State and Local - Deferred	-	4.7	1.2	2.7
Total Deferred	$ (0.2)	$ 47.9	$ 57.1	$ 198.7
Total tax expense	$ 0.6	$ 102.0	$ 143.0	$ 112.5

Components of Deferred Tax Assets and Liabilities

$ in millions	Successor December 31, 2011	Predecessor December 31, 2010
Net Noncurrent Assets / (Liabilities)		
Depreciation / property basis	$ (490.7)	$ (618.6)
Income taxes recoverable	(8.6)	(10.3)
Regulatory assets	(25.1)	(12.4)
Investment tax credit	10.5	11.3
Intangibles	(57.5)	-
Compensation and employee benefits	(7.9)	21.0
Long-term debt	10.3	-
Other (c)	19.6	(14.1)
Net noncurrent (liabilities)	$ (549.4)	$ (623.1)
Net Current Assets / (Liabilities) (d)		
Other	$ 0.8	$ (1.1)
Net current assets	$ 0.8	$ (1.1)

(a) The statutory tax rate of 35% was applied to pre-tax earnings from continuing operations.

(b) Includes benefits of $2.3 million and $0.3 million, and an expense of $2.0 million in 2011, 2010 and 2009, respectively, of income tax related to adjustments from prior years.

(c) The Other noncurrent liabilities caption includes deferred tax assets of $15.4 million in 2011 and $13.1 million in 2010 related to state and local tax net operating loss carryforwards, net of related valuation allowances of $6.7 million in 2011 and $13.1 million in 2010. These net operating loss carryforwards expire from 2017 to 2026.

*(d) Amounts are included within Other prepayments and current assets on the Consolidated Balance Sheets of **DPL**.*

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

	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31,	
$ in millions			2010	2009
Expense / (benefit)	**$ (1.2)**	**$ (33.2)**	$ 5.8	$ (1.7)

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	
2009 (Predecessor):	
Balance at January 1, 2009	$ 1.9
Tax positions taken during prior periods	-
Tax positions taken during current period	20.6
Settlement with taxing authorities	(3.2)
Lapse of applicable statute of limitations	-
Balance at December 31, 2009	19.3
2010 (Predecessor):	
Tax positions taken during prior periods	(0.4)
Tax positions taken during current period	-
Settlement with taxing authorities	0.3
Lapse of applicable statute of limitations	0.2
Balance at December 31, 2010	19.4
January 1, 2011 through November 27, 2011 (Predecessor):	
Tax positions taken during prior periods	**2.0**
Tax positions taken during current period	**3.5**
Settlement with taxing authorities	**-**
Lapse of applicable statute of limitations	**-**
Balance at November 27, 2011	**$ 24.9**
November 28, 2011 through December 31, 2011 (Successor):	
Balance at November 28, 2011	**$ 24.9**
Tax positions taken during prior periods	**-**
Tax positions taken during current period	**0.1**
Settlement with taxing authorities	**-**
Lapse of applicable statute of limitations	**-**
Balance at December 31, 2011	**$ 25.0**

Of the December 31, 2011 balance of unrecognized tax benefits, $26.1 million is due to uncertainty in the timing of deductibility offset by $1.1 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet	Successor	Predecessor	
$ in millions	**December 31, 2011**	December 31, 2010	December 31, 2009
Liability / (asset)	**$ 0.9**	$ 0.3	$ (1.0)

Amounts in Statement of Operations	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	**January 1, 2011 through November 27, 2011**	Years ended December 31,	
$ in millions			2010	2009
Expense / (benefit)	**$ -**	**$ 0.6**	$ 0.4	$ (0.1)

Following is a summary of the tax years open to examination by major tax jurisdiction:

U.S. Federal – 2007 and forward
State and Local – 2005 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The examination is still ongoing and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

9. 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.

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 active and retired key executives. Benefits under this SERP have been frozen and no additional benefits can be earned. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 1, 2006. The Compensation Committee of the Board of Directors designates the eligible employees. Pursuant to the SEDCRP, we provide a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designate as hypothetical investment funds under the SEDCRP one or more of the investment funds provided under The Dayton Power and Light Company Employee Savings Plan. Each participant may change his or her hypothetical investment fund selection at specified times. If a participant does not elect a hypothetical investment fund(s), then we select the hypothetical investment fund(s) for such participant. We also have an unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. The unfunded liabilities for these agreements and the SEDCRP were $0.8 million and $1.8 million at December 31, 2011 and 2010, respectively. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December 2011. The SEDCRP continued and a contribution for 2011 was calculated in January 2012.

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. **DP&L** made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the period January 1, 2011 through November 27, 2011 and the year ended December 31, 2010, respectively.

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 at age 65. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

Regulatory assets and liabilities are recorded for the portion of the under- or over-funded obligations related to the transmission and distribution areas of our electric business and for 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. These regulatory assets and liabilities 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.

The following tables set forth our pension and postretirement benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2011 and 2010. 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 postretirement include both health and life insurance benefits.

$ in millions	Pension		
	Successor	**Predecessor**	
Change in Benefit Obligation	**November 28, 2011 through December 31, 2011**	**January 1, 2011 through November 27, 2011**	Year ended December 31, 2010
Benefit obligation at beginning of period	$ 365.0	$ 333.8	$ 323.9
Service cost	0.5	4.5	4.8
Interest cost	1.5	15.5	17.7
Plan amendments	-	7.2	-
Actuarial (gain) / loss	-	21.6	8.0
Benefits paid	(1.8)	(17.6)	(20.6)
Benefit obligation at end of period	365.2	365.0	333.8
Change in Plan Assets			
Fair value of plan assets at beginning of period	335.8	291.8	243.4
Actual return / (loss) on plan assets	1.9	21.2	28.6
Contributions to plan assets	-	40.4	40.4
Benefits paid	(1.8)	(17.6)	(20.6)
Fair value of plan assets at end of period	335.9	335.8	291.8
Funded status of plan	$ (29.3)	$ (29.2)	$ (42.0)

$ in millions	Postretirement		
	Successor	**Predecessor**	
Change in Benefit Obligation	**November 28, 2011 through December 31, 2011**	**January 1, 2011 through November 27, 2011**	Year ended December 31, 2010
Benefit obligation at beginning of period	$ 21.9	$ 23.7	$ 26.2
Service cost	-	0.1	0.1
Interest cost	0.1	0.9	1.2
Plan amendments	-	-	-
Actuarial (gain) / loss	(0.1)	(1.3)	(2.0)
Benefits paid	(0.2)	(1.8)	(2.0)
Medicare Part D Reimbursement	-	0.3	0.2
Benefit obligation at end of period	21.7	21.9	23.7
Change in Plan Assets			
Fair value of plan assets at beginning of period	4.5	4.8	5.0
Actual return / (loss) on plan assets	-	0.2	0.3
Contributions to plan assets	0.2	1.3	1.5
Benefits paid	(0.2)	(1.8)	(2.0)
Fair value of plan assets at end of period	4.5	4.5	4.8
Funded status of plan	$ (17.2)	$ (17.4)	$ (18.9)

$ in millions	Pension		Postretirement	
	Successor	**Predecessor**	**Successor**	**Predecessor**
	2011	*2010*	***2011***	*2010*
Amounts Recognized in the Balance Sheets at December 31				
Current liabilities	**$ (1.3)**	$ (0.4)	**$ (0.6)**	$ (0.6)
Noncurrent liabilities	**(27.9)**	(41.6)	**(16.6)**	(18.3)
Net asset / (liability) at December 31	**$ (29.2)**	$ (42.0)	**$ (17.2)**	$ (18.9)
Amounts Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost / (credit)	**$ 12.5**	$ 16.8	**$ 0.7**	$ 0.9
Net actuarial loss / (gain)	**78.7**	125.4	**(6.4)**	(7.6)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 91.2**	$ 142.2	**$ (5.7)**	$ (6.7)
Recorded as:				
Regulatory asset	**$ 91.2**	$ 80.0	**$ 0.5**	$ 0.5
Regulatory liability	**-**	-	**(6.2)**	(6.1)
Accumulated other comprehensive income	**-**	62.2	**-**	(1.1)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 91.2**	$ 142.2	**$ (5.7)**	$ (6.7)

The accumulated benefit obligation for our defined benefit pension plans was $355.5 million and $325.1 million at December 31, 2011 and 2010, respectively.

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

	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31,	
$ in millions			2010	2009
Service cost	$ 0.5	$ 4.5	$ 4.8	$ 3.6
Interest cost	1.5	15.5	17.7	18.1
Expected return on assets (a)	(2.0)	(22.5)	(22.4)	(22.5)
Amortization of unrecognized:				
Actuarial (gain) / loss	0.4	7.6	7.2	4.4
Prior service cost	0.1	2.0	3.7	3.4
Net periodic benefit cost before adjustments	$ 0.5	$ 7.1	$ 11.0	$ 7.0

(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 $317 million in 2011, $274 million in 2010, and $275 million in 2009.

Net Periodic Benefit Cost / (Income) - Postretirement

	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31,	
$ in millions			2010	2009
Service cost	$ -	$ 0.1	$ 0.1	$ -
Interest cost	0.1	0.9	1.2	1.5
Expected return on assets (a)	-	(0.3)	(0.3)	(0.4)
Amortization of unrecognized:				
Actuarial (gain) / loss	-	(1.0)	(1.1)	(0.7)
Prior service cost	(0.1)	0.1	0.1	0.1
Net periodic benefit cost / (income) before adjustments	$ -	$ (0.2)	$ -	$ 0.5

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

Pension	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31,	
$ in millions			2010	2009
Net actuarial (gain) / loss	$ -	$ (38.7)	$ 1.9	$ 5.3
Prior service cost / (credit)	-	(2.2)	-	7.2
Reversal of amortization item:				
Net actuarial (gain) / loss	(0.4)	(7.6)	(7.2)	(4.4)
Prior service cost / (credit)	(0.1)	(2.0)	(3.7)	(3.4)
Transition (asset) / obligation	-	-	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ (0.5)	$ (50.5)	$ (9.0)	$ 4.7
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ (0.5)	$ (43.4)	$ 2.0	$ 11.7

Postretirement	Successor	Predecessor		
	November 28, 2011 through December 31, 2011	January 1, 2011 through November 27, 2011	Years ended December 31,	
$ in millions			2010	2009
Net actuarial (gain) / loss	$ -	$ 0.2	$ (1.9)	$ 0.3
Prior service cost / (credit)	(0.1)	(0.1)	-	1.1
Reversal of amortization item:				
Net actuarial (gain) / loss	-	1.0	1.1	0.7
Prior service cost / (credit)	0.1	(0.1)	(0.1)	(0.1)
Transition (asset) / obligation	-	-	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ -	$ 1.0	$ (0.9)	$ 2.0
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	$ -	$ 0.8	$ (0.9)	$ 2.5

Estimated amounts that will be amortized from Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2012 are:

$ in millions	Pension	Postretiremen
Net actuarial (gain) / loss	$ 4.9	$ 0.1
Prior service cost / (credit)	1.6	(0.8)

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 the Successor period in 2011 and continuing in 2012, we have decreased our expected long-term rate of return on assets assumption from 8.00% to 7.00% for pension plan assets. We are maintaining our expected long-term rate of return on assets assumption at approximately 6.00% for postretirement benefit plan assets. These expected returns are based primarily on portfolio investment allocation. There can be no assurance of our ability to generate these rates of return in the future.

Our overall discount rate was evaluated in relation to the Hewitt Top Quartile Yield Curve which represents a portfolio of top-quartile AA-rated bonds used to settle pension obligations. Peer data and historical returns were also reviewed to verify the reasonableness and appropriateness of our discount rate used in the calculation of benefit obligations and expense.

The weighted average assumptions used to determine benefit obligations during 2011, 2010 and 2009 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate for obligations	**4.88%**	5.31%	5.75%	**4.17%**	4.96%	5.35%
Rate of compensation increases	**3.94%**	3.94%	4.44%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2011, 2010 and 2009 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate (Predecessor/Successor)	**5.31% / 4.88%**	5.75%	6.25%	**4.96% / 4.62%**	5.35%	6.25%
Expected rate of return on plan assets (Predecessor/Successor)	**8.00% / 7.00%**	8.50%	8.50%	**6.00% / 6.00%**	6.00%	6.00%
Rate of compensation increases (Predecessor/Successor)	**3.94% / 3.94%**	4.44%	5.44%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2011, 2010 and 2009 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligations		
	2011	2010	2009	**2011**	2010	2009
Pre - age 65						
Current health care cost trend rate	**8.50%**	9.50%	9.50%	**8.50%**	8.50%	9.50%
Year trend reaches ultimate (Predecessor/Successor)	**2018/2019**	2015	2014	**2019**	2018	2015
Post - age 65						
Current health care cost trend rate	**8.00%**	9.00%	9.00%	**8.00%**	8.00%	9.00%
Year trend reaches ultimate (Predecessor/Successor)	**2017/2018**	2014	2013	**2018**	2017	2014
Ultimate health care cost trend rate	**5.00%**	5.00%	5.00%	**5.00%**	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 postretirement benefit cost and the accumulated postretirement benefit obligation:

Effect of Change in Health Care Cost Trend Rate $ in millions	One-percent increase	One-percent decrease
Service cost plus interest cost	$ -	$ -
Benefit obligation	$ 0.9	$ (0.8)

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

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension		Postretirement	
2012	$	23.1	$	2.6
2013	$	22.7	$	2.5
2014	$	23.2	$	2.4
2015	$	23.8	$	2.2
2016	$	24.0	$	2.1
2017 - 2021	$	124.4	$	8.2

We expect to make contributions of $1.4 million to our SERP in 2012 to cover benefit payments. We also expect to contribute $2.3 million to our other postretirement benefit plans in 2012 to cover benefit payments.

The Pension Protection Act (the Act) of 2006 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 2011 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 104.37% and is estimated to be 104.37% until the 2012 status is certified in September 2012 for the 2012 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 30-80% for equity securities, 30-65% for fixed income securities, 0-10% for cash and 0-25% for alternative 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 types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011 (Successor)

Asset Category $ in millions	**Market Value at December 31, 2011**	**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	$ 16.2	$ -	$ 16.2	$ -
Large Cap Equity	54.5	-	54.5	-
International Equity	34.2	-	34.2	-
Total Equity Securities	104.9	-	104.9	-
Debt Securities (b)				
Emerging Markets Debt	-	-	-	-
Fixed Income	-	-	-	-
High Yield Bond	-	-	-	-
Long Duration Fund	130.8	-	130.8	-
Total Debt Securities	130.8	-	130.8	-
Cash and Cash Equivalents (c)				
Cash	28.0	28.0	-	-
Other Investments (d)				
Limited Partnership Interest	0.8	-	-	0.8
Common Collective Fund	71.4	-	-	71.4
Total Other Investments	72.2	-	-	72.2
Total Pension Plan Assets	$ 335.9	$ 28.0	$ 235.7	$ 72.2

(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.

(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. 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 and the proceeds received from the DPL Inc. Common Stock, which was cashed-out at $30/share. The fair value of cash equals its book value. (Subsequent to the measurement date, the proceeds from the DPL Inc. Common Stock were invested in the other various investments.)

(d) This category represents a private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner based on the performance of the individual companies. 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, 2010 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2010 (Predecessor)

Asset Category $ in millions	**Market Value at December 31, 2010**	**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	$ 15.2	$ -	$ 15.2	$ -
Large Cap Equity	49.4	-	49.4	-
DPL Inc. Common Stock	23.8	23.8	-	-
International Equity	31.5	-	31.5	-
Total Equity Securities	119.9	23.8	96.1	-
Debt Securities (b)				
Emerging Markets Debt	5.2	-	5.2	-
Fixed Income	39.0	-	39.0	
High Yield Bond	8.2	-	8.2	-
Long Duration Fund	58.9	-	58.9	-
Total Debt Securities	111.3	-	111.3	-
Cash and Cash Equivalents (c)				
Cash	0.4	0.4	-	-
Other Investments (d)				
Limited Partnership Interest	2.8	-	-	2.8
Common Collective Fund	57.4	-	-	57.4
Total Other Investments	60.2	-	-	60.2
Total Pension Plan Assets	$ 291.8	$ 24.2	$ 207.4	$ 60.2

(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 private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner based on the performance of the individual companies. 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 change in the fair value for the pension assets valued using significant unobservable inputs (Level 3) was due to the following:

Fair Value Measurements of Pension Assets Using Significant Unobservable Inputs (Level 3)

$ in millions	Limited *Partnership* Interest	Common *Collective* Fund
2010 (Predecessor):		
Beginning balance January 1, 2010	$ 3.1	$ 50.6
Actual return on plan assets:		
Relating to assets still held at the reporting date	0.1	0.8
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(0.4)	6.0
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2010	$ 2.8	$ 57.4
January 1, 2011 through November 27, 2011 (Predecessor):		
Beginning balance January 1, 2011	$ 2.8	$ 57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	(0.8)	(1.5)
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(1.1)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at November 27, 2011	0.9	71.3
November 28, 2011 through December 31, 2011 (Successor):		
Beginning balance November 28, 2011	$ 0.9	$ 71.3
Actual return on plan assets:		
Relating to assets still held at the reporting date	-	0.1
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(0.1)	-
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	$ 0.8	$ 71.4

The fair values of our other postretirement benefit plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2011 (Successor)

Asset Category $ in millions	*Market* Value at 12/31/11	*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)	$ 4.5	$ -	$ 4.5	$ -

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

The fair values of our other postretirement benefit plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2010 (Predecessor)

Asset Category $ in millions	**Market Value at 12/31/10**	**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)	$ 4.8	$ -	$ 4.8	$ -

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

10. 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, 2011 and 2010. See also Note 11 for the fair values of our derivative instruments.

	Successor		**Predecessor**	
	At December 31, 2011		At December 31, 2010	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
DPL				
Assets				
Money Market Funds	**$ 0.2**	**$ 0.2**	$ 1.6	$ 1.6
Equity Securities	**3.9**	**4.4**	3.8	4.4
Debt Securities	**5.0**	**5.5**	5.2	5.5
Multi-Strategy Fund	**0.3**	**0.2**	0.3	0.3
	9.4	**10.3**	10.9	11.8
Short-term Investments - VRDNs	**-**	**-**	54.2	54.2
Short-term Investments - Bonds	**-**	**-**	15.1	15.1
Total Short-term Investments	**-**	**-**	69.3	69.3
Total Assets	**9.4**	**10.3**	80.2	81.1
Liabilities				
Debt	**$ 2,629.3**	**$ 2,710.6**	$ 1,324.1	$ 1,307.5

Debt

The carrying value of **DPL's** debt was adjusted to fair value at the Merger date. The fair value of the debt at December 31, 2011 did not change substantially from the value at the Merger date. Unrealized gains or losses are not recognized in the financial statements as debt is presented at the carrying value established at the Merger date, 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 2013 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 immaterial unrealized gains and losses on the Master Trust assets in AOCI at December 31, 2011 and $0.9 million ($0.6 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2010.

Due to the liquidation of the **DPL Inc.** common stock held in the Master Trust, there is sufficient cash to cover the next twelve months of benefits payable to employees covered under the benefit plans covered by the trust. Therefore, no unrealized gains or losses are expected to be transferred to earnings since we will not need to sell any investments in the next twelve months.

Short-term Investments
DPL, from time to time, utilizes VRDNs as part of its short-term investment strategy. The VRDNs are of high credit quality and are secured by irrevocable letters of credit from major financial institutions. VRDN investments have variable rates tied to short-term interest rates. Interest rates are reset every seven days and these VRDNs can be tendered for sale upon notice back to the financial institution. Although **DPL's** VRDN investments have original maturities over one year, they are frequently re-priced and trade at par. We account for these VRDNs as available-for-sale securities and record them as short-term investments at fair value, which approximates cost, since they are highly liquid and are readily available to support **DPL's** current operating needs.

DPL also from time to time utilizes investment-grade fixed income corporate securities in its short-term investment portfolio. These securities are accounted for as held-to-maturity investments.

Net Asset Value (NAV) per Unit

The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2011 and 2010. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2011, **DPL** did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit (Successor)

$ in millions	Fair Value at December 31, 2011	*Unfunded* Commitments	*Redemption* Frequency
Money Market Fund (a)	$ 0.2	$ -	Immediate
Equity Securities (b)	4.4	-	Immediate
Debt Securities (c)	5.5	-	Immediate
Multi-Strategy Fund (d)	0.2	-	Immediate
Total	$ 10.3	$ -	

Fair Value Estimated Using Net Asset Value per Unit (Predecessor)

$ in millions	Fair Value at December 31, 2010	Unfunded Commitments	Redemption Frequency
Money Market Fund (a)	$ 1.6	$ -	Immediate
Equity Securities (b)	4.4	-	Immediate
Debt Securities (c)	5.5	-	Immediate
Multi-Strategy Fund (d)	0.3	-	Immediate
Total	$ 11.8	$ -	

(a) *This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(b) *This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(c) *This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

(d) *This category includes a mix of actively managed funds holding investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.*

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); or 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, 2011 and 2010.

The fair value of assets and liabilities at December 31, 2011 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

	Successor					
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
		Level 1	Level 2	Level 3		
$ in millions	Fair Value at December 31, 2011*	Based on Quoted Prices in Active Markets	Other Observable Inputs	Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2011
Assets						
Master Trust Assets						
Money Market Funds	$ 0.2	$ -	$ 0.2	$ -	$ -	$ 0.2
Equity Securities	4.4	-	4.4	-	-	4.4
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.2	-	0.2	-	-	0.2
Total Master Trust Assets	10.3	-	10.3	-	-	10.3
Derivative Assets						
FTRs	0.1	-	0.1	-	-	0.1
Heating Oil Futures	1.8	1.8	-	-	(1.8)	-
Forward Power Contracts	17.3	-	17.3	-	(1.0)	16.3
Total Derivative Assets	19.2	1.8	17.4	-	(2.8)	16.4
Short-term Investments - VRDNs	-	-	-	-	-	-
Short-term Investments - Bonds	-	-	-	-	-	-
Total Short-term investments	-	-	-	-	-	-
Total Assets	$ 29.5	$ 1.8	$ 27.7	$ -	$ (2.8)	$ 26.7
Liabilities						
Derivative Liabilities						
Interest Rate Hedge	$ (32.5)	$ -	$ (32.5)	$ -	$ -	$ (32.5)
Forward NYMEX Coal Contracts	(14.5)	-	(14.5)	-	10.8	(3.7)
Forward Power Contracts	(13.3)	-	(13.3)	-	5.6	(7.7)
Total Derivative Liabilities	(60.3)	-	(60.3)	-	16.4	(43.9)
Total Liabilities	$ (60.3)	$ -	$ (60.3)	$ -	$ 16.4	$ (43.9)

*Includes credit valuation adjustments for counterparty risk.

The fair value of assets and liabilities at December 31, 2010 measured on a recurring basis and the respective category within the fair value hierarchy for **DPL** was determined as follows:

	Predecessor					
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
		Level 1	Level 2	Level 3		
$ in millions	Fair Value at December 31, 2010*	Based on Quoted Prices in Active Markets	Other Observable Inputs	Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2010
Assets						
Master Trust Assets						
Money Market Funds	$ 1.6	$ -	$ 1.6	$ -	$ -	$ 1.6
Equity Securities (a)	4.4	-	4.4	-	-	4.4
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.3	-	0.3	-	-	0.3
Total Master Trust Assets	11.8	-	11.8	-	-	11.8
Derivative Assets						
FTRs	0.3	-	0.3	-	-	0.3
Heating Oil Futures	1.6	1.6	-	-	(1.6)	-
Interest Rate Hedge	20.7	-	20.7	-	-	20.7
Forward NYMEX Coal Contracts	37.5	-	37.5	-	(21.9)	15.6
Forward Power Contracts	0.2	-	0.2	-	(0.2)	-
Total Derivative Assets	60.3	1.6	58.7	-	(23.7)	36.6
Short-term Investments - VRDNs	54.2	-	54.2	-	-	54.2
Short-term Investments - Bonds	15.1	-	15.1	-	-	15.1
Total Short-term investments	69.3	-	69.3	-	-	69.3
Total Assets	$ 141.4	$ 1.6	$ 139.8	$ -	$ (23.7)	$ 117.7
Liabilities						
Derivative Liabilities						
Interest Rate Hedge	$ 6.6	$ -	$ 6.6	$ -	$ -	$ 6.6
Forward Power Contracts	3.1	-	3.1	-	(1.1)	2.0
Total Derivative Liabilities	9.7	-	9.7	-	(1.1)	8.6
Total Liabilities	$ 9.7	$ -	$ 9.7	$ -	$ (1.1)	$ 8.6

*Includes credit valuation adjustments for counterparty risk.

(a) DPL stock in the Master Trust was eliminated in consolidation.

We use the market approach to value our financial instruments. Level 1 inputs are used for derivative contracts such as heating oil futures. 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 financial transmission rights (where the quoted prices are from a relatively inactive market), 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). VRDNs and bonds are considered Level 2 because they are priced using recent transactions for similar assets. 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.

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. There were $1.0 million and $1.4 million of gross additions to our existing river structures and asbestos AROs during the twelve months ended December 31, 2011 and 2010. In addition, it was determined that a river structure would be retired earlier than previously estimated. This resulted in a partial reduction to the ARO liability of $0.8 million in 2010.

Cash Equivalents

DPL had $125.0 million and $29.9 million in money market funds classified as cash and cash equivalents in its Consolidated Balance Sheets at December 31, 2011 and 2010, respectively. The money market funds have quoted prices that are generally equivalent to par.

11. 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 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 asset and liability derivative positions with the same counterparty are netted on the balance sheet if we have a Master Netting Agreement with the counterparty. We also net any collateral posted or received against the corresponding derivative asset or liability position. 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 marked to market each reporting period.

At December 31, 2011, **DPL** had the following outstanding derivative instruments:

Successor

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	7.1	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	1,769.4	(1,739.5)	29.9
NYMEX-quality Coal Contracts*	Mark to Market	Tons	2,015.0	-	2,015.0
Interest Rate Swaps	Cash Flow Hedge	USD	160,000.0	-	160,000.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

At December 31, 2010, **DPL** had the following outstanding derivative instruments:

Predecessor

Commodity	Accounting Treatment	Unit	Purchases (in thousands)	Sales (in thousands)	Net Purchases/ (Sales) (in thousands)
FTRs	Mark to Market	MWh	9.0	-	9.0
Heating Oil Futures	Mark to Market	Gallons	6,216.0	-	6,216.0
Forward Power Contracts	Cash Flow Hedge	MWh	580.8	(572.9)	7.9
Forward Power Contracts	Mark to Market	MWh	195.6	(108.5)	87.1
NYMEX-quality Coal Contracts*	Mark to Market	Tons	4,006.8	-	4,006.8
Interest Rate Swaps	Cash Flow Hedge	USD	360,000.0	-	360,000.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

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 value of cash flow hedges as 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 enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure. During 2011, interest rate hedging relationships with a notional amount of $200.0 million settled resulting in **DPL** making a cash payment of $48.1 million ($31.3 million net of tax). As part of the Merger discussed in Note 2, **DPL** entered into a $425.0 million unsecured term loan agreement with a syndicated bank group on August 24, 2011, in part, to pay the approximately $297.4 million principal amount of **DPL's** 6.875% debt that was due in September 2011. The remainder was drawn for other corporate purposes. This agreement is for a three year term expiring on August 24, 2014. See Note 7 for further information. As a result, some of the forecasted transactions originally being hedged are probable of not occurring and therefore approximately $5.1 million ($3.3 million net of tax) has been reclassified to earnings during the period January 1, 2011 through November 27, 2011. Because the interest rate swap had already cash settled as of the Merger date, this hedge had no future value and was not valued as a part of the purchase accounting (See Note 2 for more information). We reclassify gains and losses on interest rate derivative hedges related to debt financings from AOCI into earnings in those periods in which hedged interest payments occur.

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

	Successor		Predecessor					
					Years ended December 31,			
	November 28, 2011 through December 31, 2011		January 1, 2011 through November 27, 2011		2010		2009	
$ in millions (net of tax)	Power	Interest Rate Hedge	Power	Interest Rate Hedge	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI*	$ -	$ -	$ (1.8)	$ 21.4	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2
Net gains / (losses) associated with current period hedging transactions	0.1	(0.6)	(1.2)	(57.0)	3.1	9.2	2.2	-
Net (gains) / losses reclassified to earnings								
Interest Expense	-	(0.2)	-	(2.3)	-	(2.5)	-	(2.5)
Revenues	0.1	-	1.1	-	(3.5)	-	(4.0)	-
Purchased Power	0.1	-	0.9	-	-	-	0.6	-
Ending accumulated derivative gain / (loss) in AOCI*	$ 0.3	$ (0.8)	$ (1.0)	$ (37.9)	$ (1.8)	$ 21.4	$ (1.4)	$ 14.7
Net gains / (losses) associated with the ineffective portion of the hedging transaction:								
Interest expense	-	(0.4)	-	5.1	-	-	-	-
Revenues	-	-	-	-	-	-	-	-
Portion expected to be reclassified to earnings in the next twelve months**	0.1	-						
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	36.0	21.0						

* Approximately $38.9 million of unrealized losses previously deferred into AOCI were removed as a result of purchase accounting. See Note 2 of Notes to Consolidated Financial Statements for further details of the preliminary purchase price allocation.

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

The following table shows the fair value and balance sheet classification of **DPL's** derivative instruments designated as hedging instruments at December 31, 2011 and 2010.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2011 (Successor)

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 1.5	$ (0.9)	Other current assets	$ 0.6
Forward Power Contracts in a Liability Position	(0.2)	-	Other current liabilities	(0.2)
Total short-term cash flow hedges	1.3	(0.9)		0.4
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.1	(0.1)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(2.6)	1.7	Other deferred credits	(0.9)
Interest Rate Hedges in a Liability Position	(32.5)	-	Other deferred credits	(32.5)
Total long-term cash flow hedges	(35.0)	1.6		(33.4)
Total cash flow hedges	$ (33.7)	$ 0.7		$ (33.0)

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2010 (Predecessor)

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in a Liability Position	$ (2.8)	$ 1.0	Other current liabilities	$ (1.8)
Interest Rate Hedges in a Liability Position	(6.6)	-	Other current liabilities	(6.6)
Total short-term cash flow hedges	(9.4)	1.0		(8.4)
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.2	(0.2)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(0.2)	0.1	Other deferred credits	(0.1)
Interest Rate Hedges in an Asset Position	20.7	-	Other deferred assets	20.7
Total long-term cash flow hedges	20.7	(0.1)		20.6
Total cash flow hedges	$ 11.3	$ 0.9		$ 12.2

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

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, 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 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 and the NYMEX-quality coal contracts 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 periods November 28, 2011 through December 31, 2011, January 1, 2011 through November 27, 2011, and the years ended December 31, 2010 and 2009.

November 28, 2011 through December 31, 2011 (Successor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (1.4)	$ (0.5)	$ -	$ (0.8)	$ (2.7)
Realized gain / (loss)	(1.2)	0.1	0.1	(0.9)	(1.9)
Total	$ (2.6)	$ (0.4)	$ 0.1	$ (1.7)	$ (4.6)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (0.3)	$ -	$ -	$ -	$ (0.3)
Regulatory (asset) / liability	(0.1)	(0.1)	-	-	(0.2)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	0.6	0.6
Purchased power	-	-	0.1	(2.3)	(2.2)
Fuel	(2.2)	(0.3)	-	-	(2.5)
O&M	-	-	-	-	-
Total	$ (2.6)	$ (0.4)	$ 0.1	$ (1.7)	$ (4.6)

January 1, 2011 through November 27, 2011 (Predecessor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (50.7)	$ 0.6	$ (0.2)	$ 0.8	$ (49.5)
Realized gain / (loss)	8.7	2.2	(0.6)	(2.7)	7.6
Total	$ (42.0)	$ 2.8	$ (0.8)	$ (1.9)	$ (41.9)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (25.9)	$ -	$ -	$ -	$ (25.9)
Regulatory (asset) / liability	(7.0)	0.1	-	-	(6.9)
Recorded in Income Statement: gain / (loss)					
Revenue	-	-	-	(3.8)	(3.8)
Purchased power	-	-	(0.8)	1.9	1.1
Fuel	(9.1)	2.5	-	-	(6.6)
O&M	-	0.2	-	-	0.2
Total	$ (42.0)	$ 2.8	$ (0.8)	$ (1.9)	$ (41.9)

For the Year Ended December 31, 2010 (Predecessor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 33.5	$ 2.8	$ (0.6)	$ 0.1	$ 35.8
Realized gain / (loss)	3.2	(1.6)	(1.5)	(0.1)	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 20.1	$ -	$ -	$ -	$ 20.1
Regulatory (asset) / liability	4.6	1.1	-	-	5.7
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	(2.1)	-	(2.1)
Fuel	12.0	0.1	-	-	12.1
O&M	-	-	-	-	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8

For the Year Ended December 31, 2009 (Predecessor)

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 4.1	$ 5.1	$ 0.8	$ (0.2)	$ 9.8
Realized gain / (loss)	1.1	(3.1)	(0.4)	-	(2.4)
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 1.8	$ -	$ -	$ -	$ 1.8
Regulatory (asset) / liability	1.5	(0.5)	-	-	1.0
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	0.4	(0.2)	0.2
Fuel	1.9	2.3	-	-	4.2
O&M	-	0.2	-	-	0.2
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4

The following tables show the fair value and balance sheet classification of **DPL**'s derivative instruments not designated as hedging instruments at December 31, 2011 and 2010.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2011 (Successor)

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.1	$ -	Other prepayments and current assets	$ 0.1
Forward Power Contracts in an Asset position	9.9	-	Other prepayments and current assets	9.9
Forward Power Contracts in a Liability position	(6.5)	2.6	Other current liabilities	(3.9)
NYMEX-Quality Coal Forwards in a Liability position	(8.3)	4.6	Other current liabilities	(3.7)
Heating Oil Futures in an Asset position	1.8	(1.8)	Other prepayments and current assets	-
Total short-term derivative MTM positions	(3.0)	5.4		2.4
Long-term Derivative Positions				
Forward Power Contracts in an Asset position	5.8	-	Other deferred assets	5.8
Forward Power Contracts in a Liability position	(4.0)	1.3	Other deferred credits	(2.7)
NYMEX-Quality Coal Forwards in a Liability position	(6.2)	6.2	Other deferred credits	-
Total long-term derivative MTM positions	(4.4)	7.5		3.1
Total MTM Position	$ (7.4)	$ 12.9		$ 5.5

[1]Includes credit valuation adjustment.
[2]Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2010 (Predecessor)

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.3	$ -	Other prepayments and current assets	$ 0.3
Forward Power Contracts in a Liability position	(0.1)	-	Other current liabilities	(0.1)
NYMEX-Quality Coal Forwards in an Asset position	14.0	(7.4)	Other prepayments and current assets	6.6
Heating Oil Futures in an Asset position	0.5	(0.5)	Other prepayments and current assets	-
Total short-term derivative MTM positions	14.7	(7.9)		6.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an Asset position	23.5	(14.5)	Other deferred assets	9.0
Heating Oil Futures in an Asset position	1.1	(1.1)	Other deferred assets	-
Total long-term derivative MTM positions	24.6	(15.6)		9.0
Total MTM Position	$ 39.3	$ (23.5)		$ 15.8

[1]Includes credit valuation adjustment.
[2]Includes counterparty and collateral netting.

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. Even though our debt has fallen below investment grade, our counterparties to the derivative instruments have not requested immediate payment or demanded immediate and ongoing full overnight collateralization of the MTM loss.

The aggregate fair value of **DPL's** derivative instruments that are in a MTM loss position at December 31, 2011 is $28.0 million. This amount is offset by $16.3 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 $4.0 million. If our debt is below investment grade, we could have to post collateral for the remaining $7.7 million.

12. Share-Based Compensation

In April 2006, **DPL's** shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of **DPL** common stock had been reserved for issuance under the EPIP.

As a result of the Merger with AES (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	**January 1, 2011 through November 27, 2011**	2010	2009
Restricted stock units	**$ -**	$ -	$ -
Performance shares	**2.4**	2.1	1.8
Restricted shares	**5.3**	1.7	0.7
Non-employee directors' RSUs	**0.6**	0.4	0.5
Management performance shares	**1.8**	0.5	0.7
Share-based compensation included in Operation and maintenance expense	**10.1**	4.7	3.7
Income tax expense / (benefit)	**(3.5)**	(1.6)	(1.3)
Total share-based compensation, net of tax	**$ 6.6**	$ 3.1	$ 2.4

Share-based awards issued in **DPL's** common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger Agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized the fair value of all awards on a straight-line basis over the requisite service periods, which were generally the vesting periods.

Expected Volatility – Our expected volatility assumptions were based on the historical volatility of **DPL** common stock. The volatility range captured the high and low volatility values for each award granted based on its specific terms.

Expected Life – The expected life assumption represented the estimated period of time from the grant date until the exercise date and reflected historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was based on the corresponding yield curve in effect at the time of the valuation for U.S. Treasury bonds having the same term as the expected life of the award, i.e., a five-year bond rate was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was based on **DPL's** current dividend rate, adjusted as necessary to capture anticipated dividend changes and the 12 month average **DPL** common stock price.

Expected Forfeitures – The forfeiture rate used to calculate compensation expense was based on **DPL's** historical experience, adjusted as necessary to reflect special circumstances.

Stock Options

In 2000, **DPL's** Board of Directors adopted and **DPL's** shareholders approved The DPL Inc. Stock Option Plan. With the approval of the EPIP in April 2006, no new awards were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Options:			
Outstanding at beginning of period	**351,500**	417,500	836,500
Granted	**-**	-	-
Exercised	**(75,500)**	(66,000)	(419,000)
Expired	**(276,000)**	-	-
Forfeited	**-**	-	-
Outstanding at end of period	**-**	351,500	417,500
Exercisable at end of period	**-**	351,500	417,500
Weighted average option prices per share:			
Outstanding at beginning of period	**$ 28.04**	$ 27.16	$ 24.64
Granted	**$ -**	$ -	$ -
Exercised	**$ 21.02**	$ 21.00	$ 21.53
Expired	**$ 29.42**	$ -	$ -
Forfeited	**$ -**	$ -	$ -
Outstanding at end of period	**$ -**	$ 28.04	$ 27.16
Exercisable at end of period	**$ -**	$ 28.04	$ 27.16

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	January 1, 2011 through November 27, 2011	2010	2009
Weighted-average grant date fair value of options granted during the period	$ -	$ -	$ -
Intrinsic value of options exercised during the period	$ 0.7	$ 0.5	$ 2.2
Proceeds from stock options exercised during the period	$ 1.6	$ 1.4	$ 9.0
Excess tax benefit from proceeds of stock options exercised	$ 0.2	$ 0.1	$ 0.7
Fair value of shares that vested during the period	$ -	$ -	$ -
Unrecognized compensation expense	$ -	$ -	$ -
Weighted average period to recognize compensation expense (in years)	-	-	-

Restricted Stock Units (RSUs)
RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
RSUs:			
Outstanding at beginning of period	-	3,311	10,120
Granted	-	-	-
Dividends	-	-	-
Exercised	-	(3,311)	(6,809)
Forfeited	-	-	-
Outstanding at end of period	-	-	3,311
Exercisable at end of period	-	-	-

Performance Shares
Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which **DPL** granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Performance Share activity was as follows (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Performance shares:			
Outstanding at beginning of year	**278,334**	237,704	156,300
Granted	**85,093**	161,534	124,588
Exercised	**(198,699)**	(91,253)	-
Expired	**(66,836)**	-	(36,445)
Forfeited	**(97,892)**	(29,651)	(6,739)
Outstanding at period end	**-**	278,334	237,704
Exercisable at period end	**-**	66,836	47,355

The following table reflects information about Performance Share activity during the period (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	January 1, 2011 through November 27, 2011	2010	2009
Weighted-average grant date fair value of performance shares granted during the period	**$ 2.2**	$ 2.9	$ 2.8
Intrinsic value of performance shares exercised during the period	**$ 6.0**	$ 2.5	$ -
Proceeds from performance shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of performance shares exercised	**$ 0.7**	$ -	$ -
Fair value of performance shares that vested during the period	**$ 4.7**	$ 1.6	$ 1.6
Unrecognized compensation expense	**$ -**	$ 2.4	$ 2.1
Weighted average period to recognize compensation expense (in years)	**-**	1.7	1.7

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the performance shares granted during the period:

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Expected volatility	**24.0%**	24.3%	22.8% - 23.3%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.4% - 5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	0.3% - 1.5%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of **DPL** Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all **DPL** common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

On September 17, 2009, the Board of Directors approved a two-part equity compensation award under the EPIP for certain of **DPL's** executive officers. The first part was a Restricted Share grant and the second part was a matching Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with **DPL** or a **DPL** subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase **DPL** common stock equal in value to up to two times their 2009 base salary. **DPL** matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by **DPL** is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with **DPL** or a **DPL** subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

The matching criteria were:

Value (Cost Basis) of Shares Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the Long-Term Incentive Plan (LTIP). These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Restricted shares:			
Outstanding at beginning of year	**219,391**	218,197	69,147
Granted	**67,346**	42,977	159,050
Exercised	**(286,737)**	(20,803)	(10,000)
Forfeited	**-**	(20,980)	-
Outstanding at period end	**-**	219,391	218,197
Exercisable at period end	**-**	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	**January 1, 2011 through November 27, 2011**	2010	2009
Weighted-average grant date fair value of restricted shares granted during the period	**$ 1.8**	$ 1.1	$ 4.2
Intrinsic value of restricted shares exercised during the period	**$ 8.6**	$ 0.4	$ 0.3
Proceeds from restricted shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of restricted shares exercised	**$ 0.5**	$ 0.1	$ -
Fair value of restricted shares that vested during the period	**$ 7.5**	$ 0.6	$ 0.3
Unrecognized compensation expense	**$ -**	$ 3.4	$ 4.3
Weighted-average period to recognize compensation expense (in years)	**-**	2.7	3.4

Non-Employee Director Restricted Stock Units

Under the EPIP, as part of their annual compensation for service to **DPL** and **DP&L**, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in **DPL** common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

The following table reflects information about Restricted Stock Unit activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Restricted stock units:			
Outstanding at beginning of year	**16,320**	20,712	15,546
Granted	**14,392**	15,752	20,016
Dividends accrued	**3,307**	2,484	1,737
Vested and exercised	**(34,019)**	(2,618)	(2,066)
Vested, exercised and deferred	**-**	(20,010)	(14,521)
Forfeited	**-**	-	-
Outstanding at period end	**-**	16,320	20,712
Exercisable at period end	**-**	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	**January 1, 2011 through November 27, 2011**	2010	2009
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	**$ 0.5**	$ 0.5	$ 0.5
Intrinsic value of non-employee Director RSUs exercised during the period	**$ 1.0**	$ 0.5	$ 0.4
Proceeds from non-employee Director RSUs exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of non-employee Director RSUs exercised	**$ -**	$ -	$ -
Fair value of non-employee Director RSUs that vested during the period	***$ 1.0***	*$ 0.6*	*$ 0.5*
Unrecognized compensation expense	**$ -**	$ 0.1	$ 0.1
Weighted-average period to recognize compensation expense (in years)	**-**	0.3	0.3

Management Performance Shares

Under the EPIP, the Board of Directors granted compensation awards for select management employees. The grants had a three year requisite service period and certain performance conditions during the performance period. The management performance shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Management Performance Share activity was as follows (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Management performance shares:			
Outstanding at beginning of year	**104,124**	84,241	39,144
Granted	**49,510**	37,480	48,719
Expired	**(31,081)**	-	-
Exercised	**(111,289)**	-	-
Forfeited	**(11,264)**	(17,597)	(3,622)
Outstanding at period end	**-**	104,124	84,241
Exercisable at period end	**-**	31,081	-

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the Management Performance Shares granted during the period:

	Predecessor		
		For the years ended December 31,	
	January 1, 2011 through November 27, 2011	2010	2009
Expected volatility	**24.0%**	24.3%	22.8%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	1.5%

The following table reflects information about Management Performance Share activity during the period (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

	Predecessor		
		For the years ended December 31,	
$ in millions	**January 1, 2011 through November 27, 2011**	2010	2009
Weighted-average grant date fair value of management performance shares granted during the period	**$ 1.3**	$ 0.9	$ 1.0
Intrinsic value of management performance shares exercised during the period	**$ 3.3**	$ -	$ -
Proceeds from management performance shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of management performance shares exercised	**$ -**	$ -	$ -
Fair value of management performance shares that vested during the period	**$ 2.7**	$ 0.9	$ -
Unrecognized compensation expense	**$ -**	$ 0.9	$ 1.0
Weighted-average period to recognize compensation expense (in years)	**-**	1.7	1.6

13. 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, 2011. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2011. The table below details the preferred shares outstanding at December 31, 2011:

				Successor	Predecessor
	Preferred Stock Rate	Redemption Price at December 31, 2011 ($ per share)	Shares Outstanding at December 31, 2011	Carrying Value[(a)] December 31, 2011 ($ in millions)	Carrying Value[(b)] December 31, 2010 ($ in millions)
DP&L Series A	3.75%	$ 102.50	93,280	$ 7.4	$ 9.3
DP&L Series B	3.75%	$ 103.00	69,398	5.6	7.0
DP&L Series C	3.90%	$ 101.00	65,830	5.4	6.6
Total			228,508	$ 18.4	$ 22.9

(a) Carrying value is fair value at Merger date - November 28, 2011.
(b) Carrying value is par value.

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. 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 affected **DP&L's** ability to pay cash dividends and, as of December 31, 2011, **DP&L's** retained earnings of $589.1 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 Results of Operations.

14. 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, 2011.

On October 27, 2010, the **DPL** Board of Directors approved a new Stock Repurchase Program that permitted **DPL** to repurchase up to $200 million of its common stock from time to time in the open market, through private transactions or otherwise. This 2010 Stock Repurchase Program was scheduled to run through December 31, 2013, but was suspended in connection with the Merger with The AES Corporation, discussed further in Note 2.

On October 28, 2009, the **DPL** Board of Directors approved a Stock Repurchase Program that permitted **DPL** to use proceeds from the exercise of **DPL** warrants by warrant holders to repurchase other outstanding **DPL** warrants or its common stock from time to time in the open market, through private transactions or otherwise. This 2009 Stock Repurchase Program was scheduled to run through June 30, 2012, but was suspended in connection with the Merger with The AES Corporation, discussed further in Note 2. In June 2011, 0.7 million warrants were exercised with proceeds of $14.7 million. Since the Stock Repurchase Program was suspended, the proceeds from the June 2011 exercise of warrants were not used to repurchase stock.

As a result of the Merger involving **DPL** and AES, the outstanding shares of **DPL** common stock were converted into the right to receive merger consideration of $30.00 per share. When the remaining warrants were exercised in March 2012, **DPL** paid the warrant holders an amount equal to $9.00 per warrant, which is the difference between the merger consideration of $30.00 per share of **DPL** common stock and the exercise price of $21.00 per share. This amount was recorded as a $9 million liability at the Merger date. At December 31, 2011, **DPL** had 1.0 million outstanding warrants which were exercised in March 2012.

Rights Agreement

DPL's Rights Agreement, dated as of September 25, 2001, with Computershare Trust Company, N.A. (the "Rights Agreement") expired in December 2011. The Rights Agreement attached one right to each common share outstanding at the close of business on December 31, 2001. The rights were separate from the common shares and had been exercisable at the exercise price of $130 per right in the event of certain attempted business combinations.

The Rights Agreement was amended as of April 19, 2011, to provide that neither the execution of the Merger Agreement nor the consummation of the transactions contemplated by the Merger Agreement would trigger the provisions of the Rights Agreement.

ESOP

During October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to **DP&L's** 401(k) retirement savings plan and certain other payments to eligible full-time employees. ESOP shares used to fund matching contributions to **DP&L's** 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the Plan entered into a $90 million loan agreement with **DPL** in order to purchase shares of **DPL** common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. The term loan agreement provided for principal and interest on the loan to be paid prior to October 9, 2007, with the right to extend the loan for an additional ten years. In

2007, the maturity date was extended to October 7, 2017. Effective January 1, 2009, the interest on the loan was amended to a fixed rate of 2.06%, payable annually. Dividends received by the ESOP were used to repay the principal and interest on the ESOP loan to **DPL**. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

During December 2011, the ESOP Plan was terminated and participant balances were transferred to one of the two **DP&L** sponsored defined contribution 401(k) plans. On December 5, 2011, the ESOP Trust paid the total outstanding principal and interest of $68 million on the loan with **DPL**, using the merger proceeds from **DPL** common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to zero from November 28, 2011 through December 31, 2011 (successor), $4.8 million from January 1, 2011 through November 27, 2011 (predecessor), $6.7 million in 2010 and $4.0 million in 2009.

For purposes of EPS computations and in accordance with GAAP, we treated ESOP shares as outstanding if they were allocated to participants, released or had been committed to be released. ESOP cumulative shares outstanding for the calculation of EPS were 4.6 million in 2010 and 4.2 million in 2009.

15. Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business entity during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: Net income (loss) and Other comprehensive income (loss).

The following table provides the tax effects allocated to each component of Other comprehensive income (loss) for **DPL** for the periods November 28, 2011 through December 31, 2011, January 1, 2011 through November 27, 2011, and for the years ended December 31, 2010 and 2009:

$ in millions		Amount before tax		DPL Tax (expense) / benefit		Amount after tax
2009 (Predecessor):						
Unrealized gains / (losses) on financial instruments	$	0.8	$	(0.3)	$	0.5
Deferred gains / (losses) on cash flow hedges		(4.3)		0.6		(3.7)
Unrealized gains / (losses) on *pension and postretirement benefits*		(4.1)		1.4		(2.7)
Other comprehensive income (loss)	$	(7.6)	$	1.7	$	(5.9)
2010 (Predecessor):						
Unrealized gains / (losses) on financial instruments	$	0.6	$	(0.2)	$	0.4
Deferred gains / (losses) on cash flow hedges		11.0		(4.6)		6.4
Unrealized gains / (losses) on pension and postretirement benefits		4.3		(1.0)		3.3
Other comprehensive income (loss)	$	15.9	$	(5.8)	$	10.1
January 1, 2011 through November 27, 2011 (Predecessor):						
Unrealized gains / (losses) on financial instruments	$	-	$	-	$	-
Deferred gains / (losses) on cash flow hedges		(89.4)		30.9		(58.5)
Unrealized gains / (losses) on pension and postretirement benefits		4.0		(0.8)		3.2
Other comprehensive income (loss)	$	(85.4)	$	30.1	$	(55.3)
November 28, 2011 through December 31, 2011 (Successor):						
Unrealized gains / (losses) on financial instruments	$	-	$	-	$	-
Deferred gains / (losses) on cash flow hedges		(0.8)		0.3		(0.5)
Unrealized gains / (losses) on pension and postretirement benefits		0.1		-		0.1
Other comprehensive income (loss)	$	(0.7)	$	0.3	$	(0.4)

The following table provides the detail of each component of Other comprehensive income (loss) reclassified to Net income:

	Successor		Predecessor					
$ in millions	November 28, 2011 through December 31, 2011		January 1, 2011 through November 27, 2011		For the years ende December 31, 2010		20	
Unrealized gains/(losses) on financial instruments net of income tax (expenses)/benefits of $0.0 million, ($0.1) million, ($0.0) million and ($0.0), respectively.	$	-	$	0.1	$	-	$	
Deferred gains/(losses) on cash flow hedges net of income tax (expenses)/benefits of $0.1 million, $0.1 million, $2.0 million and ($1.8) million, respectively.		(0.2)		(0.2)		(6.0)		
Unrealized losses on pension and postretirement benefits net of income tax benefits of $0.1 million, $1.5 million, $1.3 million and $1.1 million, respectively.		(0.3)		(2.8)		(2.4)		
	$	(0.5)	$	(2.9)	$	(8.4)	$	

Accumulated Other Comprehensive Income (Loss)
AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at December 31, 2011 and 2010:

DPL	**Successor**		**Predecessor**	
$ in millions	**2011**		2010	
Financial instruments, net of tax	$	-	$	0.6
Cash flow hedges, net of tax		(0.5)		19.6
Pension and postretirement benefits, net of tax		0.1		(39.1)
Total	$	(0.4)	$	(18.9)

16. EPS

Basic EPS is based on the weighted-average number of **DPL** common shares outstanding during the year. Diluted EPS is based on the weighted-average number of **DPL** common and common-equivalent shares outstanding during the year, except in periods where the inclusion of such common-equivalent shares is anti-dilutive. Excluded from outstanding shares for these weighted-average computations are shares held by **DP&L's** Master Trust Plan for deferred compensation and unreleased shares held by **DPL's** ESOP.

The common-equivalent shares excluded from the calculation of diluted EPS, because they were anti-dilutive, were not material for the period January 1, 2011, through November 27, 2011 and the years ended December 31, 2010 and 2009. Effective with the Merger with AES, **DPL** is wholly-owned by AES and earnings per share information is no longer required.

The following illustrates the reconciliation of the numerators and denominators of the basic and diluted EPS computations:

$ and shares in millions except per share amounts	**January 1, 2011 through November 27, 2011**			For the years ended December 31, 2010			2009		
	Income	**Shares**	**Per Share**	Income	Shares	Per Share	Income	Shares	Per Share
Basic EPS	**$ 150.5**	**114.5**	**$ 1.31**	$ 290.3	115.6	$ 2.51	$ 229.1	112.9	$ 2.03
Effect of Dilutive Securities:									
Warrants		**0.4**			0.3			1.1	
Stock options, performance and restricted shares		**0.2**			0.2			0.2	
Diluted EPS	**$ 150.5**	**115.1**	**$ 1.31**	$ 290.3	116.1	$ 2.50	$ 229.1	114.2	$ 2.01

17. Insurance Recovery

On May 16, 2007, **DPL** filed a claim with Energy Insurance Mutual (EIM) to recoup legal costs associated with our litigation against certain former executives. On February 15, 2010, after having engaged in both mediation and arbitration, **DPL** and EIM entered into a settlement agreement resolving all coverage issues and finalizing all obligations in connection with the claim. The proceeds from the settlement amounted to $3.4 million, net of associated expenses, and were recorded as a reduction to operation and maintenance expense during the year ended December 31, 2010.

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, 2011, **DPL** had $54.4 million of guarantees to third parties for future financial or performance assurance under such agreements, including $47.1 million of guarantees on behalf of DPLE and DPLER and $7.3 million of guarantees on behalf of MC Squared. The guarantee arrangements entered into by **DPL** with these third parties cover select present and future obligations of DPLE, DPLER and MC Squared to such beneficiaries and are terminable by **DPL** upon written notice within a certain time to the beneficiaries. The carrying amount of obligations for commercial transactions covered by these guarantees and recorded in our Consolidated Balance Sheets was $0.1 million and $1.7 million at December 31, 2011 and 2010, respectively.

To date, **DPL** has not incurred any losses related to the guarantees of DPLE's, DPLER'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 DPLE's, DPLER's and MC Squared's obligations.

Equity Ownership Interest
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. As of December 31, 2011, **DP&L** could be responsible for the repayment of 4.9%, or $65.3 million, of a $1,332.3 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2011, 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, 2011, these include:

		Payment Due			
$ in millions	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Long-term debt	$ 2,599.1	$ 0.4	$ 895.6	$ 450.2	$ 1,252.9
Interest payments	1,171.2	138.6	243.9	203.5	585.2
Pension and postretirement payments	261.1	25.6	50.8	52.1	132.6
Capital leases	0.7	0.3	0.4	-	-
Operating leases	1.5	0.5	0.8	0.2	-
Coal contracts (a)	818.6	233.4	265.6	162.6	157.0
Limestone contracts (a)	34.8	5.8	11.6	11.6	5.8
Purchase orders and other contractual obligations	71.3	57.5	7.8	6.0	-
Total contractual obligations	$ 4,958.3	$ 462.1	$ 1,476.5	$ 886.2	$ 2,133.5

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

Long-term debt:
DPL's long-term debt as of December 31, 2011, consists of **DPL's** unsecured notes and unsecured term loan, along with **DP&L's** first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the Wright-Patterson Air Force Base debt facility. These long-term debt amounts include current maturities but exclude unamortized debt discounts and fair value adjustments.

DP&L's long-term debt as of December 31, 2011, consists of first mortgage bonds, tax-exempt pollution control bonds, capital leases, and the Wright-Patterson Air Force Base debt facility. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 7 for additional information.

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, 2011.

Pension and postretirement payments:
As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had estimated future benefit payments as outlined in Note 9. These estimated future benefit payments are projected through 2020.

Capital leases:
As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:
As of December 31, 2011, **DPL**, through its principal subsidiary **DP&L**, had several immaterial operating leases with various terms and expiration dates.

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 plants 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, 2011, **DPL** 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 $25.0 million, 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.

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, 2011, cannot be reasonably determined.

Environmental Matters
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. We have estimated liabilities of approximately $3.4 million for environmental matters. We evaluate the potential liability related to probable losses quarterly and may revise our estimates. Such revisions in the estimates of the potential liabilities could have a material effect on our results of operations, financial condition or cash flows.

We have several pending environmental matters associated with our power plants. Some of these matters could have material adverse impacts on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. **DP&L** owns 100% of the Hutchings plant and a 50% interest in Beckjord Unit 6.

On July 15, 2011, Duke Energy, co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2014. We do not believe that any additional accruals are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals are needed related to the Hutchings Station.

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.

Cross-State Air Pollution Rule
The Clean Air Interstate Rule (CAIR) final rules were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO_2. Litigation brought by entities not including **DP&L** resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 2008 decision.

In an attempt to conform to the Court's decision, on July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR). These rules were finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011, but subsequent litigation has resulted in their implementation being delayed indefinitely. CSAPR creates four separate trading programs: two SO_2 areas (Group 1 and Group 2); and two NOx reduction requirements (annual and ozone season). Group 1 states (16 states including Ohio) will have to meet a 2012 cap and additional reductions in 2014. Group 2 states (7 states) will only have to meet the 2012 cap. We do not believe the rule will have a material effect on our operations in 2012. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If CSAPR becomes effective, it is expected to institute a federal implementation plan (FIP) in lieu of state SIPs and allow for the states to develop SIPs for approval as early as 2013. **DP&L** is unable to estimate the effect of the new requirements; however, CSAPR could have a material effect on our operations.

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 EPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. **DP&L** is evaluating the costs that may be incurred to comply with the new requirement; however, MATS could have a material adverse effect on our operations and result in material compliance costs.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. The compliance date was originally March 21, 2014. However, the USEPA has announced that the compliance date for existing boilers will be delayed until a judicial review is no longer pending or until the EPA completes its reconsideration of the rule. In December 2011, the

EPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs on **DP&L's** operations are not expected to be material.

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. As of December 31, 2011, **DP&L's** Stuart, Killen and Hutchings Stations were located in non-attainment areas for the annual PM 2.5 standard. There is a possibility that these areas will be re-designated as "attainment" for PM 2.5 within the next few quarters. 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.

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. In the final rule, the USEPA made the determination that CAIR achieves greater progress than BART and may be used by states as a BART substitute. Numerous units owned and operated by us will be affected by BART. We cannot determine the extent of the effect until Ohio determines how BART will be implemented.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. **DP&L** cannot determine the effect of this potential change, if any, on its 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 revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. **DP&L** cannot determine the effect of this potential change, if any, on its operations. No effects are anticipated before 2014.

Carbon Emissions and Other Greenhouse Gases

In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders carbon dioxide and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to **DP&L** cannot be determined at this time, but the cost of compliance could be material.

The USEPA plans to propose GHG standards for new and modified electric generating units (EGUs) under CAA subsection 111(b) – and propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d) during 2012. These rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

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 16 million tons annually. Further GHG legislation or regulation finalized 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 impact that such legislation or regulation may have on **DP&L**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of CO_2, including electric generating units. **DP&L's** first report to the USEPA was submitted prior to the September 30, 2011 due date for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. **DP&L** does not anticipate that this reporting rule will result in any significant cost or other effect on current operations.

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

<u>Litigation Involving Co-Owned Plants</u>
On June 20, 2011, the U.S. Supreme Court ruled that the USEAP's regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including **DP&L**. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

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 J.M. Stuart generating station are subject to certain specified emission targets related to NOx, 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.

<u>Notices of Violation Involving Co-Owned Plants</u>
In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued a NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy, and CSP) 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 a 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 a NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (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, USEPA issued an NOV to Zimmer for excess emissions. **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.

Notices of Violation Involving Wholly-Owned Plants
In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the O.H. Hutchings Station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the O.H. Hutchings Station relating to capital projects performed in 2001 involving Unit 3 and Unit 6. **DP&L** does not believe that the projects described in the NOV were modifications subject to NSR. **DP&L** is engaged in discussions with the USEPA and Justice Department to resolve these matters, but **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

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

Clean Water Act – Regulation of Water Intake
On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act 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. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA released new proposed regulations on March 28, 2011, published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. The final rules are expected to be in place by mid-2012. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, we submitted an application for the renewal of the Stuart Station NPDES Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, **DP&L** and the Ohio EPA reached an agreement to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. 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 does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will 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 would require **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 and is considering legal options. Depending on the outcome of the process, the effects could be material on **DP&L's** operation.

In September 2009, the USEPA announced that it will 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. Subsequent to the information collection effort, it is anticipated that the USEPA will release a proposed rule by mid-2012 with a final regulation in place by early 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its 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. However, 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, is ongoing. 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**. The USEPA has indicated that a proposed rule will be released in late 2012. 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 J.M. Stuart Stations. Subsequently, the USEPA collected similar information for O.H. Hutchings Station.

In August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the O.H. 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. **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts 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 anticipates issuing a final rule on this topic in late 2012. **DP&L** is unable to predict the financial effect of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on operations.

Notice of Violation involving Co-Owned Plants
On September 9, 2011, **DP&L** received a notice of violation from the USEPA with respect to its co-owned J.M. 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 Clean Water Act National Pollutant Discharge Elimination System 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 flow.

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 plants 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. With respect to unsettled claims, **DP&L** management has deferred $17.8 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, as Other deferred credits representing the amount of unearned income and interest where the earnings process is not complete. The amount at December 31, 2011 includes estimated earnings and interest of $5.2 million. On September 30, 2011, the FERC issued two SECA-related orders that affirmed an earlier order issued in 2010 by denying the rehearing requests that a number of different parties, including **DP&L**, had filed. These orders are now final, subject to possible appellate court review. These orders do not affect prior settlements that had been reached with other parties that owed SECA revenues to **DP&L** or were recipients of amounts paid by **DP&L**. For other parties that had not previously settled with **DP&L**, the exact timing and amounts of any payments that would be made or received by **DP&L** under these orders is still uncertain.

The following lawsuits were filed in connection with the Merger (See Item 1A, "Risk Factors," for additional risks related to the Merger) seeking, among other things, one or more of the following: to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, or a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty. Only the lawsuit filed by the Payne Family Trust noted below remains pending as of the date of this report.

On April 21, 2011, a lawsuit was filed in the Court of Common Pleas of Montgomery County, Ohio, naming **DPL** and each member of **DPL's** board of directors, AES and Dolphin Sub, Inc. as defendants. The lawsuit was a purported class action filed by Patricia A. Heinmullter on behalf of herself and an alleged class of **DPL** shareholders. On March 22, 2012, the Court entered an order dismissing this lawsuit with prejudice pursuant to a stipulation filed by the parties. Plaintiff had alleged, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that AES and Dolphin Sub, Inc. aided and abetted such breach.

On April 26, 2011, a lawsuit was filed in the United States District Court for the Southern District of Ohio, Western Division (the "District Court"), naming each member of **DPL's** board of directors, AES and Dolphin Sub, Inc. as defendants and naming **DPL** as a nominal defendant. The lawsuit filed by Stephen Kubiak is a purported class action on behalf of plaintiff and an alleged class of **DPL** shareholders and a purported derivative action on behalf of **DPL**. Plaintiff alleges, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that AES and Dolphin Sub, Inc. aided and abetted such breach.

On April 27, 2011, another lawsuit was filed in the Court of Common Pleas of Montgomery County, Ohio, naming **DPL**, each member of **DPL's** board of directors, AES and Dolphin Sub, Inc. as defendants. The lawsuit filed by Laurence D. Paskowitz was a purported class action on behalf of plaintiff and an alleged class of **DPL** shareholders. On March 21, 2012, the Court entered an order dismissing this lawsuit with prejudice pursuant to a stipulation filed by the parties. Plaintiff had alleged, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that **DPL**, AES and Dolphin Sub, Inc. aided and abetted such breach.

On April 28, 2011, a lawsuit was filed in the Court of Common Pleas of Montgomery County, Ohio, naming **DPL** and each member of **DPL's** board of directors as defendants. The lawsuit filed by Payne Family Trust is a purported class action on behalf of plaintiff and an alleged class of **DPL** shareholders. Plaintiff alleges, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES.

On May 4, 2011, a lawsuit was filed in the District Court naming **DPL**, each member of **DPL's** board of directors, AES and Dolphin Sub, Inc. as defendants. The lawsuit filed by Patrick Nichting is a purported class action on behalf of plaintiff and an alleged class of **DPL** shareholders and a purported derivative action on behalf of **DPL**. Plaintiff alleges, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that **DPL**, AES and Dolphin Sub, Inc. aided and abetted such breach.

On May 20, 2011, a lawsuit was filed in the District Court naming **DPL**, each member of **DPL's** board of directors, AES and Dolphin Sub, Inc. as defendants. The lawsuit filed by Ralph B. Holtmann and Catherine P. Holtmann is a purported class action on behalf of plaintiffs and an alleged class of **DPL** shareholders. Plaintiffs allege, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that **DPL**, AES and Dolphin Sub, Inc. aided and abetted such breach.

On May 24, 2011, a lawsuit was filed in the Court of Common Pleas of Montgomery County, Ohio, naming each member of **DPL's** board of directors and AES as defendants and naming **DPL** as a nominal defendant. The lawsuit filed by Maxine Levy was a purported class action on behalf of plaintiff and an alleged class of **DPL** shareholders and a purported derivative action on behalf of **DPL**. On March 22, 2012, the Court entered an order dismissing this lawsuit with prejudice pursuant to a stipulation filed by the parties. Plaintiff had alleged, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger of **DPL** and AES and that AES and Dolphin Sub, Inc. aided and abetted such breach.

On June 13, 2011, the three actions in the District Court were consolidated. On June 14, 2011, the District Court granted Plaintiff Nichting's motion to appoint lead and liaison counsel. On June 30, 2011, plaintiffs in the consolidated federal action filed an amended complaint that added claims based on alleged omissions in the preliminary proxy statement that **DPL** filed on June 22, 2011 (the "Preliminary Proxy Statement"). Plaintiffs, in their individual capacity only, asserted a claim against **DPL** and its directors under Section 14(a) of the Securities Exchange Act of 1934 (the "Exchange Act") for purported omissions in the Preliminary Proxy Statement and a claim against **DPL's** directors for control person liability under Section 20(a) of the Exchange Act. In addition, plaintiffs purported to assert state law claims directly on behalf of Plaintiffs and an alleged class of **DPL** shareholders and derivatively on behalf of **DPL**. Plaintiffs alleged, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger Agreement for the Merger of **DPL** and AES and that **DPL**, AES and Dolphin Sub, Inc. aided and abetted such breach.

On February 24, 2012, the District Court entered an order approving a settlement between **DPL**, **DPL's** directors, AES and Dolphin Sub, Inc. and the plaintiffs in the consolidated federal action. The settlement resolves all pending federal court litigation related to the Merger, including the Kubiak, Holtmann and Nichting actions, results in the release by the plaintiffs and the proposed settlement class of all claims that were or could have been brought challenging any aspect of the Merger Agreement, the Merger and any disclosures made in connection therewith and provides for an immaterial award of plaintiffs' attorneys' fees and expenses.

19. 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) and DPLER's wholly-owned subsidiary, MC Squared (Competitive Retail segment). 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 sell electricity to residential, commercial, industrial and governmental customers. Electricity for the segment's 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 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 rates for its generation business are deemed competitive under Ohio law.

The Competitive Retail segment is DPLER's and MC Squared'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 MC Squared as their alternative electric supplier. The Competitive Retail segment sells electricity to approximately 40,000 customers currently located throughout Ohio and in Illinois. In February 2011, DPLER purchased MC Squared, a Chicago-based retail electricity supplier, which serves approximately 3,157 customers in Northern Illinois. Due to increased competition in Ohio, since 2010 we have increased the number of employees and resources assigned to manage the Competitive Retail segment and increased its marketing to customers. The Competitive Retail segment's electric energy used to meet its sales obligations was purchased from **DP&L** and PJM. During 2010, we implemented a new wholesale agreement between **DP&L** and DPLER. Under this agreement, intercompany sales from **DP&L** to DPLER were based on the market prices for wholesale power. In periods prior to 2010, DPLER's purchases from **DP&L** were transacted at prices that approximated DPLER's sales prices to its end-use retail customers. 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.

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
November 28, 2011 through December 31, 2011 (Successor)					
Revenues from external customers	$ 116.2	$ 38.2	$ 2.5	$ -	$ 156.9
Intersegment revenues	27.8	-	0.3	(28.1)	-
Total revenues	144.0	38.2	2.8	(28.1)	156.9
Fuel	34.5	-	1.3	-	35.8
Purchased power	31.0	33.4	-	(27.7)	36.7
Gross margin (a)	78.5	4.8	(10.1)	(0.4)	72.8
Depreciation and amortization	12.7	-	(1.1)	-	11.6
Interest expense	2.8	0.1	8.8	(0.2)	11.5
Income tax expense (benefit)	5.8	1.1	(6.3)	-	0.6
Net income (loss)	$ 45.8	$ 1.7	$ (53.7)	$ -	$ (6.2)
Total assets	$ 3,525.7	$ 69.9	$ 2,511.9	$ -	$ 6,107.5
Capital expenditures	$ 30.5	$ -	$ -	$ -	$ 30.5
January 1, 2011 through November 27, 2011 (Predecessor)					
Revenues from external customers	$ 1,234.5	$ 387.2	$ 49.2	$ -	$ 1,670.9
Intersegment revenues	299.2	-	3.7	(302.9)	-
Total revenues	1,533.7	387.2	52.9	(302.9)	1,670.9
Fuel	346.1	-	9.7	-	355.8
Purchased power	370.6	330.5	2.7	(299.2)	404.6
Gross margin (a)	817.0	56.7	40.5	(3.7)	910.5
Depreciation and amortization	122.2	0.6	6.6	-	129.4
Interest expense	35.4	0.2	23.4	(0.3)	58.7
Income tax expense (benefit)	98.4	16.7	(13.1)	-	102.0
Net income (loss)	$ 147.4	$ 24.1	$ (21.0)	$ -	$ 150.5
Capital expenditures	$ 174.0	$ -	$ 0.2	$ -	$ 174.2

(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, 2010 (Predecessor)					
Revenues from external customers	$ 1,500.3	$ 277.0	$ 54.1	$ -	$ 1,831.4
Intersegment revenues	238.5	-	4.5	(243.0)	-
Total revenues	1,738.8	277.0	58.6	(243.0)	1,831.4
Fuel	371.9	-	12.0	-	383.9
Purchased power	383.5	238.5	3.9	(238.5)	387.4
Gross margin (a)	983.4	38.5	42.7	(4.5)	1,060.1
Depreciation and amortization	130.7	0.2	8.5	-	139.4
Interest expense	37.1	-	33.5	-	70.6
Income tax expense (benefit)	135.2	10.5	(2.7)	-	143.0
Net income (loss)	$ 277.7	$ 18.8	$ (3.5)	$ (2.7)	$ 290.3
Total assets	$ 3,475.4	$ 35.7	$ 302.2	$ -	$ 3,813.3
Capital expenditures	$ 148.2	$ -	$ 3.2	$ -	$ 151.4
Year Ended December 31, 2009 (Predecessor)					
Revenues from external customers	$ 1,436.0	$ 65.5	$ 37.8	$ -	$ 1,539.3
Intersegment revenues	64.8	-	3.8	(68.6)	-
Total revenues	1,500.8	65.5	41.6	(68.6)	1,539.3
Fuel	323.6	-	6.8	-	330.4
Purchased power	259.2	64.8	1.0	(64.8)	260.2
Gross margin (a)	918.0	0.7	33.7	(3.6)	948.8
Depreciation and amortization	135.5	0.1	9.9	-	145.5
Interest expense	38.5	-	44.5	-	83.0
Income tax expense (benefit)	124.5	(0.8)	(11.2)	-	112.5
Net income (loss)	$ 258.9	$ (2.7)	$ (21.4)	$ (5.7)	$ 229.1
Total assets	$ 3,457.4	$ 6.6	$ 177.7	$ -	$ 3,641.7
Capital expenditures	$ 144.0	$ -	$ 1.3	$ -	$ 145.3

(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.*

20. Selected Quarterly Information (Unaudited)

DPL

$ in millions except per share amount and common stock market price	For the 2011 periods ended (a) Predecessor March 31	June 30	September 30	November 27	Successor December 31
Revenues	$ 480.6	$ 433.4	$ 497.5	$ 259.4	$ 156.9
Operating income	$ 100.9	$ 65.8	$ 112.9	$ 48.2	$ 6.1
Net income (loss)	$ 43.5	$ 31.7	$ 67.1	$ 8.2	$ (6.2)
Earnings per share of common stock:					
Basic	$ 0.38	$ 0.28	$ 0.58	$ 0.07	N/A
Diluted	$ 0.38	$ 0.28	$ 0.58	$ 0.07	N/A
Dividends declared per share	$ 0.3325	$ 0.3325	$ 0.3325	$ 0.5400	N/A

(a) Periods ended March 31, June 30, and September 30 represent three months then ended. Period ended November 27 represents approximately two months then ended and period ended December 31, represents approximately one month then ended.

$ in millions except per share amount and common stock market price		For the 2010 quarters ended Predecessor March 31	June 30	September 30	December 31
Revenues		$ 437.0	$ 434.1	$ 502.3	$ 458.0
Operating income		$ 126.0	$ 109.3	$ 144.6	$ 124.5
Net income		$ 71.0	$ 61.4	$ 86.4	$ 71.5
Earnings per share of common stock:					
Basic		$ 0.61	$ 0.53	$ 0.75	$ 0.62
Diluted		$ 0.61	$ 0.53	$ 0.74	$ 0.62
Dividends declared and paid per share		$ 0.3025	$ 0.3025	$ 0.3025	$ 0.3025
Common stock market price	- High	$ 28.47	$ 28.18	$ 26.65	$ 27.51
	- Low	$ 26.51	$ 23.80	$ 23.95	$ 25.33

Report of Independent Registered Public Accounting Firm

The Board of Directors
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, 2011 and 2010, and the related statements of results of operations, shareholder's equity and cash flows for each of the years in the three-year period ended December 31, 2011. In connection with our audits of the financial statements, we also have audited the financial statement schedule, "Schedule II – Valuation and Qualifying Accounts." These financial statements are the responsibility of DP&L's management. Our responsibility is to express an opinion on these financial statements 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of DP&L as of December 31, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011, 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/ KPMG LLP

Philadelphia, Pennsylvania
March 27, 2012

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF RESULTS OF OPERATIONS

$ in millions	Years ended December 31, 2011	2010	2009
Revenues	**$ 1,677.7**	$ 1,738.8	$ 1,500.8
Cost of revenues:			
Fuel	**380.6**	371.9	323.6
Purchased power	**401.6**	383.5	259.2
Total cost of revenues	**782.2**	755.4	582.8
Gross margin	**895.5**	983.4	918.0
Operating expenses:			
Operation and maintenance	**364.8**	330.1	293.4
Depreciation and amortization	**134.9**	130.7	135.5
General taxes	**75.9**	72.4	67.2
Total operating expenses	**575.6**	533.2	496.1
Operating income	**319.9**	450.2	421.9
Other income / (expense), net:			
Investment income	**17.3**	1.7	2.8
Interest expense	**(38.2)**	(37.1)	(38.5)
Other income (deductions)	**(1.6)**	(1.9)	(2.8)
Total other income / (expense), net	**(22.5)**	(37.3)	(38.5)
Earnings before income tax	**297.4**	412.9	383.4
Income tax expense	**104.2**	135.2	124.5
Net income	**193.2**	277.7	258.9
Dividends on preferred stock	**0.9**	0.9	0.9
Earnings on common stock	**$ 192.3**	$ 276.8	$ 258.0

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
STATEMENTS OF CASH FLOWS

$ in millions	Years ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income	$ 193.2	$ 277.7	$ 258.9
Adjustments to reconcile Net income to Net cash provided by operating activities:			
Depreciation and amortization	134.9	130.7	135.5
Deferred income taxes	50.7	54.3	200.1
Gain on liquidation of DPL stock, held in trust	(14.6)	-	-
Changes in certain assets and liabilities:			
Accounts receivable	5.3	15.2	25.7
Inventories	(15.5)	10.1	(20.5)
Prepaid taxes	8.1	(8.9)	-
Taxes applicable to subsequent years	(9.0)	(3.6)	(1.3)
Deferred regulatory costs, net	(12.6)	21.8	(23.6)
Accounts payable	7.1	16.9	(65.9)
Accrued taxes payable	15.2	1.7	(0.9)
Accrued interest payable	0.2	(5.4)	0.2
Pension, retiree and other benefits	(24.0)	(58.2)	15.2
Unamortized investment tax credit	(2.5)	(2.8)	(2.8)
Other	19.3	(3.1)	(6.9)
Net cash provided by operating activities	355.8	446.4	513.7
Cash flows from investing activities:			
Capital expenditures	(204.5)	(150.0)	(167.4)
Proceeds from liquidation of DPL stock, held in trust	26.9	-	-
Other investing activities, net	1.0	1.4	1.4
Net cash used for investing activities	(176.6)	(148.6)	(166.0)
Cash flows from financing activities:			
Dividends paid on common stock to parent	(220.0)	(300.0)	(325.0)
Dividends paid on preferred stock	(0.9)	(0.9)	(0.9)
Retirement of long-term debt	(0.1)	-	-
Cash contribution from parent	20.0	-	-
Withdrawal of restricted funds held in trust, net	-	-	14.5
Withdrawals from revolving credit facilities	50.0	-	260.0
Repayment of borrowings from revolving credit facilities	(50.0)	-	(260.0)
Net cash used for financing activities	(201.0)	(300.9)	(311.4)
Cash and cash equivalents:			
Net change	(21.8)	(3.1)	36.3
Balance at beginning of period	54.0	57.1	20.8
Cash and cash equivalents at end of period	$ 32.2	$ 54.0	$ 57.1
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 39.2	$ 45.1	$ 39.5
Income taxes (refunded) / paid, net	$ 13.9	$ 87.0	$ (94.7)
Non-cash financing and investing activities:			
Accruals for capital expenditures	$ 26.5	$ 23.2	$ 20.8
Long-term liability incurred for purchase of assets	$ 18.7	$ -	$ -

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32.2	$ 54.0
Accounts receivable, net (Note 3)	178.5	178.0
Inventories (Note 3)	123.1	111.4
Taxes applicable to subsequent years	71.9	62.8
Regulatory assets, current (Note 4)	17.7	22.0
Other prepayments and current assets	25.0	42.7
Total current assets	448.4	470.9
Property, plant and equipment:		
Property, plant and equipment	5,277.9	5,093.7
Less: Accumulated depreciation and amortization	(2,568.9)	(2,453.1)
	2,709.0	2,640.6
Construction work in process	150.7	119.6
Total net property, plant and equipment	2,859.7	2,760.2
Other non-current assets:		
Regulatory assets, non-current (Note 4)	177.8	167.0
Intangible assets (Note 1)	6.5	2.7
Other assets	33.3	74.6
Total other non-current assets	217.6	244.3
Total Assets	$ 3,525.7	$ 3,475.4

See Notes to Financial Statements.

THE DAYTON POWER AND LIGHT COMPANY
BALANCE SHEETS

$ in millions	December 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Current portion - long-term debt (Note 6)	$ 0.4	$ 0.1
Accounts payable	106.0	95.7
Accrued taxes	72.8	66.6
Accrued interest	7.9	7.7
Customers security deposits	15.8	18.7
Regulatory liabilities, current (Note 4)	-	10.0
Other current liabilities	41.4	36.0
Total current liabilities	244.3	234.8
Non-current liabilities:		
Long-term debt (Note 6)	903.0	884.0
Deferred taxes (Note 7)	637.7	595.7
Regulatory liabilities, non-current (Note 4)	118.6	114.0
Pension, retiree and other benefits	47.5	64.9
Unamortized investment tax credit	29.9	32.4
Other deferred credits	163.9	147.2
Total non-current liabilities	1,900.6	1,838.2
Redeemable preferred stock	22.9	22.9
Commitments and contingencies (Note 15)		
Common shareholder's equity:		
Common stock, at par value of $0.01 per share	0.4	0.4
Other paid-in capital	803.1	782.4
Accumulated other comprehensive loss	(34.7)	(20.2)
Retained earnings	589.1	616.9
Total common shareholder's equity	1,357.9	1,379.5
Total Liabilities and Shareholder's Equity	$ 3,525.7	$ 3,475.4

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	$ 783.1	$ (16.1)	$ 707.5	$ 1,474.9
2009:						
Net income					258.9	
Change in unrealized gains (losses) on financial instruments, net of tax				2.7		
Change in deferred gains (losses) on cash flow hedges, net of tax				(3.7)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				(2.7)		
Total comprehensive income						255.2
Common stock dividends					(325.0)	(325.0)
Preferred stock dividends					(0.9)	(0.9)
Tax effects to equity			0.8			0.8
Employee / Director stock plans			(2.5)			(2.5)
Other			0.2	0.1	(0.2)	0.1
Ending balance	41,172,173	$ 0.4	$ 781.6	$ (19.7)	$ 640.3	$ 1,402.6
2010:						
Net income					277.7	
Change in unrealized gains (losses) on financial instruments, net of tax				(1.0)		
Change in deferred gains (losses) on cash flow hedges, net of tax				(2.8)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				3.3		
Total comprehensive income						277.2
Common stock dividends					(300.0)	(300.0)
Preferred stock dividends					(0.9)	(0.9)
Tax effects to equity			0.2			0.2
Employee / Director stock plans			0.4			0.4
Other			0.2		(0.2)	-
Ending balance	41,172,173	$ 0.4	$ 782.4	$ (20.2)	$ 616.9	$ 1,379.5
2011:						
Net income					193.2	
Change in unrealized gains (losses) on financial instruments, net of tax				(7.8)		
Change in deferred gains (losses) on cash flow hedges, net of tax				(1.5)		
Change in unrealized gains (losses) on pension and postretirement benefits, net of tax				(5.2)		
Total comprehensive income						178.7
Common stock dividends					(220.0)	(220.0)
Preferred stock dividends					(0.9)	(0.9)
Parent company capital contribution			20.0			20.0
Tax effects to equity			1.4			1.4
Employee / Director stock plans			(5.4)			(5.4)
Other			4.7	-	(0.1)	4.6
Ending balance	41,172,173	$ 0.4	$ 803.1	$ (34.7)	$ 589.1	$ 1,357.9

(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

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. **DP&L** is engaged in the generation, transmission, distribution and sale of electricity to residential, commercial, industrial and governmental customers in a 6,000 square mile area of West Central Ohio. Electricity for **DP&L's** 24 county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. **DP&L** is a wholly-owned subsidiary of **DPL**.

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. See Note 2 for more information.

DP&L's sales reflect the general economic conditions and seasonal weather patterns of the area. **DP&L** sells any excess energy and capacity into the wholesale market.

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 1,468 people as of December 31, 2011. Approximately 53% of all employees are under a collective bargaining agreement which expires on October 31, 2014.

Financial Statement Presentation
DP&L does not have any subsidiaries. **DP&L** has undivided ownership interests in seven 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 excise taxes collected from customers have been reclassified out of revenue and operating expense in the 2010 and 2009 presentation to conform to AES' presentation of these items. Certain immaterial amounts from prior periods have been reclassified to conform to the current reporting presentation.

Deferred SECA revenue of $15.4 million at December 31, 2010 was reclassified from Regulatory liabilities to Other deferred credits. The balance of deferred SECA revenue at December 31, 2011 and 2010 was $17.8 million and $15.4 million, respectively. The balance at December 31, 2011 included estimated interest of $5.2 million. The FERC-approved SECA billings are unearned revenue where the earnings process is not complete and do not represent a potential overpayment by retail ratepayers or potential refunds of costs that had been previously charged to retail ratepayers through rates. Therefore, any amounts that are ultimately collected related to these charges would not be a reduction to future rates charged to retail ratepayers and therefore do not meet the criteria for recording as a regulatory liability under GAAP. See Note 15 for more information relating to SECA.

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 plants is sold to an RTO and we in turn purchase it back from the RTO to supply our customers. These power sales and purchases 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.

Property, Plant and Equipment

We record our ownership share of our undivided interest in jointly-held plants 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 $4.4 million, $3.4 million, and $3.1 million the years ended December 31, 2011, 2010 and 2009, 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.

At December 31, 2011, **DP&L** did not have any material plant acquisition adjustments or other plant-related adjustments.

Repairs and Maintenance

Costs associated with maintenance activities, primarily power plant 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 Study – Change in Estimate

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. In July 2010, **DP&L** completed a depreciation rate study for non-regulated generation property based on its property, plant and equipment balances at December 31, 2009, with certain adjustments for subsequent property additions. The results of the depreciation study concluded that many of **DP&L's** composite depreciation rates should be reduced due to projected useful asset lives which are longer than those previously estimated. **DP&L** adjusted the depreciation rates for its non-regulated generation property effective July 1, 2010, resulting in a net reduction of depreciation expense. For the year ended December 31, 2011, the net reduction in depreciation expense amounted to $3.4 million ($2.2 million net of tax) compared to the prior year. On an annualized basis, the net reduction in depreciation expense is projected to be approximately $6.8 million ($4.4 million net of tax).

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 2.5% in 2011, 2.6% in 2010 and 2.7% in 2009.

The following is a summary of **DP&L's** Property, plant and equipment with corresponding composite depreciation rates at December 31, 2011 and 2010:

DP&L

$ in millions	**2011**	**Composite Rate**	2010	Composite Rate
Regulated:				
Transmission	**$ 367.5**	**2.4%**	$ 360.6	2.5%
Distribution	**1,371.5**	**3.4%**	1,256.5	3.4%
General	**84.8**	**4.1%**	79.5	3.7%
Non-depreciable	**59.7**	**N/A**	58.7	N/A
Total regulated	**1,883.5**		1,755.3	
Unregulated:				
Production / Generation	**3,377.9**	**2.2%**	3,323.0	2.3%
Non-depreciable	**16.5**	**N/A**	15.4	N/A
Total unregulated	**3,394.4**		3,338.4	
Total property, plant and equipment in service	**$ 5,277.9**	**2.5%**	$ 5,093.7	2.6%

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 January 1, 2010	$ 16.2
Accretion expense	0.2
Additions	0.8
Settlements	(0.3)
Estimated cash flow revisions	0.6
Balance at December 31, 2010	$ 17.5
Accretion expense	0.8
Additions	-
Settlements	(0.5)
Estimated cash flow revisions	1.0
Balance at December 31, 2011	$ 18.8

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 $112.4 million and $107.9 million in estimated costs of removal at December 31, 2011 and 2010, 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.

Changes in the Liability for Transmission and Distribution Asset Removal Costs

DP&L $ in millions		
Balance at January 1, 2010	$	99.1
Additions		11.2
Settlements		(2.4)
Balance at December 31, 2010		107.9
Additions		9.4
Settlements		(4.9)
Balance at December 31, 2011	$	112.4

Regulatory Accounting

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and Regulatory liabilities represent current recovery of expected future costs.

We evaluate our Regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator. If we were required to terminate application of these GAAP provisions for all of our regulated operations, we would have to write off the amounts of all regulatory assets and liabilities to the statements of results of operations at that time. See Note 4.

Effective November 28, 2011, Regulatory assets and Liabilities are presented on a current and non-current basis, depending on the term recovery is anticipated. This change was made to conform with AES' presentation of 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. During the years ended December 31, 2010 and 2009, **DP&L** recognized gains from the sale of emission allowances in the amounts of $0.8 million and $5.0 million, respectively. There were no gains in 2011. Beginning in January 2010, part of the gains on emission allowances were 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.

Prior to the Merger date, emission allowances and renewable energy credits were carried as inventory. Emission allowances and renewable energy credits are now carried as intangibles in accordance with AES' policy. The amounts for 2010 have been reclassified to reflect this change in presentation.

Income Taxes
GAAP 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. Deferred tax assets are recognized for deductible temporary differences. 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.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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 are accounted for on a net basis and recorded as a reduction in revenues in the accompanying Statements of Results of Operations.

Prior to the Merger date, certain excise and other taxes were recorded gross. Effective on the Merger date, certain excise and other taxes are accounted for on a net basis and recorded as a reduction in revenues for presentation in accordance with AES policy. The amounts for the years ended December 31, 2011, 2010 and 2009, $53.7 million, $51.7 million and $49.5 million, respectively, were reclassified to conform to this presentation.

Share-Based Compensation
We measure the cost of employee services received and paid with equity instruments based on the fair-value of such equity instrument on the grant date. This cost is recognized in results of operations over the period that employees are required to provide service. Liability awards are initially recorded based on the fair-value of equity instruments and are to be re-measured for the change in stock price at each subsequent reporting date until the liability is ultimately settled. The fair-value for employee share options and other similar instruments at the grant date are estimated using option-pricing models and any excess tax benefits are recognized as an addition to paid-in capital. The reduction in income taxes payable from the excess tax benefits is presented in the statements of cash flows within Cash flows from financing activities. See Note 11 for additional information. As a result of the Merger (see Note 2), vesting of all share-based awards was accelerated as of the Merger date, and none are in existence at December 31, 2011.

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.

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 and MTM accounting when the hedge or a portion of the hedge is not effective. See Note 10.

Insurance and Claims Costs

In addition to insurance obtained from third-party providers, MVIC, a wholly-owned captive subsidiary of **DPL**, provides insurance coverage to **DP&L** and, in some cases, our partners in commonly owned facilities we operate, for workers' compensation, general liability, property damage, and directors' and officers' liability. **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. We record these additional insurance and claims costs of approximately $18.9 million and $19.0 million for 2011 and 2010, 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 at **DP&L** are actuarially determined based on a reasonable estimation of insured events occurring. 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.

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. The following table provides a summary of these transactions:

	Years ended December 31,		
$ in millions	2011	2010	2009
DP&L Revenues:			
Sales to DPLER *(a)*	**327.0**	238.5	64.8
DP&L Operation & Maintenance Expenses:			
Premiums paid for insurance services provided by MVIC *(b)*	**(3.1)**	(3.3)	(3.4)
Expense recoveries for services provided to DPLER *(c)*	**4.6**	5.8	1.5

(a) ***DP&L** sells power to DPLER to satisfy the electric requirements of DPLER's retail customers. The revenue dollars associated with sales to DPLER are recorded as wholesale revenues in **DP&L's** Financial Statements. The increase in **DP&L's** sales to DPLER during the year ended December 31, 2011, compared to the year ended December 31, 2010 is primarily due to customers electing to switch their generation service from **DP&L** to DPLER. **DP&L** did not sell any physical power to MC Squared during either of these periods.*

(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.*

Recently Adopted Accounting Standards

There were no newly adopted accounting standards during 2011.

Recently Issued Accounting Standards

Fair Value Disclosures

In May 2011, the FASB issued ASU 2011-04 "Fair Value Measurements" (ASU 2011-04) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 820, "Fair Value Measurements." ASU 2011-04 essentially converges US GAAP guidance on fair value with the IFRS guidance. The ASU requires more disclosures around Level 3 inputs. It also increases reporting for financial instruments disclosed at fair value but not recorded at fair value and provides clarification of blockage factors and other premiums and discounts. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Comprehensive Income

In June 2011, the FASB issued ASU 2011-05 "Presentation of Comprehensive Income" (ASU 2011-05) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC 220, "Comprehensive Income." ASU 2011-05 essentially converges US GAAP guidance on the presentation of comprehensive income with the IFRS guidance. The ASU requires the presentation of comprehensive income in one continuous financial statement or two separate but consecutive statements. Any reclassification adjustments from other comprehensive income to net income are required to be presented on the face of the Statement of Comprehensive Income. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

Goodwill Impairment
In September 2011, the FASB issued ASU 2011-08 "Testing Goodwill for Impairment" (ASU 2011-08) effective for interim and annual reporting periods beginning after December 15, 2011. We adopted this ASU on January 1, 2012. This standard updates FASC Topic 350, "Intangibles-Goodwill and Other." ASU 2011-08 allows an entity to first test Goodwill using qualitative factors to determine if it is more likely than not that the fair value of a reporting unit has been impaired, then the two-step impairment test is not performed. We do not expect these new rules to have a material effect on our overall results of operations, financial position or cash flows.

2. Business Combination

On November 28, 2011, all of the outstanding common stock of **DP&L's** parent company, **DPL**, was acquired by AES. In accordance with FASC 805, the assets and liabilities of **DPL** were valued at their fair value at the Merger date. These adjustments were "pushed down" to **DPL's** records. These adjustments were not pushed down to **DP&L** which will continue to use its historic costs for its assets and liabilities. Therefore, **DP&L** does not need to show a Predecessor and Successor split of its financial statements.

A number of lawsuits have been filed in connection with the Merger (See Item 1A, "Risk Factors," for additional risks related to the Merger). Each of these lawsuits seeks, among other things, one or more of the following: to rescind the Merger or for rescissory damages, or to commence a sale process and/or obtain an alternative transaction or to recover an unspecified amount of other damages and costs, including attorneys' fees and expenses, or a constructive trust or an accounting from the individual defendants for benefits they allegedly obtained as a result of their alleged breach of duty.

On June 13, 2011, the three actions in the District Court were consolidated. On June 14, 2011, the District Court granted Plaintiff Nichting's motion to appoint lead and liaison counsel. On June 30, 2011, plaintiffs in the consolidated federal action filed an amended complaint that added claims based on alleged omissions in the preliminary proxy statement that **DPL** filed on June 22, 2011 (the "Preliminary Proxy Statement"). Plaintiffs, in their individual capacity only, asserted a claim against **DPL** and its directors under Section 14(a) of the Securities Exchange Act of 1934 (the "Exchange Act") for purported omissions in the Preliminary Proxy Statement and a claim against **DPL's** directors for control person liability under Section 20(a) of the Exchange Act. In addition, plaintiffs purported to assert state law claims directly on behalf of Plaintiffs and an alleged class of **DPL** shareholders and derivatively on behalf of **DPL**. Plaintiffs alleged, among other things, that **DPL's** directors breached their fiduciary duties in approving the Merger Agreement for the Merger of **DPL** and AES and that **DPL**, AES and Dolphin Sub, Inc. aided and abetted such breach.

On February 24, 2012, the District Court entered an order approving a settlement between **DPL**, **DPL's** directors, AES and Dolphin Sub, Inc. and the plaintiffs in the consolidated federal action. The settlement resolves all pending federal court litigation related to the Merger, including the Kubiak, Holtmann and Nichting actions, results in the release by the plaintiffs and the proposed settlement class of all claims that were or could have been brought challenging any aspect of the Merger Agreement, the Merger and any disclosures made in connection therewith and provides for an immaterial award of plaintiffs' attorneys' fees and expenses.

3. Supplemental Financial Information

$ in millions	At December 31, 2011	At December 31, 2010
Accounts receivable, net:		
Unbilled revenue	**$ 49.5**	$ 64.3
Customer receivables	**85.8**	95.6
Amounts due from partners in jointly-owned plants	**29.2**	7.0
Coal sales	**1.0**	4.0
Other	**13.9**	7.9
Provision for uncollectible accounts	**(0.9)**	(0.8)
Total accounts receivable, net	**$ 178.5**	$ 178.0
Inventories, at average cost:		
Fuel and limestone	**$ 82.8**	$ 73.2
Plant materials and supplies	**38.6**	37.7
Other	**1.7**	0.5
Total inventories, at average cost	**$ 123.1**	$ 111.4

4. Regulatory Matters

In accordance with GAAP, regulatory assets and liabilities are recorded in the balance sheets for our regulated electric transmission and distribution businesses. Regulatory assets are the deferral of costs expected to be recovered in future customer rates and regulatory liabilities represent current recovery of expected future costs or gains probable of recovery being reflected in future rates.

We evaluate our regulatory assets each period and believe recovery of these assets is probable. We have received or requested a return on certain regulatory assets for which we are currently recovering or seeking recovery through rates. We record a return after it has been authorized in an order by a regulator.

Regulatory assets and liabilities for **DP&L** are as follows:

$ in millions	Type of Recovery (a)	Amortization Through	December 31, 2011	December 31, 2010
Current Regulatory Assets:				
TCRR, transmission, ancillary and other PJM-related costs	F	Ongoing	$ 4.7	$ 14.5
Power plant emission fees	C	Ongoing	4.8	6.6
Electric Choice systems costs	F	2011	-	0.9
Fuel and purchased power recovery costs	C	Ongoing	8.2	-
Total current regulatory assets			$ 17.7	$ 22.0
Non-current Regulatory Assets:				
Deferred recoverable income taxes	B/C	Ongoing	$ 24.1	$ 29.9
Pension and postretirement benefits	C	Ongoing	92.1	81.1
Unamortized loss on reacquired debt	C	Ongoing	13.0	14.3
Regional transmission organization costs	D	2014	4.1	5.5
Deferred storm costs - 2008	D		17.9	16.9
CCEM smart grid and advanced metering infrastructure costs	D		6.6	6.6
CCEM energy efficiency program costs	F	Ongoing	8.8	4.8
Consumer education campaign	D		3.0	3.0
Retail settlement system costs	D		3.1	3.1
Other costs			5.1	1.8
Total non-current regulatory assets			$ 177.8	$ 167.0
Current Regulatory Liabilities:				
Fuel and purchased power recovery costs	C	Ongoing	$ -	$ 10.0
Total current regulatory liabilities			$ -	$ 10.0
Non-current Regulatory Liabilities:				
Estimated costs of removal - regulated property			$ 112.4	$ 107.9
Postretirement benefits			6.2	6.1
Total non-current regulatory liabilities			$ 118.6	$ 114.0

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

Regulatory Assets

TCRR, transmission, ancillary and other PJM-related 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.

Power plant emission fees represent costs paid to the State of Ohio since 2002. An application is pending before the PUCO to amend an approved rate rider that had been in effect to collect fees that were paid and deferred in years prior to 2002. The deferred costs incurred prior to 2002 have been fully recovered. As the previously approved rate rider continues to be in effect, we believe these costs are probable of future rate recovery.

Electric Choice systems costs represent costs incurred to modify the customer billing system for unbundled customer rates and electric choice utility bills relative to other generation suppliers and information reports provided to the state administrator of the low-income payment program. In March 2006, the PUCO issued an order that approved our tariff as filed. We began collecting this rider immediately and expect to recover all costs over five years.

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. **DP&L** implemented the fuel and purchased power recovery rider on January 1, 2010. As part of the PUCO approval process, an outside auditor is hired to review fuel costs and the fuel procurement process. On October 6, 2011, **DP&L** and all of the active participants in this proceeding reached a Stipulation and Recommendation that resolves the majority of the issues raised related to the fuel audit. In November 2011, **DP&L** recorded a $25 million pretax ($16 million net of tax) adjustment as a result of the approval of the fuel settlement agreement by the PUCO. The adjustment was due to the reversal of a provision recorded in accordance with the regulatory accounting rules. An audit of 2011 costs is currently ongoing. The outcome of that audit is uncertain.

Deferred recoverable income taxes represent deferred income tax assets recognized from the normalization of flow through items as the result of amounts 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.

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 other comprehensive income (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.

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.

Regional transmission organization costs represent costs incurred to join an RTO. The recovery of these costs will be requested in a future FERC rate case.

Deferred storm costs – 2008 relate to costs incurred to repair the damage caused by hurricane force winds in September 2008, as well as other major 2008 storms. On January 14, 2009, the PUCO granted **DP&L** the authority to defer these costs with a return until such time that **DP&L** seeks recovery in a future rate proceeding.

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.

CCEM energy efficiency program costs represent costs incurred to develop and implement various new customer programs addressing energy efficiency. These costs are being recovered through an energy efficiency rider that began July 1, 2009 and is subject to a two-year true-up for any over/under recovery of costs. The two-year true-up was approved by the PUCO and a new rate was set.

Consumer education campaign represents costs for consumer education advertising regarding electric deregulation and its related rate case.

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

Other costs primarily include RPM capacity, other PJM and rate case costs and alternative energy costs that are or will be recovered over various periods.

Regulatory Liabilities

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.

5. Ownership of Coal-fired Facilities

DP&L and certain other Ohio utilities have undivided ownership interests in seven 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, 2011, **DP&L** had $52.0 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 Results 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 plant.

DP&L's undivided ownership interest in such facilities as well as our wholly-owned coal fired Hutchings plant at December 31, 2011, is as follows:

	DP&L Share		**DP&L** Investment			
	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)
Production Units:						
Beckjord Unit 6	50.0	207	$ 75	$ 58	$ -	No
Conesville Unit 4	16.5	129	121	32	6	Yes
East Bend Station	31.0	186	202	133	2	Yes
Killen Station	67.0	402	617	299	4	Yes
Miami Fort Units 7 and 8	36.0	368	366	129	2	Yes
Stuart Station	35.0	808	725	278	14	Yes
Zimmer Station	28.1	365	1,059	626	24	Yes
Transmission (at varying percentages)			91	57	-	
Total		2,465	$ 3,256	$ 1,612	$ 52	
Wholly-owned production unit:						
Hutchings Station	100.0	365	$ 124	$ 114	$ 2	No

On July 15, 2011, Duke Energy, a co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2014. This was followed by a notification by Duke Energy to PJM, dated February 1, 2012, of a planned April 1, 2015 deactivation of this unit. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals or impairment charges are needed related to the Hutchings Station.

As part of the provisional **DPL** purchase accounting adjustments related to the Merger with AES, four plants (Beckjord, Conesville, East Bend and Hutchings) had future expected cash flows that, when discounted, produced a zero fair market value. Since **DP&L** did not apply push down accounting, this valuation did not affect the book value of these plants' valuation at **DP&L**. However, **DP&L** performed an impairment review of these plants, which is initially based on undiscounted future cash flows and exceed their net book value so no impairment is required as of December 31, 2011. Significant changes in expected future revenues or costs for any of these plants could result in a future impairment charge.

6. Debt Obligations

Long-term debt is as follows:

Long-term Debt

$ in millions	**December 31, 2011**	December 31, 2010
First mortgage bonds maturing in October 2013 - 5.125%	**$ 470.0**	$ 470.0
Pollution control series maturing in January 2028 - 4.70%	**35.3**	35.3
Pollution control series maturing in January 2034 - 4.80%	**179.1**	179.1
Pollution control series maturing in September 2036 - 4.80%	**100.0**	100.0
Pollution control series maturing in November 2040 - variable rates: 0.06% - 0.32% and 0.16% - 0.36% (a)	**100.0**	100.0
U.S. Government note maturing in February 2061 - 4.20%	**18.5**	-
	902.9	884.4
Obligation for capital lease	**0.4**	0.1
Unamortized debt discount	**(0.3)**	(0.5)
Total long-term debt	**$ 903.0**	$ 884.0

Current portion - Long-term Debt

$ in millions	**December 31, 2011**	December 31, 2010
U.S. Government note maturing in February 2061 - 4.20%	**$ 0.1**	$ -
Obligation for capital lease	**0.3**	0.1
Total current portion - long-term debt at subsidiary	**$ 0.4**	$ 0.1

(a) Range of interest rates for the twelve months ended December 31, 2011 and 2010, respectively.

At December 31, 2011, maturities of long-term debt, including capital lease obligations, are summarized as follows:

$ in millions	Amount
Due within one year	$ 0.4
Due within two years	470.6
Due within three years	0.2
Due within four years	0.1
Due within five years	0.1
Thereafter	432.3
	$ 903.7

On November 21, 2006, **DP&L** entered into a $220 million unsecured revolving credit agreement. This agreement was terminated by **DP&L** on August 29, 2011.

On December 4, 2008, the OAQDA issued $100 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 December 2013, is irrevocable and has no subjective acceleration clauses. Fees associated with this letter of credit facility were not material during the twelve months ended December 31, 2011 and 2010, respectively.

On April 20, 2010, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a three year term expiring on April 20, 2013 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the period between April 20, 2010 and December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, **DP&L** had no outstanding letters of credit against the facility.

On March 1, 2011, **DP&L** completed the purchase of $18.7 million electric transmission and distribution assets from the federal government that are located at the Wright-Patterson Air Force Base. **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 August 24, 2011, **DP&L** entered into a $200 million unsecured revolving credit agreement with a syndicated bank group. This agreement is for a four year term expiring on August 24, 2015 and provides **DP&L** with the ability to increase the size of the facility by an additional $50 million. **DP&L** had no outstanding borrowings under this credit facility at December 31, 2011. Fees associated with this revolving credit facility were not material during the five months ended December 31, 2011. This facility also contains a $50 million letter of credit sublimit. As of December 31, 2011, **DP&L** had no outstanding letters of credit against the facility.

Substantially all property, plant and equipment of **DP&L** is subject to the lien of the mortgage securing **DP&L's** First and Refunding Mortgage, dated October 1, 1935, with the Bank of New York Mellon as Trustee.

7. Income Taxes

For the years ended December 31, 2011, 2010 and 2009, ***DP&L's*** *components of income tax were as follows:*

$ in millions	For the years ended December 31, 2011	2010	2009
Computation of Tax Expense			
Federal income tax (a)	**$ 103.8**	$ 144.2	$ 134.2
Increases (decreases) in tax resulting from:			
State income taxes, net of federal effect	**1.4**	1.9	0.4
Depreciation of AFUDC - Equity	**(3.2)**	(2.2)	(2.0)
Investment tax credit amortized	**(2.5)**	(2.8)	(2.8)
Section 199 - domestic production deduction	**(4.9)**	(9.1)	(4.6)
Non-deductible merger-related compensation	**3.6**	-	-
ESOP	**13.6**	-	-
Compensation and benefits	**(5.3)**	-	-
Other, net (b)	**(2.3)**	3.2	(0.7)
Total tax expense	**$ 104.2**	$ 135.2	$ 124.5
Components of Tax Expense			
Federal - Current	**$ 54.9**	$ 83.1	$ (70.3)
State and Local - Current	**0.9**	0.8	(2.5)
Total Current	**55.8**	83.9	(72.8)
Federal - Deferred	**47.1**	50.1	194.4
State and Local - Deferred	**1.3**	1.2	2.9
Total Deferred	**48.4**	51.3	197.3
Total tax expense	**$ 104.2**	$ 135.2	$ 124.5

Components of Deferred Tax Assets and Liabilities

$ in millions	At December 31, 2011	2010
Net Noncurrent Assets / (Liabilities)		
Depreciation / property basis	**$ (613.1)**	$ (595.6)
Income taxes recoverable	**(8.6)**	(10.3)
Regulatory assets	**(18.8)**	(12.4)
Investment tax credit	**10.5**	11.3
Compensation and employee benefits	**(4.2)**	21.0
Other	**(3.5)**	(9.7)
Net noncurrent (liabilities)	**$ (637.7)**	$ (595.7)
Net Current Assets / (Liabilities) (c)		
Other	**$ 1.5**	$ (1.1)
Net current assets	**$ 1.5**	$ (1.1)

(a) *The statutory tax rate of 35% was applied to pre-tax earnings.*
(b) *Includes a benefit of $2.4 million, $0.3 million and, an expense of $0.8 million in 2011, 2010 and 2009, respectively, of income tax related to adjustments from prior years.*
(c) *Amounts are included within Other prepayments and current assets on the Balance Sheets of* ***DP&L.***

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

$ in millions	For the years ended December 31, 2011	2010	2009
Expense / (benefit)	**$ (7.2)**	$ 0.1	$ (0.5)

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 for **DP&L** is as follows:

$ in millions		
Balance at January 1, 2009	$	1.9
Tax positions taken during prior periods		-
Tax positions taken during current period		20.6
Settlement with taxing authorities		(3.2)
Lapse of applicable statute of limitations		-
Balance at December 31, 2009	$	19.3
Tax positions taken during prior periods		(0.4)
Tax positions taken during current period		-
Settlement with taxing authorities		0.3
Lapse of applicable statute of limitations		0.2
Balance at December 31, 2010	$	19.4
Tax positions taken during prior periods		**2.0**
Tax positions taken during current period		**3.6**
Settlement with taxing authorities		**-**
Lapse of applicable statute of limitations		**-**
Balance at December 31, 2011	**$**	**25.0**

Of the December 31, 2011 balance of unrecognized tax benefits, $26.1 million is due to uncertainty in the timing of deductibility offset by $1.1 million of unrecognized tax liabilities that would affect the effective tax rate.

We recognize interest and penalties related to unrecognized tax benefits in Income tax expense. The following table represents the amounts accrued as well as the expense / (benefit) recorded as of and for the periods noted below:

Amounts in Balance Sheet

	Years ended December 31,					
$ in millions	**2011**		2010		2009	
Liability / (asset)	**$**	**0.9**	$	0.3	$	(1.0)

Amounts in Statement of Operations

	Years ended December 31,					
$ in millions	**2011**		2010		2009	
Expense / (benefit)	**$**	**0.6**	$	0.4	$	(0.1)

Following is a summary of the tax years open to examination by major tax jurisdiction:

U.S. Federal – 2007 and forward
State and Local – 2005 and forward

None of the unrecognized tax benefits are expected to significantly increase or decrease within the next twelve months.

The Internal Revenue Service began an examination of our 2008 Federal income tax return during the second quarter of 2010. The examination is still ongoing and we do not expect the results of this examination to have a material effect on our financial condition, results of operations and cash flows.

As a result of the Merger, **DPL** and its subsidiaries file U.S. federal income tax returns as a part of the consolidated U.S. income tax return filed by AES. Prior to the Merger, **DPL** and its subsidiaries filed a consolidated U.S. federal income tax return. 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.

8. Pension and Postretirement Benefits

DP&L sponsors a traditional defined benefit pension plan for substantially all employees of **DPL**. 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.

All **DP&L** management employees beginning employment on or after January 1, 2011 are enrolled in a cash balance pension plan. Similar to the traditional defined benefit 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 active and retired key executives. Benefits under this SERP have been frozen and no additional benefits can be earned. The SERP was replaced by the DPL Inc. Supplemental Executive Defined Contribution Retirement Plan (SEDCRP) effective January 7, 2006. The Compensation Committee of the Board of Directors designates the eligible employees. Pursuant to the SEDCRP, we provide a supplemental retirement benefit to participants by crediting an account established for each participant in accordance with the Plan requirements. We designate as hypothetical investment funds under the SEDCRP one or more of the investment funds provided under The Dayton Power and Light Company Employee Savings Plan. Each participant may change his or her hypothetical investment fund selection at specified times. If a participant does not elect a hypothetical investment fund(s), then we select the hypothetical investment fund(s) for such participant. We also have an unfunded liability related to agreements for retirement benefits of certain terminated and retired key executives. The unfunded liabilities for these agreements and the SEDCRP were $0.8 million and $1.8 million at December 31, 2011 and 2010, respectively. Per the SEDCRP plan document, the balances in the SEDCRP, including earnings on contributions, were paid out to participants in December 2011. The SEDCRP continued and a contribution for 2011 was calculated in January 2012.

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. **DP&L** made discretionary contributions of $40.0 million and $40.0 million to the defined benefit plan during the period January 1, 2011 through November 27, 2011 and the year ended December 31, 2010, respectively.

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 at age 65. We have funded a portion of the union-eligible benefits using a Voluntary Employee Beneficiary Association Trust.

Regulatory assets and liabilities are recorded for the portion of the under- or over-funded obligations related to the transmission and distribution areas of our electric business and for 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. These regulatory assets and liabilities 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. This factor, combined with the historical precedents from the PUCO and FERC, make these costs probable of future rate recovery.

The following tables set forth our pension and postretirement benefit plans' obligations and assets recorded on the balance sheets as of December 31, 2011 and 2010. 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 postretirement include both health and life insurance benefits.

$ in millions	Pension	
	Years ended December 31,	
Change in Benefit Obligation	**2011**	2010
Benefit obligation at beginning of period	**$ 333.8**	$ 323.9
Service cost	**5.0**	4.8
Interest cost	**17.0**	17.7
Plan amendments	**7.2**	-
Actuarial (gain) / loss	**21.6**	8.0
Benefits paid	**(19.4)**	(20.6)
Medicare Part D Reimbursement	**-**	-
Benefit obligation at end of period	**365.2**	333.8
Change in Plan Assets		
Fair value of plan assets at beginning of period	**291.8**	243.4
Actual return / (loss) on plan assets	**23.1**	28.6
Contributions to plan assets	**40.4**	40.4
Benefits paid	**(19.4)**	(20.6)
Medicare reimbursements	**-**	-
Fair value of plan assets at end of period	**335.9**	291.8
Funded status of plan	**$ (29.3)**	$ (42.0)

$ in millions	Postretirement	
	Years ended December 31,	
Change in Benefit Obligation	**2011**	2010
Benefit obligation at beginning of period	**$ 23.7**	$ 26.2
Service cost	**0.1**	0.1
Interest cost	**1.0**	1.2
Plan amendments	**(1.3)**	-
Actuarial (gain) / loss	**(2.0)**	(2.0)
Benefits paid	**0.2**	(2.0)
Medicare Part D Reimbursement	**-**	0.2
Benefit obligation at end of period	**21.7**	23.7
Change in Plan Assets		
Fair value of plan assets at beginning of period	**4.8**	5.0
Actual return / (loss) on plan assets	**0.2**	0.3
Contributions to plan assets	**1.5**	1.5
Benefits paid	**(2.0)**	(2.0)
Medicare reimbursements	**-**	-
Fair value of plan assets at end of period	**4.5**	4.8
Funded status of plan	**$ (17.2)**	$ (18.9)

$ in millions	Pension 2011	Pension 2010	Postretirement 2011	Postretirement 2010
Amounts Recognized in the Balance Sheets at December 31				
Current liabilities	**$ (1.3)**	$ (0.4)	**$ (0.6)**	$ (0.6)
Noncurrent liabilities	**(27.9)**	(41.6)	**(16.6)**	(18.3)
Net asset / (liability) at December 31	**$ (29.2)**	$ (42.0)	**$ (17.2)**	$ (18.9)
Amounts Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities, pre-tax				
Components:				
Prior service cost / (credit)	**$ 21.9**	$ 16.8	**$ 0.9**	$ 0.9
Net actuarial loss / (gain)	**140.2**	125.4	**(7.7)**	(7.6)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 162.1**	$ 142.2	**$ (6.8)**	$ (6.7)
Recorded as:				
Regulatory asset	**$ 91.1**	$ 80.0	**$ 1.0**	$ 0.5
Regulatory liability	**-**	-	**(6.6)**	(6.1)
Accumulated other comprehensive income	**71.0**	62.2	**(1.2)**	(1.1)
Accumulated other comprehensive income, regulatory assets and regulatory liabilities, pre-tax	**$ 162.1**	$ 142.2	**$ (6.8)**	$ (6.7)

The accumulated benefit obligation for our defined benefit pension plans was $355.5 million and $325.1million at December 31, 2011 and 2010, respectively.

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

Net Periodic Benefit Cost / (Income) - Pension

$ in millions	Years Ended December 31, 2011	2010	2009
Service cost	**$ 5.0**	$ 4.8	$ 3.6
Interest cost	**17.0**	17.7	18.1
Expected return on assets (a)	**(24.5)**	(22.4)	(22.5)
Amortization of unrecognized:			
Actuarial (gain) / loss	**8.0**	7.2	4.4
Prior service cost	**2.1**	3.7	3.4
Net periodic benefit cost / (income) before adjustments	**$ 7.6**	$ 11.0	$ 7.0

(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 $317 million in 2011, $274 million in 2010, and $275 million in 2009.

Net Periodic Benefit Cost / (Income) - Postretirement

$ in millions	Years Ended December 31, 2011	2010	2009
Service cost	**$ 0.1**	$ 0.1	$ -
Interest cost	**1.0**	1.2	1.5
Expected return on assets	**(0.3)**	(0.3)	(0.4)
Amortization of unrecognized:			
Actuarial (gain) / loss	**(1.1)**	(1.1)	(0.7)
Prior service cost	**0.1**	0.1	0.1
Net periodic benefit cost / (income) before adjustments	**$ (0.2)**	$ -	$ 0.5

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

Pension	Years ended December 31,		
$ in millions	**2011**	2010	2009
Net actuarial (gain) / loss	**$ 22.8**	$ 1.9	$ 5.3
Prior service cost / (credit)	**7.1**	-	7.2
Reversal of amortization item:			
Net actuarial (gain) / loss	**(8.0)**	(7.2)	(4.4)
Prior service cost / (credit)	**(2.0)**	(3.7)	(3.4)
Transition (asset) / obligation	**-**	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 19.9**	$ (9.0)	$ 4.7
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ 27.5**	$ 2.0	$ 11.7

Postretirement	Years ended December 31,		
$ in millions	**2011**	2010	2009
Net actuarial (gain) / loss	**$ (1.3)**	$ (1.9)	$ 0.3
Prior service cost / (credit)	**-**	-	1.1
Reversal of amortization item:			
Net actuarial (gain) / loss	**1.2**	1.1	0.7
Prior service cost / (credit)	**(0.1)**	(0.1)	(0.1)
Transition (asset) / obligation	**-**	-	-
Total recognized in Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ (0.2)**	$ (0.9)	$ 2.0
Total recognized in net periodic benefit cost and Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities	**$ (0.4)**	$ (0.9)	$ 2.5

Estimated amounts that will be amortized from Accumulated other comprehensive income, Regulatory assets and Regulatory liabilities into net periodic benefit costs during 2012 are:

$ in millions	Pension	Postretirement
Net actuarial (gain) / loss	**$ 8.7**	**$ 0.1**
Prior service cost / (credit)	**2.8**	**(0.9)**

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 2012, we have decreased our expected long-term rate of return on assets assumption from 8.00% to 7.00% for pension plan assets. We are maintaining our expected long-term rate of return on assets assumption at approximately 6.00% for postretirement benefit plan assets. These expected returns are based primarily on portfolio investment allocation. There can be no assurance of our ability to generate these rates of return in the future.

Our overall discount rate was evaluated in relation to the 2011 Hewitt Top Quartile Yield Curve which represents a portfolio of top-quartile AA-rated bonds used to settle pension obligations. Peer data and historical returns were also reviewed to verify the reasonableness and appropriateness of our discount rate used in the calculation of benefit obligations and expense.

The weighted average assumptions used to determine benefit obligations during 2011, 2010 and 2009 were:

Benefit Obligation Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate for obligations	**4.88%**	5.32%	5.75%	**4.17%**	4.96%	5.35%
Rate of compensation increases	**3.94%**	3.94%	4.44%	**N/A**	N/A	N/A

The weighted-average assumptions used to determine net periodic benefit cost (income) for the years ended December 31, 2011, 2010 and 2009 were:

Net Periodic Benefit Cost / (Income) Assumptions	Pension			Postretirement		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**4.88%**	5.75%	6.25%	**4.62%**	5.35%	6.25%
Expected rate of return on plan assets	**8.00%**	8.50%	8.50%	**6.00%**	6.00%	6.00%
Rate of compensation increases	**3.94%**	4.44%	5.44%	**N/A**	N/A	N/A

The assumed health care cost trend rates at December 31, 2011, 2010 and 2009 are as follows:

Health Care Cost Assumptions	Expense			Benefit Obligations		
	2011	2010	2009	**2011**	2010	2009
Pre - age 65						
Current health care cost trend rate	**8.50%**	9.50%	9.50%	**8.50%**	8.50%	9.50%
Year trend reaches ultimate	**2018**	2015	2014	**2019**	2018	2015
Post - age 65						
Current health care cost trend rate	**8.00%**	9.00%	9.00%	**8.00%**	8.00%	9.00%
Year trend reaches ultimate	**2017**	2014	2013	**2018**	2017	2014
Ultimate health care cost trend rate	**5.00%**	5.00%	5.00%	**5.00%**	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 postretirement benefit cost and the accumulated postretirement benefit obligation:

Effect of Change in Health Care Cost Trend Rate $ in millions	One-percent increase	One-percent decrease
Service cost plus interest cost	$ -	$ -
Benefit obligation	$ 0.9	$ (0.8)

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

Estimated Future Benefit Payments and Medicare Part D Reimbursements

$ in millions	Pension	Postretirement
2012	$ 23.1	$ 2.6
2013	22.7	2.5
2014	23.2	2.4
2015	23.8	2.2
2016	24.0	2.1
2017 - 2021	124.4	8.2

We expect to make contributions of $1.4 million to our SERP in 2012 to cover benefit payments. We also expect to contribute $2.3 million to our other postretirement benefit plans in 2012 to cover benefit payments.

The Pension Protection Act (the Act) of 2006 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 2011 plan year, the funded status of our defined benefit pension plan as calculated under the requirements of the Act was 104.37% and is estimated to be 104.37% until the 2012 status is certified in September 2012 for the 2012 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 30-80% for equity securities, 30-65% for fixed income securities, 0-10% for cash and 0-25% for alternative 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 types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of our pension plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2011

Asset Category $ in millions	**Market Value at December 31, 2011**	**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	$ 16.2	$ -	$ 16.2	$ -
Large Cap Equity	54.5	-	54.5	-
International Equity	34.2	-	34.2	-
Total Equity Securities	104.9	-	104.9	-
Debt Securities (b)				
Emerging Markets Debt	-	-	-	-
Fixed Income	-	-	-	-
High Yield Bond	-	-	-	-
Long Duration Fund	130.8	-	130.8	-
Total Debt Securities	130.8	-	130.8	-
Cash and Cash Equivalents (c)				
Cash	28.0	28.0	-	-
Other Investments (d)				
Limited Partnership Interest	0.8	-	-	0.8
Common Collective Fund	71.4	-	-	71.4
Total Other Investments	72.2	-	-	72.2
Total Pension Plan Assets	**$ 335.9**	**$ 28.0**	**$ 235.7**	**$ 72.2**

(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.

(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. 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 and the proceeds received from the DPL Inc Common Stock, which was cashed out at $30/share. The fair value of cash equals its book value. (Subsequent to the measurement date, the proceeds from the DPL Inc. Common Stock were invested in the other various investments.)

(d) This category represents a private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner based on the performance of the individual companies. 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, 2010 by asset category are as follows:

Fair Value Measurements for Pension Plan Assets at December 31, 2010

Asset Category $ in millions	Market Value at December 31, 2010	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	$ 15.2	$ -	$ 15.2	$ -
Large Cap Equity	49.4	-	49.4	-
DPL Inc. Common Stock	23.8	23.8	-	-
International Equity	31.5	-	31.5	-
Total Equity Securities	119.9	23.8	96.1	-
Debt Securities (b)				
Emerging Markets Debt	5.2	-	5.2	-
Fixed Income	39.0	-	39.0	-
High Yield Bond	8.2	-	8.2	-
Long Duration Fund	58.9	-	58.9	-
Total Debt Securities	111.3	-	111.3	-
Cash and Cash Equivalents (c)				
Cash	0.4	0.4	-	-
Other Investments (d)				
Limited Partnership Interest	2.8	-	-	2.8
Common Collective Fund	57.4	-	-	57.4
Total Other Investments	60.2	-	-	60.2
Total Pension Plan Assets	$ 291.8	$ 24.2	$ 207.4	$ 60.2

(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 private equity fund that specializes in management buyouts 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 private equity fund is determined by the General Partner based on the performance of the individual companies. 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 change in the fair value for the pension assets valued using significant unobservable inputs (Level 3) was due to the following:

Fair Value Measurements of Pension Assets Using Significant Unobservable Inputs (Level 3)

$ in millions	Limited Partnership Interest	Common Collective Fund
Ending balance at December 31, 2009	$ 3.1	$ 50.6
Actual return on plan assets:		
Relating to assets still held at the reporting date	0.1	0.8
Relating to assets sold during the period	-	-
Purchases, sales, and settlements	(0.4)	6.0
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2010	$ 2.8	$ 57.4
Actual return on plan assets:		
Relating to assets still held at the reporting date	$ (0.8)	$ (1.4)
Relating to assets sold during the period	-	-
Purchases, sales and settlements	(1.2)	15.4
Transfers in and / or out of Level 3	-	-
Ending balance at December 31, 2011	$ 0.8	$ 71.4

The fair values of our other postretirement benefit plan assets at December 31, 2011 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2011

Asset Category $ in millions	Market Value at December 31, 2011	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)	$ 4.5	$ -	$ 4.5	$ -

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

The fair values of our other postretirement benefit plan assets at December 31, 2010 by asset category are as follows:

Fair Value Measurements for Postretirement Plan Assets at December 31, 2010

Asset Category $ in millions	Market Value at December 31, 2010	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)	$ 4.8	$ -	$ 4.8	$ -

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

During October 1992, our Board of Directors approved the formation of a Company-sponsored ESOP to fund matching contributions to **DP&L's** 401(k) retirement savings plan and certain other payments to eligible full-time employees. ESOP shares used to fund matching contributions to **DP&L's** 401(k) vested after either two or three years of service in accordance with the match formula effective for the respective plan match year; other compensation shares awarded vested immediately. In 1992, the Plan entered into a $90 million loan agreement with **DPL** in order to purchase shares of **DPL** common stock in the open market. The leveraged ESOP was funded by an exempt loan, which was secured by the ESOP shares. As debt service payments were made on the loan, shares were released on a pro rata basis. The term loan agreement provided for principal and interest on the loan to be paid prior to October 9, 2007, with the right to extend the loan for an additional ten years. In 2007, the maturity date was extended to October 7, 2017. Effective January 1, 2009, the interest on the loan was amended to a fixed rate of 2.06%, payable annually. Dividends received by the ESOP were used to repay the principal and interest on the ESOP loan to **DPL**. Dividends on the allocated shares were charged to retained earnings and the share value of these dividends was allocated to participants.

During December 2011, the ESOP Plan was terminated and participant balances were transferred to one of the two DP&L sponsored defined contribution 401(k) plans. On December 5, 2011, the ESOP Trust paid the total outstanding principal and interest of $68 million on the loan with **DPL**, using the merger proceeds from **DPL** common stock held within the ESOP suspense account.

Compensation expense recorded, based on the fair value of the shares committed to be released, amounted to zero from November 28, 2011 through December 31, 2011 (successor), $4.8 million from January 1, 2011 through November 27, 2011 (predecessor), $6.7 million in 2010 and $4.0 million in 2009.

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, 2011 and 2010. See also Note 10 for the fair values of our derivative instruments.

	At December 31, 2011		At December 31, 2010	
$ in millions	**Cost**	**Fair Value**	Cost	Fair Value
DP&L				
Assets				
Money Market Funds	**$ 0.2**	**$ 0.2**	$ 1.6	$ 1.6
Equity Securities [(a)]	**3.9**	**4.4**	17.5	30.2
Debt Securities	**5.0**	**5.5**	5.2	5.5
Multi-Strategy Fund	**0.3**	**0.2**	0.3	0.3
	$ 9.4	**$ 10.3**	$ 24.6	$ 37.6
Liabilities				
Debt	**$ 903.4**	**$ 934.5**	$ 884.1	$ 850.6

*(a) **DPL** stock held in the **DP&L** Master Trust was cashed out at the $30/share merger* consideration price. Approximately $26.9 million in gross proceeds was received and a gain of $14.6 million was recognized in earnings.

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 2013 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 $1.0 million ($0.7 million after tax) in unrealized gains and immaterial unrealized losses on the Master Trust assets in AOCI at December 31, 2011 and $13.0 million ($8.5 million after tax) in unrealized gains and immaterial unrealized losses in AOCI at December 31, 2010. Unrealized gains in AOCI decreased due to the realization of $30/share for the **DPL Inc.** common stock held in the Master Trust as a result of the Merger.

Due to the liquidation of the **DPL Inc.** common stock, there is sufficient cash to cover the next twelve months of benefits payable to employees covered under the benefit plans. Therefore, no unrealized gains or losses are expected to be transferred to earnings since we will not need to sell any in the next twelve months.

Net Asset Value (NAV) per Unit
The following table discloses the fair value and redemption frequency for those assets whose fair value is estimated using the NAV per unit as of December 31, 2011 and 2010. These assets are part of the Master Trust. Fair values estimated using the NAV per unit are considered Level 2 inputs within the fair value hierarchy, unless they cannot be redeemed at the NAV per unit on the reporting date. Investments that have restrictions on the redemption of the investments are Level 3 inputs. As of December 31, 2011, **DP&L** did not have any investments for sale at a price different from the NAV per unit.

Fair Value Estimated Using Net Asset Value per Unit

$ in millions	Fair Value at December 31, 2011	Fair Value at December 31, 2010	Unfunded Commitments	Redemption Frequency
Money Market Fund (a)	$ 0.2	$ 1.6	$ -	Immediate
Equity Securities (b)	4.4	4.4	-	Immediate
Debt Securities (c)	5.5	5.5	-	Immediate
Multi-Strategy Fund (d)	0.2	0.3	-	Immediate
Total	$ 10.3	$ 11.8	$ -	

(a) This category includes investments in high-quality, short-term securities. Investments in this category can be redeemed immediately at the current net asset value per unit.

(b) This category includes investments in hedge funds representing an S&P 500 index and the Morgan Stanley Capital International (MSCI) U.S. Small Cap 1750 Index. Investments in this category can be redeemed immediately at the current net asset value per unit.

(c) This category includes investments in U.S. Treasury obligations and U.S. investment grade bonds. Investments in this category can be redeemed immediately at the current net asset value per unit.

(d) This category includes a mix of actively managed funds holding investments in stocks, bonds and short-term investments in a mix of actively managed funds. Investments in this category can be redeemed immediately at the current net asset value per unit.

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); or 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, 2011 and 2010.

The fair value of assets and liabilities at December 31, 2011 and 2010 measured on a recurring basis and the respective category within the fair value hierarchy for **DP&L** was determined as follows:

$ in millions	Fair Value at December 31, 2011*	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2011
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
Assets						
Master Trust Assets						
Money Market Funds	$ 0.2	$ -	$ 0.2	$ -	$ -	$ 0.2
Equity Securities (a)	4.4	-	4.4	-	-	4.4
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.2	-	0.2	-	-	0.2
Total Master Trust Assets	10.3	-	10.3	-	-	10.3
Derivative Assets						
FTRs	0.1	-	0.1	-	-	0.1
Heating Oil Futures	1.8	1.8	-	-	(1.8)	-
Forward Power Contracts	4.1	-	4.1	-	(1.0)	3.1
Total Derivative Assets	6.0	1.8	4.2	-	(2.8)	3.2
Total Assets	$ 16.3	$ 1.8	$ 14.5	$ -	$ (2.8)	$ 13.5
Liabilities						
Derivative Liabilities						
Forward Power Contracts	$ (5.0)	$ -	$ (5.0)	$ -	$ 1.7	$ (3.3)
Forward NYMEX Coal Contracts	(14.5)	-	(14.5)	-	10.8	(3.7)
Total Derivative Liabilities	(19.5)	-	(19.5)	-	12.5	(7.0)
Total Liabilities	$ (19.5)	$ -	$ (19.5)	$ -	$ 12.5	$ (7.0)

*Includes credit valuation adjustments for counterparty risk.

(a) **DPL** stock in the Master Trust was cashed out at the $30/share merger consideration price.

$ in millions	Fair Value at December 31, 2010*	Level 1 Based on Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Unobservable Inputs	Collateral and Counterparty Netting	Fair Value on Balance Sheet at December 31, 2010
	Assets and Liabilities Measured at Fair Value on a Recurring Basis					
Assets						
Master Trust Assets						
Money Market Funds	$ 1.6	$ -	$ 1.6	$ -	$ -	$ 1.6
Equity Securities (a)	30.2	25.8	4.4	-	-	30.2
Debt Securities	5.5	-	5.5	-	-	5.5
Multi-Strategy Fund	0.3	-	0.3	-	-	0.3
Total Master Trust Assets	37.6	25.8	11.8	-	-	37.6
Derivative Assets						
FTRs	0.3	-	0.3	-	-	0.3
Heating Oil Futures	1.6	1.6	-	-	(1.6)	-
Forward NYMEX Coal Contracts	37.5	-	37.5	-	(21.9)	15.6
Forward Power Contracts	0.2	-	0.2	-	(0.2)	-
Total Derivative Assets	39.6	1.6	38.0	-	(23.7)	15.9
Total Assets	$ 77.2	$ 27.4	$ 49.8	$ -	$ (23.7)	$ 53.5
Liabilities						
Derivative Liabilities						
Heating Oil Futures	$ -	$ -	$ -	$ -	$ -	$ -
Forward Power Contracts	3.1	-	3.1	-	(1.1)	2.0
Forward NYMEX Coal Contracts	-	-	-	-	-	-
Total Derivative Liabilities	3.1	-	3.1	-	(1.1)	2.0
Total Liabilities	$ 3.1	$ -	$ 3.1	$ -	$ (1.1)	$ 2.0

*Includes credit valuation adjustments for counterparty risk.

(a) **DPL** stock in the Master Trust is eliminated in consolidation.

We use the market approach to value our financial instruments. Level 1 inputs are used for **DPL** common stock held by the Master Trust and for derivative contracts such as heating oil futures. 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 financial transmission rights (where the quoted prices are from a relatively inactive market), 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.

Approximately 100% 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. There were $1.0 million and $1.4 million of gross additions to our existing river structures and asbestos AROs during the twelve months ended December 31, 2011 and 2010. In addition, it was determined that a river structure would be retired at an earlier date and at a much lower cost than previously estimated. This resulted in a partial reduction to the ARO liability of $0.8 million in 2010.

10. 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 asset and liability derivative positions with the same counterparty are netted on the balance sheet if we have a Master Netting Agreement with the counterparty. We also net any collateral posted or received against the corresponding derivative asset or liability position. 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 marked to market each reporting period.

At December 31, 2011, **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	(0.7)	6.4
Heating Oil Futures	Mark to Market	Gallons	2,772.0	-	2,772.0
Forward Power Contracts	Cash Flow Hedge	MWh	886.2	(341.6)	544.6
Forward Power Contracts	Mark to Market	MWh	525.1	(525.1)	-
NYMEX-quality Coal Contracts*	Mark to Market	Tons	2,015.0	-	2,015.0

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

At December 31, 2010, **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	9.0	-	9.0
Heating Oil Futures	Mark to Market	Gallons	6,216.0	-	6,216.0
Forward Power Contracts	Cash Flow Hedge	MWh	580.8	(572.9)	7.9
Forward Power Contracts	Mark to Market	MWh	195.6	(108.5)	87.1
NYMEX-quality Coal Contracts*	Mark to Market	Tons	4,006.8	-	4,006.8

*Includes our partners' share for the jointly-owned plants that **DP&L** operates.

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 value of cash flow hedges as 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:

	December 31, 2011		December 31, 2010		December 31, 2009	
$ in millions (net of tax)	**Power**	**Interest Rate Hedge**	Power	Interest Rate Hedge	Power	Interest Rate Hedge
Beginning accumulated derivative gain / (loss) in AOCI	**$ (1.8)**	**$ 12.2**	$ (1.4)	$ 14.7	$ (0.2)	$ 17.2
Net gains / (losses) associated with current period hedging transactions	**(1.2)**	**-**	3.1	-	2.2	-
Net (gains) / losses reclassified to earnings						
Interest Expense	**-**	**(2.4)**	-	(2.5)	-	(2.5)
Revenues	**1.2**	**-**	(3.5)	-	(3.4)	-
Purchased Power	**1.0**	**-**	-	-	-	-
Ending accumulated derivative gain / (loss) in AOCI	**$ (0.8)**	**$ 9.8**	$ (1.8)	$ 12.2	$ (1.4)	$ 14.7
Net gains / (losses) associated with the ineffective portion of the hedging transaction:						
Interest expense	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Revenues	**$ -**	**$ -**	$ -	$ -	$ -	$ -
Portion expected to be reclassified to earnings in the next twelve months*	**$ 1.3**	**$ 2.4**				
Maximum length of time that we are hedging our exposure to variability in future cash flows related to forecasted transactions (in months)	**36**	**-**				

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

The following table shows the fair value and balance sheet classification of **DP&L's** derivative instruments designated as hedging instruments at December 31, 2011.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in an Asset Position	$ 1.5	$ (0.9)	Other deferred assets	$ 0.6
Forward Power Contracts in a Liability Position	(0.2)	-	Other current liabilities	(0.2)
Total short-term cash flow hedges	1.3	(0.9)		0.4
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.1	(0.1)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(2.6)	1.7	Other deferred credits	(0.9)
Total long-term cash flow hedges	(2.5)	1.6		(0.9)
Total cash flow hedges	$ (1.2)	$ 0.7		$ (0.5)

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Designated as Hedging Instruments at December 31, 2010

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
Forward Power Contracts in a Liability Position	$ (2.8)	$ 1.0	Other current liabilities	$ (1.8)
Total short-term cash flow hedges	(2.8)	1.0		(1.8)
Long-term Derivative Positions				
Forward Power Contracts in an Asset Position	0.2	(0.2)	Other deferred assets	-
Forward Power Contracts in a Liability Position	(0.2)	0.1	Other deferred credits	(0.1)
Total long-term cash flow hedges	-	(0.1)		(0.1)
Total cash flow hedges	$ (2.8)	$ 0.9		$ (1.9)

[1] Includes credit valuation adjustment.
[2] Includes counterparty and collateral netting.

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 and the NYMEX-quality coal contracts 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, 2011 and 2010.

For the Year Ended December 31, 2011

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ (52.1)	$ 0.1	$ (0.1)	$ 0.3	$ (51.8)
Realized gain / (loss)	7.5	2.3	(0.6)	(1.4)	7.8
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ (26.1)	$ -	$ -	$ -	$ (26.1)
Regulatory (asset) / liability	(7.1)	-	-	-	(7.1)
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	(0.7)	(3.6)	(4.3)
Revenue	-	-	-	2.5	2.5
Fuel	(11.4)	2.2	-	-	(9.2)
O&M	-	0.2	-	-	0.2
Total	$ (44.6)	$ 2.4	$ (0.7)	$ (1.1)	$ (44.0)

For the Year Ended December 31, 2010

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 33.5	$ 2.8	$ (0.6)	$ 0.1	$ 35.8
Realized gain / (loss)	3.2	(1.6)	(1.5)	(0.1)	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 20.1	$ -	$ -	$ -	$ 20.1
Regulatory (asset) / liability	4.6	1.1	-	-	5.7
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	(2.1)	-	(2.1)
Fuel	12.0	0.1	-	-	12.1
O&M	-	-	-	-	-
Total	$ 36.7	$ 1.2	$ (2.1)	$ -	$ 35.8

For the Year Ended December 31, 2009

$ in millions	NYMEX Coal	Heating Oil	FTRs	Power	Total
Change in unrealized gain / (loss)	$ 4.1	$ 5.1	$ 0.8	$ (0.2)	$ 9.8
Realized gain / (loss)	1.1	(3.1)	(0.4)	-	(2.4)
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4
Recorded on Balance Sheet:					
Partners' share of gain / (loss)	$ 1.8	$ -	$ -	$ -	$ 1.8
Regulatory (asset) / liability	1.5	(0.5)	-	-	1.0
Recorded in Income Statement: gain / (loss)					
Purchased power	-	-	0.4	(0.2)	0.2
Fuel	1.9	2.3	-	-	4.2
O&M	-	0.2	-	-	0.2
Total	$ 5.2	$ 2.0	$ 0.4	$ (0.2)	$ 7.4

The following tables show the fair value and balance sheet classification of **DP&L**'s derivative instruments not designated as hedging instruments at December 31, 2011 and 2010.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2011

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.1	$ -	Other prepayments and current assets	$ 0.1
Forward Power Contracts in an Asset position	1.0	-	Other prepayments and current assets	1.0
Forward Power Contracts in a Liability position	(0.9)	-	Other current liabilities	(0.9)
NYMEX-Quality Coal Forwards in a Liability position	(8.3)	4.6	Other current liabilities	(3.7)
Heating Oil Futures in an Asset position	1.8	(1.8)	Other prepayments and current assets	-
Total short-term derivative MTM positions	(6.3)	2.8		(3.5)
Long-term Derivative Positions				
Forward Power Contracts in an Asset position	1.5	-	Other deferred assets	1.5
Forward Power Contracts in a Liability position	(1.3)	-	Other deferred credits	(1.3)
NYMEX-Quality Coal Forwards in a Liability position	(6.2)	6.2	Other deferred credits	-
Total long-term derivative MTM positions	(6.0)	6.2		0.2
Total MTM Position	$ (12.3)	$ 9.0		$ (3.3)

[1]Includes credit valuation adjustment.
[2]Includes counterparty and collateral netting.

Fair Values of Derivative Instruments Not Designated as Hedging Instruments at December 31, 2010

$ in millions	Fair Value[1]	Netting[2]	Balance Sheet Location	Fair Value on Balance Sheet
Short-term Derivative Positions				
FTRs in an Asset position	$ 0.3	$ -	Other prepayments and current assets	$ 0.3
Forward Power Contracts in a Liability position	(0.1)	-	Other current liabilities	(0.1)
NYMEX-Quality Coal Forwards in an Asset position	14.0	(7.4)	Other prepayments and current assets	6.6
Heating Oil Futures in an Asset position	0.5	(0.5)	Other prepayments and current assets	-
Total short-term derivative MTM positions	14.7	(7.9)		6.8
Long-term Derivative Positions				
NYMEX-Quality Coal Forwards in an Asset position	23.5	(14.5)	Other deferred assets	9.0
Heating Oil Futures in an Asset position	1.1	(1.1)	Other deferred assets	-
Total long-term derivative MTM positions	24.6	(15.6)		9.0
Total MTM Position	$ 39.3	$ (23.5)		$ 15.8

[1]Includes credit valuation adjustment.
[2]Includes counterparty and collateral netting.

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. If our debt were to fall below investment grade, we would be 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. The changes in our credit ratings in April 2011 have not triggered the provisions discussed above; however, there is a possibility of further downgrades related to the Merger with AES that could trigger such provisions.

The aggregate fair value of **DP&L's** derivative instruments that are in a MTM loss position at December 31, 2011 is $19.6 million. This amount is offset by $12.5 million 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 $1.6 million. If **DP&L** debt were to fall below investment grade, **DP&L** could be required to post collateral for the remaining $5.5 million.

11. Share-Based Compensation

In April 2006, **DPL's** shareholders approved The DPL Inc. Equity and Performance Incentive Plan (the EPIP) which became immediately effective for a term of ten years. The Compensation Committee of the Board of Directors designated the employees and directors eligible to participate in the EPIP and the times and types of awards to be granted. A total of 4,500,000 shares of **DPL** common stock had been reserved for issuance under the EPIP. The EPIP also covered certain employees of **DP&L**.

As a result of the Merger with AES (see Note 2), vesting of all share-based awards was accelerated as of the Merger date. The remaining compensation expense of $5.5 million ($3.6 million after tax) was expensed as of the Merger date.

The following table summarizes share-based compensation expense (note that there is no share-based compensation activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Restricted stock units	**$ -**	$ -	$ -
Performance shares	**2.4**	2.1	1.8
Restricted shares	**5.3**	1.7	0.7
Non-employee directors' RSUs (a)	**0.6**	0.4	0.5
Management performance shares	**1.8**	0.5	0.7
Share-based compensation included in Operation and maintenance expense	**10.1**	4.7	3.7
Income tax expense / (benefit)	**(3.5)**	(1.6)	(1.3)
Total share-based compensation, net of tax	**$ 6.6**	$ 3.1	$ 2.4

(a) Includes an amount associated with compensation awarded to DPL Inc.'s Board of Directors which is immaterial in total.

Share-based awards issued in **DPL's** common stock were distributed from treasury stock prior to the Merger; as of the Merger date, remaining share-based awards were distributed in cash in accordance with the Merger Agreement.

Determining Fair Value

Valuation and Amortization Method – We estimated the fair value of performance shares using a Monte Carlo simulation; restricted shares were valued at the closing market price on the day of grant and the Directors' RSUs were valued at the closing market price on the day prior to the grant date. We amortized the fair value of all awards on a straight-line basis over the requisite service periods, which are generally the vesting periods.

Expected Volatility – Our expected volatility assumptions were based on the historical volatility of **DPL** common stock. The volatility range captured the high and low volatility values for each award granted based on its specific terms.

Expected Life – The expected life assumption represented the estimated period of time from the grant date until the exercise date and reflected historical employee exercise patterns.

Risk-Free Interest Rate – The risk-free interest rate for the expected term of the award was based on the corresponding yield curve in effect at the time of the valuation for U.S. Treasury bonds having the same term as the expected life of the award, i.e., a five-year bond rate was used for valuing an award with a five year expected life.

Expected Dividend Yield – The expected dividend yield was based on **DPL's** current dividend rate, adjusted as necessary to capture anticipated dividend changes and the 12 month average **DPL** common stock price.

Expected Forfeitures – The forfeiture rate used to calculate compensation expense was based on **DPL's** historical experience, adjusted as necessary to reflect special circumstances.

Stock Options

In 2000, **DPL's** Board of Directors adopted and **DPL's** shareholders approved The DPL Inc. Stock Option Plan. With the approval of the EPIP in April 2006, no new awards were granted under The DPL Inc. Stock Option Plan. Prior to the Merger, all outstanding stock options had been exercised or had expired.

Summarized stock option activity was as follows (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Options:			
Outstanding at beginning of period	**351,500**	417,500	836,500
Granted	**-**	-	-
Exercised	**(75,500)**	(66,000)	(419,000)
Expired	**(276,000)**	-	-
Forfeited	**-**	-	-
Outstanding at end of period	**-**	351,500	417,500
Exercisable at end of period	**-**	351,500	417,500
Weighted average option prices per share:			
Outstanding at beginning of period	**$ 28.04**	$ 27.16	$ 24.64
Granted	**$ -**	$ -	$ -
Exercised	**$ 21.02**	$ 21.00	$ 21.53
Expired	**$ 29.42**	$ -	$ -
Forfeited	**$ -**	$ -	$ -
Outstanding at end of period	**$ -**	$ 28.04	$ 27.16
Exercisable at end of period	**$ -**	$ 28.04	$ 27.16

The following table reflects information about stock option activity during the period (note that there is no stock option activity after November 27, 2011 as a result of the Merger):

$ in millions	2011	2010	2009
	For the years ended December 31,		
Weighted-average grant date fair value of options granted during the period	$ -	$ -	$ -
Intrinsic value of options exercised during the period	$ **0.7**	$ 0.5	$ 2.2
Proceeds from stock options exercised during the period	$ **1.6**	$ 1.4	$ 9.0
Excess tax benefit from proceeds of stock options exercised	$ **0.2**	$ 0.1	$ 0.7
Fair value of shares that vested during the period	$ -	$ -	$ -
Unrecognized compensation expense	$ -	$ -	$ -
Weighted average period to recognize compensation expense (in years)	-	-	-

Restricted Stock Units (RSUs)
RSUs were granted to certain key employees prior to 2001. As of the Merger date, there were no RSUs outstanding.

Summarized RSU activity was as follows (note that there is no RSU activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
RSUs:			
Outstanding at beginning of period	-	3,311	10,120
Granted	-	-	-
Dividends	-	-	-
Exercised	-	(3,311)	(6,809)
Forfeited	-	-	-
Outstanding at end of period	-	-	3,311
Exercisable at end of period	-	-	-

Performance Shares
Under the EPIP, the Board of Directors adopted a Long-Term Incentive Plan (LTIP) under which **DPL** granted a targeted number of performance shares of common stock to executives. Grants under the LTIP were awarded based on a Total Shareholder Return Relative to Peers performance. The Total Shareholder Return Relative to Peers is considered a market condition in accordance with the accounting guidance for share-based compensation.

At the Merger date, vesting for all non-vested LTIP performance shares was accelerated on a pro rata basis and such shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Performance Share activity was as follows (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Performance shares:			
Outstanding at beginning of year	**278,334**	237,704	156,300
Granted	**85,093**	161,534	124,588
Exercised	**(198,699)**	(91,253)	-
Expired	**(66,836)**	-	(36,445)
Forfeited	**(97,892)**	(29,651)	(6,739)
Outstanding at period end	-	278,334	237,704
Exercisable at period end	-	66,836	47,355

The following table reflects information about Performance Share activity during the period (note that there is no Performance Share activity after November 27, 2011 as a result of the Merger):

$ in millions	*For the years ended December 31,* 2011	2010	2009
Weighted-average grant date fair value of performance shares granted during the period	**$ 2.2**	$ 2.9	$ 2.8
Intrinsic value of performance shares exercised during the period	**$ 6.0**	$ 2.5	$ -
Proceeds from performance shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of performance shares exercised	**$ 0.7**	$ -	$ -
Fair value of performance shares that vested during the period	**$ 4.7**	$ 1.6	$ 1.6
Unrecognized compensation expense	**$ -**	$ 2.4	$ 2.1
Weighted average period to recognize compensation expense (in years)	**-**	1.7	1.7

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the performance shares granted during the period:

	For the years ended December 31, 2011	2010	2009
Expected volatility	**24.0%**	24.3%	22.8% - 23.3%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.4% - 5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	0.3% - 1.5%

Restricted Shares

Under the EPIP, the Board of Directors granted shares of **DPL** Restricted Shares to various executives and other key employees. These Restricted Shares were registered in the recipient's name, carried full voting privileges, received dividends as declared and paid on all **DPL** common stock and vested after a specified service period.

In July 2008, the Board of Directors granted Restricted Share awards under the EPIP to a select group of management employees. The management Restricted Share awards had a three-year requisite service period, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

On September 17, 2009, the Board of Directors approved a two-part equity compensation award under the EPIP for certain of **DPL's** executive officers. The first part was a Restricted Share grant and the second part was a matching Restricted Share grant. These Restricted Share grants generally vested after five years if the participant remained continuously employed with **DPL** or a **DPL** subsidiary and if the year-over-year average EPS had increased by at least 1% from 2009 to 2013. Under the matching Restricted Share grant, participants had a three-year period from the date of plan implementation during which they could purchase **DPL** common stock equal in value to up to two times their 2009 base salary. **DPL** matched the shares purchased with another grant of Restricted Shares (matching Restricted Share grant). The percentage match by **DPL** is detailed in the table below. The matching Restricted Share grant would have generally vested over a three-year period if the participant continued to hold the originally purchased shares and remained continuously employed with **DPL** or a **DPL** subsidiary. The Restricted Shares were registered in the recipient's name, carried full voting privileges and received dividends as declared and paid on all **DPL** common stock.

The matching criteria were:

Value (Cost Basis) of Shares Purchased as a % of 2009 Base Salary	Company % Match of Value of Shares Purchased
1% to 25%	25%
>25% to 50%	50%
>50% to 100%	75%
>100% to 200%	125%

The matching percentage was applied on a cumulative basis and the resulting Restricted Share grant was adjusted at the end of each calendar quarter. As a result of the Merger, the matching Restricted Share grants were suspended in March 2011.

In February 2011, the Board of Directors granted a targeted number of time-vested Restricted Shares to executives under the Long-Term Incentive Plan (LTIP). These Restricted Shares did not carry voting privileges nor did they receive dividend rights during the vesting period. In addition, a one-year holding period was implemented after the three-year vesting period was completed.

Restricted Shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested Restricted Shares was accelerated and all outstanding shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Restricted Share activity was as follows (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Restricted shares:			
Outstanding at beginning of year	**219,391**	218,197	69,147
Granted	**67,346**	42,977	159,050
Exercised	**(286,737)**	(20,803)	(10,000)
Forfeited	-	(20,980)	-
Outstanding at period end	-	219,391	218,197
Exercisable at period end	-	-	-

The following table reflects information about Restricted Share activity during the period (note that there is no Restricted Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Weighted-average grant date fair value of restricted shares granted during the period	**$ 1.8**	$ 1.1	$ 4.2
Intrinsic value of restricted shares exercised during the period	**$ 8.6**	$ 0.4	$ 0.3
Proceeds from restricted shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of restricted shares exercised	**$ 0.5**	$ 0.1	$ -
Fair value of restricted shares that vested during the period	**$ 7.5**	$ 0.6	$ 0.3
Unrecognized compensation expense	**$ -**	$ 3.4	$ 4.3
Weighted average period to recognize compensation expense (in years)	-	2.7	3.4

Non-Employee Director Restricted Stock Units

Under the EPIP, as part of their annual compensation for service to **DPL** and **DP&L**, each non-employee Director received a retainer in RSUs on the date of the shareholders' annual meeting. The RSUs became non-forfeitable on April 15 of the following year. The RSUs accrued quarterly dividends in the form of additional RSUs. Upon vesting, the RSUs became exercisable and were distributed in **DPL** common stock, unless the Director chose to defer receipt of the shares until a later date. The RSUs were valued at the closing stock price on the day prior to the grant and the compensation expense was recognized evenly over the vesting period.

At the Merger date, vesting for the remaining non-vested RSUs was accelerated and all vested RSUs (current and prior years) were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

The following table reflects information about Restricted Stock Unit activity (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Restricted stock units:			
Outstanding at beginning of year	**16,320**	20,712	15,546
Granted	**14,392**	15,752	20,016
Dividends accrued	**3,307**	2,484	1,737
Vested and exercised	**(34,019)**	(2,618)	(2,066)
Vested, exercised and deferred	-	(20,010)	(14,521)
Forfeited	-	-	-
Outstanding at period end	-	16,320	20,712
Exercisable at period end	-	-	-

The following table reflects information about non-employee Director RSU activity during the period (note that there is no non-employee Director RSU activity after November 27, 2011 as a result of the Merger):

$ in millions	For the years ended *December 31,*		
	2011	2010	2009
Weighted-average grant date fair value of non-employee Director RSUs granted during the period	**$ 0.5**	$ 0.5	$ 0.5
Intrinsic value of non-employee Director RSUs exercised during the period	**$ 1.0**	$ 0.5	$ 0.4
Proceeds from non-employee Director RSUs exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of non-employee Director RSUs exercised	**$ -**	$ -	$ -
Fair value of non-employee Director RSUs that vested during the period	**$ 1.0**	$ 0.6	$ 0.5
Unrecognized compensation expense	**$ -**	$ 0.1	$ 0.1
Weighted average period to recognize compensation expense (in years)	-	0.3	0.3

Management Performance Shares

Under the EPIP, the Board of Directors granted compensation awards for select management employees. The grants had a three year requisite service period and certain performance conditions during the performance period. The management performance shares could only be awarded in **DPL** common stock.

At the Merger date, vesting for all non-vested management performance shares was accelerated; some of the awards vested at target shares and other awards vested at a pro rata share of target. All vested shares were cashed out at the $30.00 per share merger consideration price in accordance with the Merger Agreement.

Summarized Management Performance Share activity was as follows (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
	2011	2010	2009
Management performance shares:			
Outstanding at beginning of year	**104,124**	84,241	39,144
Granted	**49,510**	37,480	48,719
Expired	**(31,081)**	-	-
Exercised	**(111,289)**	-	-
Forfeited	**(11,264)**	(17,597)	(3,622)
Outstanding at period end	**-**	104,124	84,241
Exercisable at period end	**-**	31,081	-

The following table shows the assumptions used in the Monte Carlo Simulation to calculate the fair value of the Management Performance Shares granted during the period:

	For the years ended December 31,		
	2011	2010	2009
Expected volatility	**24.0%**	24.3%	22.8%
Weighted-average expected volatility	**24.0%**	24.3%	22.8%
Expected life (years)	**3.0**	3.0	3.0
Expected dividends	**5.0%**	4.5%	5.6%
Weighted-average expected dividends	**5.0%**	4.5%	5.6%
Risk-free interest rate	**1.2%**	1.4%	1.5%

The following table reflects information about Management Performance Share activity during the period (note that there is no Management Performance Share activity after November 27, 2011 as a result of the Merger):

	For the years ended December 31,		
$ in millions	**2011**	2010	2009
Weighted-average grant date fair value of management perfomance shares granted during the period	**$ 1.3**	$ 0.9	$ 1.0
Intrinsic value of management performance shares exercised during the period	**$ 3.3**	$ -	$ -
Proceeds from management performance shares exercised during the period	**$ -**	$ -	$ -
Excess tax benefit from proceeds of management performance shares exercised	**$ -**	$ -	$ -
Fair value of management performance shares that vested during the period	**$ 2.7**	$ 0.9	$ -
Unrecognized compensation expense	**$ -**	$ 0.9	$ 1.0
Weighted average period to recognize compensation expense (in years)	**-**	1.7	1.6

12. 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, 2011. **DP&L** also has $25 par value preferred stock, 4,000,000 shares authorized, none of which was outstanding as of December 31, 2011. The table below details the preferred shares outstanding at December 31, 2011:

	Preferred Stock Rate	Redemption Price at December 31, 2011	Shares Outstanding at December 31, 2011	Par Value at December 31, 2011 ($ in millions)	Par Value at December 31, 2010 ($ in millions)
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. 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, 2011, **DP&L's** retained earnings of $589.1 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 Results of Operations.

13. Common Shareholders' Equity

DP&L has 250,000,000 authorized common shares, of which 41,172,173 are outstanding at December 31, 2011. 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.

14. Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business entity during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: Net income (loss) and Other comprehensive income (loss).

The following table provides the tax effects allocated to each component of Other comprehensive income (loss) for **DP&L** for the years ended December 31, 2011, 2010 and 2009:

$ in millions	Amount before tax	Tax (expense) / benefit	Amount after tax
2009:			
Unrealized gains / (losses) on financial instruments	$ 4.2	$ (1.5)	$ 2.7
Deferred gains / (losses) on cash flow hedges	(4.3)	0.6	(3.7)
Unrealized gains / (losses) on pension and postretirement benefits	(4.1)	1.4	(2.7)
Other comprehensive income (loss)	$ (4.2)	$ 0.5	$ (3.7)
2010:			
Unrealized gains / (losses) on financial instruments	$ (1.6)	$ 0.6	$ (1.0)
Deferred gains / (losses) on cash flow hedges	(3.1)	0.3	(2.8)
Unrealized gains / (losses) on pension and postretirement benefits	4.3	(1.0)	3.3
Other comprehensive income (loss)	$ (0.4)	$ (0.1)	$ (0.5)
2011:			
Unrealized gains / (losses) on financial instruments	**$ (12.1)**	**$ 4.3**	**$ (7.8)**
Deferred gains / (losses) on cash flow hedges	**(0.9)**	**(0.6)**	**(1.4)**
Unrealized gains / (losses) on pension and postretirement benefits	**(8.7)**	**3.6**	**(5.2)**
Other comprehensive income (loss)	**$ (21.7)**	**$ 7.3**	**$ (14.4)**

The following table provides the detail of each component of Other comprehensive income (loss) reclassified to Net income:

$ in millions	**2011**	2010	2009
Unrealized gains / (losses) on financial instruments net of income tax (expenses) / benefits of ($5.4) million, zero and ($0.4) million, respectively.	**$ 10.1**	$ (0.1)	$ 0.7
Deferred gains / (losses) on cash flow hedges net of income tax (expenses) / benefits of ($2.1) million, $2.0 million and ($1.8) million, respectively.	**(3.8)**	(6.0)	5.9
Unrealized losses on pension and postretirement benefits net of income tax benefits of $1.6 million, $1.3 million and $1.1 million respectively.	**(3.0)**	(2.4)	(2.1)
Total	**$ 3.3**	$ (8.5)	$ 4.5

Accumulated Other Comprehensive Income (Loss)

AOCI is included on our balance sheets within the Common shareholders' equity sections. The following table provides the components that constitute the balance sheet amounts in AOCI at December 31, 2011 and 2010:

$ in millions	**2011**	2010
Financial instruments, net of tax	**$ 0.6**	$ 8.4
Cash flow hedges, net of tax	**9.0**	10.5
Pension and postretirement benefits, net of tax	**(44.3)**	(39.1)
Total	**$ (34.7)**	$ (20.2)

DP&L – Equity Ownership Interest
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. As of December 31, 2011, **DP&L** could be responsible for the repayment of 4.9%, or $65.3 million, of a $1,332.3 million debt obligation comprised of both fixed and variable rate securities with maturities between 2013 and 2040. This would only happen if this electric generation company defaulted on its debt payments. As of December 31, 2011, 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, 2011, these include:

		Payment Due			
$ in millions	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Long-term debt	$ 903.7	$ 0.4	$ 470.8	$ 0.2	$ 432.3
Interest payments	404.3	39.9	49.9	31.8	282.7
Pension and postretirement payments	261.1	25.6	50.8	52.1	132.6
Capital leases	0.7	0.3	0.4	-	-
Operating leases	1.5	0.5	0.8	0.2	-
Coal contracts	818.6	233.4	265.6	162.6	157.0
Limestone contracts	34.8	5.8	11.6	11.6	5.8
Purchase orders and other contractual obligations	71.3	57.5	7.8	6.0	-
Total contractual obligations	$ 2,496.0	$ 363.4	$ 857.7	$ 264.5	$ 1,010.4

Long-term debt:
DP&L's long-term debt as of December 31, 2011, consists of first mortgage bonds and tax-exempt pollution control bonds. These long-term debt amounts include current maturities but exclude unamortized debt discounts.

See Note 7 for additional information.

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, 2011.

Pension and postretirement payments:
As of December 31, 2011, **DP&L** had estimated future benefit payments as outlined in Note 8. These estimated future benefit payments are projected through 2020.

Capital leases:
As of December 31, 2011, **DP&L** had two immaterial capital leases that expire in 2013 and 2014.

Operating leases:
As of December 31, 2011, **DP&L** had several immaterial operating leases with various terms and expiration dates. Total lease expense under operating leases was $0.6 million in 2011.

Coal contracts:
DP&L has entered into various long-term coal contracts to supply the coal requirements for the generating plants it operates. 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, 2011, **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 $25.0 million, 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.

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, 2011, cannot be reasonably determined.

Environmental Matters
DP&L's facilities and operations are subject to a wide range of federal, state and local environmental regulations and laws. 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. We have estimated liabilities of approximately $3.4 million for environmental matters. We evaluate the potential liability related to probable losses 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 power plants. Some of these matters could have material adverse impacts on the operation of the power plants; especially the plants that do not have SCR and FGD equipment installed to further control certain emissions. Currently, Hutchings and Beckjord are our only coal-fired power plants that do not have this equipment installed. **DP&L** owns 100% of the Hutchings plant and a 50% interest in Beckjord Unit 6.

On July 15, 2011, Duke Energy, co-owner at the Beckjord Unit 6 facility, filed their Long-term Forecast Report with the PUCO. The plan indicated that Duke Energy plans to cease production at the Beckjord Station, including our jointly-owned Unit 6, in December 2014. We are depreciating Unit 6 through December 2014 and do not believe that any additional accruals or impairment charges are needed as a result of this decision. We are considering options for Hutchings Station, but have not yet made a final decision. We do not believe that any accruals or impairment charges are needed related to the Hutchings Station.

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.

Cross-State Air Pollution Rule
The Clean Air Interstate Rule (CAIR) final rules were published on May 12, 2005. CAIR created an interstate trading program for annual NOx emission allowances and made modifications to an existing trading program for SO_2. Litigation brought by entities not including **DP&L** resulted in a decision by the U.S. Court of Appeals for the District of Columbia Circuit on July 11, 2008 to vacate CAIR and its associated Federal Implementation Plan. On December 23, 2008, the U.S. Court of Appeals issued an order on reconsideration that permits CAIR to remain in effect until the USEPA issues new regulations that would conform to the CAA requirements and the Court's July 2008 decision.

In an attempt to conform to the Court's decision, on July 6, 2010, the USEPA proposed the Clean Air Transport Rule (CATR). These rules were finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011, but subsequent litigation has resulted in their implementation being delayed indefinitely. CSAPR creates four separate trading programs: two SO_2 areas (Group 1 and Group 2); and two NOx reduction requirements (annual and ozone season). Group 1 states (16 states including Ohio) will have to meet a 2012 cap and additional reductions in 2014. Group 2 states (7 states) will only have to meet the 2012 cap. We do not believe the rule will have a material impact on our operations in 2012. The Ohio EPA has a State Implementation Plan (SIP) that incorporates the CAIR program requirements, which remain in effect pending judicial review of CSAPR. If and when CSAPR becomes effective, it is expected to institute a federal implementation plan (FIP) in lieu of state SIPs and allow for the states to develop SIPs for approval as early as 2013. **DP&L** is unable to estimate the effect of the new requirements; however, CSAPR could have a material effect on our operations.

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 EPA Administrator signed the final rule, now called MATS (Mercury and Air Toxics Standards), on December 16, 2011, and the rule was published in the Federal Register on February 16, 2012. Affected electric generating units (EGUs) will have to come into compliance with the new requirements by April 16, 2015, but may be granted an additional year contingent on Ohio EPA approval. **DP&L** is evaluating the costs that may be incurred to comply with the new requirement; however, MATS could have a material adverse effect on our operations and result in material compliance costs.

On April 29, 2010, the USEPA issued a proposed rule that would reduce emissions of toxic air pollutants from new and existing industrial, commercial and institutional boilers, and process heaters at major and area source facilities. The final rule was published in the Federal Register on March 21, 2011. This regulation affects seven auxiliary boilers used for start-up purposes at **DP&L's** generation facilities. The regulations contain emissions limitations, operating limitations and other requirements. The compliance date was originally March 21, 2014. However, the USEPA has announced that the compliance date for existing boilers will be delayed until a judicial review is no longer pending or until the EPA completes its reconsideration of the rule. In December 2011, the EPA proposed additional changes to this rule and solicited comments. Compliance costs are not expected to be material to **DP&L's** operations.

On May 3, 2010, the USEPA finalized the "National Emissions Standards for Hazardous Air Pollutants" for compression ignition (CI) reciprocating internal combustion engines (RICE). The units affected at **DP&L** are 18 diesel electric generating engines and eight emergency "black start" engines. The existing CI RICE units must comply by May 3, 2013. The regulations contain emissions limitations, operating limitations and other requirements. Compliance costs on **DP&L's** operations are not expected to be material.

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. As of December 31, 2011, **DP&L's** Stuart, Killen and Hutchings Stations were located in non-attainment areas for the annual PM 2.5 standard. There is a possibility that these areas will be re-designated as "attainment" for PM 2.5 within the next few quarters. 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.

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. In the final rule, the USEPA made the determination that CAIR achieves greater progress than BART and may be used by states as a BART substitute. 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.

On September 16, 2009, the USEPA announced that it would reconsider the 2008 national ground level ozone standard. On September 2, 2011, the USEPA decided to postpone their revisiting of this standard until 2013. **DP&L** cannot determine the effect of this potential change, if any, on its 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 revisions to its primary NAAQS for SO_2 replacing the current 24-hour standard and annual standard with a one hour standard. **DP&L** cannot determine the effect of this potential change, if any, on its operations. No effects are anticipated before 2014.

Carbon Emissions and Other Greenhouse Gases
In response to a U.S. Supreme Court decision that the USEPA has the authority to regulate CO_2 emissions from motor vehicles, the USEPA made a finding that CO_2 and certain other GHGs are pollutants under the CAA. Subsequently, under the CAA, USEPA determined that CO_2 and other GHGs from motor vehicles threaten the health and welfare of future generations by contributing to climate change. This finding became effective in January 2010. Numerous affected parties have petitioned the USEPA Administrator to reconsider this decision. On April 1, 2010, USEPA signed the "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards" rule. Under USEPA's view, this is the final action that renders carbon dioxide and other GHGs "regulated air pollutants" under the CAA.

Under USEPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the USEPA began regulating GHG emissions from certain stationary sources in January 2011. The Tailoring rule sets forth criteria for determining which facilities are required to obtain permits for their GHG emissions pursuant to the CAA Prevention of Significant Deterioration and Title V operating permit programs. Under the Tailoring Rule, permitting requirements are being phased in through successive steps that may expand the scope of covered sources over time. The USEPA has issued guidance on what the best available control technology entails for the control of GHGs and individual states are required to determine what controls are required for facilities on a case-by-case basis. The ultimate impact of the Tailoring Rule to **DP&L** cannot be determined at this time, but the cost of compliance could be material.

The USEPA plans to propose GHG standards for new and modified electric generating units (EGUs) under CAA subsection 111(b) – and propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d) during 2012. These rules may focus on energy efficiency improvements at power plants. We cannot predict the effect of these standards, if any, on **DP&L's** operations.

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 16 million tons annually. Further GHG legislation or regulation finalized 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**.

On September 22, 2009, the USEPA issued a final rule for mandatory reporting of GHGs from large sources that emit 25,000 metric tons per year or more of CO_2, including electric generating units. **DP&L's** first report to the USEPA was submitted prior to the September 30, 2011 due date for 2010 emissions. This reporting rule will guide development of policies and programs to reduce emissions. **DP&L** does not anticipate that this reporting rule will result in any significant cost or other impact on current operations.

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

Litigation Involving Co-Owned Plants
On June 20, 2011, the U.S. Supreme Court ruled that the USEPA's regulation of GHGs under the CAA displaced any right that plaintiffs may have had to seek similar regulation through federal common law litigation in the court system. Although we are not named as a party to these lawsuits, **DP&L** is a co-owner of coal-fired plants with Duke Energy and AEP (or their subsidiaries) that could have been affected by the outcome of these lawsuits or similar suits that may have been filed against other electric power companies, including **DP&L**. Because the issue was not squarely before it, the U.S. Supreme Court did not rule against the portion of plaintiffs' original suits that sought relief under state law.

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 J.M. Stuart generating station are subject to certain specified emission targets related to NOx, 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 Plants
In November 1999, the USEPA filed civil complaints and NOVs against operators and owners of certain generation facilities for alleged violations of the CAA. Generation units operated by Duke Energy (Beckjord Unit 6) and CSP (Conesville Unit 4) and co-owned by **DP&L** were referenced in these actions. Although **DP&L** was not identified in the NOVs, civil complaints or state actions, the results of such proceedings could materially affect **DP&L's** co-owned plants.

In June 2000, the USEPA issued a NOV to the **DP&L**-operated J.M. Stuart generating station (co-owned by **DP&L**, Duke Energy, and CSP) 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 a 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 a NOV and a Finding of Violation (FOV) from the USEPA alleging violations of the CAA, the Ohio State Implementation Program (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, USEPA issued an NOV to Zimmer for excess emissions. **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.

Notices of Violation Involving Wholly-Owned Plants
In 2007, the Ohio EPA and the USEPA issued NOVs to **DP&L** for alleged violations of the CAA at the O.H. Hutchings Station. The NOVs' alleged deficiencies relate to stack opacity and particulate emissions. Discussions are under way with the USEPA, the U.S. Department of Justice and Ohio EPA. On November 18, 2009, the USEPA issued an NOV to **DP&L** for alleged NSR violations of the CAA at the O.H. 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. **DP&L** is engaged in discussions with the USEPA and Justice Department to resolve these matters, but **DP&L** is unable to determine the timing, costs or method by which these issues may be resolved. The Ohio EPA is kept apprised of these discussions.

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

Clean Water Act – Regulation of Water Intake
On July 9, 2004, the USEPA issued final rules pursuant to the Clean Water Act 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. A number of parties appealed the rules. In April 2009, the U.S. Supreme Court ruled that the USEPA did have the authority to compare costs with benefits in determining best technology available. The USEPA released new proposed regulations on March 28, 2011, published in the Federal Register on April 20, 2011. We submitted comments to the proposed regulations on August 17, 2011. The final rules are expected to be in place by mid-2012. We do not yet know the impact these proposed rules will have on our operations.

Clean Water Act – Regulation of Water Discharge
In December 2006, we submitted an application for the renewal of the Stuart Station NPDES Permit that was due to expire on June 30, 2007. In July 2007, we received a draft permit proposing to continue our authority to discharge water from the station into the Ohio River. On February 5, 2008, we received a letter from the Ohio EPA indicating that they intended to impose a compliance schedule as part of the final Permit, that requires us to implement one of two diffuser options for the discharge of water from the station into the Ohio River as identified in a thermal discharge study completed during the previous permit term. Subsequently, **DP&L** and the Ohio EPA reached an agreement to allow **DP&L** to restrict public access to the water discharge area as an alternative to installing one of the diffuser options. Ohio EPA issued a revised draft permit that was received on November 12, 2008. In December 2008, the USEPA requested that the Ohio EPA provide additional information regarding the thermal discharge in the draft permit. In June 2009, **DP&L** provided information to the USEPA in response to their request to the Ohio EPA. In September 2010, the USEPA formally objected to a revised permit provided by

Ohio EPA due to questions regarding the basis for the alternate thermal limitation. In December 2010, **DP&L** requested a public hearing on the objection, which was held on March 23, 2011. We participated in and presented our position on the issue at the hearing and in written comments submitted on April 28, 2011. 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 does not re-draft the permit to address the USEPA's objection, then the authority for issuing the permit will 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 would require **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 and is considering legal options. Depending on the outcome of the process, the effects could be material on **DP&L's** operation.

In September 2009, the USEPA announced that it will 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. Subsequent to the information collection effort, it is anticipated that the USEPA will release a proposed rule by mid-2012 with a final regulation in place by early 2014. At present, **DP&L** is unable to predict the impact this rulemaking will have on its 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. However, 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, is ongoing. 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 us.

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 us.

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**. The USEPA has indicated that a proposed rule will be released in late 2012. 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 J.M. Stuart Stations. Subsequently, the USEPA collected similar information for O.H. Hutchings Station.

In August 2010, the USEPA conducted an inspection of the O.H. Hutchings Station ash ponds. In June 2011, the USEPA issued a final report from the inspection including recommendations relative to the O.H. 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. **DP&L** is unable to predict the outcome this inspection will have on its operations.

There has been increasing advocacy to regulate coal combustion byproducts 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 anticipates issuing a final rule on this topic in late 2012. **DP&L** is unable to predict the financial impact of this regulation, but if coal combustion byproducts are regulated as hazardous waste, it is expected to have a material adverse effect on **DP&L's** operations.

Notice of Violation involving Co-Owned Plants
On September 9, 2011, **DP&L** received a notice of violation from the USEPA with respect to its co-owned J.M. 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 Clean Water Act National Pollutant Discharge Elimination System 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 flow.

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 plants 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. With respect to unsettled claims, **DP&L** management has deferred $17.8 million and $15.4 million as of December 31, 2011 and December 31, 2010, respectively, as Other deferred credits representing the amount of unearned income and interest where the earnings process is not complete. The amount at December 31, 2011 includes estimated interest of $5.2 million. On September 30, 2011, the FERC issued two SECA-related orders that affirmed an earlier order issued in 2010 by denying the rehearing requests that a number of different parties, including **DP&L**, had filed. These orders are now final, subject to possible appellate court review. These orders do not affect prior settlements that had been reached with other parties that owed SECA revenues to **DP&L** or were recipients of amounts paid by **DP&L**. For other parties that had not previously settled with **DP&L**, the exact timing and amounts of any payments that would be made or received by **DP&L** under these orders is still uncertain.

16. *Selected Quarterly Information (Unaudited)*

	For the three months ended			
$ in millions	March 31, **2011**	June 30, **2011**	September 30, **2011**	December 31, **2011**
Revenues	**$ 449.8**	**$ 397.0**	**$ 452.5**	**$ 378.4**
Operating income	**$ 89.3**	**$ 55.8**	**$ 100.0**	**$ 74.8**
Net income	**$ 52.7**	**$ 30.8**	**$ 63.9**	**$ 45.8**
Earnings on common stock	**$ 52.5**	**$ 30.6**	**$ 63.7**	**$ 45.5**
Dividends paid on common stock to **DPL**	**$ 70.0**	**$ 45.0**	**$ 65.0**	**$ 40.0**

	For the three months ended			
$ in millions	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Revenues	$ 423.8	$ 412.6	$ 472.4	$ 430.0
Operating income	$ 118.4	$ 97.0	$ 131.9	$ 102.9
Net income	$ 72.1	$ 59.4	$ 83.2	$ 63.0
Earnings on common stock	$ 71.9	$ 59.2	$ 83.0	$ 62.7
Dividends paid on common stock to **DPL**	$ 90.0	$ 60.0	$ -	$ 150.0

Item 9 – Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On November 28, 2011, **DPL** changed auditors to Ernst & Young LLP. **DP&L** continued to use KPMG LLP through December 31, 2011 but changed auditors to Ernst & Young LLP effective January 1, 2012. Ernst & Young LLP are the auditors of AES.

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 our disclosure controls and procedures are effective: (i) 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; and (ii) to ensure that information required to be disclosed by us in the reports that we submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting during the most recently completed fiscal period that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

The following report is our report on internal control over financial reporting as of December 31, 2011.

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). Under the supervision and with the participation of management, including the CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on an evaluation under the framework in *Internal Control - Integrated Framework*, we concluded that our internal control over financial reporting was effective as of December 31, 2011.

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 and KPMG LLP for 2011 and 2010. Other than as set forth below, no professional services were rendered or fees billed by Ernst & Young LLP and KPMG LLP during 2011 and 2010.

Ernst & Young (DPL only)		**2011 Fees Billed**
Audit Fees (1)	$	550,000
Audit-Related Fees (2)		-
Tax Fees (3)		-
All Other Fees (4)		-
Total	$	550,000

KPMG LLP		**2011 Fees Billed**		**2010 Fees Billed**
Audit Fees (1)	$	2,080,046	$	1,269,200
Audit-Related Fees (2)		41,000		40,000
Tax Fees (3)		4,000		930
All Other Fees (4)		12,000		15,000
Total	$	2,137,046	$	1,325,130

(1) 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.

(2) Audit-related fees relate to services rendered to us for assurance and related services.

(3) Tax fees consisted principally of tax compliance services.

(4) Other fees relate to services rendered under an agreed upon procedure engagement related to environmental studies.

PART IV

Item 15 – Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this report:

1. **Financial Statements**

	Page No.
DPL - Report of Independent Registered Public Accounting Firms	77
DPL - Consolidated Statements of Results of Operations for the periods November 28, 2011 through December 31, 2011, January 1, 2011 through November 27, 2011 and the years ended December 31, 2010 and 2009.	79
DPL - Consolidated Statements of Cash Flows for the periods November 28, 2011 through December 31, 2011, January 1, 2011 through November 27, 2011 and the years ended December 31, 2010 and 2009.	80
DPL - Consolidated Balance Sheets at December 31, 2011 and 2010	81
DPL - Consolidated Statement of Shareholders' Equity for the periods November 28, 2011 through December 31, 2011, January 1, 2011 through November 27, 2011 and the years ended December 31, 2010 and 2009.	83
Notes to Consolidated Financial Statements	84
DP&L - Report of Independent Registered Public Accounting Firm	149
DP&L - Statements of Results of Operations for each of the three years in the period ended December 31, 2011	150
DP&L - Statements of Cash Flows for each of the three years in the period ended December 31, 2011	151
DP&L - Balance Sheets at December 31, 2011 and 2010	152
DP&L - Statement of Shareholder's Equity for each of the three years in the period ended December 31, 2011	154
Notes to Financial Statements	155

2. **Financial Statement Schedule**

For each of the three years in the period ended December 31, 2011:

Schedule II – Valuation and Qualifying Accounts	213

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.

3. **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 Inc.	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. 1-9052)
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 Inc.	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. 1-9052)
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. 1-9052)
X	X	10(a)	Credit Agreement, dated as of April 20, 2010, among the Dayton Power and Light Company, Bank of America, N.A., as Administrative Agent and an L/C Issuer, and the lenders party to the Credit Agreement	Exhibit 10.1 to Form 8-K filed April 22, 2010 (File No. 1-2385)
X	X	10(b)	Limited Consent and Waiver, dated as of May 24, 2011, to the Credit Agreement, dated as of April 20, 2010, among The Dayton Power and Light Company, Bank of America, N.A., as Administrative Agent and an L/C Issuer, and the lenders party to the Credit Agreement	Exhibit 10.1 to Report on Form 8-K filed May 31, 2011 (File No. 1-2385)
X	X	10(c)	First Amendment Agreement, dated as of November 18, 2011, to the Credit Agreement, dated as of April 20, 2010, among The Dayton Power and Light Company, Bank of America, N.A., as Administrative Agent and an L/C Issuer, and the lender party to the Credit Agreement	Exhibit 10(c) to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-9052)

DPL Inc.	DP&L	Exhibit Number	Exhibit	Location
X		10(d)	Credit Agreement, dated as of August 24, 2011, among DPL Inc., PNC Bank, National Association, as Administrative Agent, Bank of America, N.A., Fifth Third Bank and U.S. Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-9052)
X		10(e)	Credit Agreement, dated as of August 24, 2011, among DPL Inc., U.S. Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer, Bank of America, N.A., Fifth Third Bank and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-9052)
X	X	10(f)	Credit Agreement, dated as of August 24, 2011, among The Dayton Power and Light Company, Fifth Third Bank, as Administrative Agent, Swing Line Lender and an L/C Issuer, Bank of America, N.A., U.S. Bank, National Association and PNC Bank, National Association, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and the lenders party to the Credit Agreement	Exhibit 10(b) to Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-2385)
X	X	21	List of Subsidiaries of DPL Inc. and The Dayton Power and Light Company	Exhibit 21 to Report on Form 10-K for the year ended December 31, 2011 (File No. 1-9052)
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)
DPL Inc.	DP&L	Exhibit	Exhibit	Location

		Number		
	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)
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 amendment to be signed on their behalf by the undersigned, thereunto duly authorized.

DPL Inc.

March 28, 2012	By:	/s/ Philip Herrington Philip Herrington President and Chief Executive Officer (principal executive officer)

The Dayton Power and Light Company

March 28, 2012	By:	/s/ Philip Herrington Philip Herrington President and Chief Executive Officer (principal executive officer)

Schedule II

DPL Inc.
VALUATION AND QUALIFYING ACCOUNTS

For the years ended December 31, 2009 - 2011

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions (1)	Balance at End of Period
November 28, 2011 through December 31, 2011 (Successor):				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,062	$ 643	$ 569	$ 1,136
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 7,086	$ 349	$ 733	$ 6,702
January 1, 2011 through November 27, 2011 (Predecessor):				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 871	$ 5,716	$ 5,525	$ 1,062
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 13,079	$ 2,705	$ 8,698	$ 7,086
2010 (Predecessor):				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,101	$ 4,148	$ 4,378	$ 871
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 11,955	$ 1,124	$ -	$ 13,079
2009 (Predecessor):				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,084	$ 5,168	$ 5,151	$ 1,101
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ 10,685	$ 1,270	$ -	$ 11,955

(1) Amounts written off, net of recoveries of accounts previously written off.

The Dayton Power and Light Company
VALUATION AND QUALIFYING ACCOUNTS

For the years ended December 31, 2009 - 2011

$ in thousands

Description	Balance at Beginning of Period	Additions	Deductions (1)	Balance at End of Period
2011:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 832	$ 6,137	$ 6,028	$ 941
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ -	$ -	$ -	$ -
2010:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,101	$ 4,100	$ 4,369	$ 832
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ -	$ -	$ -	$ -
2009:				
Deducted from accounts receivable - Provision for uncollectible accounts	$ 1,084	$ 5,168	$ 5,151	$ 1,101
Deducted from deferred tax assets - Valuation allowance for deferred tax assets	$ -	$ -	$ -	$ -

(1) Amounts written off, net of recoveries of accounts previously written off.

Exhibit 31(a)

CERTIFICATIONS

I, Philip Herrington, certify that:

1. I have reviewed this annual report on Form 10-K of DPL Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 28, 2012

/s/ Philip Herrington
Philip Herrington
President and Chief Executive Officer

Exhibit 31(b)

CERTIFICATIONS

I, Joseph Mulpas, certify that:

1. I have reviewed this annual report on Form 10-K of DPL Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 28, 2012

/s/ Joseph Mulpas
Joseph Mulpas
Vice President, Controller, Chief Accounting Officer
and Interim Chief Financial Officer

Exhibit 31(c)

CERTIFICATIONS

I, Philip Herrington, certify that:

1. I have reviewed this annual report on Form 10-K of The Dayton Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 28, 2012

/s/ Philip Herrington
Philip Herrington
President and Chief Executive Officer

Exhibit 31(d)

CERTIFICATIONS

I, Joseph Mulpas, certify that:

1. I have reviewed this annual report on Form 10-K of The Dayton Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 28, 2012

/s/ Joseph Mulpas
Joseph Mulpas
Vice President, Controller, Chief Accounting Officer
and Interim Chief Financial Officer

Exhibit 32(a)

DPL Inc.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned officer of DPL Inc. (the "Issuer") hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Issuer's Annual Report on Form 10-K for the period ended December 31, 2011, which this certificate accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Issuer as of the dates and for the periods expressed therein.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this statement required by Section 906 of the Sarbanes-Oxley Act of 2002, has been provided to the Issuer and will be retained by the Issuer and furnished to the Securities and Exchange Commission or its staff upon request.

Signed:

/s/ Philip Herrington
Philip Herrington
President and Chief Executive Officer

Date: March 28, 2012

The foregoing certificate is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Issuer's Annual Report or as a separate disclosure document.

Exhibit 32(b)

DPL Inc.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned officer of DPL Inc. (the "Issuer") hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Issuer's Annual Report on Form 10-K for the period ended December 31, 2011, which this certificate accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Issuer as of the dates and for the periods expressed therein.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this statement required by Section 906 of the Sarbanes-Oxley Act of 2002, has been provided to the Issuer and will be retained by the Issuer and furnished to the Securities and Exchange Commission or its staff upon request.

Signed:

/s/ Joseph Mulpas

Joseph Mulpas
Vice President, Controller, Chief Accounting Officer
and Interim Chief Financial Officer

Date: March 28, 2012

The foregoing certificate is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Issuer's Annual Report or as a separate disclosure document.

Exhibit 32(c)

The Dayton Power and Light Company

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned officer of The Dayton Power and Light Company (the "Issuer") hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Issuer's Annual Report on Form 10-K for the period ended December 31, 2011, which this certificate accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Issuer as of the dates and for the periods expressed therein.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this statement required by Section 906 of the Sarbanes-Oxley Act of 2002, has been provided to the Issuer and will be retained by the Issuer and furnished to the Securities and Exchange Commission or its staff upon request.

Signed:

/s/ Philip Herrington
Philip Herrington
President and Chief Executive Officer

Date: March 28, 2012

The foregoing certificate is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Issuer's Annual Report or as a separate disclosure document.

Exhibit 32(d)

The Dayton Power and Light Company

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned officer of The Dayton Power and Light Company (the "Issuer") hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Issuer's Annual Report on Form 10-K for the period ended December 31, 2011, which this certificate accompanies, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Issuer as of the dates and for the periods expressed therein.

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this statement required by Section 906 of the Sarbanes-Oxley Act of 2002, has been provided to the Issuer and will be retained by the Issuer and furnished to the Securities and Exchange Commission or its staff upon request.

Signed:

/s/ Joseph Mulpas

Joseph Mulpas
Vice President, Controller, Chief Accounting Officer
and Interim Chief Financial Officer

Date: March 28, 2012

The foregoing certificate is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Issuer's Annual Report or as a separate disclosure document.