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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of and for the years ended December 31 (dollars in thousands):

	2009	2008	2007
Balance outstanding at end of period	$ 87,000	$250,000	$ —
Maximum balance outstanding during the period	$275,000	$250,000	$48,000
Average balance outstanding during the period	$186,474	$ 48,426	$ 6,833
Average interest rate during the period	0.65%	3.04%	7.91%
Average interest rate at end of period	0.59%	0.81%	— %

Advantage IQ

Advantage IQ has a committed credit agreement with an expiration date of February 2011. On July 1, 2009, the committed amount was increased from $12.5 million to $15.0 million under the terms of the credit agreement. Advantage IQ may elect to increase the credit facility to $25.0 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets. Balances outstanding and interest rates of borrowings under Advantage IQ's credit agreement were as follows as of and for the years ended December 31 (dollars in thousands):

	2009	2008	2007
Balance outstanding at end of period	$5,700	$2,200	$—
Maximum balance outstanding during the period	$9,700	$3,000	$—
Average balance outstanding during the period	$4,090	$1,658	$—
Average interest rate during the period	1.42%	3.48%	—
Average interest rate at end of period	1.23%	2.08%	—

NOTE 15. LONG-TERM DEBT

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2009	2008
2010	Secured Medium-Term Notes	6.67%-8.02%	$ 35,000	$ 35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2013	First Mortgage Bonds	7.25%	30,000	30,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2022	First Mortgage Bonds (1)	5.13%	250,000	—
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (3)	(3)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		1,151,700	901,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Other long-term debt and capital leases		3,018	3,006
	Interest rate swaps		(1,844)	(14,129)
	Unamortized debt discount		(1,936)	(1,512)
	Total		1,155,038	893,165
	Secured Pollution Control Bonds held by Avista Corporation (2) (3)		(83,700)	(66,700)
	Current portion of long-term debt		(35,189)	(17,207)
	Total long-term debt		$1,036,149	$809,258

(1) In September 2009, the Company issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022.
(2) On December 31, 2008, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2032 were remarketed. Avista Corp. purchased these Pollution Control Bonds and expects that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. Although Avista Corp.

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is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.

(3) In December 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corp. Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of the Bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corp. Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp., which were subject to remarketing or refunding on December 31, 2008. In December 2009, Avista Corp. purchased the Bonds and expects that at a later date, subject to market conditions, the bonds will be refunded or remarketed to unaffiliated investors. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 16) (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Debt maturities	$35,000	$—	$7,000	$75,000	$—	$1,006,647	$1,123,647

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 70 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash; provided, however, that the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2009, property additions and retired bonds would have entitled the Company to issue $668.5 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2009, the net earnings test would limit the principal amount of additional bonds the Company could issue to $607.5 million.

See Note 14 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $75.0 million committed line of credit agreements.

NOTE 16. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. On April 1, 2009, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties with a principal balance of $60.0 million and all of the Common Trust Securities issued to the Company with a principal balance of $1.9 million. Concurrently, the Company redeemed the total amount outstanding of its Junior Subordinated Debt Securities, at 100 percent of the principal amount ($61.9 million) plus accrued interest held by AVA Capital Trust III. The Company's net redemption of $60.0 million was funded by borrowings under its $320.0 million committed line of credit agreement.

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The annual distribution rate paid during 2009 ranged from 1.22 percent to 3.06 percent. As of December 31, 2009, the annual distribution rate was 1.22 percent. Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 17. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years. Rental expense under operating leases was $5.6 million in 2009, $4.8 million in 2008 and $4.8 million in 2007. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009 were as follows (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments required	$4,420	$3,966	$3,759	$3,503	$3,529	$ 6,750	$25,927

NOTE 18. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities issued by its affiliate, Avista Capital II, to the extent that this entity has funds available for such payments from its debt securities.

The output from the Lancaster Plant is contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement. Avista Corp. has provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP’s performance under the power purchase agreement. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the power purchase agreement were conveyed to Avista Utilities.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other’s affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, and matters related to storage rights at Jackson Prairie. In general, such indemnification is not required unless and until a party’s claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy’s obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

NOTE 19. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2009 and 2008. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of preferred stock for $26.25 million.

NOTE 20. FAIR VALUE

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The carrying values of cash and cash equivalents, restricted cash, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion, but excluding capital leases) and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Consolidated Balance Sheets as of December 31, 2009 and 2008 (dollars in thousands):

	2009		2008	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$1,072,100	$1,079,857	$839,100	$875,451
Long-term debt to affiliated trusts	51,547	43,534	113,403	102,027

These estimates of fair value were primarily based on available market information.

Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Consolidated Balance Sheets. U.S. GAAP defines a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to the Company's needs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2009 and 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2009					
Assets:					
Energy commodity derivatives	$ —	$11,898	$57,276	$ (15,934)	$53,240
Deferred compensation assets:					
Fixed income securities (2)	2,011	—	—	—	2,011
Equity securities (2)	5,863	—	—	—	5,863
Total	$7,874	$11,898	$57,276	$ (15,934)	$61,114
Liabilities:					
Energy commodity derivatives	$ —	$27,086	$ 7,806	$ (15,934)	$18,958
Foreign currency derivatives	—	50	—	—	50
Total	$ —	$27,136	$ 7,806	$ (15,934)	$19,008

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2008					
Assets:					
Energy commodity derivatives	$ —	$ 40,104	$68,047	$ (47,604)	$60,547
Deferred compensation assets:					
Fixed income securities (2)	1,889	—	—	—	1,889
Equity securities (2)	5,101	—	—	—	5,101
Interest rate swaps	—	875	—	—	875
Total	$6,990	$ 40,979	$68,047	$ (47,604)	$68,412
Liabilities:					
Energy commodity derivatives	$ —	$110,123	$16,085	$ (47,604)	$78,604

(1) The Company is permitted to net derivative assets and derivative liabilities when a legally enforceable master netting agreement exists.
(2) These assets are trading securities.

Avista Utilities enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Utilities' management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2. The Company also has certain contracts that, primarily due to the length of the respective contract, require the use of internally developed forward price estimates, which include significant inputs that may not be observable or corroborated in the market. These derivative contracts are included in Level 3. Refer to Note 7 for further discussion of the Company's energy commodity derivative assets and liabilities.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an Executive Deferral Plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $1.6 million as of December 31, 2009 and $1.8 million as of December 31, 2008.

The following table presents activity for energy commodity derivative assets and (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Assets		Liabilities	
	2009	2008	2009	2008
Balance as of January 1	$68,047	$ 98,943	$(16,085)	$(36,506)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	(7,202)	(22,586)	7,747	18,715
Purchases, issuances, and settlements, net	(3,569)	(8,310)	532	1,706
Transfers to other categories	—	—	—	—
Ending balance as of December 31	$57,276	$ 68,047	$ (7,806)	$(16,085)

(1) The WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

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NOTE 21. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value. Shares issued under this plan in 2009, 2008 and 2007 are disclosed in the Consolidated Statements of Equity.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

In December 2009, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 2 million shares of its common stock in December 2006. In 2008, the Company issued 750,000 shares of its common stock under this sales agency agreement. The Company did not issue any shares under this sales agency agreement in 2009 and 2007.

NOTE 22. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation for the years ended December 31 (in thousands, except per share amounts):

	2009	2008	2007
Numerator:			
Net income attributable to Avista Corporation	$87,071	$73,620	$38,475
Subsidiary earnings adjustment for dilutive securities	(114)	(249)	(349)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$86,957	$73,371	$38,126
Denominator:			
Weighted-average number of common shares outstanding-basic	54,694	53,637	52,796
Effect of dilutive securities:			
Contingent stock awards	163	213	168
Stock options	85	178	299
Weighted-average number of common shares outstanding-diluted	54,942	54,028	53,263
Earnings per common share attributable to Avista Corporation:			
Basic	$ 1.59	$ 1.37	$ 0.73
Diluted	$ 1.58	$ 1.36	$ 0.72

Total stock options outstanding excluded in the calculation of diluted earnings per common share attributable to Avista Corporation were 218,450 for 2009, 250,950 for 2008 and 303,950 for 2007. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 23. STOCK COMPENSATION PLANS

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2009, 0.7 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2009, 1.7 million shares were remaining for grant under this plan.

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AVISTA CORPORATION

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Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued. The Company recorded stock-based compensation expense of $2.9 million for 2009, $3.0 million for 2008 and $2.7 million for 2007, which is included in other operating expenses in the Consolidated Statements of Income. The total income tax benefit recognized in the Consolidated Statements of Income was $1.0 million for 2009, $1.1 million for 2008 and $1.0 million for 2007.

Stock Options

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2009	2008	2007
Number of shares under stock options:			
Options outstanding at beginning of year	748,673	1,411,911	1,541,045
Options granted	—	—	—
Options exercised	(200,225)	(582,238)	(123,134)
Options canceled	(24,475)	(81,000)	(6,000)
Options outstanding and exercisable at end of year	523,973	748,673	1,411,911
Weighted average exercise price:			
Options exercised	$ 13.83	$ 13.91	$ 15.14
Options canceled	$ 22.69	$ 21.70	$ 26.59
Options outstanding and exercisable at end of year	$ 16.30	$ 15.85	$ 15.38
Intrinsic value of options exercised (in thousands)	$ 1,180	$ 4,248	$ 1,022
Intrinsic value of options outstanding (in thousands)	$ 2,774	$ 2,643	$ 8,697

Information for options outstanding and exercisable as of December 31, 2009 is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$12.41	285,323	$ 11.11	2.4
$15.88-$19.34	11,200	16.56	2.0
$20.11-$23.00	213,050	22.46	0.9
$26.59-$28.47	14,400	27.69	0.2
Total	523,973	$ 16.30	1.7

Total cash received from the exercise of stock options was $2.8 million for 2009, $8.1 million for 2008 and $1.9 million for 2007. As of December 31, 2009 and 2008, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2009 was one year. The following table summarizes restricted stock activity for the years ended December 31:

	2009	2008	2007
Unvested shares at beginning of year	55,939	28,137	36,180
Shares granted	44,400	43,400	31,860
Shares cancelled	(10,000)	(1,230)	(19,936)
Shares vested	(18,435)	(14,368)	(19,967)
Unvested shares at end of year	71,904	55,939	28,137
Weighted average fair value at grant date	$ 18.18	$ 20.05	$ 25.60
Unrecognized compensation expense at end of year (in thousands)	$ 668	$ 691	$ 517
Intrinsic value, unvested shares at end of year (in thousands)	$ 1,552	$ 1,084	$ 606
Intrinsic value, shares vested during the year (in thousands)	$ 345	$ 293	$ 461

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Performance Shares

Performance share grants have vesting periods of three years. Performance awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares granted. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures. The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2009	2008	2007
Risk-free interest rate	1.3%	2.2%	4.8%
Expected life, in years	3	3	3
Expected volatility	25.8%	20.2%	19.4%
Dividend yield	3.6%	2.8%	2.5%
Weighted average grant date fair value (per share)	$17.22	$16.96	$18.71

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2009	2008	2007
Opening balance of unvested performance shares	252,923	207,841	300,406
Performance shares granted	163,900	170,100	114,640
Performance shares canceled	(43,758)	(5,239)	(45,632)
Performance shares vested	(72,464)	(119,779)	(161,573)
Ending balance of unvested performance shares	300,601	252,923	207,841
Intrinsic value of unvested performance shares (in thousands)	$ 6,490	$ 4,902	$ 4,477
Unrecognized compensation expense (in thousands)	$ 2,453	$ 2,227	$ 2,058

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2009 was 1.5 years. Unrecognized compensation expense as of December 31, 2009 will be recognized during 2010 and 2011. The following summarizes the impact of the market condition on the vested performance shares:

	2009	2008	2007
Performance shares vested	72,464	119,779	161,573
Impact of market condition on shares vested	(72,464)	21,560	(56,551)
Shares of common stock earned	—	141,339	105,022
Intrinsic value of common stock earned (in thousands)	$ —	$ 2,739	$ 2,262

In 2009, 2008 and 2007, the number of performance shares vested was adjusted by (100) percent, 18 percent and (35) percent based on the performance condition achieved. Shares earned under this plan are distributed to participants in the quarter following vesting.

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Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2009 and 2008, the Company had recognized compensation expense and a liability of $0.3 million and $0.5 million related to the dividend component of performance share grants.

Advantage IQ

Advantage IQ has an employee stock incentive plan under which certain employees of Advantage IQ may be granted options to purchase shares at prices no less than the estimated fair value on the date of grant. Options outstanding under this plan generally vest over periods of four years from the date granted and terminate ten years from the date granted. Unrecognized compensation expense for stock based awards at Advantage IQ was $2.2 million as of December 31, 2009, which will be expensed during 2010 through 2013.

In 2007, Advantage IQ amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ providing the shares are held for a minimum of six months. In 2009, Advantage IQ amended its employee stock incentive plan to make this put feature optional for future stock option grants. Stock is reacquired at fair market value at the date of reacquisition. As the repurchase feature is at the discretion of the minority shareholders and option holders, there was redeemable noncontrolling interests of $6.9 million as of December 31, 2009 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. Additionally, there was redeemable noncontrolling interests of $27.9 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Advantage IQ (refer to Note 5 for further information). During 2009, $4.7 million of common stock was repurchased from Advantage IQ employees. During 2008, $6.6 million of common stock was repurchased from Advantage IQ employees.

NOTE 24. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, California Parties and the City of Tacoma, Washington challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the

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Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In June 2009, the FERC reversed, in part, its previous decision and ordered a compliance filing requiring an adjustment to the return on investment component of Avista Energy's cost filing. That compliance filing was made in July 2009.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In May 2009, the CalISO filed its 43rd status report on the California recalculation process confirming that the preparatory and the FERC refund recalculations are complete (as are calculations related to fuel cost allowance offsets, emission offsets, cost-recovery offsets, and the majority of the interest calculations). Once the FERC rules on several open issues, the CalISO states that it intends to: (1) perform the necessary adjustment to remove refunds associated with non-jurisdictional entities and allocate that shortfall to net refund recipients; and (2) work with the parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. After completing these calculations, the CalISO states that it intends to make a compliance filing with the FERC that presents the final financial position of each party that participated in its markets during the Refund Period.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2009, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

Many of the orders that the FERC has issued in the California refund proceedings were appealed to the Ninth Circuit. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. Petitions for rehearing were denied in April 2009. In July 2009, Avista Energy and Avista Utilities filed a motion at the FERC, asking that the companies be dismissed from any further proceedings arising under section 309 pursuant to the remand. The filing pointed out that section 309 relief is based on tariff violations of the seller, and as to Avista Energy and Avista Utilities, these allegations had already been fully adjudicated in the proceeding that gave rise to the Agreement in Resolution, discussed above. There, the FERC absolved both companies of all allegations of market manipulation or wrongdoing that would justify or permit FPA sections 206 or 309 remedies during 2000 and 2001. In November 2009, the FERC issued an order establishing an evidentiary hearing before an administrative law judge to address the issues remanded by the Ninth Circuit without addressing the Company's pending motion. In December 2009, the Company again brought the issue to the FERC's attention but its motion remains pending.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company. As such, the Company has not accrued a liability related to this matter.

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Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Department of Water Resources (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests for rehearing were denied in April 2009.

In May 2009, the California AG filed a complaint against both Avista Energy and Avista Utilities seeking refunds on sales made to CERS during the period January 18, 2001 to June 20, 2001 under section 309 of the FPA (the Brown Complaint). The sales at issue are limited in scope and are duplicative of claims already at issue in the Pacific Northwest proceeding, discussed above. In August 2009, the City of Tacoma and the Port of Seattle filed a motion asking the FERC to summarily re-price sales of energy in the Pacific Northwest during 2000 and 2001. In October 2009, Avista Corp. filed, as part of the Transaction Finality Group, an answer to that motion and in addition, made its own recommendations for further proceedings in this docket. Those pleadings are pending before the FERC.

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, if refunds were ordered by the FERC, could be liable to make payments, but also could be entitled to receive refunds from other FERC-jurisdictional entities. The opportunity to make claims against non-jurisdictional entities may be limited based on existing law. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Utilities or Avista Energy could be ordered to make or could be entitled to receive. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows. The Company has not accrued a liability related to this matter.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, but did not order any refunds, leaving it to the FERC to consider appropriate remedial options.

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets will be allowed to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In particular, the parties are directed to address whether the seller at any point reached a 20 percent generation market share threshold, and if the seller did reach a 20 percent market share, whether other factors were present to indicate that the seller did not have the ability to exercise market power. The California AG, CPUC, PG&E, and SCE filed their testimony in July 2009. Avista Energy's answering testimony was filed in September 2009. On the same day, the FERC staff filed its answering testimony taking the position that, using the test the FERC directed to be applied in this proceeding, Avista Energy does not have market power. Cross answering testimony and rebuttal testimony were filed in November 2009. A hearing is expected to commence in April 2010.

Based on information currently known to the Company's management and the fact that neither Avista Utilities nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued any liability related to this matter.

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Colstrip Generating Project Complaints

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. The trial is set to begin in May 2011. Because the resolution of this complaint remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $1.5 million and it is expected that it will be completed by early 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. Other than its share of the RI/FS, the Company has not accrued a liability related to this matter.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe (the Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Tribe's reservation lands. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit and the United States Supreme Court in June 2001. This ownership decision resulted in, among other things, Avista Corp. being liable to the Tribe for water storage on the Tribe's land and for the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments). The Company's Post Falls Hydroelectric Generating Station (Post Falls) controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe).

In December 2008, Avista Corp., the Tribe and the United States Department of Interior (DOI) finalized an agreement regarding a range of issues related to Post Falls and the Lake. The agreement establishes the amount of past and future compensation Avista Corp. will pay for Section 10(e) payments and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Licensing below).

Avista Corp. agreed to compensate the Tribe a total of $39 million ($25 million paid in 2008, $10 million paid in 2009 and $4 million to be paid in 2010) for trespass and Section 10(e) payments for past storage of water for the period from 1907 through 2007. Avista Corp. agreed to compensate the Tribe for future storage of water through Section 10(e) payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of the new license and $0.7 million per year through the remaining term of the license.

In addition to Section 10(e) payments, Avista Corp. agreed to make annual payments over the life of the new FERC license to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation required under Section 4(e) of the Federal Power Act. These payments involve creation of a Coeur d'Alene Reservation Trust Restoration Fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements commenced with the issuance of the new FERC license in June 2009 and total $100 million over the 50-year license term.

The WUTC and IPUC approved deferral and future recovery of amounts paid to the Tribe and the Trust Fund through general rate cases in 2009.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving the Company's general rate case settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether the recovery of settlement costs associated with resolving the dispute with the Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony to update the Company's filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls, which have a total present capability of 144.1 MW) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The FERC issued a new single 50-year license for the Spokane River Project on June 18, 2009.

The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the DOI and the Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification. Various issues that were appealed under the Washington 401 Water Quality Certification were subsequently resolved through settlement.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company is currently engaged with the DOE and the EPA Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On February 12, 2010, the DOE submitted the TMDL for the EPA's review and approval. Once the TMDL process is completed, and the Company's level of responsibility related to low dissolved oxygen in Lake Spokane is established, the Company will identify potential mitigation measures. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully indentified or approved by the DOE. It is also possible the TMDL will be appealed by one or more parties if it is approved by the EPA.

The Company has begun implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions for the five hydroelectric plants is $334 million over the 50 year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates.

The IPUC and the WUTC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the licensing of the Spokane River Project.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. In 2002, the Company submitted a Gas Supersaturation Control Program ("GSCP") with the Idaho Department of Environmental Quality (Idaho DEQ) and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provides for the opening and modification of possibly two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed addendum to the GSCP. The GSCP addendum abandons the existing concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of smaller capacity options to abate TDG over the next several years. The addendum was filed with the FERC in October 2009 and is pending approval.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In the fall of 2009 the Company initiated a contractor selection process for the design of a permanent upstream passage facility at Cabinet Gorge. On January 13, 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. The USFWS is accepting public comment on the proposed revisions until March 15, 2010. The Company is reviewing the proposed revisions.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions.

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities.

Compliance with new and proposed requirements and possible additional legislation or regulations results in increases to capital expenditures and operating expenses for expanded emission controls at the Company’s thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Current estimates indicate that the Company’s share of installation capital costs will be $1.4 million and annual operating costs will increase by $1.5 million (began in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Corporation) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act (MTCA), under Washington state law. The subject property adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by DOE as “Aluminum Recycling – Trentwood.” Operators of that property maintained piles of aluminum “black dross,” which can be designated as a state-only dangerous waste in Washington State. Operators placed a portion of the aluminum dross pile on the site owned by Pentzer Corporation. The Company does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to the DOE’s proposed findings in November 2009. In December 2009, the Company received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. The Company has not accrued a liability related to this matter.

Collective Bargaining Agreements

As of December 31, 2009, the Company’s collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 45 percent of all of Avista Utilities’ employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires on March 26, 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010. Negotiations are currently ongoing for these labor agreements.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company’s estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

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The Company routinely assesses, based on in-depth studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who have and have not agreed to a settlement and recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho is conducting an adjudication in northern Idaho, which will ultimately include both the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated its intent to initiate an adjudication for the Spokane River basin in the next several years. The Company is participating in these extensive adjudication processes, which are unlikely to be concluded in the foreseeable future.

NOTE 25. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.5 million in 2009, $15.4 million in 2008 and $15.4 million in 2007. The majority of the costs are included in other operating expenses in the Consolidated Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.2 million in 2010, $12.9 million in 2011, and $12.2 million in 2012. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 26. AVISTA UTILITIES REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities (dollars in thousands):

	Remaining Amortization Period	Receiving Regulatory Treatment (1) Earning A Return	Receiving Regulatory Treatment Not Earning A Return	(2) Pending Regulatory Treatment	Total 2009	Total 2008
Regulatory assets:						
Investment in exchange power-net	2019	$ 23,683	$ —	$ —	$ 23,683	$ 26,133
Regulatory assets for deferred income tax	(3)	—	97,945	—	97,945	115,005
Regulatory assets for pensions and other postretirement benefit plans	(4)	—	—	141,085	141,085	172,278
Current regulatory asset for utility derivatives	(5)	—	8,332	—	8,332	60,229
Power deferrals	(3)	27,771	—	—	27,771	57,607
Unamortized debt repurchase costs	(6)	15,196	—	—	15,196	17,152
Regulatory asset for settlement with Coeur d'Alene Tribe	2059	49,134	—	6,000	55,134	41,733
Demand side management programs	(3)	—	11,894	—	11,894	11,137
Montana lease payments	(3)	7,171	—	—	7,171	8,208
Other regulatory assets	(3)	5,113	6,349	8,968	20,430	24,033
Total regulatory assets		$128,068	$124,520	$156,053	$408,641	$533,515
Regulatory Liabilities:						
Residential exchange	2010	$ 2,900	$ —	$ —	$ 2,900	$ —
Oregon Senate Bill 408	2010-2011	1,790	—	—	1,790	2,452
Natural gas deferrals	(3)	39,952	—	—	39,952	18,646
Regulatory liability for utility plant retirement costs	(7)	217,176	—	—	217,176	213,747
Non-current regulatory liability for utility derivatives	(5)	—	42,611	—	42,611	42,172
Income tax related liabilities	(3)	—	13,045	—	13,045	8,484
Other regulatory liabilities	(3)	4,792	1,648	—	6,440	8,483
Total regulatory liabilities		$266,610	$ 57,304	$ —	$323,914	$293,984

(1) Earning a return includes either interest on the regulatory asset/liability, or a return on the investment as a component of rate base or the weighted cost of capital.
(2) Pending regulatory treatment includes regulatory assets that have prior regulatory precedent.
(3) Remaining amortization period varies depending on timing of underlying transactions.
(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.
(5) The WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.
(6) For the Company's primary regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.
(7) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs and the amount included in base retail rates for Washington customers. The Company must make a filing (no sooner than January 1, 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its customers. There is a 50 percent customers/50 percent Company sharing when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates. The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Avista Utilities has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with an annual rate adjustment provision. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period.

The following table shows activity in deferred power costs for Washington and Idaho during 2007, 2008 and 2009 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2006	$ 70,159	$ 9,357	$ 79,516
Activity from January 1 – December 31, 2007:			
Power costs deferred	16,344	16,750	33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
Deferred power costs as of December 31, 2007	58,524	21,163	79,687
Activity from January 1 – December 31, 2008:			
Power costs deferred	7,049	10,029	17,078
Interest and other net additions	2,231	1,153	3,384
Recovery of deferred power costs through retail rates	(30,852)	(11,690)	(42,542)
Deferred power costs as of December 31, 2008	$ 36,952	$ 20,655	$ 57,607
Activity from January 1 – December 31, 2009:			
Power costs deferred	$ —	$ 17,985	$ 17,985
Interest and other net additions	879	388	1,267
Recovery of deferred power costs through retail rates	(31,567)	(17,521)	(49,088)

Deferred power costs as of December 31, 2009	$ 6,264	$ 21,507	$ 27,771

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In February 2010, the WUTC approved the Company's request to eliminate the existing ERM surcharge. The surcharge was eliminated because the previous balance of deferred power costs has been substantially recovered. This will result in an overall rate reduction of 7 percent for the Company's Washington customers with no impact on income from operations or net income.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs for the prior year, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Utilities defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $40.0 million as of December 31, 2009 and $18.6 million as of December 31, 2008.

General Rate Cases

The following is a summary of the Company's authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2010	8.25%	10.2%	46.5%
Idaho electric and natural gas	August 2009	8.55%	10.5%	50.0%
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

Washington General Rate Cases

As approved by the WUTC, on January 1, 2008, electric rates for the Company's Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the ERM calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, Avista Corp. entered into a settlement stipulation in its general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for the Company's Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving Avista Corp.'s multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These included whether the recovery of settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by the Company to update its filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

On December 22, 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas rate general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for the Company's Washington customers of 2.8 percent, which is designed to increase annual revenues by $12.1 million. Base natural gas rates for the Company's Washington customers increased by an average of 0.3 percent, which is designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

Following the execution of a partial settlement stipulation in September 2009, Avista Corp. revised downward its electric rate increase request from $69.8 million to $37.5 million, primarily due to the decline in the wholesale prices of electricity and natural gas. Avista Corp. also reduced its natural gas request from $4.9 million to $2.8 million. Under the partial settlement stipulation, the Company reached agreement with the other settling parties on issues in the areas of cost of capital, power supply, rate spread and rate design, and funding under the Low-Income Ratepayer Assistance Program. The WUTC approved this partial settlement stipulation in its order on December 22, 2009.

The WUTC did not allow Avista Corp. to include the costs associated with the power purchase agreement for the Lancaster Plant in rates, indicating the Company did not demonstrate compliance with certain requirements necessary for immediate inclusion in rates. However, the WUTC directed Avista Corp. to file to defer costs associated with the Lancaster Plant, with a carrying charge, for potential recovery in a future rate proceeding if the Company demonstrates that it has satisfied these requirements. The Company's proposed deferred accounting treatment for the net costs associated with the Lancaster Plant was approved by the WUTC in February 2010. The net costs associated with the power purchase agreement for the Lancaster Plant account for approximately half of the difference between the Company's revised electric rate increase request of $37.5 million and the $12.1 million increase approved by the WUTC.

The WUTC also did not allow for certain pro forma future capital additions to rate base, as well as certain increases in labor costs, tree trimming costs and information systems costs. These costs account for the majority of the remaining difference between the Company's revised electric rate increase request and the amount approved by the WUTC.

The partial settlement stipulation (as approved by the WUTC on December 22, 2009) is based on an overall rate of return of 8.25 percent with a common equity ratio of 46.5 percent and a 10.2 percent return on equity. The Company's original request was based on a proposed overall rate of return of 8.68 percent with a common equity ratio of 47.5 percent and an 11.0 percent return on equity.

Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, the Company entered into an all-party settlement stipulation in its electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the PCA surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million. Offsetting the natural gas rate increase for residential customers was an equivalent PGA decrease of 2.1 percent. Large general services received a PGA decrease of 2.4 percent and interruptible services received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to customers with no change in gross margin or net income.

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Oregon General Rate Cases

As approved by the OPUC in March 2008, natural gas rates for the Company's Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

In September 2009, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the OPUC in June 2009. This settlement stipulation was approved by the OPUC in October 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for Oregon customers increased by an average of 7.1 percent, which is designed to increase annual revenues by $8.8 million.

NOTE 27. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes the remaining activities of Avista Energy, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital. The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Advantage IQ	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the year ended December 31, 2009:						
Operating revenues	$1,395,201	$ 77,275	$ 40,089	$117,364	$ —	$1,512,565
Resource costs	799,539	—	23,408	23,408	—	822,947
Other operating expenses	229,907	60,985	21,710	82,695	—	312,602
Depreciation and amortization	93,783	4,687	1,305	5,992	—	99,775
Income (loss) from operations	195,389	11,603	(6,334)	5,269	—	200,658
Interest expense (2)	66,688	302	231	533	(187)	67,034
Income taxes	44,480	3,969	(2,126)	1,843	—	46,323
Net income (loss) attributable to Avista Corporation	86,744	5,329	(5,002)	327	—	87,071
Capital expenditures	205,384	3,031	89	3,120	—	208,504
For the year ended December 31, 2008:						
Operating revenues	$1,572,664	$ 59,085	$ 45,014	$104,099	$ —	$1,676,763
Resource costs	1,031,989	—	23,553	23,553	—	1,055,542
Other operating expenses	206,528	44,349	20,744	65,093	—	271,621
Depreciation and amortization	87,845	3,439	1,348	4,787	—	92,632
Income (loss) from operations	174,245	11,297	(631)	10,666	—	184,911
Interest expense (2)	79,401	110	157	267	(81)	79,587
Income taxes	41,527	4,067	31	4,098	—	45,625
Net income (loss) attributable to Avista Corporation	70,032	6,090	(2,502)	3,588	—	73,620
Capital expenditures	219,239	3,485	175	3,660	—	222,899
For the year ended December 31, 2007:						
Operating revenues	$1,288,363	$ 47,255	$ 82,139	$129,394	$ —	$1,417,757
Resource costs	780,998	—	68,676	68,676	—	849,674
Other operating expenses	198,778	33,841	33,942	67,783	—	266,561
Depreciation and amortization	86,091	2,402	2,157	4,559	—	90,650
Income (loss) from operations	150,053	11,012	(22,636)	(11,624)	—	138,429
Interest expense (2)	86,389	194	811	1,005	(954)	86,440
Income taxes	26,663	3,942	(6,271)	(2,329)	—	24,334
Net income (loss) attributable to Avista Corporation	43,822	6,651	(11,998)	(5,347)	—	38,475
Capital expenditures	205,811	2,323	957	3,280	—	209,091
Total Assets:						
As of December 31, 2009	$3,400,384	$143,060	$ 63,515	$206,575	—	$3,606,959
As of December 31, 2008	3,434,844	125,911	69,992	195,903	—	3,630,747

(1) Intersegment eliminations reported as interest expense represent intercompany interest.
(2) Including interest expense to affiliated trusts.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

NOTE 28. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions. A summary of quarterly operations (in thousands, except per share amounts) for 2009 and 2008 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2009				
Operating revenues	$487,470	$307,111	$ 314,692	$ 403,292
Operating expenses	421,625	249,029	290,938	350,315
Income from operations	$ 65,845	$ 58,082	$ 23,754	$ 52,977
Net income	$ 31,419	$ 26,289	$ 8,634	$ 22,305
Less: Net income attributable to noncontrolling interests	(393)	(437)	(495)	(252)
Net income attributable to Avista Corporation	$ 31,026	$ 25,852	$ 8,139	$ 22,053
Outstanding common stock:				
Weighted average, basic	54,616	54,654	54,706	54,796
End of period	54,643	54,671	54,741	54,837
Earnings per common share attributable to Avista Corporation, diluted	$ 0.57	$ 0.47	$ 0.15	$ 0.40
Dividends paid per common share	$ 0.18	$ 0.21	$ 0.21	$ 0.21
Trading price range per common share:				
High	$ 20.01	$ 18.13	$ 20.83	$ 22.44
Low	$ 12.67	$ 13.44	$ 17.59	$ 18.48
2008				
Operating revenues	$496,307	$350,310	$ 382,685	$ 447,461
Operating expenses	437,246	293,820	357,353	403,433
Income from operations	$ 59,061	$ 56,490	$ 25,332	$ 44,028
Net income	$ 25,364	$ 23,552	$ 7,828	$ 18,013
Less: Net income attributable to noncontrolling interests	(133)	(7)	(469)	(528)
Net income attributable to Avista Corporation	$ 25,231	$ 23,545	$ 7,359	$ 17,485
Outstanding common stock:				
Weighted average, basic	53,020	53,301	53,773	54,445
End of period	53,049	53,496	54,422	54,488
Earnings per common share attributable to Avista Corporation, diluted	$ 0.47	$ 0.44	$ 0.13	$ 0.32
Dividends paid per common share	$ 0.165	$ 0.165	$ 0.18	$ 0.18
Trading price range per common share:				
High	$ 21.39	$ 22.10	$ 23.30	$ 22.06
Low	$ 18.09	$ 19.86	$ 20.72	$ 16.58

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2009.

Management's Report on Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2009 is effective.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attest report on the Company's internal control over financial reporting as of December 31, 2009.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Avista Corporation
Spokane, Washington

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting* . Our responsibility is to express an opinion on the Company's internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2010

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Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding the directors of the Registrant and compliance with Section 16(a) of the Exchange Act has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 2010.

Executive Officers of the Registrant Name	Age	Business Experience
Scott L. Morris	52	Chairman, President and Chief Executive Officer effective January 1, 2008. Director since February 9, 2007; President and Chief Operating Officer May 2006 – December 2007; Senior Vice President February 2002 – May 2006; Vice President November 2000 – February 2002; President – Avista Utilities August 2000 – December 2008; General Manager – Avista Utilities for the Oregon and California operations October 1991 – August 2000; various other management and staff positions with the Company since 1981.
Mark T. Thies	46	Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000.
Marian M. Durkin	56	Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Senior Vice President and General Counsel August 2005 – November 2005; prior to employment with the Company: held several legal positions with United Air Lines, Inc. from 1995 to August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary.
Karen S. Feltes	54	Senior Vice President of Human Resources and Corporate Secretary since November 2005; Vice President of Human Resources and Corporate Secretary March 2003 – November 2005; Vice President of Human Resources and Corporate Services February 2002 – March 2003; various human resources positions with the Company April 1998 – February 2002.
Dennis P. Vermillion	48	Senior Vice President since January 2010; Vice President July 2007- December 2009; President – Avista Utilities since January 2009; Vice President of Energy Resources and Optimization – Avista Utilities July 2007 – December 2008; President and Chief Operating Officer of Avista Energy February 2001 – July 2007; various other management and staff positions with the Company since 1985.
Christy M. Burmeister-Smith	53	Vice President, Controller and Principal Accounting Officer since May 2007. Vice President and Treasurer January 2006 – May 2007; Vice President and Controller June 1999 – January 2006; various other management and staff positions with the Company since 1980.
James M. Kensok	51	Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001 – December 2006; various other management and staff positions with the Company since 1996.

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Don F. Kopczynski	54	Vice President since May 2004; Vice President of Transmission and Distribution Operations – Avista Utilities since May 2004; various other management and staff positions with the Company and its subsidiaries since 1979.
David J. Meyer	56	Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998 – February 2004.
Kelly O. Norwood	51	Vice President since November 2000; Vice President of State and Federal Regulation – Avista Utilities since March 2002; Vice President and General Manager of Energy Resources - Avista Utilities August 2000 – March 2002; various other management and staff positions with the Company since 1981.
Richard L. Storro	59	Vice President since January 2009; Vice President Energy Resources – Avista Utilities since January 2009. Various other management and staff positions with the Company since 1973.
Jason R. Thackston	39	Vice President of Finance since June 2009; various other management and staff positions with the Company since 1996.
Roger D. Woodworth	53	Vice President since November 1998; Vice President, Sustainable Energy Solutions Avista Utilities since February 2007; Vice President, Customer Solutions for Avista Utilities March 2003 – February 2007; Vice President of Utility Operations of Avista Utilities September 2001 – March 2003; Vice President – Corporate Development November 1998 – September 2001; various other management and staff positions with the Company since 1979.

All of the Company’s executive officers, with the exception of James M. Kensok, Don F. Kopczynski, David J. Meyer, Kelly O. Norwood and Richard L. Storro, were officers or directors of one or more of the Company’s subsidiaries in 2009. The Company’s executive officers are elected annually by the Board of Directors.

The Company has adopted a Code of Business Conduct and Ethics (Code of Conduct) for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company’s Web site at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-12
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company’s Code of Conduct will be posted on the Company’s Web site.

Item 11. Executive Compensation

Information regarding executive compensation has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant’s annual meeting of shareholders to be held on May 13, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant’s voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant’s voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant’s annual meeting of shareholders to be held on May 13, 2010.

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AVISTA CORPORATION

(b) Security ownership of management:

Information regarding security ownership of management has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 2010.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2009:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders (2)	299,400	$ 15.86	655,496
Equity compensation plans not approved by security holders (3)	224,573	$ 16.88	1,715,052
Total	523,973	$ 16.30	2,370,548

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2009, 71,904 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 300,601 shares at target level; or 450,902 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance share awards, such shares are not included in the weighted-average price calculation.
(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.
(3) Represents stock options outstanding and stock available for future issuance under the Non-Officer Employee Long-Term Incentive Plan, which was adopted by the Company in 2000. The Company currently does not plan to issue any further options or securities under this plan. Under this plan, employees (excluding directors and executive officers) of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards, performance awards, other stock-based awards and dividend equivalent rights. Stock options granted under this plan are equal to the market price of the Company's common stock on the date of grant. Stock options granted under this plan have terms of up to 10 years and generally vest at a rate of 25 percent per year over a four-year period.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information regarding certain relationships and related transactions has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 2010.

Item 14. Principal Accounting Fees and Services

Information regarding principal accounting fees and services has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 13, 2010.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 115. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 26, 2010
Date

By /s/ Scott L. Morris
Scott L. Morris
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Scott L. Morris **Scott L. Morris** **Chairman of the Board, President and Chief Executive Officer**	Principal Executive Officer	February 26, 2010
/s/ Mark T. Thies **Mark T. Thies** **(Senior Vice President and Chief Financial Officer)**	Principal Financial Officer	February 26, 2010
/s/ Christy M. Burmeister-Smith **Christy M. Burmeister-Smith** **(Vice President, Controller and Principal Accounting Officer)**	Principal Accounting Officer	February 26, 2010
/s/ Erik J. Anderson **Erik J. Anderson**	Director	February 26, 2010
/s/ Kristianne Blake **Kristianne Blake**	Director	February 26, 2010
/s/ Brian W. Dunham **Brian W. Dunham**	Director	February 26, 2010
/s/ Roy L. Eiguren **Roy L. Eiguren**	Director	February 26, 2010
/s/ Jack W. Gustavel **Jack W. Gustavel**	Director	February 26, 2010
/s/ John F. Kelly **John F. Kelly**	Director	February 26, 2010
/s/ Michael L. Noël **Michael L. Noël**	Director	February 26, 2010
/s/ Marc Racicot **Marc Racicot**	Director	February 26, 2010
/s/ Heidi B. Stanley **Heidi B. Stanley**	Director	February 26, 2010
/s/ R. John Taylor **R. John Taylor**	Director	February 26, 2010

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
3(i)	1-3701 (with June 30, 2008 Form 10-Q)	3(i)	Restated Articles of Incorporation of Avista Corporation as amended and restated June 6, 2008.
3(ii)	1-3701 (with Form 8-K dated as of May 9, 2008)	3(ii)	Bylaws of Avista Corporation, as amended May 9, 2008.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.
4.20	1-3701 (with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.22	1-3701 (with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.
4.24	1-3701 (with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.
4.25	1-3701 (with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.
4.26	1-3701 (with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.
4.28	1-3701 (with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	1-3701 (with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001
4.31	1-3701 (with June 30, 2002 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003
4.33	1-3701 (with September 30, 2003 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004
4.35	1-3701 (with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	1-3701 (with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	1-3701 (with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	1-3701 (with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed (1) With Registration Number	As Exhibit	
4.39	1-3701 (with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	1-3701 (with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	1-3701 (with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	1-3701 (with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.
4.43	1-3701 (with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	1-3701 (with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	1-3701 (with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	1-3701 (with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	1-3701 (with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	1-3701 (with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	1-3701 (with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.50	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.51	1-3701 (with Form 8-K dated as of May 12, 2005)	4.2	First Supplemental Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [(1)] With Registration Number	As Exhibit	
4.52	1-3701 (with Form 8-K dated as of May 12, 2005)	4.3	First Supplemental Trust Indenture between City of Forsyth, Montana, and J.P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, National Association) as Trustee, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.53	1-3701 (with Form 8-K dated as of May 12, 2005)	4.6	Loan Agreement, Restated as of May 1, 2005, between City of Forsyth, Montana and Avista Corporation, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.54	1-3701 (with Form 8-K dated as of May 12, 2005)	4.7	Trust Indenture, Restated as of May 1, 2005, between City of Forsyth, Montana and J. P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, N.A.) as Trustee, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.55	1-3701 (with Form 8-K dated as of December 30, 2008)	4.1	Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of December 1, 2008 relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
4.56	1-3701 (with Form 8-K dated as of December 30, 2008)	4.2	Trust Indenture between City of Forsyth, Montana, and Bank of New York Mellon Trust Company, N.A. as Trustee, dated as of December 1, 2008, relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
10.1	1-3701 (with Form 8-K dated as of December 15, 2004)	10.1	Credit Agreement, dated as of December 17, 2004 among Avista Corporation, the Banks listed therein, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.
10.2	1-3701 (with Form 8-K dated as of April 6, 2006)	10.1	Amendment No. 1, dated as of April 6, 2006, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [(1)] With Registration Number	As Exhibit	
10.3	1-3701(with 2008 Form 10-K)	10.3	Amendment No. 2, dated as of December 19, 2008, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York Mellon f/k/a The Bank of New York, as Administrative Agent and an Issuing Bank.
10.4	1-3701 (with Form 8-K dated as of December 15, 2004)	10.2	Bond Delivery Agreement, dated as of December 17, 2004, between Avista Corporation and The Bank of New York.
10.5	1-3701 (with June 30, 2002 Form 10-Q)	4(e)	Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corp., as Seller, Avista Corporation, as initial Servicer and Eaglefunding Capital Corporation, as Conduit Purchaser and Fleet National Bank, as Committed Purchaser and Fleet Securities, Inc. as Administrator.
10.6	1-3701 (with 2004 Form 10-K)	4(d)-1	Amendment No. 1 to Receivables Purchase Agreement.
10.7	1-3701 (with 2004 Form 10-K)	4(d)-2	Amendment No. 2 to Receivables Purchase Agreement.
10.8	1-3701 (with Form 8-K dated March 22, 2005)	10.1	Amendment No. 3, dated as of March 22, 2005, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Adminstrator.
10.9	1-3701 (with Form 8-K dated March 20, 2006)	10.1	Amendment No. 4, dated as of March 20, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Adminstrator.
10.10	1-3701 (with March 31, 2006 Form 10-Q)	10.1	Amendment No. 5, dated as of May 4, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [(1)] With Registration Number	As Exhibit	
10.11	1-3701 (with Form 8-K dated March 19, 2007)	10.1	Amendment No. 6, dated as of March 19, 2007, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.12	1-3701 (with Form 8-K dated March 14, 2008)	10.1	Amendment No. 7, dated as of March 14, 2008, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.13	1-3701 (with Form 8-K dated March 13, 2009)	10.1	Amendment No. 8, dated as of March 13, 2009, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator and appendix A.
10.14	1-3701 (with Form 8-K dated as of November 25, 2009)	10.1	Credit Agreement, dated as of November 25, 2009 among Avista Corporation, the Banks party thereto, JPMorgan Chase Bank, N.A. and UBS Securities LLC, as Co-Documentation Agents, Wells Fargo Securities, LLC, as Syndication Agent, and Union Bank, N.A., as Administrative Agent.
10.15	2-13788	13(e)	Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of November 14, 1957.
10.16	2-60728	10(b)-1	Amendment to Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of June 1, 1968.
10.17	1-3701 (with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.18	1-3701 (with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.19	1-3701 (with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.20	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.21	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.22	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.
10.23	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.
10.24	1-3701 (with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.
10.25	1-3701 (with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 and 4, dated as of May 6, 1981.
10.26	1-3701 (with 1992 Form 10-K)	10(s)-1	Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992.
10.27	1-3701 (with 2003 Form 10-K)	10(l)	Power Purchase and Sale Agreement between Avista Corporation and Potlatch Corporation, dated as of July 22, 2003.
10.28	1-3701 (with June 30, 2007 Form 10-Q)	10.1	Indemnification Agreement entered into as of June 30, 2007 by Coral Energy Holding, L.P. and certain of its affiliates and Avista Energy, Inc. and certain of its affiliates.
10.29	1-3701 (with June 30, 2007 Form 10-Q)	10.2	Guaranty Agreement effective as of June 30, 2007 entered into by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates.

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.30	1-3701 (with 2008 Form 10-K)	10.33	Executive Deferral Plan of the Company. [3][5]
10.31	1-3701 (with 2008 Form 10-K)	10.34	The Company's Unfunded Supplemental Executive Retirement Plan. [3][5]
10.32	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]
10.33	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.34	1-3701 (with 2006 Form 10-K)	10.37	Avista Corporation Long-Term Incentive Plan. [3]
10.35	1-3701 (with 2004 Form 10-K)	10(o)-6	Avista Corp. Performance Award Plan Summary [3]
10.36	1-3701 (with 2004 Form 10-K)	10(o)-7	Avista Corporation Performance Award Agreement [3]
10.37	1-3701(with Form 8-K dated June 21, 2005)	10.1	Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. [3]
10.38	1-3701(with Form 8-K dated August 13, 2008)	10.1	Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3]
10.39	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan
10.40	1-3701 (with 2008 Form 10-K)	10.44	Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][6]
10.41	1-3701 (with 2008 Form 10-K)	10.45	Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][7]
10.42	1-3701 (with September 30, 2007 Form 10-Q)	10.1	Avista Corporation Non-Employee Director Compensation.
12	(2)		Statement re computation of ratio of earnings to fixed charges.
21	(2)		Subsidiaries of Registrant
23	(2)		Consent of Independent Registered Public Accounting Firm
31.1	(2)		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)

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AVISTA CORPORATION

EXHIBIT INDEX (continued)

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
31.2	(2)		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002)
32	(4)		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

(1) Incorporated herein by reference.
(2) Filed herewith.
(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).
(4) Furnished herewith.
(5) The plans were modified to comply with Section 409A of the Internal Revenue Code. No significant changes were made to the plans.
(6) Applies for Christy M. Burmeister-Smith, Don F. Kopczynski, James M. Kensok, David J. Meyer, Kelly O. Norwood, Richard L. Storro, Jason R. Thackston, Dennis P. Vermillion, and Roger D. Woodworth.
(7) Applies for Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.

EXHIBIT 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges
Consolidated
(Thousands of Dollars)

	Years Ended December 31				
	2009	2008	2007	2006	2005
Fixed charges, as defined:					
Interest charges	$ 61,361	$ 74,914	$ 80,095	$ 88,426	$ 84,952
Amortization of debt expense and premium - net	5,673	4,673	6,345	7,741	7,762
Interest portion of rentals	1,874	1,601	1,612	1,802	2,394
Total fixed charges	$ 68,908	$ 81,188	$ 88,052	$ 97,969	$ 95,108
Earnings, as defined:					
Pre-tax income from continuing operations	$134,971	$120,382	$ 63,061	$114,927	$ 70,752
Add (deduct):					
Capitalized interest	(545)	(4,612)	(3,864)	(2,934)	(1,689)
Total fixed charges above	68,908	81,188	88,052	97,969	95,108
Total earnings	$203,334	$196,958	$147,249	$209,962	$164,171
Ratio of earnings to fixed charges	2.95	2.43	1.67	2.14	1.73

Exhibit 21

Avista Corporation

SUBSIDIARIES OF REGISTRANT

Subsidiary	State or Country of Incorporation
Avista Capital, Inc.	Washington
Advantage IQ, Inc.	Washington
Avista Development, Inc.	Washington
Avista Energy, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Avista Power, LLC	Washington
Avista Turbine Power, Inc.	Washington
Avista Ventures, Inc.	Washington
Pentzer Corporation	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Receivables Corporation	Washington
Avista Capital II	Delaware
Spokane Energy, LLC	Delaware
Steam Plant Square, LLC	Washington
Courtyard Office Center, LLC	Washington
Ecos IQ, Inc.	Washington

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-58197, 333-33790, 333-47290, and 333-126577 on Form S-8; and in Registration Statement Nos. 033-53655, 333-63243, 333-64652, and 333-155657, and 333-163609 on Form S-3 of our reports dated February 26, 2010, relating to the consolidated financial statements of Avista Corporation and subsidiaries, and the effectiveness of Avista Corporation and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2009.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 26, 2010

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;
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 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 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: February 26, 2010

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;
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 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 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: February 26, 2010

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, 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 Company's Annual Report on Form 10-K for the year ended December 31, 2009 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2010

/s/ Scott L. Morris
Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer

/s/ Mark T. Thies
Mark T. Thies
Senior Vice President and
Chief Financial Officer

ALLEGHENY ENERGY, INC

FORM 10-K
(Annual Report)

Filed 03/01/10 for the Period Ending 12/31/09

Address	800 CABIN HILL DRIVE GREENSBURG, PA 15601
Telephone	7248373000
CIK	0000003673
Symbol	AYE
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTIONS 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) of the SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2009**

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) of the SECURITIES EXCHANGE ACT OF 1934**

Commission file number 1-00267

ALLEGHENY ENERGY, INC.
(Name of Registrant)

Maryland **(State of Incorporation)** **800 Cabin Hill Drive, Greensburg, Pennsylvania**	**13-5531602** **(IRS Employer Identification Number)**
(Address of Principal Executive Offices)	**15601** **(Zip Code)**

(724) 837-3000
(Telephone Number)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.25 per share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

Indicate by check mark whether the 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 and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a small reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one).

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer (Do not check if a smaller reporting company)	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of December 31, 2009, 169,569,604 shares of the common stock, par value of $1.25 per share, of the registrant were outstanding.

Documents Incorporated by Reference

Portions of the Allegheny Energy, Inc. definitive Proxy Statement for its 2010 Annual Meeting of Stockholders are incorporated by reference to Part III of this Annual Report on Form 10-K.

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GLOSSARY

I. The following abbreviations and terms are used in this report to identify Allegheny Energy, Inc. and its subsidiaries:

AE	Allegheny Energy, Inc., a diversified utility holding company
AESC	Allegheny Energy Service Corporation, a subsidiary of AE
AE Supply	Allegheny Energy Supply Company, LLC, an unregulated generation subsidiary of AE
AGC	Allegheny Generating Company, a generation subsidiary of AE Supply and Monongahela
Allegheny	Allegheny Energy, Inc., together with its consolidated subsidiaries
Distribution Companies	Monongahela, Potomac Edison and West Penn, which collectively do business as Allegheny Power
Monongahela	Monongahela Power Company, a regulated subsidiary of AE
PATH, LLC	Potomac-Appalachian Transmission Highline, LLC, a joint venture between Allegheny and a subsidiary of American Electric Power Company, Inc.
PATH-Allegheny	PATH Allegheny Transmission Company, LLC
PATH-Allegheny MD	PATH-Allegheny Maryland Transmission Company, LLC
PATH-Allegheny VA	PATH-Allegheny Virginia Transmission Corporation
PATH-WV	PATH West Virginia Transmission Company, LLC
Potomac Edison	The Potomac Edison Company, a regulated subsidiary of AE
TrAIL Company	Trans-Allegheny Interstate Line Company
West Penn	West Penn Power Company, a regulated subsidiary of AE

II. The following abbreviations and acronyms are used in this report to identify entities and terms relevant to Allegheny's business and operations:

CDD	Cooling Degree-Days
Clean Air Act	Clean Air Act of 1970
CO_2	Carbon dioxide
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission, an independent commission within the DOE
FirstEnergy	FirstEnergy Corp.
FPA	Federal Power Act
FTRs	Financial Transmission Rights
GAAP	Generally accepted accounting principles used in the United States of America
HDD	Heating Degree-Days
kW	Kilowatt, which is equal to 1,000 watts
kWh	Kilowatt-hour, a unit of electric energy equivalent to one kW operating for one hour
Maryland PSC	Maryland Public Service Commission
MW	Megawatt, which is equal to 1,000,000 watts
MWh	Megawatt-hour, a unit of electric energy equivalent to one MW operating for one hour
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxide
NSR	The New Source Performance Review Standards, or "New Source Review," applicable to facilities deemed "new" sources of emissions by the EPA
OVEC	Ohio Valley Electric Corporation
PATH	Potomac-Appalachian Transmission Highline
Pennsylvania PUC	Pennsylvania Public Utility Commission
PJM	PJM Interconnection, L.L.C., a regional transmission organization
PLR	Provider-of-last-resort
PURPA	Public Utility Regulatory Policies Act of 1978
RPM	Reliability Pricing Model, which is PJM's capacity market
RTEP	Regional Transmission Expansion Plan, the process by which PJM identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers.
RTO	Regional Transmission Organization
Scrubbers	Flue-gas desulfurization equipment
SEC	Securities and Exchange Commission
SO_2	Sulfur dioxide
SOS	Standard Offer Service
T&D	Transmission and distribution
TrAIL	Trans-Allegheny Interstate Line
Virginia SCC	Virginia State Corporate Commission
West Virginia PSC	Public Service Commission of West Virginia

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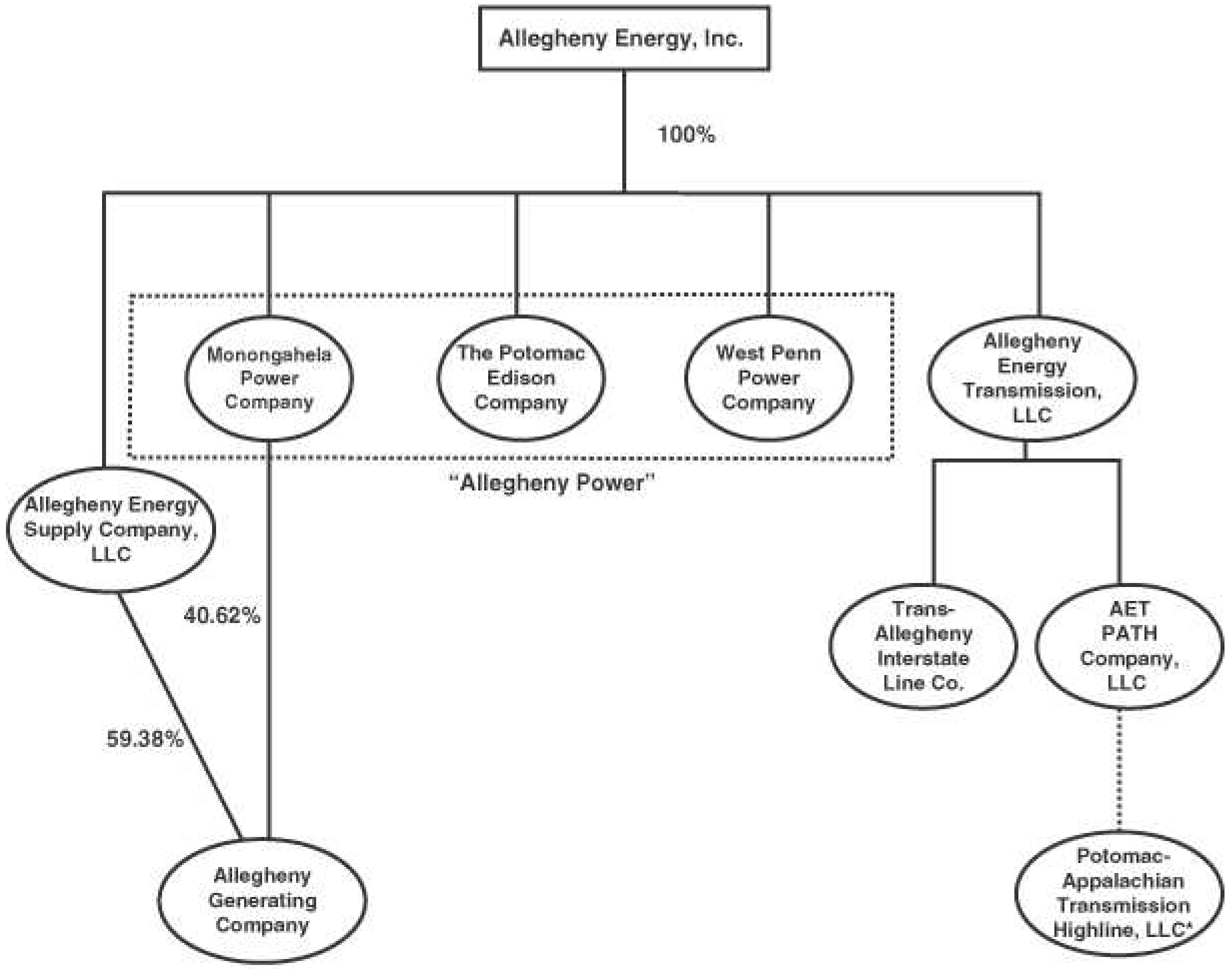
ALLEGHENY ENERGY, INC. AND ITS PRINCIPAL OPERATING SUBSIDIARIES



* Joint venture with a subsidiary of American Electric Power Company, Inc.

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PART I

ITEM 1. BUSINESS

OVERVIEW

Allegheny is an integrated energy business that owns and operates electric generation facilities and delivers electric services to customers in Pennsylvania, West Virginia, Maryland and Virginia. AE, Allegheny's parent holding company, was incorporated in Maryland in 1925. Allegheny operates its business primarily through AE's various directly and indirectly owned subsidiaries.

Allegheny's operations are organized into two business segments:

- **The Merchant Generation segment** includes Allegheny's merchant power generation operations, including the operations of AE Supply and AGC.
- **The Regulated Operations segment** includes all of Allegheny's regulated operations, including its electric T&D operations and transmission expansion projects, as well as Monongahela's power generation operations.

Allegheny changed the composition of its business segments during the fourth quarter of 2009. Prior to the fourth quarter of 2009, Allegheny's business was comprised of the Generation and Marketing segment and the Delivery and Services segment. The Generation and Marketing segment included the operations of AE Supply and Monongahela's generating assets. The Delivery and Services segment included the operations of Potomac Edison, West Penn, TrAIL Company, PATH, LLC and Monongahela's electric T&D business.

The changes in Allegheny's reportable segments during 2009 consisted primarily of the following:

- Monongahela's regulated generation operations were moved from the Generation and Marketing segment to the Delivery and Services segment.
- The Generation and Marketing segment was renamed the Merchant Generation segment.
- The Delivery and Services segment was renamed the Regulated Operations segment.

See consolidated financial statement Note 1, "Business, Basis of Presentation and Significant Accounting Policies" and Note 12, "Segment Information."

Proposed Merger with FirstEnergy

On February 10, 2010, AE, FirstEnergy, and Element Merger Sub, Inc., a direct wholly-owned subsidiary of FirstEnergy ("Merger Sub"), entered into an Agreement and Plan of Merger (the "Merger Agreement"), pursuant to which, and subject to certain terms and conditions, Merger Sub will merge with and into Allegheny (the "Merger"), with Allegheny continuing as the surviving corporation and a wholly-owned subsidiary of FirstEnergy. The merger agreement has been unanimously approved by the boards of directors of both Allegheny and FirstEnergy, but completion of the merger is contingent upon, among other things, the approval of the transaction by shareholders of both companies, the expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the receipt of required regulatory approvals. See "Risk Factors" and consolidated financial statement Note 27, "Subsequent Event – Merger Agreement."

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The Merchant Generation Segment

The principal companies and operations in AE's Merchant Generation segment include the following:

- ***AE Supply*** was formed in Delaware in 1999. AE Supply owns, operates and manages electric generation facilities. AE Supply also purchases and sells energy and energy-related commodities. As of December 31, 2009, AE Supply owned or contractually controlled 7,015 MWs of generation capacity. See "Electric Facilities."

  AE Supply markets its electric generation capacity to various customers and markets, including certain of its affiliates, and uses both derivative and nonderivative contracts to manage its portfolio of contracts. AE Supply's portfolio management and trading activities involve the use of physical commodity inventories and a variety of instruments, such as forward contracts, futures contracts, swap agreements and similar instruments. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and consolidated financial statement Note 13, "Fair Value Measurements, Derivative Instruments and Hedging Activities."

  AE Supply currently is contractually obligated to provide West Penn with most of the power that it needs to meet its PLR obligations in Pennsylvania through the end of 2010 and has contracts of varying length with West Penn to serve a portion of its load beyond 2010. In addition, AE Supply has contracts with Potomac Edison to supply most of the power necessary to serve Potomac Edison's Virginia customers through mid-2011 and is serving a portion of Potomac Edison's customer load in Maryland pursuant to contracts that range in length from three to 29 months. Together, these contracts currently comprise a majority of AE Supply's normal operating capacity. AE Supply had total operating revenues of $1.6 billion in 2009.

- ***AGC*** was incorporated in Virginia in 1981. As of December 31, 2009, AGC was owned approximately 59% by AE Supply and approximately 41% by Monongahela. AGC's sole asset is a 40% undivided interest in the Bath County, Virginia pumped-storage hydroelectric generation facility and its connecting transmission facilities. All of AGC's revenues are derived from sales of its 1,109 MW share of generation capacity from the Bath County generation facility to AE Supply and Monongahela. AGC had total operating revenues of $65.8 million in 2009. See "Electric Facilities."

All of Allegheny's generation facilities are located within PJM's competitive wholesale market. AE Supply and Monongahela sell into the PJM market the power that they generate and purchase from the PJM market the power necessary to meet their contractual obligations to supply power. See "Fuel, Power and Resource Supply" and "Regulatory Framework Affecting Allegheny."

During 2009, the Merchant Generation segment had total operating revenues of $1.6 billion and net income of $234.0 million. As of December 31, 2009, the Merchant Generation segment held approximately $4.3 billion of identifiable assets. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and consolidated financial statement Note 12, "Segment Information."

The Regulated Operations Segment

The principal companies and operations in Allegheny's Regulated Operation's segment include the following:

- ***The Distribution Companies*** include Monongahela, Potomac Edison and West Penn. Each of the Distribution Companies is a public utility company and does business under the trade name Allegheny Power. Allegheny Power's principal business is the operation of electric public utility systems. In April 2002, the Distribution Companies transferred functional control over their transmission systems to PJM. As an RTO, PJM coordinates the movement of electricity over the transmission grid 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.

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- ***Monongahela*** was incorporated in Ohio in 1924. It conducts an electric T&D business that serves approximately 383,600 customers in northern West Virginia in a service area of approximately 13,000 square miles with a population of approximately 779,000. Monongahela sold 10 million MWhs of electricity to retail customers in 2009.

  Monongahela also owns generation assets, which are included in the Regulated Operations segment. As of December 31, 2009, Monongahela owned or contractually controlled 2,741 MWs of generation capacity. Monongahela's generation capacity supplies its electric T&D business. In addition, Monongahela is contractually obligated to provide Potomac Edison with the power that it needs to meet its load obligations in West Virginia. Monongahela had total operating revenues of $695.2 million in 2009. See "Electric Facilities."

- ***Potomac Edison*** was incorporated in Maryland in 1923 and was also incorporated in Virginia in 1974. It operates an electric T&D system in portions of West Virginia, Maryland and Virginia. Potomac Edison serves approximately 483,400 customers in a service area of about 7,500 square miles with a population of approximately 1.06 million. Potomac Edison had total operating revenues of $832.6 million and sold 12.8 million MWhs of electricity to retail customers in 2009. In May 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative for cash proceeds of approximately $340 million, subject to certain closing conditions. Allegheny serves approximately 102,000 customers in northern Virginia. See "Regulatory Framework Affecting Allegheny," "Risk Factors" and consolidated financial statement Note 3, "Assets Held for Sale."

- ***West Penn*** was incorporated in Pennsylvania in 1916. It operates an electric T&D system in southwestern, south-central and northern Pennsylvania. West Penn serves approximately 714,900 customers in a service area of about 10,400 square miles with a population of approximately 1.6 million. West Penn had total operating revenues of $1.4 billion and sold 19.2 million MWhs of electricity to retail customers in 2009.

- ***TrAIL Company*** was incorporated in Maryland and Virginia in 2006. In June 2006, PJM, which manages a regional planning process for transmission expansion, approved an RTEP designed to maintain the reliability of the transmission grid in the mid-Atlantic region. The transmission expansion plan includes TrAIL, a new 500 kV transmission line that will extend from southwestern Pennsylvania through West Virginia to a point of interconnection with Virginia Electric and Power Company, a subsidiary of Dominion Resources, in northern Virginia. PJM designated Allegheny to construct the portion of the line that will be located in the Distribution Companies' PJM zone. TrAIL Company was formed in connection with the management and financing of transmission expansion projects, including this project (the "TrAIL Project"), and will build, own and operate the new transmission line. TrAIL Company currently expects to complete construction of the new line in 2011. See "Capital Expenditures" and "Regulatory Framework Affecting Allegheny."

- ***PATH, LLC*** was formed in Delaware in 2007 following PJM approval of PATH. As currently proposed, PATH is a new, 765 kV transmission line that will extend from a substation owned by American Electric Power Company ("AEP") near St. Albans, West Virginia, to a new substation near Kemptown, Maryland. PATH, LLC, which was formed in connection with the management and financing of this project (the "PATH Project"), is a series limited liability company. The "West Virginia Series" is owned equally by Allegheny and a subsidiary of AEP. The "Allegheny Series" is 100% owned by Allegheny. Each Series will, through an operating subsidiary, build, own and operate a portion of the line. Construction of the line remains subject to siting approval by the relevant state utility commissions, among other matters. In December 2009, PJM conducted certain sensitivity analyses that suggest that PATH may not be required by June 2014, as had been anticipated, to address congestion and reliability concerns and, therefore, will be considered in its 2010 RTEP. See "Capital Expenditures" and "Regulatory Framework Affecting Allegheny."

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During 2009, the Regulated Operations segment had operating revenues of $3.1 billion and net income of $157.9 million. As of December 31, 2009, the Regulated Operations segment held approximately $7.3 billion of identifiable assets. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and consolidated financial statement Note 12, "Segment Information."

Shared Services

AESC was incorporated in Maryland in 1963 and is a service company for Allegheny. AESC employs substantially all of the Allegheny personnel who provide services to AE and its subsidiaries, including among others, AE Supply, AGC, the Distribution Companies, TrAIL Company, PATH, LLC and their respective subsidiaries. These companies reimburse AESC at cost for services provided to them by AESC's employees. AESC had 4,383 employees as of December 31, 2009.

Certain Recent Initiatives and Developments

Throughout 2009, Allegheny's strategy has been to focus on its core generation and expanding transmission business, which management believes is enabling Allegheny to take advantage of its regional presence, operational expertise and knowledge of its markets to add shareholder value, despite challenging regulatory, market and overall economic conditions. Significant initiatives and developments include, among others:

- ***Transmission Expansion*** . In June 2006, PJM approved an RTEP designed to maintain the reliability of the transmission grid in the mid-Atlantic region that included TrAIL, and in June 2007, PJM authorized the construction of PATH. Although PJM currently is reevaluating the date by which PATH may be required to address NERC reliability requirements, in general these lines are intended to alleviate future reliability concerns and increase the west to east transmission capability of the PJM system. PJM designated Allegheny to construct the portion of TrAIL that is located in the Distribution Companies' PJM zone, and Allegheny and a subsidiary of AEP formed PATH, LLC to construct PATH. FERC, which has jurisdiction over rates for the transmission of electric power, has approved incentive rate treatment for both TrAIL and PATH, including incentive rates of return on equity, returns on construction work in progress and recovery of prudently incurred development and construction costs in the event that construction of either line is abandoned for reasons beyond Allegheny's control.

  Primary jurisdiction for approval of the siting and construction of transmission lines lies with the state public utility commission in the states in which the lines are proposed to be located. Applications for approval of PATH are pending in West Virginia and Maryland, but a similar request in Virginia was recently withdrawn on the basis of certain PJM analyses suggesting that PATH may not be required until some time beyond the originally anticipated 2014 target completion date. TrAIL Company received the requisite state utility commission approvals to construct TrAIL in Pennsylvania, West Virginia and Virginia in 2008, and construction of TrAIL is currently underway. At this time, overall TrAIL-related substation work is nearly 90% complete and tower construction is underway. TrAIL Company has obtained nearly 80% of the rights-of-way necessary to construct TrAIL and all significant construction and material contracts necessary to complete TrAIL.

  Allegheny has also taken steps in recent years to enhance the performance and reliability of its transmission system. For example, in 2007, Trail Company completed the installation of a new static volt-ampere reactive power compensator at the Black Oak substation (the "Black Oak SVC") that is designed to enhance the reliability of Allegheny's high-voltage Black Oak-Beddington transmission line, which is one of the most congested lines in the PJM region, and increase transmission capacity across the PJM region. TrAIL Company was granted an incentive rate of return on equity by FERC for the Black Oak SVC. TrAIL Company has also undertaken upgrades or replacements of transformers, buses or both at seven other substations and is constructing a new transmission operations center in West Virginia that it expects to complete during 2010. Allegheny has also identified various other transmission enhancement opportunities, some of which may be subject to PJM's RTEP process. See

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"Capital Expenditures," "Regulatory Framework Affecting Allegheny," "Risk Factors," and consolidated financial statement Note 5, "Transmission Expansion."

- ***Liquidity Enhancement, Investment Grade Status and Reinstatement of Common Stock Dividend*** . In 2007, following a period of financial difficulty and recovery, Allegheny achieved a significant milestone with the upgrade to investment grade status of its corporate credit ratings by all three major credit rating agencies and the reinstatement of AE's common stock dividend, as well as subsequent upgrades to investment grade status of the unsecured debt ratings of AE Supply and Monongahela. Additionally, TrAIL Company received inaugural investment grade ratings for its unsecured debt from all three major rating agencies.

  As widely reported, the financial markets and overall economies in the United States and abroad are currently experiencing a period of significant uncertainty that began in mid to late 2008 and has negatively affected overall market liquidity and access to credit. In spite of these prevailing economic conditions, Allegheny has maintained its investment grade credit ratings and has succeeded in enhancing its overall liquidity. During 2009 and the first part of 2010, Allegheny refinanced and extended the maturities of certain existing debt, while also obtaining favorable transmission-related financing.

  Specifically, in the third quarter of 2009, AE Supply issued $600 million aggregate principal amount of senior unsecured notes, consisting of $350 million of 5.75% Notes due 2019 and $250 million of 6.75% Notes due 2039, and obtained a new $1 billion senior secured revolving credit facility that matures in 2012. The new revolving credit facility replaced AE Supply's previous $400 million revolving credit facility that would have matured in 2011 and, in combination with the proceeds of the note offering, allowed AE Supply to repay its existing $447 million term loan, which also would have matured in 2011, and to complete tender offers for a total of $249.5 million in 7.8% Medium Term Notes due 2011 and $146.8 million of 8.25% Medium Term Notes due 2012.

  Also in 2009, AE Supply, in conjunction with the Pennsylvania Economic Development Authority, completed a tax exempt transaction that resulted in proceeds of approximately $235 million to finance a portion of the costs to install the Scrubbers at the Hatfield's Ferry generating facility. Additionally, in December 2009, subsidiaries of Monongahela and Potomac Edison completed an $86 million securitization transaction to finance the remaining costs to complete the installation of the Scrubbers at the Fort Martin generating facility, and Monongahela entered into a new, $110 million senior unsecured revolving credit facility. Finally, in January 2010, TrAIL Company refinanced its existing construction loan through the issuance of $450 million aggregate principal amount of 4.0% senior unsecured notes due 2015 and obtained a new, $350 million unsecured revolving credit facility that matures in 2013.

  In addition to these transactions, Allegheny continues to take other steps, such as proactively managing and controlling operations and maintenance expense and otherwise prudently managing cash, to maintain and improve its liquidity position. See "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and consolidated financial statement Note 8, "Capitalization and Debt."

- ***Environmental Compliance and Risk Management*** . Allegheny is working to effectively manage its environmental compliance efforts to ensure continuing compliance with applicable federal and state regulations while controlling its compliance costs, reducing emissions levels and minimizing its risk exposure.

  During the latter part of 2009, Allegheny completed a significant, multi-year effort to install Scrubbers at its Fort Martin and Hatfield's Ferry generating facilities. Now in-service, the Scrubbers will reduce overall SO_2 emissions at these two facilities by more than 95%. In addition to this initiative, Allegheny completed the elimination of a partial Scrubber bypass at its Pleasants generating facility in 2007 and is currently evaluating pollution control projects at other facilities. Although applicable environmental regulations and initiatives, including but not limited to air and water quality issues and climate change concerns, continue to present Allegheny with significant challenges, all of Allegheny's supercritical coal

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generating units are scrubbed and a significant amount of SO_2 and mercury emissions have been eliminated. See “Risk Factors,” “Capital Expenditures” and “Environmental Matters.”

- ***Energy Efficiency and Conservation*** . Through its Watt Watchers program introduced in 2007, Allegheny has implemented a number of programs to encourage energy efficiency and conservation among its customers, in addition to its long-standing portfolio of existing energy conservation programs.

  Recently, Allegheny has undertaken initiatives in response to Pennsylvania’s Act 129 and Maryland’s EmPOWER Maryland program, both of which establish demand-side reduction goals and required, among other things, that affected utilities file with the relevant state utility commissions specific plans describing the demand-side management programs that they propose to implement in order to reach those goals, as well as separate plans for the implementation of advanced, or “smart,” metering. During 2009, the Maryland PSC approved and provided for cost recovery with respect to, Potomac Edison’s proposed demand-side management programs in Maryland, and the Pennsylvania PUC largely approved West Penn’s proposed portfolio of energy efficiency and conservation programs. In both Maryland and Pennsylvania, Allegheny’s proposed advanced infrastructure and metering proposals remain subject to regulatory review.

  Other conservation initiatives include, for example, Allegheny’s partnership with Energy Star ®, the EPA’s voluntary market-based program to reduce greenhouse gasses through energy efficiency and its proposal to offer a voluntary wind energy program to customers in Pennsylvania. Allegheny continues to explore other programs through which customers can purchase electricity from renewable sources, and in December 2009, purchased an additional 13 MW of hydroelectric generation. Allegheny is also developing a number of other new programs for customers that it believes can help drive energy efficiency and conservation, such as opportunities for home energy audits. See “Regulatory Matters Affecting Allegheny.”

- ***Transition to Market-Based Rates*** . Each of the states in Allegheny’s service territory, other than West Virginia has, to some extent, taken steps to deregulate its electric utility industry, although Virginia has essentially reversed deregulation plans. Pennsylvania and Maryland instituted customer choice and are transitioning to market-based, rather than cost-based pricing for generation. Virginia undertook to deregulate the provision of generation services beginning in 1999, but subsequent legislation resulted in the re-regulation of these services in January 2009 for most customers. In West Virginia, the rates charged to retail customers are regulated by the West Virginia PSC and are determined through traditional, cost-based regulated utility rate-making.

  In 2005, Allegheny implemented a plan to transition Pennsylvania customers to generation rates based on market prices through increases in applicable rate caps in 2007, 2009 and 2010 and a two-year extension of the applicable transition period. Although the Pennsylvania state legislature has, at times, debated their extension, the rate caps applicable to Allegheny’s Pennsylvania customers remain scheduled to expire at the end of 2010. West Penn conducted auctions in April, June and October 2009 and in January 2010 to purchase a portion of the power required to serve its customers in Pennsylvania beginning on January 1, 2011. West Penn now has contracts for approximately 67% of the power needed to serve its residential customers, and nearly half of the power needed to serve its small and mid-sized nonresidential customers, in 2011, resulting in only modest expected increases in customer bills. Assuming that average prices for the remaining auctions remain the same as the average of the first four auctions, the result would be an increase in the typical West Penn residential customer’s bill of 8.5%, assuming usage of 1,000 kWh per month, and increases of only 0.6% and 2.0% for small and mid-sized nonresidential customers, respectively, in 2011 as compared to 2010.

  Potomac Edison’s Maryland residential customers currently can participate in a Maryland PSC-approved transition plan. Residential customers who did not opt out of the plan began paying a surcharge in June 2007 that, with the expiration of residential rate caps and the move to market-based rates on January 1, 2009, converted to a credit on customers’ bills, such that funds collected via the surcharge in 2007 and 2008 are being returned to customers to mitigate the effect of the rate cap

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expiration until December 2010 or such time as all amounts collected through the surcharge, plus interest, are returned to customers.

AE Supply is serving a portion of Potomac Edison's Maryland customers pursuant to contracts that range in length from three to 29 months. Potomac Edison also has contracts with AE Supply to supply most of the power necessary to serve Potomac Edison's Virginia customers through mid-2011. These contracts were awarded to AE Supply as a result of competitive bidding processes in both Virginia and Maryland. Suppliers that are not affiliated with Potomac Edison also were awarded contracts for portions of Potomac Edison's Virginia and Maryland load pursuant to the competitive bidding process. In Maryland, Potomac Edison will conduct rolling auctions to procure its power supply. The arrangements to serve Potomac Edison's load obligations in Virginia after July 1, 2011 are still under development. See "Competition," "Regulatory Matters Affecting Allegheny," "Risk Factors" and consolidated financial statement Note 4, "Rates and Regulation."

- ***Cost Recovery*** . In addition to its efforts to manage the transition to market-based generation rates, Allegheny is working to achieve full recovery of its costs and a reasonable rate of return through the traditional rate-making process. In November 2008, following a protracted dispute over Potomac Edison's ability to recover purchased power costs, the Virginia SCC approved a settlement allowing Potomac Edison to transition all of its Virginia customers to rates that would allow for full recovery of purchased power costs no later than July 2011, and the Virginia SCC separately approved a transmission rate adjustment related to third party transmission costs and a rate increase to recover purchased power costs in 2009.

  In West Virginia, a base rate case by which Monongahela and Potomac Edison propose to increase retail rates by approximately $106 million beginning in June 2010 is under review by the West Virginia PSC. Additionally, in December 2009, the West Virginia PSC approved a settlement with respect to annual fuel adjustments for Monongahela and Potomac Edison providing for an aggregate increase of $118 million, effective January 1, 2010, plus deferred recovery of an additional $23.1 million. See "Regulatory Matters Affecting Allegheny," "Risk Factors" and consolidated financial statement Note 4, "Rates and Regulation."

- ***Customer Satisfaction*** . Allegheny continues to see high levels of satisfaction among its customers. For example, a leading independent survey firm has ranked Allegheny first in commercial and industrial satisfaction in the northeastern United States for the last five consecutive years, and another firm ranked Allegheny in the top quartile nationally for residential customer satisfaction.

- ***Virginia Asset Sale*** . On May 4, 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative (together, the "Cooperatives") for cash proceeds of approximately $340 million, subject to state and federal regulatory approval, certain third-party consents and applicable price adjustments. On September 15, 2009, Potomac Edison and the Cooperatives filed with the Virginia SCC a joint request for approval of the transaction. The Virginia SCC issued a procedural order scheduling an evidentiary hearing on the matter for March 2, 2010. See "Regulatory Matters Affecting Allegheny" and consolidated financial statement Note 3, "Assets Held for Sale."

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Where You Can Find More Information

AE files or furnishes Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, proxy statements and other information with or to the SEC. You may read and copy any document that AE files with the SEC at the SEC's public reference room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. These SEC filings are also available to the public from the SEC's website at *http://www.sec.gov* .

The Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, proxy statements, statements of changes in beneficial ownership and other SEC filings, and any amendments to those reports, that AE files with or furnishes to the SEC under the Exchange Act are made available free of charge on AE's website at *http://www.alleghenyenergy.com* as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC. AE's website and the information contained therein are not incorporated into this report.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

In addition to historical information, this report contains a number of forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking information often may be identified by the use of words such as anticipate, expect, project, intend, plan, believe and words and terms of similar substance used in connection with any discussion of future plans, actions or events. However, the absence of these or similar words does not mean that any particular statement is not forward-looking. Forward-looking statements herein may relate to, among other matters:

- regulatory matters, including but not limited to environmental regulation, state rate regulation, and the status of retail generation service supply competition in states served by the Distribution Companies;
- financing plans;
- market demand and prices for energy, capacity, coal and natural gas;
- the cost and availability of raw materials, including coal, and Allegheny's ability to enter into, modify and enforce long-term fuel purchase agreements;
- PLR and power supply contracts;
- results of litigation;
- results of operations;
- internal controls and procedures;
- capital expenditures;
- status and condition of plants and equipment;
- changes in technology and their effects on the competitiveness of Allegheny's generation facilities;
- work stoppages by Allegheny's unionized employees;
- capacity purchase commitments; and
- Allegheny's proposed merger with FirstEnergy.

Forward-looking statements involve estimates, expectations and projections and, as a result, are subject to risks and uncertainties. There can be no assurance that actual results will not differ materially from expectations. Actual results have varied materially and unpredictably from past expectations. Factors that could cause actual results to differ materially include, among others, the following:

- the results of regulatory proceedings, including proceedings related to rates;
- plant performance and unplanned outages;
- volatility and changes in the price and demand for energy and capacity and changes in the value of FTRs;
- volatility and changes in the price of coal, natural gas and other energy-related commodities, as well as transportation costs;
- Allegheny's ability to enter into, modify and enforce long term fuel purchase agreements;
- the effectiveness of Allegheny's risk management policies and procedures;
- the ability and willingness of counterparties to satisfy their financial and performance obligations;
- changes in the weather and other natural phenomena;
- changes in Allegheny's requirements for, and the availability and price of, emission allowances;
- changes in industry capacity, development and other activities by Allegheny's competitors;
- changes in market rules, including changes to PJM's participant rules and tariffs, and defaults by other market participants;

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- the loss of any significant customers or suppliers;
- changes in both customer usage and customer switching behavior and their resulting effects on existing and future load requirements;
- the impact of government-mandated energy consumption initiatives, as well as general trends in resource conservation;
- dependence on other electric transmission and gas transportation systems and their constraints on availability;
- the reliability of Allegheny's own system and its ongoing compliance with NERC reliability standards;
- environmental regulations;
- changes in other laws and regulations applicable to Allegheny, its markets or its activities;
- changes in the underlying inputs and assumptions, including market conditions, used to estimate the fair values of commodity contracts;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- entry into, any failure to consummate, or any delay in the consummation of, contemplated asset sales or other strategic transactions;
- the likelihood and timing of the completion of the proposed merger with FirstEnergy, the terms and conditions of any required regulatory approvals of the proposed merger, the impact of the proposed merger on Allegheny's employees and potential diversion of management's time and attention from ongoing business during this time period;
- complications or other factors that make it difficult or impossible to obtain necessary lender consents or regulatory authorizations on a timely basis;
- recent and any future disruptions in the financial markets and changes in access to capital markets;
- the availability of credit;
- actions of rating agencies;
- inflationary or deflationary trends and interest rate trends;
- general economic and business conditions, including the effects of the current recession; and
- other risks, including the effects of global instability, terrorism and war.

For a more detailed discussion of certain risk factors affecting Allegheny's risk profile, see "Risk Factors."

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ALLEGHENY'S SALES AND REVENUES

Merchant Generation

The Merchant Generation segment generated 26,004 million kWhs and 34,464 million kWhs of electricity in 2009 and 2008, respectively. The segment's revenues were composed of the following:

Revenues (in millions)	2009	2008
PJM energy revenue	$ 936.5	$1,913.1
PJM capacity revenue	356.2	195.2
Power hedge revenues	213.5	(363.8)
Other	102.4	48.4
Total operating revenues	$1,608.6	$1,792.9

Regulated Operations

The Regulated Operations segment sold 42,040 million kWhs and 44,192 million kWhs of electricity to retail customers in 2009 and 2008, respectively. The segment's operating revenues were composed of the following:

Revenues (in millions)	2009	2008
Retail electric:		
Generation and ancillary	$2,280.0	$1,902.7
Transmission	118.6	124.2
Distribution	661.7	675.1
Total retail electric	3,060.3	2,702.0
Transmission services and bulk power:		
PJM revenue, net	(198.8)	(34.2)
Warrior Run generation revenue	52.7	86.0
Transmission and other	100.1	73.3
Total transmission Services and bulk power	(46.0)	125.1
Other	36.9	28.2
Total operating revenues	$3,051.2	$2,855.3

For more information regarding each segment's revenues and operating results, as well as intersegment revenues and costs eliminated in Allegheny's consolidated financial statements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" and consolidated financial statement Note 12, "Segment Information."

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CAPITAL EXPENDITURES

Actual capital expenditures for 2009 and estimated capital expenditures for 2010 and 2011 are shown on a cash basis in the following table. The amounts and timing of capital expenditures are subject to continuing review and adjustment, and actual capital expenditures may vary from these estimates.

	Actual	Projected	
(in millions)	2009 (a)	2010	2011
Transmission and distribution facilities:			
TrAIL and related transmission expansion (b)	$ 455.4	$ 358.9	$ 95.4
PATH Project (c)	43.7	21.3	23.8
Other transmission and distribution facilities	216.1	402.7	340.7
Total transmission and distribution facilities	715.2	782.9	459.9
Environmental:			
Fort Martin Scrubbers (d)	160.7	34.0	—
Hatfield Scrubbers (d)	135.2	21.0	—
Other	39.0	97.0	158.5
Total environmental	334.9	152.0	158.5
Other generation facilities	81.6	100.0	58.7
Other capital expenditures	20.5	46.0	19.1
Total capital expenditures	$1,152.2	$1,080.9	$696.2

(a) For more information, see consolidated financial statement Note 12, "Segment Information."
(b) TrAIL has a target completion date of 2011 and an estimated cost of approximately $850 million. TrAIL Company is also engaged in other transmission projects.
(c) Excludes capital expenditures related to AEP's portion of the West Virginia Series of PATH, LLC, which were $14.1 million in 2009. Allegheny's share of the total cost of the project is estimated at $1.2 billion. The revised in-service date for PATH is expected to be determined in PJM's 2010 RTEP.
(d) The installation of Scrubbers at both the Fort Martin and Hatfield's Ferry generating stations was completed in 2009.

The foregoing table does not include certain other potential capital projects the need or regulatory mandate for which currently may be uncertain, including but not limited to additional transmission investment opportunities, some of which will be subject to the PJM RTEP process, and costs that Allegheny could incur in connection with the installation of certain additional pollution control equipment at its generating facilities.

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ELECTRIC FACILITIES

Generation Capacity

Allegheny's owned or controlled generation capacity, other than the capacity owned and controlled by Monongahela, is included in the Merchant Generation segment. Monongahela's generation is included in the Regulated Operations segment.

Nominal Maximum Operational Generation Capacity

Stations	Units	Total MW	Merchant Generation Segment (MW)	Regulated Operations Segment (MW)	Commencement Dates (a)
Supercritical Coal Fired (Steam):					
Harrison (Haywood, WV)	3	1,983	1,576	407	1972-74
Hatfield's Ferry (Masontown, PA)	3	1,710	1,710		1969-71
Pleasants (Willow Island, WV)	2	1,300	1,200	100	1979-80
Fort Martin (Maidsville, WV)	2	1,107		1,107	1967-68
Other Coal Fired (Steam):					
Armstrong (Adrian, PA)	2	356	356		1958-59
Albright (Albright, WV)	3	292		292	1952-54
Mitchell (Courtney, PA)	1	288	288		1963
Willow Island (Willow Island, WV)	2	243		243	1949-60
Rivesville (Rivesville, WV)	2	130		130	1943-51
R. Paul Smith (Williamsport, MD)	2	116	116		1947-58
OVEC (Chelsea, OH) (Madison, IN) (b)	11	78	67	11	
Pumped-Storage and Hydro:					
Bath County (Warm Springs, VA) (c)	6	1,109	658	451	1985; 2001
Lake Lynn (Lake Lynn, PA) (d)	4	52	52		1926
Allegheny Lock & Dam 5 (Freeport, PA) (e)	2	6	6		1987
Allegheny Lock & Dam 6 (Freeport, PA) (e)	2	7	7		1989
Green Vally Hydro (f)	21	6	6		Various
Gas Fired:					
AE Nos. 3, 4 & 5 (Springdale, PA)	3	540	540		2003
AE Nos. 1 & 2 (Springdale, PA)	2	88	88		1999
AE Nos. 8 & 9 (Gans, PA)	2	88	88		2000
AE Nos. 12 & 13 (Chambersburg, PA)	2	88	88		2001
Buchanan (Oakwood, VA) (g)	2	43	43		2002
Hunlock CT (Hunlock Creek, PA)	1	44	44		2000
Oil-Fired (Steam):					
Mitchell (Courtney, PA)	1	82	82		1949
Total Capacity		**9,756**	**7,015**	**2,741**	

(a) When more than one year is listed as a commencement date for a particular generation facility, the dates refer to the years in which operations commenced for the different units at that generation facility.

(b) The amount attributed to OVEC represents capacity entitlement through AE's ownership of OVEC shares. AE holds a 3.5% equity stake in, and is a sponsoring company of, OVEC. OVEC supplies power to its sponsoring companies under an intercompany power agreement.

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(c) This figure represents capacity entitlement through ownership of AGC.
(d) AE Supply has a license for Lake Lynn through 2024.
(e) AE Supply purchased hydroelectric generation facilities at Allegheny Lock and Dam Nos. 5 & 6 in December 2009. See consolidated financial statement Note 14, "Purchase of Hydroelectric Generation Facilities."
(f) The licenses for Green Valley hydroelectric facilities Dam No. 4 and Dam No. 5, located in West Virginia and Maryland, will expire in November 2024. The licenses for the Shenandoah, Warren, Luray and Newport projects located in Virginia run through 2024.
(g) Buchanan Energy Company of Virginia, LLC ("Buchanan") is a subsidiary of AE Supply. CNX Gas Corporation and Buchanan have equal ownership interests in Buchanan Generation LLC ("Buchanan Generation"). AE Supply operates and dispatches 100% of Buchanan Generation's 86 MWs.

PURPA Capacity

The following table shows generation capacity, in addition to that reflected in the table above, that is available to the Distribution Companies through state utility commission-approved arrangements pursuant to PURPA. PURPA requires electric utility companies, such as the Distribution Companies, to interconnect with, provide back-up electric service to and purchase electric capacity and energy from qualifying small power production and cogeneration facilities, although electric utilities are no longer required to enter into any new contractual obligation to purchase energy from a qualifying facility if FERC finds that the facility has non-discriminatory access to a functioning wholesale market and open-access transmission. The capacity purchases reflected in this table are reflected in the results of the Regulated Operations segment.

	PURPA Capacity (MW)				
PURPA Stations (a)	Project Total	Monongahela	Potomac Edison	West Penn	Contract Termination Date
Coal Fired (Steam)					
AES Warrior Run (Cumberland, MD) (b)	180		180		2030
AES Beaver Valley (Monaca, PA)	125			125	2016
Grant Town (Grant Town, WV)	80	80			2036
West Virginia University (Morgantown, WV)	50	50			2027
Hydro:					
Hannibal Lock and Dam (New Martinsville, WV)	31	31			2034
Total PURPA Capacity	466	161	180	125	

(a) AE Supply purchased hydroelectric generating facilities at Allegheny Lock and Dam Nos. 5 & 6, previously PURPA stations with generating capacity of 13 MW, in December 2009.
(b) As required under the terms of a Maryland restructuring settlement, Potomac Edison offers the 180 MW output of the AES Warrior Run project to the wholesale market and will continue to do so for the term of the AES Warrior Run contract, which ends on February 10, 2030. Revenue received from the sale reduces the AES Warrior Run surcharge paid by Maryland customers.

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Transmission and Distribution Facilities

The following table sets forth the existing miles of T&D lines and the number of substations of the Distribution Companies and AGC as of December 31, 2009:

	Underground	Above-Ground	Total Miles	Total Miles Consisting of 500-Kilovolt (kV) Lines	Number of Transmission and Distribution Substations
Monongahela	923	24,244	25,167	250	242
Potomac Edison	5,443	19,671	25,114	176	225
West Penn	3,047	25,927	28,974	276	507
AGC (a)	—	87	87	87	1
Total	9,413	69,929	79,342	789	975

(a) Total Bath County transmission lines, of which AGC owns an undivided 40% interest and Virginia Electric and Power Company owns the remainder.

The Distribution Companies' transmission network has 12 extra-high-voltage (345 kV and above) and 36 lower-voltage interconnections with neighboring utility systems.

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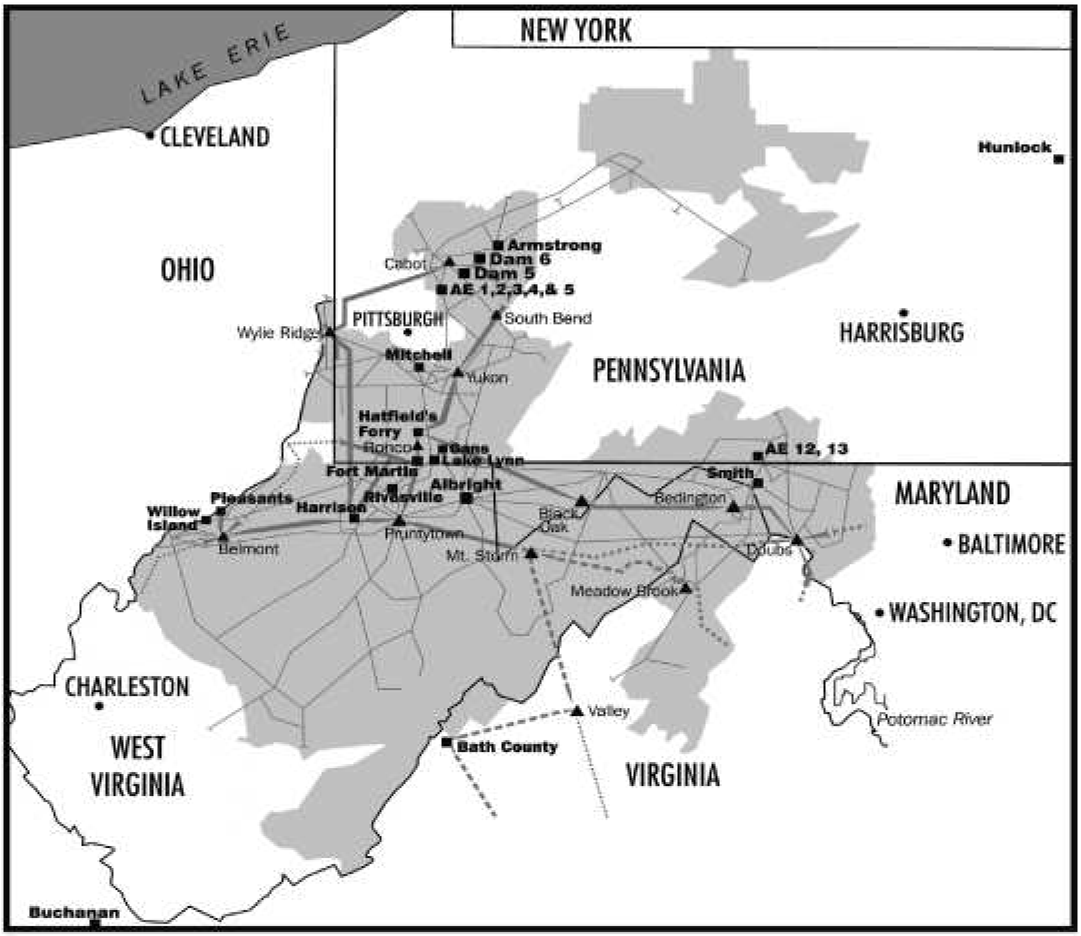
ALLEGHENY MAP*



Allegheny's Generation and Major Transmission Facilities*

- Distribution Companies
- ■ Generating Station
- ▲ EHV Substation
- Interconnection with Other Utilities
- 138 kV or 230 kV Allegheny
- 345 kV or 500 kV Allegheny
- 500 kV Joint Ownership
- 500 kV or 765 kV Other Utilities

* Omits OVEC, in which AE owns a 3.5% interest, and does not reflect the TrAIL and PATH Projects.

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FUEL, POWER AND RESOURCE SUPPLY

Coal Supply

Allegheny primarily uses Northern Appalachian coal at its coal-fired generating facilities. Most of Allegheny's coal purchase agreements contain specified prices and include price adjustment provisions related to changes in specified cost indices, as well as to specific events, such as changes in regulations that affect the coal industry.

Developments and operational factors affecting Allegheny's coal suppliers, including increased costs, transportation constraints, safety issues and operational difficulties, may have negative effects on coal supplier performance. Additionally, Allegheny has experienced, and may continue to experience, increases in other fuel-related costs, such as its fuel handling and transportation costs and its costs to procure lime, urea and other materials necessary to the operation of its pollution control equipment. Furthermore, while the longer-term contracts that AE Supply and Monongahela have in place are intended to partially mitigate Allegheny's exposure to negative fluctuations in coal prices, in some cases, those contracts may require that AE Supply and Monongahela purchase a minimum volume of coal over a given time period. During 2009, as a result of falling demand and market prices for power, Allegheny's coal consumption decreased significantly, and it was required at times to purchase coal in excess of immediate needs, resulting in coal inventories at some of its facilities that exceed what it considers to be optimal levels. See "Risk Factors."

Merchant Generation . AE Supply consumed approximately 10.1 million tons of coal in 2009 at an average price of approximately $54.87 per ton delivered. Allegheny purchased these fuels primarily from mines in Pennsylvania, West Virginia and Ohio. However, Allegheny also purchases coal from other regions, and blends coal from the Powder River Basin with eastern bituminous coal at one of its generating facilities.

Historically, AE Supply has purchased a majority of its coal from a limited number of suppliers. Of AE Supply's coal purchases in 2009, 67% came from subsidiaries of four companies, the largest of which represented 24% of the total tons purchased.

As of February 19, 2010, AE Supply had commitments for the delivery of more than 98% of the coal that AE Supply expects to consume in 2010. Excluding volumes that are priced annually based on market conditions, AE Supply also had commitments for the delivery of approximately 65% of its anticipated coal needs for 2011 and for approximately 59%, 54% and 50% of its anticipated coal needs for 2012, 2013 and 2014, respectively.

Regulated Operations . Monongahela consumed approximately 3.1 million tons of coal in 2009 at an average price of approximately $60.91 per ton delivered. Monongahela purchased these fuels primarily from mines in Pennsylvania, West Virginia and Ohio. However, Monongahela also purchases coal from other regions, and blends coal from the Powder River Basin with eastern bituminous coal at several generating facilities.

Historically, Monongahela has purchased a majority of its coal from a limited number of suppliers. Of Monongahela's coal purchases in 2009, 76% came from subsidiaries of three companies, the largest of which represented 28% of the total tons purchased.

As of February 19, 2010, Monongahela had commitments for the delivery of more than 98% of the coal that Monongahela expects to consume in 2010. Excluding volumes that are priced annually based on market conditions, Monongahela also had commitments for the delivery of approximately 58% of its anticipated coal needs for 2011 and for approximately 46%, 44% and 41% of its anticipated coal needs for 2012, 2013 and 2014, respectively.

Natural Gas Supply

AE Supply purchases natural gas to supply its natural gas-fired generation facilities. In 2009, AE Supply purchased its natural gas requirements principally in the spot market.

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AE Supply has an agreement under a FERC-approved tariff with Kern River Gas Transmission Company for the firm transportation of 45,122 decatherms of natural gas per day from Opal, Wyoming to southern California. The transportation agreement runs through April 30, 2018. AE Supply is managing this obligation through monthly financial basis swaps and the concomitant purchase and sale of physical natural gas.

Electric Power

Allegheny reorganized its corporate structure in response to electric utility deregulation within its service area between 1999 and 2001. The Distribution Companies, with the exception of Monongahela and its West Virginia generation assets, do not produce their own power. Potomac Edison transferred all of its generation assets to AE Supply in 2000. West Penn transferred all of its generation assets to AE Supply in 1999. Monongahela transferred the portion of its generation assets dedicated to its previously-owned Ohio service territory to AE Supply in 2001. Effective as of January 1, 2007, Monongahela and AE Supply completed an intra-company transfer of assets that realigned generation ownership and contractual obligations within the Allegheny system (the “Asset Swap”). See “Regulatory Framework Affecting Allegheny.”

Pennsylvania instituted retail customer choice in 1996 and is transitioning to market-based, rather than cost-based pricing for generation. West Penn is the PLR for those Pennsylvania customers who do not choose an alternate supplier or whose alternate supplier does not deliver or who choose to return to West Penn service, in each case at rates that are capped at various levels through the end of the transition period. Currently, West Penn’s transition period will end on December 31, 2010. AE Supply is contractually obligated to provide West Penn with most of the power that it needs to meet its PLR obligations in Pennsylvania through the end of the transition period. In July 2008, the Pennsylvania PUC approved West Penn’s proposed power procurement plan pursuant to which West Penn has begun to procure its post-transition period power requirements through a combination of competitively bid contracts and spot market purchases.

Potomac Edison has contracts with AE Supply to supply most of the power necessary to serve Potomac Edison’s Virginia customers through mid-2011. AE Supply also is serving a portion of Potomac Edison’s Maryland customers pursuant to contracts that range in length from three to 29 months. These contracts were awarded to AE Supply as a result of competitive bidding processes in both Virginia and Maryland. Suppliers that are not affiliated with Potomac Edison also were awarded contracts for portions of Potomac Edison’s Virginia and Maryland load pursuant to the competitive bidding process. In Maryland, Potomac Edison will conduct rolling auctions to procure its power supply. In May 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative, subject to certain closing conditions. See “Business – Overview,” “Risk Factors,” and consolidated financial statement Note 3, “Assets Held for Sale.”

Prior to January 1, 2007, AE Supply sold power to Potomac Edison to serve customers in Potomac Edison’s West Virginia service territory. In connection with the Asset Swap, Monongahela assumed the obligation to supply power to Potomac Edison to meet its West Virginia load obligations through 2027. Monongahela sells the power that it generates from its West Virginia jurisdictional assets into the PJM market and purchases from the PJM market the power necessary to meet its West Virginia jurisdictional customer load and contractual obligations to provide power, including its obligations to supply power to Potomac Edison.

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COMPETITION

Each of the states in Allegheny's service territory, other than West Virginia has, to some extent, taken steps to deregulate its electric utility industry, although Virginia has essentially reversed deregulation plans. Pennsylvania and Maryland instituted customer choice and are transitioning to market-based, rather than cost-based pricing for generation. Virginia undertook to deregulate the provision of generation services beginning in 1999, but subsequent legislation resulted in the re-regulation of these services in January 2009 for most customers.

In 2005, Allegheny implemented a plan to transition Pennsylvania customers to generation rates based on market prices through increases in applicable rate caps in 2007, 2009 and 2010 and a two-year extension of the applicable transition period. Although the Pennsylvania state legislature has, at times, debated their extension, the rate caps applicable to Allegheny's Pennsylvania customers remain scheduled to expire at the end of 2010. West Penn conducted auctions in April, June and October 2009 and January 2010 to purchase a portion of the power required to serve its customers in Pennsylvania beginning on January 1, 2011. In the April 2009 auction, AE Supply was awarded 17-month and 29-month residential contracts representing approximately 2 million megawatt-hours of generation supply. In the June 2009 auction, AE Supply was awarded two non-residential contracts to deliver a total of approximately 700,000 megawatt-hours of generation supply over a 17-month period. In the October 2009 auction, AE Supply was awarded 17-month and 29-month residential contracts and three 17-month non-residential contracts to deliver a total of 1.8 million megawatt-hours of generation supply.

AE Supply is serving a portion of Potomac Edison's Maryland customers pursuant to contracts that range in length from three to 29 months. Potomac Edison also has contracts with AE Supply to supply most of the power necessary to serve Potomac Edison's Virginia customers through mid-2011. These contracts were awarded to AE Supply as a result of competitive bidding processes in both Virginia and Maryland. Suppliers that are not affiliated with Potomac Edison also were awarded contracts for portions of Potomac Edison's Virginia and Maryland load pursuant to the competitive bidding process. In Maryland, Potomac Edison will conduct rolling auctions to procure its power supply. The arrangements to serve Potomac Edison's load obligations in Virginia after July 1, 2011 are still under development. In May 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia for cash proceeds of approximately $340 million, subject to state and federal regulatory approval, certain third-party consents and applicable price adjustments. See "Regulatory Framework Affecting Allegheny," "Risk Factors," consolidated financial statement Note 3, "Assets Held for Sale" and Note 4, "Rates and Regulation."

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REGULATORY FRAMEWORK AFFECTING ALLEGHENY

The interstate transmission services and wholesale power sales of the Distribution Companies, TrAIL Company, PATH, LLC, AE Supply and AGC are regulated by FERC under the FPA. The Distribution Companies' local distribution service and sales at the retail level are subject to state regulation. In addition, Allegheny is subject to numerous other local, state and federal laws, regulations and rules. See "Risk Factors."

Federal Regulation and Rate Matters

FERC, Competition and RTOs

Allegheny's generation and transmission businesses are significantly influenced by the actions of FERC through policies, regulations and orders issued pursuant to the FPA. The FPA gives FERC exclusive jurisdiction over the rates, terms and conditions of wholesale sales and transmission of electricity in interstate commerce. Entities, such as the Distribution Companies, TrAIL Company, the operating subsidiaries of PATH, LLC, AE Supply and AGC, that sell electricity at wholesale or own transmission facilities are subject to FERC jurisdiction and must file their rates, terms and conditions for such sales with FERC. Rates for wholesale sales of electricity may be either cost-based or market-based. Rates for use of transmission facilities are determined on a cost basis.

FERC's authority under the FPA, as it pertains to Allegheny's generation and transmission businesses, also includes, but is not limited to: licensing of hydroelectricity projects; transmission interconnections with other electric facilities; transfers of public utility property; mergers, acquisitions and consolidation of public utility systems and companies; issuance of certain securities and assumption of certain liabilities; accounting and methods of depreciation; transmission reliability; siting of certain transmission facilities; allocation of transmission rights; relationships between holding companies and their public utility affiliates; availability of books and records; and holding of a director or officer position at more than one public utility or specified company.

FERC's policies, regulations and orders encourage competition among wholesale sellers of electricity. To support competition, FERC requires public utilities that own transmission facilities to make such facilities available on a non-discriminatory, open-access basis and to comply with standards of conduct that prevent transmission-owning utilities from giving their affiliated sellers of electricity preferential access to the transmission system and transmission information. To further competition, FERC encourages transmission-owning utilities to participate in regional transmission organizations ("RTOs") such as PJM, by transferring functional control over their transmission facilities to RTOs.

All of Allegheny's generation assets and power supply obligations are located within the PJM market, and PJM maintains functional control over the transmission facilities owned by the Distribution Companies and TrAIL Company. PJM operates a competitive wholesale electricity market and coordinates the movement of wholesale electricity 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 is also responsible for developing and implementing the RTEP for the PJM region to ensure reliability of the electric grid and promote market efficiency. In addition, PJM determines the requirements for, and manages the process of, interconnecting new and expanded generation facilities to the grid. Changes in the PJM tariff, operating agreement, policies and/or market rules could adversely affect Allegheny's financial results. See "Risk Factors."

Transmission Rate Design . FERC actions with respect to the transmission rate design within PJM may impact the Distribution Companies. Beginning in July 2003, FERC issued a series of orders related to transmission rate design for the PJM and Midwest Independent Transmission System Operator ("MISO") regions. Specifically, FERC ordered the elimination of multiple and additive (i.e., "pancaked") rates and called for the implementation of a long-term rate design for these regions. In November 2004, FERC rejected long-term

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regional rate proposals, concluding that neither the rate design proposals nor the existing PJM rate design had been shown to be just and reasonable. FERC ordered the continuation of the existing PJM zonal "license plate" rate design and the implementation of a transition charge for these regions during a 16-month transition period commencing on December 1, 2004 and ending on March 31, 2006. Subsequently, transition charge proposals were submitted by transmission owners and accepted by FERC subject to an evidentiary hearing to determine if the amount of the charges was just and reasonable. Rehearing of the November 2004 order is pending before FERC and will be subject to possible judicial review. Allegheny cannot predict the outcome of this proceeding or whether it will have a material impact on its business or financial position.

During the now-expired transition period, the Distribution Companies were both payers and payees of transition charges. These charges resulted in the payment by the Distribution Companies of $13.3 million and payments to the Distribution Companies of $3.5 million during the transition period. Following the evidentiary hearing, an administrative law judge issued an initial decision finding the methodologies used to develop the transition charges to be deficient. The initial decision is now before FERC for review and may be accepted, rejected or modified by FERC. Based on its review of the initial decision, FERC may require the Distribution Companies to refund some portion of the amounts received from these transition charges or entitle the Distribution Companies to receive additional revenue from these charges. In addition, the Distribution Companies may be required to pay additional amounts as a result of increases in the transition charges previously billed to them, or they may receive refunds of transition charges previously billed. Allegheny cannot predict the outcome of this proceeding or whether it will have a material impact on its business or financial position.

The Distribution Companies have entered into nine partial settlements with regard to the transition charges. FERC has approved eight of these settlements. FERC action is pending for the remaining partial settlement.

In April 2007, FERC issued an order addressing transmission rate design within the PJM region. In the order, FERC directed the continuation of the zonal "license plate" rate design for all existing transmission facilities within the PJM region, the allocation of costs of new, centrally-planned transmission facilities operating at or above 500 kV on a region-wide "postage stamp" or "socialized" basis, and the development of a detailed "beneficiary pays" methodology for the allocation of costs of new transmission facilities below 500 kV. Subsequently, FERC approved a detailed "beneficiary pays" methodology developed through settlement discussions among several parties to the underlying FERC proceedings. On August 6, 2009, the U. S. Court of Appeals for the Seventh Circuit remanded this decision to FERC for further justification with regard to the allocation of costs for new 500 kV and above transmission facilities but denied petitions for review relating to FERC's decision with regard to the pricing of existing transmission facilities. On January 21, 2010, FERC issued an order establishing a paper hearing in response to the Seventh Circuit's remand.

Under the zonal "license plate" rate design for existing transmission facilities, costs associated with such facilities are allocated on a load ratio share basis to load serving entities, such as local distribution utilities, located within the transmission owner's PJM transmission zone. As a result of this rate design, the load serving entity does not pay for the cost of transmission facilities located in other PJM transmission zones even if the load serving entity engages in transactions that rely on transmission facilities located in other zones. The region-wide "postage stamp" or "socialized" rate design for new, centrally-planned transmission facilities operating at or above 500 kV results in charging all load serving entities within the PJM region a uniform rate based on the aggregated costs of such transmission facilities within the PJM region irrespective of whether the transmission service provided to the load serving entity requires the actual use of such facilities. For the "beneficiary pays" methodology, the costs of new facilities under 500 kV are allocated to load serving entities based on a methodology that considers several factors but is not premised upon the proximity of the load serving entity to the new facilities or the zone in which the new facilities are located.

In January 2008, FERC accepted a compliance filing submitted by certain PJM and MISO transmission owners establishing the transmission pricing methodology for transactions involving transmission service originating in the PJM region or the MISO region and terminating in the other region. The methodology

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maintains the existing rate design for such transactions under which PJM and MISO treat transactions that source in one region and sink in the other region the same as transactions that source and sink entirely in one of the regions. These inter-regional transactions are assessed only the applicable zonal charge of the zone in which the transaction sinks and no charge is assessed in the zone of the region where the transaction originates. Judicial review of FERC's order in this matter is pending. Allegheny cannot predict the outcome of these proceedings or whether they will have a material impact on its business or financial position.

Wholesale Markets . In August 2005, PJM filed at FERC to replace its capacity market with a new Reliability Pricing Model, or "RPM," to address reliability concerns. On April 20, 2006, FERC issued an initial order that found PJM's capacity market to be unjust and unreasonable and set a process to resolve features of the RPM that needed to be analyzed further before it could determine whether the RPM is a just and reasonable capacity market process. FERC ordered the implementation of settlement procedures in this proceeding, and AE Supply and the Distribution Companies joined in a settlement agreement that was filed with the FERC on September 29, 2006. The settlement agreement created a locational capacity market in PJM, in which PJM procures needed capacity resources through auctions held three years in advance at prices and in quantities determined by an administratively established demand curve. Under the settlement agreement, capacity needs in PJM are met either through purchases made in the proposed auctions or through commitments by load serving entities ("LSEs") to self-supply their capacity needs. On December 22, 2006, FERC conditionally approved the settlement agreement, the implementation of which began with the 2007-2008 PJM planning year. Base year capacity auctions were held in April, July and October of 2007, in January and May of 2008 and May of 2009. On June 25, 2007 and again on November 11, 2007, FERC issued orders denying pending requests for rehearing of the December 22, 2006 order and affirming its acceptance of the RPM settlement agreement. Several parties have appealed FERC's orders approving the RPM settlement, and those appeals are currently pending at the United States Court of Appeals for the District of Columbia Circuit. On May 30, 2008, several parties naming themselves the "RPM Buyers" filed a complaint at FERC seeking a retroactive reduction in the RPM clearing prices for several RPM auctions that have already been conducted. On September 19, 2008, FERC issued an order denying the RPM Buyers' complaint. In June 2009, FERC denied requests for rehearing of the September 19, 2008 order. The Maryland PSC and New Jersey Board of Public Utilities have appealed FERC's order denying the RPM Buyers' complaint to the United States Court of Appeals for the District of Columbia circuit, which appeal remains pending.

PJM Calculation Error . In September 2009, PJM reported that it had discovered a modeling error in the market-to-market power flow calculations between PJM and MISO. The error, which dates back to April 2005, was a result of the incorrect modeling of certain generation resources that have an impact on power flows across the PJM/MISO border. Allegheny currently is participating in FERC settlement discussions on this issue. Although the amount of the error is subject to dispute, PJM estimated in September 2009 the magnitude of the error to be approximately $77 million. Should a payment by PJM to MISO relating to this modeling error be required, the method by which PJM would allocate any such payment to PJM participants, including Allegheny, is uncertain at this time.

Reliability Standards . The Energy Policy Act amended the FPA to, among other matters, provide FERC with the authority to oversee the establishment and enforcement of mandatory reliability standards designed to assure the reliable operation of the bulk power system. FERC certified NERC as the Electric Reliability Organization responsible for developing and enforcing continent-wide reliability standards. NERC has established, and the FERC has approved, reliability standards that impose certain operating, record-keeping and reporting requirements on the Distribution Companies, TrAIL Company, PATH, LLC, AE Supply and AGC.

While NERC is charged with establishing and enforcing appropriate reliability standards, it has delegated their day-to-day implementation and enforcement to eight regional oversight entities, including ReliabilityFirst Corporation ("ReliabilityFirst"). These regional oversight entities are responsible for developing regional reliability standards that are consistent with NERC's standards. Each regional entity has its own compliance program designed to monitor, assess and enforce compliance with the applicable reliability standards through

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compliance audits, self-reporting and exception reporting mechanisms, self certifications, compliance violation investigations, periodic data submissions and complaint processes. Allegheny is a member of ReliabilityFirst, participates in the NERC and ReliabilityFirst stakeholder processes and monitors and manages its operations in response to the ongoing development, implementation and enforcement of relevant reliability standards. Allegheny has been, and will continue to be, subject to routine audits with respect to its compliance with applicable reliability standards and has settled certain related issues. In addition, ReliabilityFirst is currently conducting several violation investigations that have been self-reported by Allegheny. The results of these proceedings and investigations have not had, and are not expected to have, any material impact on Allegheny's operations or the results thereof. See "Risk Factors."

Transmission Expansion

TrAIL Project . TrAIL is a new, 500kV transmission line currently under construction that will extend from southwest Pennsylvania through West Virginia and into northern Virginia. TrAIL is scheduled to be completed and placed in service no later than June 2011. PJM, which is an RTO, directed the construction of TrAIL pursuant to its 2006 RTEP to assure the continued reliability of the transmission grid and reduce congestion in the PJM region. FERC has jurisdiction over the rates for transmission of electricity under the FPA. Rates for transmission service must be filed with and approved by FERC under Section 205 of the FPA. The Energy Policy Act of 2005 directed, among other things, that FERC develop incentive-based mechanisms to encourage new investment in electric transmission facilities that will improve electric reliability and lower costs for consumers. Pursuant to FERC rules implementing that directive and a settlement agreement resolving all outstanding issues regarding TrAIL Company's formula rate filing, FERC approved certain rate incentives for TrAIL Company, including:

- a 12.7% return on equity for TrAIL and the Black Oak SVC;
- an 11.7% return on equity for all other TrAIL Company transmission projects for which an incentive rate of return is not requested;
- a return on construction work in progress ("CWIP") for most components of TrAIL prior to completion of construction and placement into service (while an Allowance of Funds Used During Construction ("AFUDC") is applicable to certain other components and related facilities of TrAIL); and
- recovery of prudently incurred development and construction costs if TrAIL is abandoned as a result of factors beyond TrAIL Company's control.

PATH Project . PJM authorized the construction of PATH in June 2007. Allegheny and a subsidiary of AEP formed PATH, LLC to build PATH, and in December 2007, PATH, LLC submitted a filing to FERC under Section 205 of the FPA to implement a formula rate tariff effective March 1, 2008. The filing also included a request for certain incentive rate treatments. In February 2008, FERC issued an order setting the cost of service formula rate to calculate annual revenue requirements for the project and granting the following incentives:

- a return on equity of 14.3%;
- a return on CWIP;
- recovery of prudently incurred start-up business and administrative costs incurred prior to the time the rates go into effect; and
- recovery of prudently incurred development and construction costs if PATH is abandoned as a result of factors beyond the control of PATH, LLC.

In December 2008, PATH submitted to FERC a settlement of the formula rate and protocols with the active parties. FERC approval of the settlement is pending. Rehearing of the February 29, 2008 order with respect to return on equity remains pending before FERC.

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In December 2009, PJM conducted certain sensitivity analyses as directed by a Virginia SCC Hearing Examiner and advised PATH-VA that these analyses suggest that the PATH Project appears not to be needed in June 2014 as a result of a reduction in the scope and severity of observed NERC reliability violations. PJM further advised that consistent with PJM processes, the PATH Project will be considered in the 2010 RTEP to determine when it will be needed to resolve NERC reliability violations.

National Interest Electric Transmission Corridor ("NIETC") . In October 2007, the DOE issued a NIETC designation for the mid-Atlantic corridor that includes the areas in which TrAIL is being constructed and PATH is proposed to be sited. Challenges by several entities to the mid-Atlantic corridor designation are pending in the United States Court of Appeals for the Ninth Circuit. Briefing has concluded in this proceeding, in which AE and certain of its subsidiaries are intervenors. Allegheny cannot predict the outcome of this proceeding or whether it will have a material impact on its business or financial position.

In February 2009, the United States Circuit Court for the Fourth Circuit ruled on challenges to FERC rules promulgated for siting transmission lines within a NIETC. The Court held, among other things, that a state's outright denial of a transmission siting application within one year does not constitute withholding of approval within one year, rejecting FERC's interpretation of the relevant provision of the FPA. FERC, the Distribution Companies, TrAIL Company and other parties filed a petition for a writ of certiorari with the United States Supreme Court with respect to the Fourth Circuit's decision, but that petition was denied.

PURPA

The Public Utility Regulatory Policies Act of 1978 ("PURPA") requires electric utility companies, such as the Distribution Companies, to interconnect with, provide back-up electric service to and purchase electric capacity and energy from qualifying small power production and cogeneration facilities, although, as a result of changes in the FPA arising out of the Energy Policy Act, electric utilities are no longer required to enter into any new contractual obligation to purchase energy from a qualifying facility if FERC finds that the facility has non-discriminatory access to a functioning wholesale market and open-access transmission.

For 2009, the Distribution Companies committed to purchase 479 MWs of qualifying PURPA capacity, and PURPA expense pursuant to these contracts totaled approximately $230.6 million. The average cost to the Distribution Companies of these power purchases was 6.8 cents/kWh. In December 2009, AE Supply purchased Allegheny Lock and Dam Nos. 5 & 6, which together supply a total of 13 MW. Previously, the Distribution Companies had purchased power generated by these facilities pursuant to PURPA contracts. Consequently, the Distribution Companies have committed to purchase 466 MWs of qualifying PURPA capacity for 2010. The Distribution Companies are currently authorized to recover substantially all of these costs in their retail rates. The Distribution Companies' obligations to purchase power from qualified PURPA projects in the future may exceed amounts they are authorized to recover from their customers, which could result in losses related to the PURPA contracts.

State Rate Regulation

Pennsylvania

Pennsylvania's Electricity Generation Customer Choice and Competition Act (the "Customer Choice Act"), which was enacted in 1996, gave all retail electricity customers in Pennsylvania the right to choose their electricity generation supplier as of January 2, 2000. Under the Customer Choice Act and a subsequent restructuring settlement (the "1998 Restructuring Settlement") approved by the Pennsylvania PUC, West Penn transferred its generation assets to AE Supply. West Penn retained its T&D assets. Under the 1998 Restructuring Settlement, West Penn is the default provider for those customers who do not choose an alternate supplier, whose alternate supplier does not deliver, or who have chosen to return to West Penn service, in each case at rates that are capped at various levels during the applicable transition period. West Penn's T&D assets are subject to traditional regulated utility ratemaking (i.e., cost-based rates).

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Joint Petition and Extension of Generation Rate Caps . By order entered on May 11, 2005, the Pennsylvania PUC approved a Joint Petition for Settlement and for Modification of the 1998 Restructuring Settlement, as amended, among West Penn, the Pennsylvania Office of Consumer Advocate, the Office of Small Business Advocate, The West Penn Power Industrial Intervenors and certain other parties (the "2004 Joint Petition"). The 2004 Joint Petition extended generation rate caps for most customers from 2008 to 2010 and provided for increases in generation rates in 2007, 2009 and 2010, in addition to previously approved rate cap increases for 2006 and 2008. The order approving the 2004 Joint Petition also extended distribution rate caps from 2005 through 2007, with an additional rate cap in place for 2009 at the rate in effect on January 1, 2009. The intent of this transition plan is to gradually move generation rates closer to market prices. Rate caps on transmission services expired on December 31, 2005.

Default Service Regulations . In May 2007, the Pennsylvania PUC entered a Final Rulemaking Order (the "May 2007 Order") promulgating regulations defining the obligations of electric distribution companies ("EDCs"), such as West Penn, to provide generation default service to retail electric customers who do not or cannot choose service from a licensed electric generation supplier ("EGS") at the conclusion of the EDCs' restructuring transition periods. West Penn's transition period will end for the majority of its customers on December 31, 2010, when its generation rate caps expire.

The regulations promulgated by the May 2007 Order provide that the incumbent EDC will be the default service provider ("DSP") in its service territory, although the Pennsylvania PUC may reassign the default service obligation to one or more alternative DSPs when necessary for the accommodation, safety and convenience of the public. The DSP is required to file a default service plan not later than 12 months prior to the end of the applicable generation rate cap. The default service plan must identify the DSP's generation supply acquisition strategy and include a rate design plan to recover all reasonable costs of default service. The default service plan must be designed to acquire generation supply at prevailing market prices to meet the DSP's anticipated default service obligation at reasonable costs. A DSP's affiliate generation supplier may participate in the DSP's competitive bid solicitations for generation service. DSPs will use an automatic energy adjustment clause to recover all reasonable costs of obtaining alternative energy pursuant to the Alternative Energy Portfolio Standards Act, and the DSP may use an automatic adjustment clause to recover non-alternative energy default service costs. Automatic adjustment clauses will be subject to annual review and audit by the Pennsylvania PUC. Default service rates will be adjusted on a quarterly basis, or more frequently, for customer classes with a peak load up to 500 kW, and on a monthly basis, or more frequently, for customer classes with peak loads greater than 500 kW.

In October 2007, West Penn filed a default service plan with the Pennsylvania PUC. The Pennsylvania PUC administrative law judge entered a final order on July 25, 2008 that largely approved West Penn's proposed default service plan, including its full requirements procurement approach and rate mitigation plan. West Penn filed tariff supplements implementing the default service plan in September 2008 and January 2009. On February 6, 2009, West Penn filed a petition with the Pennsylvania PUC requesting approval to advance the first series of default service procurements for residential customers from June 2009 to April 2009 to take advantage of a downturn in market prices for power. West Penn's petition was approved by the Pennsylvania PUC in March 2009, and it began to conduct advanced procurements in April 2009. Also in April 2009, West Penn petitioned to Pennsylvania PUC for approval to further accelerate default service procurements increasing by 550 MW the amount of power that it planned to procure in June 2009. By Order entered May 14, 2009, the Pennsylvania PUC approved the request to advance the procurement of 550 MW, and the procurement occurred in June 2009.

Advanced Metering and Demand-Side Management Initiatives . In October 2008, Pennsylvania adopted Act 129, which includes a number of measures relating to conservation, demand-side management and power procurement processes. Act 129 requires each EDC with more than 100,000 customers to adopt a plan, approved by the Pennsylvania PUC, to reduce, by May 31, 2011, electric consumption by at least one percent of its expected consumption for June 1, 2009 through May 31, 2010. By May 31, 2013, the total annual weather-

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normalized consumption is to be reduced by a minimum of three percent, and peak demand is to be reduced by a minimum of four and one-half percent of the EDC's annual system peak demand. Act 129 also:

- directed the Pennsylvania PUC to adopt an energy conservation and efficiency program to require EDCs to develop and file, by July 1, 2009, plans to reduce energy demand and consumption; and
- required EDCs to file a plan for "smart meter" technology procurement and installation in August 2009.

West Penn expects to incur significant capital expenditures in 2010 and beyond to comply with these requirements.

Act 129 also requires EDCs to obtain energy through a prudent mix of contracts, with an emphasis on competitive procurement. The Act includes a "grandfather" provision for West Penn's procurement and rate mitigation plan, which was previously approved by the Pennsylvania PUC.

On June 30, 2009 West Penn filed its Energy Efficiency and Conservation Plan containing 22 programs to meet its Act 129 demand and consumption reduction obligations. The proposed programs cover most energy-consuming devices of residential, commercial and industrial customers. The Plan also proposes a reconcilable surcharge mechanism to obtain full and current cost recovery of the Plan costs as provided in Act 129. The Plan projected an aggregated cost of the energy efficiency measures in the amount of approximately $94.3 million through mid 2013. A hearing concerning West Penn's Energy Efficiency and Conservation Plan was held August 19, 2009.

The Pennsylvania PUC approved West Penn's Energy Efficiency and Conservation Plan, in large part, by Opinion and Order entered October 23, 2009. The new programs approved by the Pennsylvania PUC include: rebates for customers who purchase high efficiency appliances, lighting and heating and cooling systems; residential home audits and rebates toward implementing audit recommendations; home audit, weatherization and air conditioner replacement programs for low-income customers; new rate options that will provide financial incentives for customers to lower their demand for electricity or shift their usage to lower-priced times; incentives for customers who install in-home devices that reduce electric usage when demand is highest; and various programs for commercial, industrial, government and non-profit customers to increase energy efficiency and conservation. The Pennsylvania PUC also approved West Penn's proposal to recover its Energy Efficiency and Conservation Plan costs on a full and current basis via an automatic surcharge to customers' bills, subject to an annual reconciliation mechanism.

The Pennsylvania PUC declined to approve West Penn's proposed distributed generation program and West Penn's proposed contract demand response program and encouraged West Penn to submit revisions to both programs. On December 21, 2009, West Penn filed an Amended Energy Efficiency and Conservation Plan as directed by the Pennsylvania PUC, in which it added a new customer resources demand response program intended to replace the previously proposed distributed generation and contract demand programs. The Pennsylvania PUC reviewed Allegheny's amended Plan at its public meeting on February 11, 2010 and ordered Allegheny to file an amended plan within 60 days to include additional detail on the costs associated with the previously approved customer load response program and the new customer resources demand response program.

On August 14, 2009, West Penn filed its Smart Meter Technology Procurement and Installation Plan. The Plan provides for extensive deployment of smart meter infrastructure with replacement of all of West Penn's approximately 725,000 meters by the end of 2014. To support two-way communications with the new meters, West Penn will build a new and secure telecommunications network. To support time of use and real time pricing as required by Act 129, West Penn will purchase and install a new customer information system. A hearing on West Penn's smart meter Plan was held on November 8, 2009. On December 18, 2009, West Penn filed a motion to reopen the evidentiary record to submit an alternative smart meter plan proposing, among other things, a less rapid deployment of smart meters. On January 13, 2010, the Pennsylvania PUC granted the motion to reopen the record and remanded the proceeding to the ALJ. The Pennsylvania PUC also waived the late January 2010 deadline by which the ALJ's recommended decision would have been required. On January 26, 2010, the ALJ set

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a hearing and briefing schedule for the reopened record, with a target deadline for the ALJ's recommended decision of April 23, 2010.

West Penn estimates that the total cost of implementing smart metering infrastructure as proposed in the Plan as originally filed would be approximately $620 million; however, West Penn's actual cost to implement smart meter infrastructure may vary from that estimate as a result of changes in its procurement and installation plan as ultimately approved by the Pennsylvania PUC and the timing of that approval, among other factors. In accordance with Act 129, West Penn's Plan requests a cost recovery surcharge for the full and current recovery of the expenditures from customers.

Transmission Expansion . By order entered on December 12, 2008, the Pennsylvania PUC authorized TrAIL Company to construct a 1.2 mile portion of TrAIL in Pennsylvania from the proposed 502 Junction Substation in Greene County to the Pennsylvania-West Virginia state line. In the same order, the Pennsylvania PUC also approved an agreement among TrAIL Company, West Penn and Greene County, Pennsylvania in which, among other provisions, TrAIL Company agreed to engage in a collaborative process to identify possible solutions to reliability problems in the Washington County, Pennsylvania area in lieu of the Prexy Facilities that had been a part of the original TrAIL proposal. Judicial review is pending in the Commonwealth Court of Pennsylvania with regard to the authorization to construct the 1.2 mile portion of TrAIL. A proposed settlement and an amendment to the application based on a consensus of participants in the collaborative process are pending before the Pennsylvania PUC for approval.

Alternative Energy Portfolio Standard . Legislation enacted in 2004 requires the implementation of an alternative energy portfolio standard in Pennsylvania. This legislation requires EDCs and retail electric suppliers in Pennsylvania to obtain certain percentages of their energy supplies from alternative sources. However, the legislation includes an exemption from this requirement for companies, such as West Penn, that are operating within a transition period under the current regulations governing the transition to market competition in Pennsylvania. The full requirement will apply to those companies when their respective transition periods end. The legislation also includes a provision that will allow the Pennsylvania PUC to modify or eliminate these obligations if alternative sources are not reasonably available. The law directs that all costs related to the purchase of electricity from alternative energy sources and payments for alternative energy credits will be fully recovered pursuant to an automatic energy adjustment clause. The Pennsylvania PUC initiated a proceeding in January 2005 regarding implementation and enforcement of the legislation.

Reliability Benchmarks . In May 2004, the Pennsylvania PUC modified its utility specific benchmarks and performance standards for electric distribution system reliability. The benchmarks were set too low for West Penn, resulting in required reliability levels that were unattainable. West Penn appealed the benchmarks to the Pennsylvania PUC. In 2005, the parties to the proceeding, including the Consumer Advocate, the Utility Workers Union of America Local 102, and the Rural Electric Association entered into an agreement settling the proceeding and providing West Penn with attainable reliability benchmarks. The Pennsylvania PUC approved the settlement in an Order issued July 27, 2006. According to the Pennsylvania PUC's Electric Service Reliability in Pennsylvania 2008 report, Allegheny's overall performance in 2008 was substantially better than its performance during 2007. In 2007 and 2008, Allegheny's System Average Interruption Frequency Index, Customer Average Interruption Duration Index and System Average Interruption Duration Index values were better than the applicable standards. As of July 2009, West Penn is satisfying all of the reliability benchmarks and standards approved by the Pennsylvania PUC in its July 2006 order.

West Virginia

In 1998, the West Virginia legislature passed legislation directing the West Virginia PSC to determine whether retail electric competition was in the best interests of West Virginia and its citizens. In response, the West Virginia PSC submitted a plan to introduce full retail competition on January 1, 2001. The West Virginia legislature approved, but never implemented, this plan. In March 2003, the West Virginia legislature passed a bill

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that clarified the jurisdiction of the West Virginia PSC over electric generation facilities. In 2000, Potomac Edison received approval to transfer its West Virginia generation assets to AE Supply. However, the West Virginia PSC never acted on a similar petition by Monongahela, and Monongahela agreed to withdraw its petition. Based on these actions, Allegheny has concluded that retail competition and the deregulation of generation is no longer likely in West Virginia.

Rate Case . On August 13, 2009, Monongahela and Potomac Edison filed with the West Virginia PSC a request to increase retail rates by approximately $122.1 million annually, effective June 10, 2010. On January 12, 2010, Monongahela and Potomac Edison filed supplemental testimony discussing a tax treatment change that would result in a revenue requirement that is approximately $7.7 million lower than the requirement included in the original filing. In addition, in December 2009, subsidiaries of Monongahela and Potomac Edison completed a securitization transaction to finance certain costs associated with the installation of Scrubbers at the Fort Martin generating station, which costs would otherwise have been included in the request for rate recovery. Consequently, Monongahela and Potomac Edison now are requesting to increase retail rates by approximately $106 million, rather than $122.1 million, annually. Additionally, the parties to the case agreed to toll the effectiveness of the new rates until June 29, 2010. An evidentiary hearing on this matter is scheduled to begin April 5, 2010.

Annual Adjustment of Fuel and Purchased Power Cost Rates . On August 29, 2008, Monongahela and Potomac Edison filed with the West Virginia PSC a request to increase retail rates by approximately $173 million annually to reflect expected increases in fuel and purchased power costs during 2009 and under-recovery of past costs through June 2008. The new rates, proposed to become effective January 1, 2009, were submitted pursuant to the schedule for annual fuel and purchased power cost reviews that was approved by the West Virginia PSC when it reinstated a fuel and purchased power cost recovery clause in the rate case described above. On December 29, 2008, the West Virginia PSC issued an order approving a settlement agreement among Allegheny, the Consumer Advocate Division, the Staff of the West Virginia PSC and the West Virginia Energy Users Group, pursuant to which Allegheny’s rates in West Virginia were increased by $142.5 million annually beginning on January 1, 2009.

On September 1, 2009, Monongahela and Potomac Edison filed their annual fuel adjustment request with the West Virginia PSC, requesting a rate increase of $143.2 million to reflect increases in their unrecovered balances of fuel and purchased power costs that have accrued through June 2009 and projected increases through June 2010. The new rates were submitted pursuant to the schedule for annual fuel and purchased power cost reviews. On December 2, 2009, the parties to the proceeding filed a Joint Stipulation providing that Monongahela and Potomac Edison would receive an increase of $118 million, effective January 1, 2010, plus deferred recovery of an additional $23.1 million effective January 1, 2011, with carrying charges of 6% on the deferred amount. The West Virginia PSC approved the Joint Stipulation on December 29, 2009.

Securitization and Scrubber Project . In May 2005, the state of West Virginia adopted legislation permitting securitization financing for the construction of certain types of pollution control equipment at facilities owned by public utilities that are regulated by the West Virginia PSC, subject to the satisfaction of certain criteria. In April 2006, the West Virginia PSC approved a settlement agreement among Monongahela, Potomac Edison and certain other interested parties relating to Allegheny’s plans to construct Scrubbers at the Fort Martin generation facility in West Virginia. Concurrently, the West Virginia PSC granted Monongahela and Potomac Edison a certificate of public convenience and necessity authorizing the construction and operation of the Scrubbers, approved the Asset Swap, and issued a related financing order (the “Financing Order”) approving a proposal by Monongahela and Potomac Edison to finance $338 million of project costs using the securitization mechanism provided for by the legislation adopted in May 2005. Specifically, Monongahela and Potomac Edison received approval to issue environmental control bonds secured by the right to collect a surcharge from West Virginia retail customers dedicated to the repayment of the bonds.

In October 2006, Monongahela and Potomac Edison filed with the West Virginia PSC a Petition to Reopen Proceedings and to Amend Financing Order (“Petition”), informing the West Virginia PSC that the current estimate for constructing the Scrubbers at Fort Martin had increased from $338 million to an amount up to $550

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million. In December 2006, Allegheny reached a settlement agreement with all parties in the reopened cases and filed the agreement with the West Virginia PSC. The West Virginia PSC approved the settlement agreement, authorizing Allegheny to securitize up to $450 million of the estimated construction costs, plus $16.5 million of upfront financing costs and certain other costs. On April 11, 2007, Allegheny completed the securitization with the sale by two indirect subsidiaries of an aggregate of $459.3 million in environmental control bonds.

On July 2, 2009, Monongahela and Potomac Edison requested authority from the West Virginia PSC to finance the remaining costs associated with the Fort Martin Scrubber project through the issuance of additional environmental control bonds. On September 30, 2009, the West Virginia PSC issued a financing order granting Monongahela and Potomac Edison the authority, subject to the terms and conditions of the financing order, to issue the bonds and impose the related environmental control charge. On December 23, 2009, MP Environmental Funding LLC, an indirect wholly owned subsidiary of Monongahela, and PE Environmental Funding LLC, an indirect wholly owned subsidiary of Potomac Edison, issued $85,890,000 aggregate principal amount of Senior Secured ROC Bonds, Environmental Control Series B.

Transmission Expansion . On May 15, 2009, PATH-WV, PATH-Allegheny and certain other related entities (the “PATH Entities”) filed an application with the West Virginia PSC for certificates of public convenience and necessity to construct portions of the PATH Project in West Virginia. On October 28, 2009, the Staff of the West Virginia PSC filed a motion to dismiss the application on the basis that, because there was no application pending at that time before any regulatory agency for approval of the Maryland portion of the PATH Project, there was no identified eastern terminus of the project. Other parties filed similar motions or statements in support of the Staff motion. The PATH Entities filed responses in which they opposed the Staff motion but agreed to toll the statutory decision due date in West Virginia until February 24, 2011, if the West Virginia PSC extended its current procedural schedule in the manner proposed by the PATH Entities. The West Virginia PSC denied the motions to dismiss and established a revised procedural schedule providing for an evidentiary hearing commencing in October 2010 and a final commission decision by February 24, 2011. The PATH Entities expect to supplement their pre-filed testimony on June 29, 2010 to reflect a new in-service date for the PATH Project based on PJM’s 2010 RTEP analysis.

On September 10, 2009, TrAIL Company filed a petition to amend its certificate for the TrAIL Project requesting authorization of the West Virginia PSC to make minor adjustments in the approved route in 21 locations. The West Virginia PSC authorized the adjustments and required the filing of property owner written consents. Subsequently, TrAIL Company determined that it had not obtained the written consent for two parcels as it had previously represented and filed a corrected petition to amend the certificate with respect to these parcels. The West Virginia PSC has not acted on the corrected petition. TrAIL Company has filed an additional petition to amend the certificate requesting authorization of the West Virginia PSC to approve five additional minor adjustments to the approved route. The West Virginia PSC has not acted on this additional petition.

On October 19, 2009, four individuals filed a complaint with the West Virginia PSC regarding TrAIL Company’s right-of-way clearing practices for the TrAIL Project that requested, among other things, a limit on right of way clearing for TrAIL. TrAIL Company responded to the complaint, denying each of its allegations. The West Virginia PSC has not acted on the complaint.

Purchase of Distribution Operations . In connection with Potomac Edison’s agreement to sell its Virginia distribution assets, Allegheny will purchase certain West Virginia distribution operations from Shenandoah Valley Electric Cooperative for approximately $15 million.

Maryland

In 1999, Maryland adopted electric industry restructuring legislation, which gave Potomac Edison’s Maryland retail electric customers the right to choose their electricity generation suppliers. In 2000, Potomac Edison transferred its Maryland generation assets to AE Supply but remained obligated to provide standard offer generation service (“SOS”) at capped rates to residential and non-residential customers for various periods. The longest such

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period, for residential customers, expired on December 31, 2008. As discussed below, Potomac Edison has implemented a rate stabilization plan to transition customers from capped generation rates to rates based on market prices. Potomac Edison retained its T&D assets. Potomac Edison's T&D rates for all customers were capped through 2004 and are otherwise subject to traditional regulated utility ratemaking (i.e., cost-based rates).

Standard Offer Service . In 2003, the Maryland PSC approved two state-wide settlements relating to the future of PLR and SOS. The settlements extended Potomac Edison's obligation to provide SOS after the expiration of the generation rate cap periods established for Potomac Edison as part of the 1999 restructuring of Maryland's electric market. The settlements provided that, after expiration of the generation rate caps, SOS would be provided through 2012 for residential customers, through 2008 for smaller commercial and industrial customers and through 2006 for Potomac Edison's medium-sized commercial customers. Potomac Edison's obligation to provide SOS for its largest industrial customers expired at the end of 2005. A 2005 settlement extended Potomac Edison's SOS obligations to its medium-sized commercial customers through May 2007, and a further order of the Maryland PSC issued on August 28, 2006 extended that obligation through at least the end of May 2009. The Maryland PSC issued an order on November 8, 2006, and a report to the Maryland legislature on December 31, 2006, that would continue SOS to small and medium-sized commercial customers with changes in procurement durations. In another proceeding, the Maryland PSC ordered the utilities to issue an RFP for possible acquisition of demand response resources for the period from 2011 to 2016 and to participate in a working group on the development of distributed generation resources. The RFP was issued on January 16, 2009. The Maryland PSC issued an order on March 11, 2009 approving the purchase of most of the resources offered, and the utilities have made the purchases.

By statute enacted in 2007, the obligation of Maryland utilities to provide SOS to residential and small commercial customers, in exchange for recovery of their costs plus a reasonable profit, was extended indefinitely. The legislation also established a five-year cycle (to begin in 2008) for the Maryland PSC to report to the legislature on the status of SOS. The other Maryland electric utilities providing SOS, all of whose initial settlement obligations have expired, continue to do so essentially in accordance with the terms of the 2003 settlements as modified by the Maryland PSC orders discussed immediately above, as does Potomac Edison. The terms on which Potomac Edison will provide SOS to residential customers after the settlement covering that initial obligation expires in 2012 depend on developments with respect to SOS in Maryland between now and then, including but not limited to possible Maryland PSC decisions in the proceedings discussed below.

The Maryland PSC opened a new docket in August 2007 (Case No. 9117) to consider matters relating to possible "managed portfolio" approaches to SOS, the aggregation of low income SOS customers, and a retail supplier proposal for the utility "purchase" of all retailer receivables at no discount and with no recourse. "Phase II" of the case addressed utility purchases or construction of generation, bidding for procurement of demand response resources and possible alternatives if the TrAIL and PATH projects are delayed or defeated. Hearings on Phase I and II were held in October and November 2007 and in January 2008. It is unclear when the Maryland PSC will issue its findings in this and other related pending proceedings discussed below.

On July 3, 2008, the Maryland PSC issued a further order requiring the utilities to prepare detailed studies of alternatives for possible managed portfolios, with a time horizon out to fifteen years, and to file those studies by October 1, 2008. The Maryland PSC expressly stated that the order, "should not be construed… as a decision to modify in any way, the current SOS procurement practice." Potomac Edison filed its study with the Maryland PSC on October 1, 2008, and the Maryland PSC held hearings on the matter in December 2008. No order has been issued.

Also, on September 29, 2009, the Maryland PSC opened another new proceeding to receive and consider proposals for construction of new generation resources in Maryland. Proposals were initially due to be filed by December 16, 2009, but the Maryland PSC has indefinitely postponed that deadline while it considers recommendations as to what the filings should be required to contain. Also, on December 18, 2009, Governor Martin O'Malley filed a letter in this proceeding in which he characterized the electricity market in Maryland as a "failure" and urged the Maryland PSC to use its existing authority to order the construction of new generation

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in Maryland, vary the means used by utilities to procure generation and include more renewables in the generation mix.

In August 2007, Potomac Edison filed a plan for seeking bids to serve its Maryland residential load for the period after the expiration of rate caps on December 31, 2008. The Maryland PSC approved the plan in a series of orders issued between September 2007 and September 2008. Potomac Edison will continue to conduct rolling auctions to procure the power supply necessary to serve its customer load going forward.

Rate Stabilization . In special session on June 23, 2006, the Maryland legislature passed emergency legislation, directing the Maryland PSC to, among other things, investigate options available to Potomac Edison to implement a rate mitigation or rate stabilization plan for SOS to protect its residential customers from rate shock when capped generation rates end on January 1, 2009.

In December 2006, Potomac Edison filed with the Maryland PSC a proposed Rate Stabilization Ramp-Up Transition Plan designed to transition residential customers from capped generation rates to rates based on market prices. Under the plan as approved by the Maryland PSC, residential customers who did not elect to opt out of the program began paying a surcharge in June 2007. The application of the surcharge resulted in an overall rate increase of approximately 15% in 2007 and 13% in 2008. With the expiration of the residential generation rate caps and the move to generation rates based on market prices on January 1, 2009, the surcharge converted to a credit on customers' bills. Funds collected through the surcharge during 2007 and 2008, plus interest, are being returned to customers as a credit on their electric bills, thereby reducing the effect of the rate cap expiration. The credit will continue, with adjustments, to maintain rate stability until December 31, 2010 or until all monies collected from customers plus interest are returned. The resulting rate increase in 2009 was 11.3%, and the rate change approved in 2009 for 2010 was actually a decrease of 2.5%. Of Potomac Edison's approximately 219,000 residential customers in Maryland, as of December 31, 2009, approximately 32,400, or 14.7%, elected to opt-out of, or are not eligible for, Potomac Edison's plan.

Advanced Metering and Demand Side Management Initiatives . On June 8, 2007, the Maryland PSC established a new case to consider advanced meters and demand side management programs. The Staff of the Maryland PSC filed its report on these matters on July 6, 2007. On September 28, 2007, the Maryland PSC issued an order in this case that required the utilities to file detailed plans for how they will meet a proposal-"EmPOWER Maryland"-that in Maryland electric consumption be reduced by 10% and electricity demand be reduced by 15%, in each case by 2015. On October 26, 2007, Potomac Edison filed its initial report on energy efficiency, conservation and demand reduction plans in connection with this order. The Maryland PSC conducted hearings on Potomac Edison's and other utilities' plans in November 2007 and further hearings on May 7, 2008.

In a related development, the Maryland legislature in 2008 adopted a statute codifying the EmPOWER Maryland goals and setting a deadline of September 1, 2008 for the utilities to file comprehensive plans for attempting to achieve those goals. Potomac Edison filed its proposals on August 29, 2008, asking the Maryland PSC to approve seven programs for residential customers, five programs for commercial, industrial, and governmental customers, a customer education program, and a pilot deployment of Advanced Utility Infrastructure ("AUI") that Allegheny has previously been testing in West Virginia. On December 31, 2008, the Maryland PSC issued an order approving some of Potomac Edison's programs and directing that others be redesigned. Potomac Edison filed its revised programs on March 31, 2009, with new cost and benefit information. The Maryland PSC approved the programs on August 6, 2009, and approved cost recovery for the programs on October 6, 2009. Expenditures are expected to be approximately $101 million and will be recovered over the next six years. Meanwhile, the AUI pilot is being examined on a separate track and is currently under discussion with the Staff of the Maryland PSC.

Renewable Energy Portfolio Standard . Legislation enacted in 2004 (and supplemented with respect to solar power in 2007) requires the implementation of a renewable energy portfolio standard in Maryland. Beginning upon the later of the expiration of the transition period for any particular customer class served by a supplier or January 1, 2006, retail electricity suppliers in Maryland must obtain certain percentages of their

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energy supplies from renewable energy resources. The law provides that if renewable resources are too expensive, or are not available in quantities sufficient to meet the standard in any given year, suppliers can instead opt to pay a "compliance fee." The law directs the Maryland PSC to allow electric suppliers to recover their costs from customers, including any compliance fees that they incur.

Moratorium on Service Terminations . On March 11, 2009, the Maryland PSC issued an order suspending until further notice the right of all electric and gas utilities in the state to terminate service to residential customers for non-payment of bills. The order directed the utilities and other interested parties to meet and devise proposals for offering payment plans to all residential customers, not just low-income customers. On April 1, 2009, the Staff of the Maryland PSC and utilities filed a plan providing for additional and longer payment plans and for a temporary suspension of requests to customers for increased deposits. The Maryland PSC held a hearing on the matter on April 7, 2009, and subsequently issued an order making various rule changes relating to terminations, payment plans, and customer deposits that make it more difficult for Maryland utilities to collect deposits or to terminate service for non-payment. Potomac Edison and several other utilities filed requests for reconsideration of various parts of the order on May 26, 2009, which motions were denied on September 23, 2009. Potomac Edison filed a notice of appeal of that order on October 23, 2009, but withdrew the appeal when the Maryland PSC issued a further order on November 23, 2009 that clarified the limited scope and duration of the rule changes. The Maryland PSC is continuing to conduct hearings on related issues, including a set of proposed regulations that would expand the summer and winter "severe weather" termination moratoria when temperatures are very high or very low, from one day, as provided by statute, to three days on each occurrence.

Transmission Expansion . On December 21, 2009, Potomac Edison filed a new application with the Maryland PSC for a certificate of public convenience and necessity to construct the Maryland portions of the PATH Project. The project in Maryland will be owned by PATH Allegheny MD, which is owned by Potomac Edison and PATH-Allegheny. The Maryland PSC has not made a decision whether to accept the application. If the application is accepted, Potomac Edison expects to supplement its pre-filed testimony on or about June 29, 2010 to reflect a new in-service date for the PATH Project based on PJM's 2010 RTEP analysis. Potomac Edison has also agreed not to file an application with FERC pursuant to Section 216(b)(1) of the FPA prior to June 29, 2011 to construct the PATH Project in Maryland.

Virginia

Sale of Distribution Operations . On May 4, 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative (together, the "Cooperatives") for cash proceeds of approximately $340 million, subject to state and federal regulatory approval, certain third-party consents and applicable price adjustments. On September 15, 2009, Potomac Edison and the Cooperatives filed with the Virginia SCC a joint request for approval of the transaction. The Virginia SCC issued a procedural order scheduling an evidentiary hearing on the matter for March 2, 2010. On January 29, 2010, consultants retained by the Staff of the Virginia SCC filed testimony analyzing the transaction, asserting that current Virginia customers of Potomac Edison would pay $370 million more in rates over nine years if the Cooperatives take over service to those customers. Potomac Edison and the Cooperatives filed rebuttal testimony on February 12, 2010, which pointed to various flaws in the consultants' analysis and concluded that current Virginia customers would see comparable or lower rates under Cooperative ownership as compared to future rates that Potomac Edison would need to charge. See "Risk Factors" and consolidated financial statement Note 3, "Assets Held for Sale."

Purchased Power Cost Recovery . Until July 1, 2007, Potomac Edison had a power purchase agreement with AE Supply to provide Potomac Edison with the power necessary to serve its retail customers in Virginia at rates that were consistent with generation rate caps in effect pursuant to the Virginia Electric Utility Restructuring Act of 1999 (the "Restructuring Act"). Effective with the expiration of that power purchase agreement on July 1, 2007, Potomac Edison began to purchase the power necessary to serve its Virginia customers through the wholesale market at market prices, through a competitive wholesale bidding process. In

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April 2007 and again in March 2008, Potomac Edison conducted a competitive bidding process to purchase power requirements from the wholesale market for its retail customer service in Virginia, and AE Supply was the successful bidder with respect to a substantial portion of these requirements.

The Restructuring Act initially capped generation rates until July 1, 2007. In 2004, it was amended to extend capped rates to 2010, but also provided that Virginia utilities that had divested their generation, such as Potomac Edison, could begin to recover purchased power costs on July 1, 2007. In 2007, the law was revised again to provide for generation rate caps to end on December 31, 2008. The market prices at which Potomac Edison has purchased power since the expiration in 2007 of its power purchase agreement with AE Supply were significantly higher than the capped generation rates initially set under the Restructuring Act.

Although the Restructuring Act does provide for generation rate caps through December 31, 2008, it was amended to provide, among other things, that Virginia utilities, such as Potomac Edison, could begin to recover purchased power costs, such that the rates a utility would be permitted to charge Virginia customers beginning on July 1, 2007 would be based on the utility's cost of purchased power.

In an April 2007 filing with the Virginia SCC, Potomac Edison requested to adjust its fuel factor and to implement a rate stabilization plan, including an increase in retail rates of approximately $103 million to be phased in over three years beginning July 1, 2007, to offset the impact of increased purchased power costs. In June 2007, the Virginia SCC issued an order that denied Potomac Edison's application and motion to establish interim rates, cancelled evidentiary hearings and dismissed the case, ruling that recovery was barred by a Memorandum of Understanding (the "MOU") that Potomac Edison entered into with the Staff of the Virginia SCC in 2000 in connection with the transfer of its Virginia generating assets to AE Supply. Under the MOU, Potomac Edison agreed to forego fuel cost adjustments otherwise permitted under the Restructuring Act during the capped rate period, which, at the time that the MOU was entered into, was scheduled to expire as of July 1, 2007.

On December 20, 2007, the Virginia SCC granted Potomac Edison partial ($9.5 million) recovery of increased purchased power costs, following a second application by Potomac Edison for rate recovery of $42.3 million. On May 15, 2008, following a third application by Potomac Edison, the Virginia SCC issued an order allowing Potomac Edison to increase its rates effective July 1, 2008, on an interim basis subject to refund, to collect $73 million of purchased power costs. Revenues were recognized based on the method under which the rates were developed and not the amounts collected. As a result, a portion of the amounts collected from July 1, 2008 to December 31, 2008 was deferred as a regulatory liability and was recognized as revenue from January through June 2009.

On July 18, 2008, the Virginia SCC issued an order finding that the rate making provisions of the MOU would expire on December 31, 2008. On November 18, 2008, Potomac Edison filed with the Virginia SCC a comprehensive rate settlement agreed to with the Staff of the Virginia SCC, the Consumers Counsel of the Virginia Office of the Attorney General and a group of Potomac Edison's industrial customers that transitions all customers to rates that allow for full recovery of purchased power costs no later than July 1, 2011. The Virginia SCC held a hearing on the settlement on November 18 and approved it without alteration or condition on November 26, 2008. Key provisions of the settlement include:

- the $73 million rate increase approved on a temporary basis on May 15, 2008 will remain in effect through June 30, 2009;
- for the period from July 1, 2009 through December 31, 2009, half of any further increase in purchased power costs for service to large non-residential customers will be forgone, up to $15 million;
- for the period from July 1, 2009 through June 30, 2010, the total rate increase for all other customers will be capped at 15%; and
- during the period from July 1, 2009 through June 30, 2011, 100 MW of the power procured by Potomac Edison will be deemed for rate purposes to have been procured at the lesser of actual cost or $55 per MWh.

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Potomac Edison successfully procured power in December 2008 to cover load for the settlement period through 2011, and AE Supply was the successful bidder with respect to a substantial portion of these requirements.

On June 5, 2009, Potomac Edison filed a request for a transmission rate adjustment clause to collect $1.0 million of third-party transmission costs that it expects to incur between January 1, 2009 and August 31, 2010, as permitted by the settlement. Potomac Edison has proposed to recover this amount from its retail customers over the rate period from September 1, 2009 through August 31, 2010. The Virginia SCC approved recovery of all but an insignificant portion of this amount in an order issued on August 28, 2009.

On May 15, 2009, the Virginia SCC issued an order concerning a request by Potomac Edison to recover purchased power costs to serve its Virginia customers. The Virginia SCC's order granted an interim rate increase of approximately $19.4 million, subject to refund, effective July 1, 2009. In October 2009, Potomac Edison and the Staff of the Virginia SCC filed a joint stipulation, pursuant to which the rate increase would be reduced by $3.2 million to approximately $16.2 million. On October 30, 2009, the Virginia SCC issued an order that approved the joint stipulation.

Transmission Expansion . On May 19, 2009, PATH-VA filed an application with the Virginia SCC for a certificate of public convenience and necessity to construct portions of the PATH Project in Virginia. The Virginia SCC established a procedural schedule that provided for an evidentiary hearing commencing on January 19, 2010. On December 21, 2009, PATH-VA filed a motion (as amended on December 29, 2009) to withdraw its application on the basis that certain sensitivity analyses conducted by PJM as directed by the Hearing Examiner suggested that the PATH Project appears not to be needed in June 2014 as a result of a reduction in the scope and severity of observed NERC reliability violations. PATH-VA further stated that, consistent with PJM processes, the PATH Project will be considered by PJM in its 2010 RTEP analysis to determine when it will be needed to resolve NERC reliability violations and that PATH-VA did not expect to file a new application prior to the third quarter of 2010. The Hearing Examiner suspended the procedural schedule and issued a report to the Virginia SCC recommending that the motion to withdraw be granted. On January 27, 2010, the Virginia SCC granted the motion to withdraw, and the application is no longer pending.

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ENVIRONMENTAL MATTERS

The operations of Allegheny's owned facilities, including its generation facilities, are subject to various federal, state and local laws, rules and regulations as to air and water quality, hazardous and solid waste disposal and other environmental matters, some of which may be uncertain. Compliance may require Allegheny to incur substantial additional costs to modify or replace existing and proposed equipment and facilities.

Information regarding capital expenditures and estimated capital expenditures associated with known environmental standards is provided under the heading "Capital Expenditures." Additional legislation or regulatory control requirements have been proposed that, if enacted, may require supplementation or replacement of equipment at existing generation facilities at substantial additional cost.

Global Climate Change

The United States relies on coal-fired power plants for more than 48% of its energy. However, coal-fired power plants have come under scrutiny due to their emission of gases implicated in climate change, primarily carbon dioxide, or "CO_2."

Allegheny produces approximately 95% of its electricity at coal-fired facilities and currently produces approximately 45 million tons of CO_2 annually through its energy production. While there are many unknowns concerning the final regulation of greenhouse gases in the United States, federal and/or state legislation and implementing regulations addressing climate change, including limits on emissions of CO_2, likely will be adopted some time in the future. Thus, CO_2 legislation and regulation, if not reasonably designed, could have a significant impact on Allegheny's operations. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act. The U.S. Senate released its draft of the bill, the Clean Energy Jobs and American Power Act, on September 30, 2009. Additionally, on December 7, 2009, the EPA announced its Greenhouse Gas Endangerment Finding, stating that greenhouse gas emissions from cars and light trucks, when mixed in the atmosphere, endanger public health. The finding provides the EPA with a basis on which to regulate greenhouse gas emissions from vehicle tailpipes under the provisions of the Clean Air Act. Once a pollutant is regulated under the Clean Air Act for one source category, the EPA has authority to apply similar regulations to other source categories, and the EPA has announced its intention to do so. Hence, with the Endangerment Finding finalized, the EPA will have the authority to regulate greenhouse gas emissions from stationary sources such as electric generating units. Allegheny can provide no assurance that limits on CO_2 emissions, if imposed by legislation or otherwise, will be set at levels that can accommodate its generation facilities absent the installation of controls.

Moreover, there is a gap between desired reduction levels in the current proposed legislation and the current capabilities of technology; no current commercial-scale technology exists to enable many of the reduction levels in national, regional and state proposals. Such technology may not become available within a timeframe consistent with the implementation of any future climate control legislation or at all. To the extent that such technology does become available, Allegheny can provide no assurance that it will be suitable for installation at Allegheny's generation facilities on a cost effective basis or at all. Based on estimates from a 2007 DOE National Electric Technology Laboratory report and announced projects by other entities, it could cost as much as $5,500 per kW to replace existing coal-based power generation with fossil fuel stations capable of capturing and sequestering CO_2 emissions. However, exact estimates are difficult because of the variance in the legislative proposals and the current lack of deployable technology.

Allegheny supports federal legislation and believes that the United States must commit to a response to climate change that both encourages the development of technology and creates a workable control system. Regardless of the eventual mechanism for limiting CO_2 emissions, however, compliance will be a major and costly challenge for Allegheny, its customers and the region in which it operates. Most notable will be the potential impact on customer bills and disproportionate increases in energy cost in areas that have built their energy and industrial infrastructure over the past century based on coal-fired electric generation.

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Because the legislative process and applicable technology each is in its infancy, it is difficult for Allegheny to aggressively implement greenhouse gas emission expenditures until the exact nature and requirements of any regulation are known and the capabilities of control or reduction technologies are more fully understood. Allegheny's current strategy in response to climate change initiatives focuses on six tasks:

- maintaining an accurate CO_2 emissions data base;
- improving the efficiency of its existing coal-burning generation facilities;
- following developing technologies for clean-coal energy and for CO_2 emission controls at coal-fired power plants, including carbon sequestration;
- participating in CO_2 sequestration efforts (e.g. reforestation projects) both domestically and abroad;
- analyzing options for future energy investment (e.g. renewables, clean-coal, etc.); and
- improving demand-side efficiency programs, as evidenced by customer conservation outreach plans and Allegheny's Watt Watchers initiatives.

Allegheny's energy portfolio also includes approximately 1,180 MWs of renewable hydroelectric and pumped storage power generation. Allegheny obtained a permit to allow for a limited use of bio-mass (wood chips and saw dust) at one of its coal-fired power stations in West Virginia and currently has approval to use waste-tire derived fuel at another of its coal-based power stations in West Virginia.

Allegheny intends to engage in the dialogue that will shape the regulatory landscape surrounding CO_2 emissions. Additionally, Allegheny intends to pursue proven and cost-effective measures to manage its emissions while maintaining an affordable and reliable supply of electricity for its customers.

Clean Air Act Compliance

Allegheny currently meets applicable standards for particulate matter emissions at its generation facilities through the use of high-efficiency electrostatic precipitators, cleaned coal, flue-gas conditioning, optimization software, fuel combustion modifications and, at times, through other means. From time to time, minor excursions of stack emission opacity that are normal to fossil fuel operations are experienced and are accommodated by the regulatory process.

Allegheny's compliance with the Clean Air Act has required, and may require in the future, that Allegheny install control technologies on many of its generation facilities at significant cost. The Clean Air Interstate Rule ("CAIR") promulgated by the EPA on March 10, 2005 may accelerate the need to install this equipment by phasing out a portion of the currently available allowances. The EPA is revising certain portions of CAIR that were invalidated by the U.S. Court of Appeals for the District of Columbia Circuit. The EPA has cautioned that it is reviewing whether or not to have an annual NO_x trading program (non-Ozone Season) beyond 2010.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule ("CAMR"), establishing a cap and trade system designed to reduce mercury emissions from coal-fired power plants. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the rule in its entirety. The State of West Virginia subsequently suspended its rule for implementing CAMR. Pennsylvania and Maryland, however, took the position that their mercury rules, which are discussed below, survived this ruling. In addition, the EPA has announced plans to propose a new maximum achievable control technology rule for hazardous air pollutant emissions from electric utility steam generating units. The EPA is expected to finalize the new rule by November 2011. Accordingly, Allegheny is monitoring the EPA's efforts to promulgate hazardous air pollutant rules that will include, but will not be limited to, mercury limits. To establish these standards with respect to mercury, the EPA must identify the best performing 12% of sources in each source category and, to that end, has issued an information request to members of the fossil fuel-fired generating industry that includes a requirement to conduct extensive stack emissions testing on selected generating units. Allegheny is required to conduct stack testing for nine of its generating units. Depending on the final hazardous air pollution limits set by the EPA, Allegheny could incur significant costs for additional control equipment.

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The Pennsylvania Department of Environmental Protection (the "PA DEP") promulgated a more aggressive mercury control rule on February 17, 2007. Pennsylvania's proposed shortened compliance schedule and more aggressive emissions limits might result in the installation of additional emission controls at any of Allegheny's three Pennsylvania coal-fired facilities or in a change in fuel specifications. Controls might include additional Scrubbers, activated carbon injection, selective catalytic reduction or other currently emerging technologies. On September 15, 2008, PPL Corporation filed a challenge to the PA DEP's mercury rule in Pennsylvania Commonwealth Court. The Commonwealth Court overturned the Pennsylvania mercury rule on January 30, 2009. On December 23, 2009, the Pennsylvania Supreme Court affirmed the Commonwealth Court's holding that the rule is invalid.

Additionally, Maryland passed the Healthy Air Act in early 2006. This legislation imposes state-wide emission caps on SO_2 and NO_x, requires greater reductions in mercury emissions more quickly than required by CAMR and mandates that Maryland join the Regional Greenhouse Gas Initiative ("RGGI") and participate in that coalition's regional efforts to reduce CO_2 emissions. On April 20, 2007, Maryland's governor signed on to RGGI, as a result of which Maryland became the 10th state to join the Northeast regional climate change and energy efficiency program. The Healthy Air Act provides a conditional exemption for the R. Paul Smith power station for NO_x, SO_2 and mercury, based on a PJM declaration that the station is vital to reliability in the Baltimore/Washington DC metropolitan area, which PJM determined in 2006. Pursuant to the legislation, the Maryland Department of the Environment (the "MDE") passed alternate NO_x and SO_2 limits for R. Paul Smith, which became effective in April 2009. The MDE still expects R. Paul Smith to meet the Healthy Air Act mercury reductions of 80% beginning in 2010. The statutory exemption does not extend to R. Paul Smith's CO_2 emissions. Maryland issued final regulations to implement RGGI requirements in February 2008. Among other things, under RGGI, the MDE now auctions 100% of CO_2 allowances associated with Maryland's power plants, and Allegheny is participating in RGGI auctions.

AE Supply and Monongahela comply with current SO_2 emission standards through a system-wide plan combining the use of emission controls, low sulfur fuel and emission allowances. Allegheny continues to evaluate and implement options for compliance. It completed the elimination of a partial bypass of Scrubbers at its Pleasants generation facility in December 2007 and the construction of Scrubbers at its Hatfield's Ferry and Fort Martin generating facilities in 2009. Allegheny now has Scrubbers installed and operating on all 10 of the units at its four supercritical generating facilities and at Mitchell Unit 3.

Allegheny's NO_x compliance plan functions on a system-wide basis, similar to its SO_2 compliance plan. AE Supply and Monongahela also have the option, in some cases, to purchase alternate fuels or NO_x allowances, if needed, to supplement their compliance strategies. Allegheny currently has installed selective non-catalytic reduction equipment at its Fort Martin and Hatfield's Ferry generating stations and selective catalytic reduction equipment at its Harrison and Pleasants generating stations, together with other NO_x controls at these supercritical generating facilities, as well as its other generating facilities.

On January 8, 2010, the West Virginia Department of Environmental Protection ("WVDEP") issued a Notice of Violation for opacity emissions at Allegheny's Pleasants generating facility. Allegheny is evaluating certain control system options for opacity reduction. Although a system has not yet been selected, the cost to install any such system could be significant.

Clean Air Act Litigation

In August 2000, AE received a letter from the EPA requesting that it provide information and documentation relevant to the operation and maintenance of the following ten electric generation facilities, which collectively include 22 generation units: Albright, Armstrong, Fort Martin, Harrison, Hatfield's Ferry, Mitchell, Pleasants, Rivesville, R. Paul Smith and Willow Island. AE Supply and/or Monongahela own these generation facilities. The letter requested information under Section 114 of the Clean Air Act to determine compliance with the Clean Air Act and related requirements, including potential application of the NSR standards of the Clean Air

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Act, which can require the installation of additional air emission control equipment when the major modification of an existing facility results in an increase in emissions. AE has provided responsive information to this and a subsequent request.

If NSR requirements are imposed on Allegheny's generation facilities, in addition to the possible imposition of fines, compliance would entail significant capital investments in emission control technology.

On May 20, 2004, AE, AE Supply, Monongahela and West Penn received a Notice of Intent to Sue Pursuant to Clean Air Act §7604 (the "Notice") from the Attorneys General of New York, New Jersey and Connecticut and from the PA DEP. The Notice alleged that Allegheny made major modifications to some of its West Virginia facilities in violation of the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act at the following coal-fired facilities: Albright Unit No. 3; Fort Martin Units No. 1 and 2; Harrison Units No. 1, 2 and 3; Pleasants Units No. 1 and 2 and Willow Island Unit No. 2. The Notice also alleged PSD violations at the Armstrong, Hatfield's Ferry and Mitchell generation facilities in Pennsylvania and identifies PA DEP as the lead agency regarding those facilities. On September 8, 2004, AE, AE Supply, Monongahela and West Penn received a separate Notice of Intent to Sue from the Maryland Attorney General that essentially mirrored the previous Notice.

On January 6, 2005, AE Supply and Monongahela filed a declaratory judgment action against the Attorneys General of New York, Connecticut and New Jersey in federal District Court in West Virginia ("West Virginia DJ Action"). This action requests that the court declare that AE Supply's and Monongahela's coal-fired generation facilities in Pennsylvania and West Virginia comply with the Clean Air Act. The Attorneys General filed a motion to dismiss the West Virginia DJ Action.

On June 28, 2005, the PA DEP and the Attorneys General of New York, New Jersey, Connecticut and Maryland filed suit against AE, AE Supply and the Distribution Companies in the United States District Court for the Western District of Pennsylvania (the "PA Enforcement Action"). This action alleges NSR violations under the federal Clean Air Act and the Pennsylvania Air Pollution Control Act at the Hatfield's Ferry, Armstrong and Mitchell facilities in Pennsylvania. The PA Enforcement Action appears to raise the same issues regarding Allegheny's Pennsylvania generation facilities that are before the federal District Court in the West Virginia DJ Action, except that the PA Enforcement Action also includes the PA DEP and the Maryland Attorney General. On January 17, 2006, the PA DEP and the Attorneys General filed an amended complaint. On May 30, 2006, the District Court denied Allegheny's motion to dismiss the amended complaint. On July 26, 2006, at a status conference, the Court determined that discovery would proceed regarding liability issues, but not remedies. Discovery on the liability phase closed on December 31, 2007, and summary judgment briefing was completed during the first quarter of 2008. On November 18, 2008, the District Court issued a Memorandum Order denying all motions for summary judgment and establishing certain legal standards to govern at trial. In December 2009, a new trial judge was assigned to the case and has since entered an order granting a motion to reconsider the rulings in the November 2008 Memorandum Order. A ruling on those issues is expected within the first quarter of 2010. Trial has been tentatively scheduled to begin on September 13, 2010.

In addition to this lawsuit, on September 21, 2007, Allegheny received a Notice of Violation ("NOV") from the EPA alleging NSR and PSD violations under the federal Clean Air Act, as well as Pennsylvania and West Virginia state laws. The NOV was directed to AE, Monongahela and West Penn and alleges violations at the Hatfield's Ferry and Armstrong generation facilities in Pennsylvania and the Fort Martin and Willow Island generation facilities in West Virginia. The projects identified in the NOV are essentially the same as the projects at issue for these four facilities in the May 20, 2004 Notice, the West Virginia DJ Action and the PA Enforcement Action.

Allegheny intends to vigorously pursue and defend against the Clean Air Act matters described above but cannot predict their outcomes.

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Clean Water Act Compliance

In 2004, the EPA issued a final rule requiring all existing power plants with once-through cooling water systems withdrawing more than 50 million gallons of water per day to meet certain standards to reduce mortality of aquatic organisms pinned against the water intake screens or, in some cases, drawn through the cooling water system. The standards varied based on the type and size of the water bodies from which the plants draw their cooling water.

In January 2007, the Second Circuit Court of Appeals issued a decision on appeal that remanded a significant portion of the rule to the EPA. As a result, the EPA suspended the rule, except for a requirement, which existed prior to the EPA's adoption of the 2004 rule, that permitting agencies use best professional judgment ("BPJ") to determine the best technology available for minimizing adverse environmental impacts for existing facility cooling water intakes. Pending re-issuance of the 2004 rule by the EPA, permitting agencies thus will rely on BPJ determinations during permit renewal at existing facilities.

On April 1, 2009, the U.S. Supreme Court reversed the appeals court decision and upheld EPA's authority to use cost/benefit analysis. The EPA has indicated that it plans to issue a proposed rule addressing the issues remanded by the Court by mid-2010 and to issue a final rule in 2012. Depending on the standards set by the EPA when it reissues this rule, Allegheny could incur significant costs for additional control equipment.

Monongahela River Water Quality

In late 2008, the PA DEP imposed water quality criteria for certain effluents, including total dissolved solid and sulfate concentrations in the Monongahela River, on new and modified sources, including the Scrubber project at the Hatfield's Ferry generation facility. These criteria are reflected in the current PA DEP water discharge permit for that project. AE Supply has appealed the PA DEP's permitting decision, which would require it to incur significant costs or negatively impact its ability to operate the Scrubbers. Preliminary studies indicate an initial capital investment of approximately $62 million in order to install technology to meet the total dissolved solid and sulfate limits in the permit. The permit has been independently appealed by Environmental Integrity Project and Citizens Coal Council who seek to impose more stringent technology-based effluent limitations. Those same parties have intervened in the appeal filed by AE Supply, and both appeals have been consolidated for discovery purposes. An order has been entered that stays the permit limits that AE Supply has challenged while the appeal is pending. No hearing date has been set. AE Supply intends to vigorously pursue these issues but cannot predict the outcome of these appeals. On November 7, 2009, the PA DEP published proposed amendments to the PA Chapter 95 rules that include an end-of-pipe limit for total dissolved solids for new and modified sources. The PA DEP's proposed rule was open for public comment until February 12, 2010.

In October, 2009, the WVDEP issued the water discharge permit for the Fort Martin generation facility. Similar to the Hatfield's Ferry water discharge permit issued for the Scrubber project, the Fort Martin permit imposes effluent limitations for total dissolved solid and sulfate concentrations. The permit also imposes temperature limitations and other effluent limits for heavy metals that are not contained in the Hatfield's Ferry water permit. Concurrent with the issuance of the Fort Martin permit, WVDEP also issued an administrative order that sets deadlines for Monongahela to meet certain of the effluent limits that are effective immediately under the terms of the permit. Monongahela has appealed the Fort Martin permit and the administrative order. The appeal includes a request to stay certain of the conditions of the permit and order while the appeal is pending. The request to stay has been granted pending a final decision on appeal and subject to WVDEP moving to dissolve the stay. The appeals have been consolidated and a hearing is likely to be scheduled for May 2010. The current terms of the Fort Martin permit would require Monongahela to incur significant costs or negatively impact operations at Fort Martin. Preliminary information indicates an initial capital investment in excess of the capital investment that may be needed at Hatfield's Ferry in order to install technology to meet the total dissolved solid and sulfate limits in the Fort Martin permit, which technology may also meet certain of the other effluent limits in the permit. Additional technology may be needed to meet certain other limits in the permit. Monongahela intends to vigorously pursue these issues but cannot predict the outcome of these appeals.

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Solid Waste

The EPA is reviewing its waste regulations relating to coal combustion byproducts ("CCB") partly in response to a Tennessee Valley Authority ash spill in Kingston, Tennessee on December 22, 2008. CCB includes bottom ash, boiler slag, fly ash and Scrubber byproducts including gypsum. CCB has historically been designated and managed as a non-hazardous waste and the EPA has twice determined it is not appropriate to regulate it as a hazardous waste under the Resource Conservation and Recovery Act ("RCRA"). The EPA is reconsidering those earlier determinations and intends to issue new regulations for the management and disposal of CCB. The EPA has not yet reached a final decision on whether to regulate CCB as hazardous (RCRA Title C) or non-hazardous (RCRA Title D) or as a hybrid, but hopes to reach that decision during the first quarter of 2010. Should the EPA elect to designate CCB as hazardous at any point in its generation, storage, transportation or disposal cycle, it could significantly increase Allegheny's cost of managing CCB materials. In addition to potential additional management costs, CCB generators could expect to see a reduction in options for beneficial reuse of CCB in applications such as mine reclamation, cement manufacture and agriculture, further increasing costs, as such materials will then enter landfills rather than beneficial reuse. The EPA might also designate CCB as hazardous only when it is destined for wet storage impoundments, which would reduce Allegheny's potential waste management exposure.

Global Warming Class Action

On April 9, 2006, AE, along with numerous other companies with coal-fired generation facilities and companies in other industries, was named as a defendant in a class action lawsuit in the United States District Court for the Southern District of Mississippi. On behalf of a purported class of residents and property owners in Mississippi who were harmed by Hurricane Katrina, the named plaintiffs allege that the emission of greenhouse gases by the defendants contributed to global warming, thereby causing Hurricane Katrina and plaintiffs' damages. The plaintiffs seek unspecified damages. On December 6, 2006, AE filed a motion to dismiss plaintiffs' complaint on jurisdictional grounds and then joined a motion filed by other defendants to dismiss the complaint for failure to state a claim. At a hearing on August 30, 2007, the Court granted the motion to dismiss that AE had joined and dismissed all of the plaintiffs' claims against all defendants. Plaintiffs appealed that ruling to the United States Court of Appeals for the Fifth Circuit. On October 6, 2009, the assigned panel of the appellate court issued a written opinion that reversed the judgment entered by the District Court in favor of the defendants with respect to certain of the plaintiffs' claims and remanded the case to the District Court for further proceedings. On November 25, 2009, AE and others filed a petition to have all of the judges of the Fifth Circuit rehear the issues addressed in the panel's October 6, 2009 opinion. There has been no ruling on that petition. AE intends to vigorously defend against this action but cannot predict its outcome.

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EMPLOYEES

Substantially all of Allegheny's officers and other personnel are employed by AESC. As of December 31, 2009, AESC employed 4,383 employees. Of these employees, 1,223 are subject to collective bargaining arrangements. Approximately 72% of the unionized employees are at the Distribution Companies and approximately 28% are at AE's other subsidiaries. As of December 31, 2009, System Local 102 of the Utility Workers Union of America (the "UWUA") represents 1,037 employees, and locals of the International Brotherhood of Electrical Workers (the "IBEW") represent 186 employees. Collective bargaining arrangements with the IBEW and UWUA expire during 2010 and 2011, respectively. Members of IBEW Local 50, which includes 34 members, recently ratified a new five-year labor agreement that will extend from March 1, 2010 through February 28, 2015. Contract negotiations with IBEW Local 2357, which includes 123 members, with respect to its current agreement that expires on February 28, 2010, are still ongoing. The parties have agreed to extend the existing contract through March 31, 2010, and union members are expected to vote on a new agreement at the beginning of March 2010.

Allegheny believes that current relations between it and its unionized and non-unionized employees are satisfactory.

On September 19, 2005, AE entered into a Professional Services Agreement with a service provider under which, on November 1, 2005, the service provider assumed responsibility for many of Allegheny's information technology functions. Unless extended by AE, the Professional Services Agreement will expire on December 31, 2012.

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Executive Officers

The names of AE's executive officers, their ages, the positions they hold, and their business experience during the past five years appear below. All of AE's officers are elected annually.

Name	Age	Title
Paul J. Evanson	68	Chairman, President, Chief Executive Officer and Director
Curtis H. Davis	57	Chief Operating Officer, Generation
Rodney L. Dickens	52	Vice President
Edward Dudzinski	57	Vice President
David M. Feinberg	40	Vice President, General Counsel and Secretary
Eric S. Gleason	43	Vice President, Corporate Development and Quality
Kirk R. Oliver	52	Senior Vice President and Chief Financial Officer
William F. Wahl, III	50	Vice President, Controller and Chief Accounting Officer

Paul J. Evanson has been Chairman of the Board, President, Chief Executive Officer and a director of AE since June 2003. Mr. Evanson is the Chair of the Executive Committee. Prior to joining Allegheny, Mr. Evanson was President of Florida Power & Light Company, the principal subsidiary of FPL Group, Inc., and a director of FPL Group, Inc. from 1995 to 2003.

Curtis H. Davis has been Chief Operating Officer, Generation, of AE since March 2008. Prior to joining Allegheny, Mr. Davis served as Senior Vice President for Duke Energy Corporation's non-regulated generation fleet from January 2003 to February 2008. Prior to that, he served in various senior operational positions at Duke Energy Corporation.

Rodney L. Dickens has been Vice President of AE since joining Allegheny in June 2009 and also serves as President of Allegheny's transmission and distribution business. Prior to joining Allegheny, Mr. Dickens was most recently Vice President, Asset Management and Centralized Services with Public Service Electric & Gas Company, where he worked in various capacities for the preceding 32 years.

Edward Dudzinski has been Vice President, Human Resources and Security, of AE since August 2004. Prior to joining Allegheny, Mr. Dudzinski was Vice President, Human Resources for the Agriculture and Nutrition Platform and Pioneer Hi-Bred International, Inc. on behalf of E. I. DuPont de Nemours and Company ("DuPont"). Prior to that, he served in various other executive and leadership positions at DuPont.

David M. Feinberg has been Vice President, General Counsel and Secretary of AE since October 2006. Mr. Feinberg joined Allegheny in August 2004 and served as Deputy General Counsel until October 2006. Prior to joining Allegheny, Mr. Feinberg was a partner with the law firm of Jenner & Block LLP in its Chicago office.

Eric S. Gleason has been Vice President, Corporate Development and Quality, of AE since October 2009. Mr. Gleason joined Allegheny in August 2008 and served as Vice President, Corporate Development until October 2009. Prior to joining Allegheny, Mr. Gleason was employed by JPMorgan Chase & Co. since 2002, and served as Executive Director, Natural Resources Investment Banking from 2005 to 2008. Prior to that, he served as Vice President in the Investment Banking Division of Goldman, Sachs & Co.

Kirk R. Oliver has been Senior Vice President and Chief Financial Officer of AE since October 2008. Prior to joining Allegheny, Mr. Oliver was employed by Hunt Power since June 2006 and served as a senior executive from June 2007 to October 2008. Prior to that, Mr. Oliver spent eight years at TXU Corp, starting as Treasurer and then serving as Executive Vice President and Chief Financial Officer.

William F. Wahl, III has been Vice President, Controller and Chief Accounting Officer of AE since May 2007. He joined Allegheny in 2003 and served as Assistant Controller, Corporate Accounting from February 2005 to May 2007. From 2002 to 2003, Mr. Wahl was employed by PNC Financial Services Group, Inc. Prior to that, he was employed by Dominion Resources, Inc.

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ITEM 1A. RISK FACTORS

Allegheny is subject to a variety of significant risks that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond its control. A number of these risks are identified below, in addition to the matters set forth under “Special Note Regarding Forward-Looking Statements.” Allegheny’s susceptibility to certain risks could exacerbate other risks. These risk factors should be considered carefully in evaluating Allegheny’s risk profile.

Risks Relating to the Merger with FirstEnergy

Allegheny may be unable to obtain the approvals required to complete its merger with FirstEnergy or, in order to do so, the combined company may be required to comply with material restrictions or conditions.

On February 11, 2010, Allegheny announced the execution of a merger agreement with FirstEnergy. Before the merger may be completed, both Allegheny and FirstEnergy will need to obtain shareholder approval for the proposed transaction. In addition, various filings must be made with FERC and various utility regulatory, antitrust and other authorities in the United States. These governmental authorities may impose conditions on the completion, or require changes to the terms, of the merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following completion of the merger. These conditions or changes could have the effect of delaying completion of the merger or imposing additional costs on or limiting the revenues of the combined company following the merger, which could have a material adverse effect on the financial results of the combined company and/or cause either Allegheny or FirstEnergy to abandon the merger.

If Allegheny and FirstEnergy are unable to complete the merger, we still will incur and will remain liable for significant transaction costs, including legal, accounting, financial advisory, filing, printing and other costs relating to the merger whether or not it is completed. Also, depending upon the reasons for not completing the merger, including whether Allegheny has received or entered into a competing takeover proposal, Allegheny may be required to pay FirstEnergy a termination fee of up to $150 million and reimburse FirstEnergy for its transaction expenses up to $45 million. Additionally, under specified circumstances in which the merger is not completed but the $150 million termination fee is not payable, Allegheny may nevertheless be required to reimburse FirstEnergy for its transaction expenses up to $45 million. Any such payment could have a material adverse effect on Allegheny’s business, results of operations, cash flows and financial condition. See consolidated financial statement Note 27, “Subsequent Event – Merger Agreement.”

If completed, Allegheny’s merger with FirstEnergy may not achieve its intended results.

Allegheny and FirstEnergy entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Allegheny and FirstEnergy are integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management’s time and energy and could have an adverse effect on the combined company’s business, financial results and prospects.

Allegheny will be subject to business uncertainties and contractual restrictions while the merger with FirstEnergy is pending that could adversely affect Allegheny’s financial results.

Uncertainty about the effect of the merger with FirstEnergy on employees, customers and suppliers may have an adverse effect on Allegheny. Although Allegheny intends to take steps designed to reduce any adverse effects, these uncertainties may impair Allegheny’s ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with Allegheny to seek to change existing business relationships.

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Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite Allegheny's retention and recruiting efforts, key employees depart or fail to accept employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, Allegheny's financial results could be affected.

The pursuit of the merger and the preparation for the integration of Allegheny and FirstEnergy may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could affect Allegheny's business, results of operations and financial condition.

In addition, the merger agreement restricts Allegheny, without FirstEnergy's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the merger agreement terminates. These restrictions may prevent Allegheny from pursuing otherwise attractive business opportunities and making other changes to its business prior to completion of the merger or termination of the merger agreement.

Risks Relating to Regulation

Allegheny is subject to substantial governmental regulation. Compliance with current and future regulatory requirements and the need to obtain necessary approvals, permits and certificates may result in substantial costs to Allegheny, and failure to obtain necessary regulatory approvals could have an adverse effect on its business.

Allegheny is subject to substantial regulation from federal, state and local regulatory agencies. Allegheny is required to comply with numerous laws and regulations and to obtain numerous authorizations, permits, approvals and certificates from governmental agencies. These agencies regulate various aspects of Allegheny's business, including customer rates, services, retail service territories, generation plant operations and construction, sales of securities, asset sales and accounting policies and practices. Although Allegheny believes that the necessary authorizations, permits, approvals and certificates have been obtained for its existing operations and that its business is conducted in accordance with applicable laws, it cannot predict the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to it. See "Environmental Matters" and "Regulatory Framework Affecting Allegheny."

Changes in regulations or the imposition of additional regulations could influence Allegheny's operating environment and may result in substantial costs to Allegheny, which could have an adverse effect on its business, results of operations, cash flows and financial condition.

Allegheny's costs to comply with environmental laws are significant. New environmental laws and regulations, or new interpretations of existing laws and regulations, could impose more stringent limitations on Allegheny's generation operations or require it to incur significant additional costs. The cost of compliance with present and future environmental laws could have an adverse effect on Allegheny's business.

Allegheny's operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and site remediation and may, in the future, become subject to new and potentially more extensive environmental regulations, including but not limited to regulations intended to address climate change. Compliance with these laws and regulations may require Allegheny to expend significant financial resources to, among other things, meet air emission and water quality standards, conduct site remediation, perform environmental monitoring, purchase emission allowances, use alternative fuels, install and operate pollution control equipment at its generation facilities and modulate operations of its generation facilities in order to reduce emissions. If Allegheny fails to comply with applicable environmental laws and regulations, even if it is unable to do so due to factors beyond its control, it

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may be subject to civil liabilities or criminal penalties and may be required to incur significant expenditures to come into compliance. In addition, any alleged violations of environmental laws and regulations may require Allegheny to expend significant resources defending itself against such alleged violations. Either result could have an adverse effect on Allegheny's business, results of operations, cash flows and financial condition.

Allegheny also may be subject to risks in connection with changing or conflicting interpretations of existing laws and regulations. For example, applicable standards under the EPA's NSR initiatives remain in flux. Under the Clean Air Act, modification of Allegheny's generation facilities in a manner that causes increased emissions could subject Allegheny's existing facilities to the far more stringent NSR standards applicable to new facilities.

The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards in connection with work believed by the companies to be routine maintenance. Allegheny currently is involved in litigation concerning alleged violations of the PSD provisions of the Clean Air Act at certain of its facilities in West Virginia and violations of the Pennsylvania Air Pollution Control Act and NSR provisions of the Clean Air Act at certain of its facilities in Pennsylvania. Allegheny intends to vigorously pursue and defend against the environmental matters described above but cannot predict their outcomes. If NSR and similar requirements are imposed on Allegheny's generation facilities, in addition to the possible imposition of fines, compliance would entail significant capital investments in pollution control technology, which could have an adverse impact on Allegheny's business, results of operations, cash flows and financial condition.

In addition, Allegheny incurs costs to obtain and comply with a variety of environmental permits, licenses, inspections and other approvals. If there is a delay in obtaining any required environmental regulatory approval, or if Allegheny fails to obtain, maintain or comply with any required approval, operations at affected facilities could be halted, curtailed or subjected to additional costs, which could have an adverse impact on Allegheny's business, results of operations, cash flows and financial condition. See "Environmental Matters."

Shifting state and federal regulatory policies impose risks on Allegheny's operations. Compliance with emerging regulatory initiatives could require Allegheny to incur significant costs. Delays, discontinuations or reversals of electricity market restructurings in the markets in which Allegheny operates could have an adverse effect on its business.

Allegheny's operations are subject to evolving regulatory policies, including initiatives regarding deregulation and re-regulation of the production and sale of electricity, the restructuring of transmission regulation and energy efficiency and conservation. Any new requirements arising from these actions could lead to increased operating expenses and capital expenditures, the full amount of which cannot be predicted at this time.

Some deregulated electricity markets in which Allegheny operates have experienced price volatility. In some of these markets, government agencies and other interested parties have made proposals to delay market restructuring or even re-regulate areas of these markets that have previously been deregulated. Although it is possible that, in an economic downturn, price increases resulting from the transition to market rates could be smaller than previously anticipated, the heightened public and political concern over the transition to market rates could nevertheless be exacerbated by the current deteriorating national economic climate and its potential effects on consumers.

In Pennsylvania, many of the state's electric utilities, including Allegheny, are scheduled to transition to market rates in 2010 and 2011, when applicable generation rate caps expire. Significant price increases in other states following the end of such regulatory transition periods have created a heightened political concern regarding price volatility in Pennsylvania following the expiration of its rate caps. In September 2007, a special legislative session was convened in Pennsylvania to consider various energy proposals. During the special session, several proposed bills involving the extension of rate caps were introduced. Currently, generation rate caps for Allegheny's Pennsylvania customers expire at the end of 2010. While the Pennsylvania General

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Assembly adopted legislation in October 2008 that includes a number of conservation and demand-side management measures and procurement procedures, it does not address rate mitigation or the transition to market rates. However, there can be no assurance that the Pennsylvania legislature will not adopt such measures in the future. See "Regulatory Matters."

Other proposals to re-regulate the industry may be made, and legislative or other action affecting the electric power restructuring process may cause the process to be delayed, discontinued or reversed in the states in which Allegheny operates. Delays, discontinuations or reversals of electricity market restructurings in the markets in which Allegheny operates could have an adverse effect on its business, results of operations, cash flows and financial condition. At a minimum, these types of actions raise uncertainty concerning the continued development of competitive power markets. Given Allegheny's multi-state operations and asset base, re-regulation of restructured obligations could prove intricate, time-consuming and costly to ongoing operations.

In addition, as a result of FERC's efforts to implement a long-term rate design for the Midwest and mid-Atlantic regions, the Distribution Companies may not fully recover their transmission costs and may have costs shifted to them from other transmission owners. Due to capped rates and the timing of state rate cases, the Distribution Companies may not be able to pass through increased transmission costs to these retail customers for some period of time. See "Regulatory Matters."

Furthermore, some of the states in which Allegheny operates have enacted or are considering various energy efficiency and conservation programs, which could prove costly for Allegheny. In 2008, for example, Pennsylvania adopted Act 129, which includes a number of provisions relating to conservation, demand-side management and power procurement processes. Maryland has adopted some similar measures as part of its EmPOWER Maryland initiative. Among other things, Act 129 requires the implementation of smart meter technology, in connection with which Allegheny expects to incur substantial costs. Although Act 129 includes cost recovery provisions, any delay in or denial of cost recovery could adversely affect Allegheny. Additionally, failure to comply with Act 129 could result in significant penalties. See "Regulatory Matters."

State rate regulation may delay or deny full recovery of costs and impose risks on Allegheny's operations. Any denial of, or delay in, cost recovery could have an adverse effect on Allegheny's business.

The retail rates in the states in which Allegheny operates are set by each state's regulatory body. As a result, in certain states, Allegheny may not be able to recover increased, unexpected or necessary costs and, even if Allegheny is able to do so, there may be a significant delay between the time Allegheny incurs such costs and the time Allegheny is allowed to recover them. Any denial of, or delay in, cost recovery could have an adverse effect on Allegheny's results of operations, cash flows and financial condition. See "Regulatory Framework Affecting Allegheny."

Allegheny could be subject to significant penalties if it violates mandatory NERC reliability standards.

The Energy Policy Act amended the FPA to, among other matters, provide for mandatory reliability standards designed to assure the reliable operation of the bulk power system. NERC established, and the FERC approved, reliability standards that impose certain operating, record-keeping and reporting requirements on the Distribution Companies, TrAIL Company, PATH, LLC, AE Supply and AGC. NERC delegated the day-to-day implementation and enforcement of these standards to eight regional oversight entities, including ReliabilityFirst, of which Allegheny is a member.

Allegheny has been, and will continue to be, subject to routine audits with respect to its compliance with applicable reliability standards and has settled certain related issues. In addition, ReliabilityFirst is currently conducting several violation investigations that have been self-reported by Allegheny. The results of these proceedings and investigations have not had, and are not expected to have, any material impact on Allegheny's operations or the results thereof. It is possible, however, that any violation of these mandatory standards could subject Allegheny to civil fines imposed by FERC for up to $1.0 million per day, per violation, which could have an adverse effect on Allegheny's results of operations, cash flows and financial condition. See "Regulatory Framework Affecting Allegheny."

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The TrAIL Project and the PATH Project are subject to permitting and state regulatory approvals, and the failure to obtain any of these permits or approvals could have an adverse effect on Allegheny's business.

The construction of both the TrAIL Project and the PATH Project are subject to the prior approval of various regulatory bodies. TrAIL Company has obtained the state siting approvals (subject to a pending appeal in Pennsylvania) necessary to construct TrAIL and is continuing to pursue necessary permits. Allegheny met with substantial political opposition, as well as opposition from environmental, community and other groups, in obtaining siting approval for TrAIL and is likely to encounter similar opposition with regard to the PATH Project. There can be no assurance that Allegheny will be able to obtain the regulatory approvals required in connection with these projects, particularly the siting approvals required to construct PATH, on a timely basis or at all. The inability to obtain any required state approval or other regulatory approval as a result of such opposition or otherwise, may have an adverse effect on Allegheny's business, results of operations, cash flows and financial condition. See "Regulatory Framework Affecting Allegheny."

The pending sale of Potomac Edison's Virginia distribution assets is subject to the approval of the Virginia SCC, the denial of which could have an adverse effect on Allegheny's financial condition.

The pending sale of Potomac Edison's distribution business in Virginia is subject to regulatory approval, which the Virginia SCC may not grant. On May 4, 2009, Potomac Edison signed definitive agreements to sell its electric distribution operations in Virginia to Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative for cash proceeds of approximately $340 million, subject to state and federal regulatory approval, certain third-party consents and applicable price adjustments. On September 15, 2009, Potomac Edison and the Cooperatives filed with the Virginia SCC a joint request for approval of the transaction. The Virginia SCC issued a procedural order scheduling an evidentiary hearing on the matter for March 2, 2010. On January 29, 2010, consultants retained by the Staff of the Virginia SCC filed testimony analyzing the transaction, asserting that current Virginia customers of Potomac Edison would pay $370 million more in rates over nine years if the Cooperatives take over service to those customers. Potomac Edison and the Cooperatives filed rebuttal testimony on February 12, 2010. Any failure to consummate the proposed sale, whether as a result of actions by the Virginia SCC or otherwise, may have an adverse effect on Allegheny's business, results of operations, cash flows and financial condition. See "Regulatory Framework Affecting Allegheny."

Allegheny is from time to time subject to federal or state tax audits the resolution of which could have an adverse effect on Allegheny's financial condition.

Allegheny is subject to periodic audits and examinations by the Internal Revenue Service ("IRS") and other state and local taxing authorities. Determinations and expenses related to these audits and examinations and other proceedings by the IRS and other state and local taxing authorities could materially and adversely affect Allegheny's financial condition.

Risks Relating to Allegheny's Operations

Decreasing demand for electric power, as well as for certain commodities underlying the production of electric power and the related decline in market prices for power are adversely affecting Allegheny's business.

During 2009, customer demand for electric power in Allegheny's region fell significantly as a result of the ongoing economic recession and mild summer weather, among other factors. Overall demand for some of the commodities that underlie the production of electricity, and as a result the prevailing prices for those commodities, have also declined. Although power prices may be influenced by many factors, weakening demand for electricity, together with significantly lower commodity prices, have contributed to sharp declines in market prices for power over the past 12 to 15 months. Partly as a consequence of these declines, AE Supply generated significantly less power in 2009 than in 2008.

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Allegheny can make no assurances regarding the impact of any economic recovery on demand and market prices for power. Improvements in demand and market prices for power, if any, may lag any future improvements in overall economic conditions, and it is also possible that the current economic climate could result in long-term reduction of demand for power in our region, particularly among large industrial consumers. It is also possible that changes in customer behavior, as a result of conservation programs such as EmPOWER Maryland and Pennsylvania's Act 129 or otherwise, could result in long-term reductions in demand for power.

Allegheny's coal inventories have, at times, exceeded desirable levels as a result of recent decreases in our power production resulting from declines in demand and market prices for power.

AE Supply and Monongahela have various longer term coal supply contracts in place that are intended to partially mitigate our exposure to negative fluctuations in coal prices. In some cases, these contracts may require that AE Supply or Monongahela purchase a minimum volume of coal over a given time period. However, as a result of falling demand and market prices for power, Allegheny experienced declines in 2009 in the frequency with which its coal burning power plants operated. As a result, Allegheny's coal consumption decreased significantly. Although Allegheny has been able to defer or cancel deliveries under certain contracts, it has at times been required to purchase coal in excess of immediate needs, resulting in coal inventories at some of its facilities that exceed what it considers to be optimal levels, which could have an adverse impact on its business. As coal inventories reach levels in excess of optimal levels, Allegheny may be unable to accept future deliveries at one or more of its facilities and may need to pursue alternative arrangements, including third party sales of inventory at levels below its cost, arrangements for third-party storage of a portion of its coal inventory, and modifications to its existing coal supply agreements.

Allegheny's generation facilities are subject to unplanned outages and significant maintenance requirements.

The operation of power generation facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption and performance below expected levels of output or efficiency. If Allegheny's facilities, or the facilities of other parties upon which it depends, operate below expectations, Allegheny may lose revenues, have increased expenses or fail to receive or deliver the amount of power for which it has contracted.

Allegheny's supercritical generation facilities were originally constructed in the late 1960s and early 1970s, and many of its other generation facilities were constructed prior to that time. Older equipment, even if maintained in accordance with good engineering practices, may require significant maintenance and capital expenditures to operate at peak efficiency or availability. If Allegheny underestimates required maintenance expenditures or is unable to make required capital expenditures due to liquidity constraints, it risks incurring more frequent unplanned outages, higher than anticipated maintenance expenditures, increased operation at higher cost of some of its less efficient generation facilities and the need to purchase power from third parties to meet its supply obligations, possibly at times when the market price for power is high, all of which may have an adverse effect on Allegheny's business, results of operations, cash flows and financial condition.

Allegheny's operating results are subject to seasonal and weather fluctuations and other factors that affect customer demand.

The sale of power generation output is generally a seasonal business, and weather patterns can have a material impact on Allegheny's operating results. Demand for electricity in Allegheny's service territory peaks during the summer and winter months. During periods of peak demand, the capacity of Allegheny's generation facilities may be inadequate to meet its contractual obligations, which could require it to purchase power at a time when the market price for power is high. In addition, although the operational costs associated with the Regulated Operations segment are not weather-sensitive, the segment's revenues are subject to seasonal fluctuation. Accordingly, Allegheny's annual results and liquidity position may depend disproportionately on its performance during the winter and summer.

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Extreme weather or events outside of Allegheny's service territory can also have a direct effect on the commodity markets. Events, such as hurricanes, that disrupt the supply of commodities used as fuel impact the price and availability of energy commodities and can have an adverse impact on Allegheny's business, results of operations, cash flow and financial condition.

Allegheny's results also may be negatively impacted as a result of other circumstances that affect customer demand for power. For example, it is possible that the current economic downturn, as well as conservation efforts such as the EmPOWER Maryland program and Pennsylvania's Act 129, have and will continue to contribute to changes in customer behavior, which may result in a significant reduction in demand, particularly among commercial and industrial customers, which could, in turn, have an adverse impact on Allegheny's business, results of operations, cash flow and financial condition.

Changes in weather patterns as a result of global warming could have an adverse effect on Allegheny's business.

Allegheny also could be impacted to the extent that global warming trends affect established weather patterns or exacerbate extreme weather or weather fluctuations. Although Allegheny's physical assets are located in a region in which they are unlikely to experience detrimental physical damage from the rising sea levels that have been modeled in various analyses that attempt to predict the effects of global warming, other weather-related effects that could be associated with global warming, such as an increase in the frequency and/or severity of storms or other significant climate changes within or outside of Allegheny's service territory, may have an adverse impact on Allegheny's business, results of operations, cash flow and financial condition.

Allegheny's assets are subject to other risks beyond its control, including, but not limited to, accidents, storms, natural catastrophes and terrorism.

Much of the value of Allegheny's business consists of its portfolio of power generation and T&D assets. Allegheny's ability to conduct its operations depends on the integrity of these assets. The cost of repairing damage to its facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events may exceed available insurance, if any, for repairs, which may adversely impact Allegheny's business, results of operations, cash flows and financial condition. Although Allegheny has taken, and will continue to take, reasonable precautions to safeguard these assets, Allegheny can make no assurance that its facilities will not face damage or disruptions or that it will have sufficient insurance, if any, to cover the cost of repairs. In addition, in the current geopolitical climate, enhanced concern regarding the risks of terrorism throughout the economy may impact Allegheny's operations in unpredictable ways. Insurance coverage may not cover costs associated with any of these risks adequately or at all. While some losses may be recoverable through regulatory proceedings, the delay and uncertainty of any such recovery may have an adverse effect on Allegheny's business, results of operations, cash flow and financial condition.

The supply and price of fuel may impact Allegheny's financial results.

Allegheny is dependent on coal for much of its electric generation capacity. Allegheny has coal supply contracts in place that partially mitigate its exposure to negative fluctuations in coal prices. However, Allegheny can provide no assurance that the counterparties to these agreements will fulfill their obligations to supply coal. The suppliers under these agreements may, as a general matter, experience financial, legal or technical problems that inhibit their ability to fulfill their obligations. Among other circumstances, the prevailing constrained credit markets and overall negative economic conditions may affect the ability of Allegheny's suppliers to access the capital markets and maintain adequate liquidity to sustain their respective businesses. Additionally, to the extent that any of Allegheny's coal suppliers seek bankruptcy protection, they may, in the current climate, be unable to obtain the financing necessary to continue their operations in bankruptcy and reorganize and, thus, may be forced to liquidate. Various industry and operational factors, including increased costs, transportation constraints, safety issues and operational difficulties may have negative effects on coal supplier performance. During periods of rising coal prices, the factors impacting supplier performance could have a more pronounced financial impact.

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Furthermore, the suppliers under these agreements may not be required to supply coal to Allegheny under certain circumstances, such as in the event of a natural disaster. If Allegheny is unable to obtain its coal requirements under these contracts, it may be required to purchase coal at higher prices. In addition, although these agreements generally contain specified prices, they also may provide for price adjustments related to changes in specified cost indices, as well as specific events, such as changes in regulations affecting the coal industry. Finally, it is possible that, in the future, market prices for coal could fall below the prices at which we have agreed to purchase coal under our long-term contracts. Changes in the supply and price of coal may have an adverse effect on Allegheny's business, results of operations, cash flow and financial condition.

Additionally, Allegheny is subject to other fuel-related costs, which may fluctuate. For example, Allegheny has experienced, and may continue to experience, increases in its fuel handling and transportation costs and its costs to procure lime, urea and other materials necessary to the operation of its pollution controls. Significant increases in these and other fuel related costs could have an adverse effect on Allegheny's business, results of operations, cash flow and financial condition.

The supply and price of emissions credits may impact Allegheny's financial results.

Allegheny's SO_2 and NO_x allowance needs, to a large extent, are affected at any given time by the amount of output produced and the types of fuel used by its generation facilities, as well as the implementation of environmental controls. Fluctuations in the availability or cost of these emission allowances could have a material adverse effect on Allegheny's business, financial condition, cash flows and results of operations. It is also possible that any climate change legislation will incorporate a cap and trade scheme involving CO_2 emission allowances. In that case, the cost and availability of CO_2 emission allowances could have an adverse effect on Allegheny's business, financial condition, cash flows and results of operations. See "Environmental Matters."

Allegheny is currently involved in capital intensive projects that may involve various implementation and financial risks.

Allegheny currently is involved in a number of capital intensive projects, including the TrAIL Project, the PATH Project and the implementation of smart meter and other information technology necessary to comply with Pennsylvania's recently-enacted Act 129. Allegheny's ability to successfully complete these projects in a timely manner, within established budgets and without significant operational disruptions is contingent upon many variables, many of which are outside of its control. Failure to complete these projects as planned may have an adverse effect on Allegheny's business, results of operations, cash flow and financial condition.

Additionally, Allegheny has contracted with specialized vendors in connection with these projects, and may in the future enter into additional such contracts with respect to these and other capital projects. As such, Allegheny is exposed to the risk that these contractors may not perform as required under their contracts. Such a failure could occur for any number of reasons. Among other things, it is possible that the prevailing constrained credit markets and overall negative economic conditions may affect the ability of Allegheny's contractors, subcontractors, suppliers and vendors to access the capital markets and maintain adequate liquidity to sustain their respective businesses. Should this occur, Allegheny may be forced to find alternate arrangements, which may cause delay and/or increased costs. Allegheny can provide no assurance that it would be able to make such alternate arrangements on terms acceptable to it or at all. Any inability to make such alternate arrangements or any substantial delays or increases in costs associated therewith may have an adverse effect on Allegheny's business, results of operations, cash flow and financial condition. For additional information regarding Act 129, see "Regulatory Matters."

Changes in PJM market policies and rules or in PJM participants may impact Allegheny's financial results.

Because Allegheny has transferred functional control of its transmission facilities to PJM, is a load serving entity within the PJM Region and owns generation within the PJM Region, changes in PJM policies and/or market rules, including changes that are currently under consideration by FERC, could adversely affect