CALAMOS CONVERTIBLE OPPORTUNITIES & INCOME FUND
Form 3
September 01, 2015

FORM 3

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

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INITIAL STATEMENT OF BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Â Hamacher Theresa
(Last) (First) (Middle)

2020 CALAMOS COURT
(Street)

NAPERVILLE,Â ILÂ 60563
(City) (State) (Zip)

2. Date of Event Requiring Statement (Month/Day/Year)
09/01/2015

3. Issuer Name **and** Ticker or Trading Symbol
CALAMOS CONVERTIBLE OPPORTUNITIES & INCOME FUND [CHI]

4. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

5. If Amendment, Date Original Filed(Month/Day/Year)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Beneficially Owned

1.Title of Security (Instr. 4)	2. Amount of Securities Beneficially Owned (Instr. 4)	3. Ownership Form: Direct (D) or Indirect (I) (Instr. 5)	4. Nature of Indirect Beneficial Ownership (Instr. 5)

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

SEC 1473 (7-02)

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Table II - Derivative Securities Beneficially Owned (*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 4)	2. Date Exercisable and Expiration Date (Month/Day/Year)		3. Title and Amount of Securities Underlying Derivative Security (Instr. 4)		4. Conversion or Exercise Price of Derivative Security	5. Ownership Form of Derivative Security: Direct (D) or Indirect (I)	6. Nature of Indirect Beneficial Ownership (Instr. 5)
	Date Exercisable	Expiration Date	Title	Amount or Number of Shares			

(Instr. 5)

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Hamacher Theresa 2020 CALAMOS COURT NAPERVILLE,Â ILÂ 60563	Â X	Â	Â	Â

Signatures

/s/ J. Christopher Jackson, Attorney-in-Fact	09/01/2015
**Signature of Reporting Person	Date

Explanation of Responses:

No securities are beneficially owned

* If the form is filed by more than one reporting person, *see* Instruction 5(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *See* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. amily:Times New Roman" SIZE="2">Total realized/unrealized gains (losses):

Included in earnings

(1) (2) (3)

Included in other comprehensive income

2 (11) 1 (22)

Fair value, end of period

$(7) $(10) $(7) $(10)

Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets/liabilities held at the end of the period

$3 $ $(2)

$

(2

)

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of our financial instruments that are actively traded in the secondary market, primarily corporate debt securities, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

For interest rate swaps, we utilize data obtained from multiple sources for the determination of fair value. Both the future cash flows for the fixed-leg and floating-leg of our swaps are discounted to present value. In addition, credit default swap rates are used to develop the adjustment for credit risk embedded in our positions. We believe that since some of the inputs and assumptions for the calculations of fair value are derived from observable market data, a Level 2 classification is appropriate.

Level 3 Valuation Techniques

We do not have significant amounts of assets or liabilities measured and reported using Level 3 valuation techniques, which include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts we could have realized in current markets.

	September 30, 2011		December 31, 2010	
	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
	(in millions)			
Notes receivable, current (a)	$ 49	$ 49	$ 50	$ 51
Notes receivable, noncurrent (b)	71	71	71	71
Long-term debt, including current maturities	10,298	12,109	10,484	11,874

(a) Included within Receivables, Net on the Condensed Consolidated Balance Sheets.
(b) Included within Investments in and Loans to Unconsolidated Affiliates on the Condensed Consolidated Balance Sheets.

The book value and fair value of long-term debt include the impacts of certain pay floating receive fixed interest rate swaps that are designated as fair value hedges.

The fair values of cash and cash equivalents, restricted cash, short-term investments, accounts receivable, accounts payable, short-term borrowings and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

During the 2011 and 2010 periods, there were no material adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

15. Risk Management and Hedging Activities

We are exposed to the impact of market fluctuations in the prices of NGLs and natural gas purchased as a result of our Empress operations in Canada. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt and commercial paper. We are exposed to foreign currency risk from our Canadian operations. We employ established policies and procedures to manage our risks associated with these market fluctuations, which may include the use of forward physical transactions as well as other derivatives, primarily around interest rate exposures.

At September 30, 2011, we had pay floating receive fixed interest rate swaps outstanding with a total notional principal amount of $1,689 million to hedge against changes in the fair value of our fixed-rate debt that arise as a result of changes in market interest rates. These swaps also allow us to transform a portion of the underlying cash flows related to our long-term fixed-rate debt securities into variable-rate debt in order to achieve our desired mix of fixed and variable-rate debt.

Our equity investment affiliate, DCP Midstream, also has risk exposures primarily associated with market prices of NGLs and natural gas. DCP Midstream manages these risks separate from Spectra Energy, and utilizes various risk management strategies, including the use of commodity derivatives.

Other than interest rate swaps described above, we did not have any significant derivatives outstanding during the nine months ended September 30, 2011.

16. Commitments and Contingencies

Environmental

We are subject to various U.S. federal, state and local laws and regulations, as well as Canadian federal and provincial laws, regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These laws and regulations can change from time to time, imposing new obligations on us.

Like others in the energy industry, we and our affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of our ongoing operations, sites formerly owned or used by us, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant international, federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, we or our affiliates could potentially be held responsible for contamination caused by other parties. In some instances, we may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliated operations.

Included in Deferred Credits and Other Liabilities Regulatory and Other on the Condensed Consolidated Balance Sheets are accruals related to extended environmental-related activities totaling $14 million at both September 30, 2011 and December 31, 2010. These accruals represent provisions for costs associated with remediation activities at some of our current and former sites, as well as other environmental contingent liabilities.

Litigation

Litigation and Legal Proceedings. We are involved in legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract and payment claims, some of which may involve substantial monetary amounts. We have insurance coverage for certain of these losses should they be incurred. We believe that the final disposition of these proceedings will not have a material effect on our consolidated results of operations, financial position or cash flows.

Legal costs related to the defense of loss contingencies are expensed as incurred. We had no material reserves recorded as of September 30, 2011 or December 31, 2010 related to litigation.

Other Commitments and Contingencies

See Note 17 for a discussion of guarantees and indemnifications.

17. Guarantees and Indemnifications

We have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. We enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Condensed Consolidated Balance Sheets. The possibility of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

We have issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. In connection with our spin-off from Duke Energy Corporation (Duke Energy) in 2007, certain guarantees that were previously issued by us were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments we could have been required to make under these performance guarantees as of September 30, 2011 was approximately $406 million, which has been indemnified by Duke Energy as discussed above. One of these performance guarantees, which has a maximum potential amount of future payment of $201 million, expires in 2028. The remaining guarantees have no contractual expirations.

We have also issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments in place at the time of our spin-off from Duke Energy. D/FD is one of the entities transferred to Duke Energy in connection with our spin-off. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that we could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners.

Westcoast Energy Inc. (Westcoast), a wholly owned subsidiary, has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third party performance; however, Duke Energy has indemnified us against any losses incurred under these guarantee arrangements. The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of unconsolidated entities and third-party entities as of September 30, 2011 was $37 million. Of these guarantees, $4 million expire in 2015 and the remaining have no contractual expirations.

We have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time depending on the nature of the claim. Our potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. We are unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

As of September 30, 2011, the amounts recorded for the guarantees and indemnifications, described above, including the indemnifications by Duke Energy to us, are not material, both individually and in the aggregate.

18. Sale of Spectra Energy Partners Units

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $218 million (net proceeds to Spectra Energy were $213 million), used to fund a portion of the acquisition of Big Sandy. See Note 2 for additional information on the acquisition of Big Sandy. The sale of the units decreased Spectra Energy s ownership in Spectra Energy Partners from 69% to 64%. In connection with the sale of the units, a $60 million gain ($38 million net of tax) to Additional Paid-in Capital and a $154 million increase in Equity Noncontrolling Interests were recorded in the second quarter of 2011.

The following table presents the effects of changes in our ownership interests in non-wholly owned consolidated subsidiaries:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2011	**2010**	**2011**	**2010**
	(in millions)			
Net Income Controlling Interests	$ 254	$ 197	$ 895	$ 729
Increase in Additional Paid-in Capital resulting from the sale of units of Spectra Energy Partners			38	
Total Net Income Controlling Interests and changes in Equity Controlling Interests	$ 254	$ 197	$ 933	$ 729

19. Employee Benefit Plans

Retirement Plans. We have a qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and non-qualified plans for various executive retirement and savings plans. Our Westcoast subsidiary maintains qualified and non-qualified contributory and non-contributory DB and defined contribution (DC) retirement plans covering substantially all employees of our Canadian operations.

23

Our policy is to fund our retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants or as required by legislation or plan terms. We made contributions of $15 million to our U.S. retirement plans in the nine-month period ended September 30, 2011 and $30 million for the same period in 2010. We made total contributions to the Canadian DC and qualified DB plans of $54 million during the nine-month period ended September 30, 2011 and $51 million during the same period in 2010. We anticipate that we will make total contributions of approximately $20 million to the U.S. plans and approximately $70 million to the Canadian plans in 2011.

Qualified Pension Plans Components of Net Periodic Pension Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
U.S.				
Service cost benefit earned	$ 3	$ 2	$ 10	$ 8
Interest cost on projected benefit obligation	6	6	18	19
Expected return on plan assets	(8)	(7)	(24)	(23)
Amortization of loss	3	2	8	6
Net periodic pension cost	$ 4	$ 3	$ 12	$ 10
Canada				
Service cost benefit earned	$ 5	$ 4	$ 15	$ 12
Interest cost on projected benefit obligation	11	11	35	34
Expected return on plan assets	(12)	(11)	(37)	(34)
Amortization of loss	7	5	20	13
Amortization of prior service costs			1	1
Net periodic pension cost	$ 11	$ 9	$ 34	$ 26

Non-Qualified Pension Benefits Plans Components of Net Periodic Pension Cost

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
U.S.				
Interest cost on projected benefit obligation	$	$	$ 1	$ 1
Net periodic pension cost	$	$	$ 1	$ 1
Canada				
Service cost benefit earned	$	$	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	4	4
Amortization of actuarial loss		1	1	1
Net periodic pension cost	$ 1	$ 2	$ 6	$ 6

Other Post-Retirement Benefit Plans. We provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Other Post-Retirement Benefit Plans Components of Net Periodic Benefit Cost

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
U.S.				
Service cost benefit earned	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	2	2	7	8
Expected return on plan assets	(1)	(1)	(3)	(4)
Amortization of net transition liability		1		3
Amortization of loss			1	1
Net periodic other post-retirement benefit cost	$ 2	$ 3	$ 6	$ 9
Canada				
Service cost benefit earned	$ 2	$ 1	$ 4	$ 3
Interest cost on accumulated post-retirement benefit obligation	1	2	5	5
Amortization of actuarial loss	1		1	
Amortization of prior service credit	(1)	(1)	(1)	(1)
Net periodic other post-retirement benefit cost	$ 3	$ 2	$ 9	$ 7

20. Consolidating Financial Information

Spectra Energy Corp has agreed to fully and unconditionally guarantee the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Energy Capital, LLC (Spectra Capital), a wholly owned, consolidated subsidiary. In accordance with Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all 100%-owned subsidiaries of Spectra Capital. This information should be read in conjunction with our accompanying Condensed Consolidated Financial Statements and notes thereto.

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,125	$ (2)	$ 1,123
Total operating expenses			767	(2)	765
Gains on sales of other assets and other, net			3		3
Operating income			361		361
Equity in earnings of unconsolidated affiliates			160		160
Equity in earnings of subsidiaries	254	368		(622)	
Other income and expenses, net		(1)	19		18
Interest expense		48	109		157
Earnings from continuing operations before income taxes	254	319	431	(622)	382
Income tax expense from continuing operations		65	43		108
Income from continuing operations	254	254	388	(622)	274
Income from discontinued operations, net of tax			7		7
Net income	254	254	395	(622)	281
Net income noncontrolling interests			27		27
Net income controlling interests	$ 254	$ 254	$ 368	$ (622)	$ 254

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 1,019	$	$ 1,019
Total operating expenses	8		670		678
Operating income (loss)	(8)		349		341
Equity in earnings of unconsolidated affiliates			98		98
Equity in earnings of subsidiaries	202	319		(521)	
Other income and expenses, net		(6)	13		7
Interest expense		51	108		159
Earnings from continuing operations before income taxes	194	262	352	(521)	287
Income tax expense (benefit) from continuing operations	(3)	60	12		69
Income from continuing operations	197	202	340	(521)	218
Income from discontinued operations, net of tax			1		1
Net income	197	202	341	(521)	219
Net income noncontrolling interests			22		22
Net income controlling interests	$ 197	$ 202	$ 319	$ (521)	$ 197

27

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 3,925	$ (2)	$ 3,923
Total operating expenses			2,612	(2)	2,610
Gains on sales of other assets and other, net			7		7
Operating income			1,320		1,320
Equity in earnings of unconsolidated affiliates			428		428
Equity in earnings of subsidiaries	895	1,303		(2,198)	
Other income and expenses, net		5	37		42
Interest expense		147	324		471
Earnings from continuing operations before income taxes	895	1,161	1,461	(2,198)	1,319
Income tax expense from continuing operations		266	106		372
Income from continuing operations	895	895	1,355	(2,198)	947
Income from discontinued operations, net of tax			23		23
Net income	895	895	1,378	(2,198)	970
Net income noncontrolling interests			75		75
Net income controlling interests	$ 895	$ 895	$ 1,303	$ (2,198)	$ 895

Spectra Energy Corp

Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total operating revenues	$	$	$ 3,562	$	$ 3,562
Total operating expenses	13	1	2,373		2,387
Operating income (loss)	(13)	(1)	1,189		1,175
Equity in earnings of unconsolidated affiliates			297		297
Equity in earnings of subsidiaries	737	1,101		(1,838)	
Other income and expenses, net		(4)	21		17
Interest expense		153	323		476
Earnings from continuing operations before income taxes	724	943	1,184	(1,838)	1,013
Income tax expense (benefit) from continuing operations	(5)	206	41		242
Income from continuing operations	729	737	1,143	(1,838)	771
Income from discontinued operations, net of tax			17		17
Net income	729	737	1,160	(1,838)	788
Net income noncontrolling interests			59		59
Net income controlling interests	$ 729	$ 737	$ 1,101	$ (1,838)	$ 729

29

Spectra Energy Corp

Condensed Consolidating Balance Sheet

September 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$ 4	$ 70	$	$ 74
Receivables (payables) consolidated subsidiaries	45	(46)	1		
Receivables other			886		886
Other current assets	14	17	617		648
Total current assets	59	(25)	1,574		1,608
Investments in and loans to unconsolidated affiliates		70	2,021		2,091
Investments in consolidated subsidiaries	11,408	14,556		(25,964)	
Advances receivable (payable) consolidated subsidiaries	(3,373)	3,985	(51)	(561)	
Goodwill			4,337		4,337
Other assets	38	106	364		508
Property, plant and equipment, net			17,591		17,591
Regulatory assets and deferred debits	3	6	1,071		1,080
Total Assets	$ 8,135	$ 18,698	$ 26,907	$ (26,525)	$ 27,215
Accounts payable other	$ 1	$ 92	$ 403	$	$ 496
Short-term borrowings and commercial paper		1,194	316	(561)	949
Accrued taxes payable (receivable)	(13)		96		83
Current maturities of long-term debt			64		64
Other current liabilities	65	59	797		921
Total current liabilities	53	1,345	1,676	(561)	2,513
Long-term debt		3,319	6,915		10,234
Deferred credits and other liabilities	143	2,626	2,675		5,444
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	7,939	11,408	14,556	(25,964)	7,939
Noncontrolling interests			827		827
Total equity	7,939	11,408	15,383	(25,964)	8,766
Total Liabilities and Equity	$ 8,135	$ 18,698	$ 26,907	$ (26,525)	$ 27,215

30

Spectra Energy Corp

Condensed Consolidating Balance Sheet

December 31, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash and cash equivalents	$	$	$ 130	$	$ 130
Receivables (payables) consolidated subsidiaries	(46)	208	(162)		
Receivables (payables) other	(4)	1	1,021		1,018
Other current assets	63	37	390		490
Total current assets	13	246	1,379		1,638
Investments in and loans to unconsolidated affiliates		74	1,959		2,033
Investments in consolidated subsidiaries	10,683	13,979		(24,662)	
Advances receivable (payable) consolidated subsidiaries	(2,835)	3,463	(57)	(571)	
Goodwill			4,305		4,305
Other assets	43	45	577		665
Property, plant and equipment, net			16,980		16,980
Regulatory assets and deferred debits		13	1,052		1,065
Total Assets	$ 7,904	$ 17,820	$ 26,195	$ (25,233)	$ 26,686
Accounts payable other	$ 1	$ 76	$ 292	$	$ 369
Short-term borrowings and commercial paper		1,250	157	(571)	836
Accrued taxes payable (receivable)	(145)	99	105		59
Current maturities of long-term debt		8	307		315
Other current liabilities	76	67	801		944
Total current liabilities	(68)	1,500	1,662	(571)	2,523
Long-term debt		3,302	6,867		10,169
Deferred credits and other liabilities	163	2,335	2,751		5,249
Preferred stock of subsidiaries			258		258
Equity					
Controlling interests	7,809	10,683	13,979	(24,662)	7,809
Noncontrolling interests			678		678
Total equity	7,809	10,683	14,657	(24,662)	8,487
Total Liabilities and Equity	$ 7,904	$ 17,820	$ 26,195	$ (25,233)	$ 26,686

31

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2011

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 895	$ 895	$ 1,378	$ (2,198)	$ 970
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			543		543
Equity in earnings of unconsolidated affiliates			(428)		(428)
Equity in earnings of subsidiaries	(895)	(1,303)		2,198	
Distributions received from unconsolidated affiliates			351		351
Other	(26)	240	37		251
Net cash provided by (used in) operating activities	(26)	(168)	1,881		1,687
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(1,299)		(1,299)
Investments in and loans to unconsolidated affiliates			(6)		(6)
Acquisitions, net of cash acquired			(390)		(390)
Purchases of held-to-maturity securities			(1,199)		(1,199)
Proceeds from sales and maturities of held-to-maturity securities			1,206		1,206
Purchases of available-for-sale securities			(938)		(938)
Proceeds from sales and maturities of available-for-sale securities			1,128		1,128
Distributions received from unconsolidated affiliates			6		6
Other			(54)		(54)
Net cash used in investing activities			(1,546)		(1,546)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			806		806
Payments for the redemption of long-term debt			(494)		(494)
Net increase (decrease) in short-term borrowings and commercial paper		(46)	193		147
Net decrease in revolving credit facilities borrowings			(289)		(289)
Distributions to noncontrolling interests			(74)		(74)
Proceeds from the issuance of Spectra Energy Partners common units			213		213
Dividends paid on common stock	(511)				(511)
Distributions and advances from (to) affiliates	517	218	(735)		
Other	20		(6)		14
Net cash provided by (used in) financing activities	26	172	(386)		(188)
Effect of exchange rate changes on cash			(9)		(9)

Net increase (decrease) in cash and cash equivalents		4	(60)		(56)
Cash and cash equivalents at beginning of period			130		130
Cash and cash equivalents at end of period	$	$ 4	$ 70	$	$ 74

Spectra Energy Corp

Condensed Consolidating Statements of Cash Flows

Nine Months Ended September 30, 2010

(Unaudited)

(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 729	$ 737	$ 1,160	$ (1,838)	$ 788
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization			493		493
Equity in earnings of unconsolidated affiliates			(297)		(297)
Equity in earnings of subsidiaries	(737)	(1,101)		1,838	
Distributions received from unconsolidated affiliates			303		303
Other	(215)	178	(243)		(280)
Net cash provided by (used in) operating activities	(223)	(186)	1,416		1,007
CASH FLOWS FROM INVESTING ACTIVITIES					
Capital expenditures			(881)		(881)
Investments in and loans to unconsolidated affiliates			(6)		(6)
Acquisitions, net of cash acquired			(492)		(492)
Purchases of held-to-maturity securities			(850)		(850)
Proceeds from sales and maturities of held-to-maturity securities			809		809
Purchases of available-for-sale securities			(19)		(19)
Proceeds from sales and maturities of available-for-sale securities			6		6
Distributions received from unconsolidated affiliates			12		12
Net cash used in investing activities			(1,421)		(1,421)
CASH FLOWS FROM FINANCING ACTIVITIES					
Proceeds from the issuance of long-term debt			479		479
Payments for the redemption of long-term debt			(346)		(346)
Net increase in short-term borrowings and commercial paper		799	22		821
Net decrease in revolving credit facilities borrowings			(10)		(10)
Distributions to noncontrolling interests			(54)		(54)
Dividends paid on common stock	(487)	(3)		3	(487)
Distributions and advances from (to) affiliates	709	(607)	(99)	(3)	
Other	1		2		3
Net cash provided by (used in) financing activities	223	189	(6)		406
Effect of exchange rate changes on cash			(2)		(2)
Net increase (decrease) in cash and cash equivalents		3	(13)		(10)
Cash and cash equivalents at beginning of period			166		166

Cash and cash equivalents at end of period	$		$	3	$	153	$		$	156

33

21. New Accounting Pronouncements

There were no significant accounting pronouncements adopted during the nine months ended September 30, 2011 that had a material impact on our consolidated results of operations, financial position or cash flows.

22. Subsequent Events

On October 28, 2011, Westcoast issued 150 million Canadian dollars (approximately $151 million as of the issuance date) aggregate principal amount of 3.883% notes due in 2021 and 150 million Canadian dollars (approximately $151 million as of the issuance date) aggregate principal amount of 4.791% notes due in 2041. Net proceeds from the offering will be used for general corporate purposes.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.
INTRODUCTION

Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the accompanying Condensed Consolidated Financial Statements.

Executive Overview

During 2011, our fee-based businesses at U.S. Transmission, Distribution and Western Canada Transmission & Processing generated increased earnings and operating cash flows by meeting the needs of our customers and from successful expansion projects. In addition, commodity prices have improved significantly compared to the same period in 2010 and have positively impacted our earnings in the first nine months of 2011.

We increased our quarterly dividend from $0.25 per share to $0.26 per share effective the first quarter of 2011. Based on the financial update that we provided to our Board of Directors in October 2011, the quarterly dividend was further increased to $0.28 per share effective the fourth quarter of 2011. We continue to anticipate our dividend payout ratio over time to be consistent with our targeted payout ratio, which is up to 65% of estimated annual net income from controlling interests per share of common stock.

For the three months ended September 30, 2011 and 2010, we reported net income from controlling interests of $254 million and $197 million, respectively. For the nine months ended September 30, 2011 and 2010, we reported net income from controlling interests of $895 million and $729 million, respectively. Earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, the positive impact of commodity prices on earnings from Field Services, a stronger Canadian dollar and colder weather at Distribution were slightly offset by higher corporate costs.

The highlights for the three and nine months ended September 30, 2011 include:

U.S. Transmission s earnings benefited from the successful execution of planned expansion projects,

Distribution s earnings reflect higher customer usage of natural gas due to colder weather early in 2011 and a stronger Canadian dollar, and also include higher operating costs,

Western Canada Transmission & Processing earnings increased mainly as a result of higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due mainly to higher sales prices in 2011 and a scheduled plant turnaround in 2010 and a stronger Canadian dollar, and

Field Services earnings increased as a result of higher commodity prices and lower interest expense, partially offset by higher operating expenses and the negative effects of severe weather.

34

In the first nine months of 2011, we had $1.3 billion of capital and investment expenditures. Excluding the acquisition of Big Sandy, we project approximately $2.0 billion of capital and investment expenditures for the full year, including expansion capital of approximately $1.2 billion.

In October 2011, we executed new five-year credit facilities at both Spectra Capital and Spectra Energy Partners that replaced existing facilities that were due to expire in 2012. We continue to have significant access to capital markets as a result of these and other available facilities and our strong financial position. We expect to continue to utilize commercial paper and revolving lines of credit to complement our ongoing cash flows to fund liquidity needs through the remainder of 2011. We also anticipate accessing the markets for other long-term financing to fund our ongoing capital expansion program.

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests and 0.1 million general partner units to Spectra Energy, resulting in total net proceeds of $218 million to Spectra Energy Partners ($213 million to Spectra Energy). The sale of the units decreased Spectra Energy s ownership in Spectra Energy Partners from 69% to 64%. On July 1, 2011, Spectra Energy Partners acquired Big Sandy from EQT for approximately $390 million in cash. See Notes 2 and 18 of Notes to Condensed Consolidated Financial Statements for further discussions.

RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Operating revenues	$ 1,123	$ 1,019	$ 3,923	$ 3,562
Operating expenses	765	678	2,610	2,387
Gains on sales of other assets and other, net	3		7	
Operating income	361	341	1,320	1,175
Other income and expenses	178	105	470	314
Interest expense	157	159	471	476
Earnings from continuing operations before income taxes	382	287	1,319	1,013
Income tax expense from continuing operations	108	69	372	242
Income from continuing operations	274	218	947	771
Income from discontinued operations, net of tax	7	1	23	17
Net income	281	219	970	788
Net income noncontrolling interests	27	22	75	59
Net income controlling interests	$ 254	$ 197	$ 895	$ 729

Three and Nine Months Ended September 30, 2011 Compared to Same Periods in 2010

Operating Revenues. Operating revenues for the three and nine months ended September 30, 2011 increased by $104 million, or 10%, and $361 million, or 10%, respectively, compared to the same periods in 2010. The increases were driven mainly by:

an increase in customer usage of natural gas due to colder weather in early 2011 at Distribution,

revenues from expansion projects at U.S. Transmission and Western Canada Transmission & Processing and the acquisitions of Bobcat Gas Storage (Bobcat) and Big Sandy at U.S. Transmission,

35

the effects of a stronger Canadian dollar on revenues at Distribution and Western Canada Transmission & Processing, and

higher NGL and other petroleum products sales volumes from the Empress operations due to higher demand for NGL and other petroleum products caused in part by colder weather as well as the effect of a scheduled plant turnaround in 2010, and higher NGL sales prices associated with the Empress operations in 2011 at Western Canada Transmission & Processing, partially offset by

lower natural gas prices passed through to customers at Distribution.

Operating Expenses. Operating expenses for the three and nine months ended September 30, 2011 increased by $87 million, or 13%, and $223 million, or 9%, respectively, compared to the same periods in 2010. The increases were driven mainly by:

higher volumes of natural gas sold as a result of colder weather in early 2011 at Distribution,

the effects of a stronger Canadian dollar at Distribution and Western Canada Transmission & Processing, and

higher volumes of natural gas purchased attributable to higher demand for NGL and other petroleum products caused in part by colder weather as well as the effect of a scheduled plant turnaround in 2010, and higher prices of natural gas purchased caused primarily by higher extraction premiums at the Empress operations at Western Canada Transmission & Processing, partially offset by

lower natural gas prices passed through to customers at Distribution.

Operating Income. Operating income for the three and nine months ended September 30, 2011 increased by $20 million, or 6%, and $145 million, or 12%, respectively, compared to the same periods in 2010. The increases were mainly driven by higher earnings from expansion projects at U.S. Transmission and Western Canada Transmission & Processing, the effects of a stronger Canadian dollar and an increase in customer usage of natural gas due to colder weather in early 2011 at Distribution.

Other Income and Expenses. Other income and expenses for the three and nine months ended September 30, 2011 increased by $73 million, or 70%, and $156 million, or 50%, respectively, compared to the same periods in 2010. The increases were attributable to higher equity earnings from Field Services mainly due to higher commodity prices, and lower interest and income tax expenses, partially offset by higher operating expenses and the negative effects of severe weather.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and nine months ended September 30, 2011 increased by $39 million and $130 million, respectively, compared to the same periods in 2010, as a result of higher earnings from continuing operations and higher effective tax rates.

The effective tax rates for income from continuing operations for the three-month periods ended September 30, 2011 and 2010 were 28% and 24%, respectively, and were also 28% and 24% for the nine-month periods. The lower effective tax rates in 2010 were primarily due to favorable tax settlements.

Income from Discontinued Operations, Net of Tax. Income from discontinued operations, net of tax for the three and nine months ended September 30, 2011 increased $6 million compared to the same periods in 2010. The 2011 results include recovery of losses incurred in the fourth quarter of 2010 related to a breach by a third party of certain scheduled propane deliveries to us. Higher income from propane deliveries and the recovery of losses in the nine-month period in 2011 were offset by a favorable income tax adjustment related to previously discontinued operations in the first quarter of 2010.

36

Net Income Noncontrolling Interests. Net income from noncontrolling interests for the three and nine months ended September 30, 2011 increased by $5 million and $16 million, respectively, compared to the same periods in 2010. The increases were mainly driven by an increase in the noncontrolling interests ownership percentage resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, primarily as a result of their acquisitions of an additional 24.5% in Gulfstream Natural Gas System, LLC (Gulfstream) in the fourth quarter of 2010 and Big Sandy in July 2011.

For a more detailed discussion of earnings drivers, see the segment discussions that follow.

Segment Results

We evaluate segment performance based on EBIT from continuing operations less noncontrolling interests related to those earnings. On a segment basis, EBIT represents earnings from continuing operations (both operating and non-operating) before interest and taxes, net of noncontrolling interests related to those earnings. Cash, cash equivalents and investments are managed centrally, so the gains and losses on foreign currency remeasurement, and interest and dividend income on those balances, are excluded from the segments   EBIT. We consider segment EBIT to be a good indicator of each segment s operating performance from its continuing operations, as it represents the results of our ownership interest in operations without regard to financing methods or capital structures.

Our segment EBIT may not be comparable to similarly titled measures of other companies because other companies may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table and detailed discussions follow:

EBIT by Business Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
U.S. Transmission	$ 235	$ 231	$ 757	$ 701
Distribution	50	63	305	282
Western Canada Transmission & Processing	119	90	373	278
Field Services	134	70	353	227
Total reportable segment EBIT	538	454	1,788	1,488
Other	(23)	(23)	(76)	(53)
Total reportable segment and other EBIT	515	431	1,712	1,435
Interest expense	157	159	471	476
Interest income and other (a)	24	15	78	54
Earnings from continuing operations before income taxes.	$ 382	$ 287	$ 1,319	$ 1,013

(a) Includes foreign currency transaction gains and losses and the add-back of noncontrolling interests related to segment EBIT. Noncontrolling interests as presented in the following segment-level discussions includes only noncontrolling interests related to EBIT of non-wholly owned subsidiaries. It does not include noncontrolling interests related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

U.S. Transmission

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Increase	2011	2010	Increase
	(in millions, except where noted)					
Operating revenues	$ 471	$ 442	$ 29	$ 1,411	$ 1,341	$ 70
Operating expenses						
Operating, maintenance and other	184	165	19	486	482	4
Depreciation and amortization	69	64	5	203	192	11
Gains on sales of other assets and other, net	4	1	3	8	1	7
Operating income	222	214	8	730	668	62
Other income and expenses	40	38	2	103	93	10
Noncontrolling interests	27	21	6	76	60	16
EBIT	$ 235	$ 231	$ 4	$ 757	$ 701	$ 56
Proportional throughput, TBtu (a)	659	624	35	2,085	2,009	76

(a) Trillion British thermal units. Revenues are not significantly affected by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

Three Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $29 million increase was driven by:

a $45 million increase from expansion projects and the acquisitions of Bobcat in August 2010 and Big Sandy in July 2011, partially offset by

a $9 million decrease from lower contracted volumes and rates as a result of contract renewals primarily at Ozark Gas Transmission.

Operating, Maintenance and Other. The $19 million increase was driven by:

a $15 million increase from higher costs, including pipeline integrity costs of $4 million due to higher levels of program activity, software costs of $5 million primarily related to a planned 2012 implementation of a new enterprise system, and an ad valorem tax benefit of $5 million in 2010, and

a $6 million increase from expansion projects and the acquisitions of Bobcat in August 2010 and Big Sandy in July 2011.

Depreciation and Amortization. The $5 million increase was mainly driven by expansion projects placed in service in 2010 and the acquisitions of Bobcat and Big Sandy.

Noncontrolling Interests. The $6 million increase was driven by an increase in the noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, as a result of their acquisitions of an additional 24.5 % in Gulfstream in the fourth quarter 2010 and Big Sandy in July 2011.

EBIT. The $4 million increase was mainly due to higher earnings from expansion projects mostly offset by higher operating costs.

Nine Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $70 million increase was driven mainly by:

a $110 million increase from expansion projects and the acquisitions of Bobcat in August 2010 and Big Sandy in July 2011, partially offset by

a $22 million decrease in recoveries of electric power and other costs passed through to customers,

a $10 million decrease in processing revenues associated with pipeline operations caused by lower volumes, and

a $16 million decrease from lower contracted volumes and rates as a result of contract renewals mainly at Ozark Gas Transmission and Algonquin Gas Transmission LLC.

Operating, Maintenance and Other. The $4 million increase was driven mainly by:

an $18 million increase from the expansion projects and the acquisitions of Bobcat and Big Sandy, and

an $11 million increase in project development costs, partially offset by

a $28 million decrease in electric power and other costs passed through to customers.

Depreciation and Amortization. The $11 million increase was mainly driven by expansion projects placed in service in 2010 and the acquisitions of Bobcat and Big Sandy.

Gains on sales of other assets and other, net. The $7 million increase was primarily driven by 2011 settlements related to customer bankruptcies.

Other Income and Expenses. The $10 million increase was primarily due to an indemnification of a tax liability related to the Bobcat acquisition.

Noncontrolling Interests. The $16 million increase was driven by an increase in the noncontrolling ownership interests resulting from the Spectra Energy Partners public sales of additional partner units in December 2010 and June 2011, and higher earnings from Spectra Energy Partners, as a result of their acquisitions of an additional 24.5% in Gulfstream in the fourth quarter 2010 and Big Sandy in July 2011.

EBIT. The $56 million increase was primarily due to higher earnings from expansion projects.

Matters Affecting Future U.S. Transmission Results

Our interstate pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines.

Legislative proposals have been introduced in Congress that would strengthen the PHMSA s enforcement and penalty authority, and expand the scope of its oversight. In August 2011, the PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. The PHMSA also has issued an Advisory Bulletin which among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Such legislative and regulatory changes may have a material adverse effect on our operations, earnings, financial condition and cash flows through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

Distribution

	Three Months Ended September 30, 2011	2010	Increase (Decrease)	Nine Months Ended September 30, 2011	2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 276	$ 261	$ 15	$ 1,347	$ 1,260	$ 87
Operating expenses						
Natural gas purchased	60	54	6	556	535	21
Operating, maintenance and other	112	96	16	326	298	28
Depreciation and amortization	54	48	6	160	145	15
EBIT	$ 50	$ 63	$ (13)	$ 305	$ 282	$ 23
Number of customers, thousands				1,352	1,334	18
Heating degree days, Fahrenheit	246	285	(39)	4,948	4,288	660
Pipeline throughput, TBtu	139	180	(41)	626	665	(39)
Canadian dollar exchange rate, average	0.98	1.04	(0.06)	0.98	1.04	(0.06)

Three Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $15 million increase was driven mainly by:

- a $16 million increase resulting from a stronger Canadian dollar, and
- a $6 million increase in customer usage of natural gas due to the return of direct-purchase customers to Union Gas as a natural gas supplier.

Natural Gas Purchased. The $6 million increase was driven primarily by higher volumes of natural gas sold due to the return of direct-purchase customers to Union Gas as a natural gas supplier.

Operating, Maintenance and Other. The $16 million increase was driven mainly by:

- an $11 million increase primarily due to higher employee benefits costs, and
- a $6 million increase resulting from a stronger Canadian dollar.

Depreciation and Amortization. The $6 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $13 million decrease was mainly a result of higher operating costs, primarily employee benefits costs, partially offset by a stronger Canadian dollar.

Nine Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $87 million increase was driven mainly by:

- a $130 million increase in customer usage of natural gas primarily due to weather that was more than 15% colder than in the same period in 2010, a $74 million increase resulting from a stronger Canadian dollar, and

an $11 million increase from growth in the number of customers, partially offset by

a $124 million decrease from lower natural gas prices passed through to customers. Prices charged to customers are based on the 12 month New York Mercantile Exchange (NYMEX) forecast.

Natural Gas Purchased. The $21 million increase was driven mainly by:

a $110 million increase due to higher volumes of natural gas sold primarily as a result of weather that was more than 15% colder than in the same period in 2010,

40

a $30 million increase resulting from a stronger Canadian dollar, and

a $7 million increase due to growth in the number of customers, partially offset by

a $124 million decrease from lower natural gas prices passed through to customers.

Operating, Maintenance and Other. The $28 million increase was driven mainly by:

an $18 million increase resulting from a stronger Canadian dollar, and

a $13 million increase primarily due to higher employee benefits costs.

Depreciation and Amortization. The $15 million increase was driven primarily by a stronger Canadian dollar.

EBIT. The $23 million increase was mainly a result of higher usage due to colder weather and a stronger Canadian dollar, partially offset by higher operating costs.

Western Canada Transmission & Processing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$ 392	$ 315	$ 77	$ 1,202	$ 959	$ 243
Operating expenses						
Natural gas and petroleum products purchased	86	62	24	275	189	86
Operating, maintenance and other	148	119	29	428	369	59
Depreciation and amortization	46	46		140	124	16
Loss on sales of other assets and other, net		(1)	1		(1)	1
Operating income	112	87	25	359	276	83
Other income and expenses	7	3	4	14	2	12
EBIT	$ 119	$ 90	$ 29	$ 373	$ 278	$ 95
Pipeline throughput, TBtu	180	151	29	529	451	78
Volumes processed, TBtu	187	164	23	537	490	47
Empress inlet volumes, TBtu	145	163	(18)	455	441	14
Canadian dollar exchange rate, average	0.98	1.04	(0.06)	0.98	1.04	(0.06)

Three Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $77 million increase was driven by:

a $26 million increase due to higher NGL sales prices associated with the Empress operations,

a $25 million increase in gathering and processing revenues due primarily to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson area, a $22 million increase as a result of a stronger Canadian dollar,

a $14 million increase in sales of natural gas to a related party at Empress, and

a $5 million increase from recovery of carbon and other non-income tax expense from customers, partially offset by

a $17 million decrease in NGL sales volumes at Empress caused mainly by reduced propane demand.

41

Natural Gas and Petroleum Products Purchased. The $24 million increase was driven by:

- a $15 million increase in volumes of natural gas purchases for extraction at Empress,
- a $12 million increase as a result of higher prices of natural gas and other petroleum products purchased for the Empress facility caused primarily by higher extraction premiums, and
- a $5 million increase due to a stronger Canadian dollars, partially offset by
- an $11 million decrease in volumes of make-up gas purchases at Empress mainly as a result of lower plant inlet volumes.

Operating, Maintenance and Other. The $29 million increase was driven by:

- an $8 million increase due primarily to higher maintenance costs related to timing,
- an $8 million increase due to a stronger Canadian dollar,
- a $5 million increase in carbon and other non-income tax expense, and
- a $3 million increase in employee benefits costs.

EBIT. The $29 million increase was driven mainly by higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due primarily to higher sales prices, and a stronger Canadian dollar.

Nine Months Ended September 30, 2011 Compared to Same Period in 2010

Operating Revenues. The $243 million increase was driven by:

- a $67 million increase as a result of a stronger Canadian dollar,
- a $63 million increase in gathering and processing revenues due primarily to contracted volumes from expansions associated with non-conventional supply discoveries in the Fort Nelson area,
- a $42 million increase due to higher NGL sales prices associated with the Empress operations,
- a $33 million increase in sales of natural gas to a related party at Empress,
- a $17 million increase from recovery of carbon and other non-income tax expense from customers, and

a $9 million increase due to higher NGL sales volumes associated with the Empress operations resulting from higher demand for NGL products caused in part by colder weather, as well as the effect of the scheduled plant turnaround in 2010.

Natural Gas and Petroleum Products Purchased. The $86 million increase was driven by:

a $35 million increase due primarily to increased volumes of natural gas purchases for extraction at Empress,

a $35 million increase as a result of higher prices of natural gas and other petroleum products purchased for the Empress facility caused primarily by higher extraction premiums, and

a $16 million increase due to a stronger Canadian dollar.

Operating, Maintenance and Other. The $59 million increase was driven by:

a $24 million increase due to a stronger Canadian dollar,

a $17 million increase in carbon and other non-income tax expense,

a $6 million increase due primarily to higher gathering and processing plant turnaround costs, a $5 million increase due primarily to higher maintenance costs, and

a $5 million increase in employee benefits costs, partially offset by

a $9 million decrease due to the Empress plant turnaround in 2010.

Depreciation and Amortization. The $16 million increase was driven mainly by expansion projects placed in service and maintenance capital incurred, as well as a stronger Canadian dollar.

Other Income and Expenses. The $12 million increase was driven primarily by higher allowance for funds used during construction (AFUDC) resulting from higher capital spent on expansion projects.

EBIT. The $95 million increase was driven mainly by higher gathering and processing earnings from expansions, higher earnings at the Empress NGL business due mainly to higher sales prices in 2011 and a plant turnaround in the second quarter of 2010, and a stronger Canadian dollar.

Field Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	$ 134	$ 70	$ 64	$ 353	$ 227	$ 126
EBIT	$ 134	$ 70	$ 64	$ 353	$ 227	$ 126
Natural gas gathered and processed/transported, TBtu/d (a,b)	7.1	7.1		6.9	6.9	
NGL production, MBbl/d (a,c)	392	378	14	375	364	11
Average natural gas price per MMBtu (d)	$ 4.19	$ 4.38	$ (0.19)	$ 4.21	$ 4.59	$ (0.38)
Average NGL price per gallon (e)	$ 1.24	$ 0.87	$ 0.37	$ 1.21	$ 0.96	$ 0.25
Average crude oil price per barrel (f)	$ 89.76	$ 76.20	$ 13.56	$ 95.48	$ 77.65	$ 17.83

(a) Reflects 100% of volumes.
(b) Trillion British thermal units per day.
(c) Thousand barrels per day.
(d) Million British thermal units. Average price based on NYMEX Henry Hub.
(e) Does not reflect results of commodity hedges.
(f) Average price based on NYMEX calendar month.

Three Months Ended September 30, 2011 Compared to Same Period in 2010

EBIT. Higher equity earnings of $64 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $62 million increase from commodity-sensitive processing arrangements due to increased NGL and crude oil prices, and

a $13 million increase in earnings from DCP Partners as a result of growth and mark-to-market gains on derivative instruments used to protect distributable cash flows, partially offset by an $11 million decrease due to higher operating expenses largely resulting from DCP Partners growth from acquisitions and increased repairs and maintenance costs.

Nine Months Ended September 30, 2011 Compared to Same Period in 2010

EBIT. Higher equity earnings of $126 million were mainly the result of the following variances, each representing our 50% ownership portion of the earnings drivers at DCP Midstream:

a $136 million increase from commodity-sensitive processing arrangements due to increased NGL and crude oil prices, net of decreased natural gas prices,

a $19 million increase attributable to a decrease in interest expense due to favorable rates during 2011,

a $13 million increase attributable to decreased income tax expense related to the de-recognition of certain deferred tax assets in the 2010 period, and

a $10 million increase in earnings from DCP Partners as a result of growth and mark-to-market gains on derivative instruments used to protect distributable cash flows, partially offset by

a $38 million decrease due to higher operating expenses largely resulting from DCP Partners growth from acquisitions, increased repairs and maintenance costs and increased benefits costs, and

an $11 million decrease in gathering and processing margins attributable to lower volumes and recoveries across higher-margin regions due to the impact of severe weather which reduced production and lowered margins.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	**2010**	**Increase (Decrease)**	**2011**	**2010**	**Increase (Decrease)**
	(in millions, except where noted)					
Operating revenues	$ 20	$ 15	$ 5	$ 53	$ 42	$ 11
Operating expenses	42	39	3	125	93	32
Operating loss	(22)	(24)	2	(72)	(51)	(21)
Other income and expenses	(1)	1	(2)	(4)	(2)	(2)
EBIT	$ (23)	$ (23)	$	$ (76)	$ (53)	$ (23)

Three Months Ended September 30, 2011 Compared to Same Period in 2010

EBIT. The EBIT results are in line with prior year quarter. The resolution of a corporate legal matter in 2010 was offset by higher benefit costs and captive insurance reserves in 2011.

Nine Months Ended September 30, 2011 Compared to Same Period in 2010

EBIT. The $23 million decrease in EBIT reflects an increase in reserves for captive insurance for miscellaneous loss events and higher corporate costs, including employee and retiree benefit costs, partially offset by an expense in the 2010 period for resolution of a corporate legal matter.

Impairment of Goodwill

We completed our annual goodwill impairment test as of April 1, 2011 and no impairments were identified. We primarily use a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions used in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, we incorporate expected long-term growth rates in key markets served by our operations, regulatory stability, the ability to renew contracts, commodity prices (where appropriate) and foreign currency exchange rates, as well as other factors that affect our revenue, expense and capital expenditure projections.

The long-term growth rates used for our reporting units reflect continued expansion of our assets, driven by new natural gas supplies such as shale gas in North America and increasing demand for natural gas transportation capacity on our pipeline systems primarily as a result of forecasted growth in natural gas-fired power plants. We assumed a weighted average long-term growth rate of 3.7% for our 2011 goodwill impairment analysis. Had we assumed a 100 basis point lower growth rate for each of our reporting units, except for the Distribution reporting unit, there would have been no impairment of goodwill. The Distribution reporting unit used a long-term growth rate assumption at the lower end of our growth rate range as a result of lower long-term projections of natural gas conversions and sustained mild economic growth in this region and therefore has a higher sensitivity to growth rate declines. Approximately $833 million of goodwill is allocated to our Distribution segment as of September 30, 2011.

We continue to monitor the effects of the economic downturn that global economies are currently facing on the long-term cost of capital utilized to calculate our reporting unit fair values. In evaluating our reporting units for our 2011 goodwill impairment analysis, we assumed weighted-average costs of capital ranging from 7.0% to 8.2% that market participants would use. Had we assumed a 100 basis point increase in the weighted- average cost of capital for each of our reporting units, there would have been no impairment of goodwill. For our regulated businesses in Canada, if an increase in the cost of capital occurred, we assume that the effect on the corresponding reporting unit s fair value would be ultimately offset by a similar increase in the reporting unit s regulated revenues since those rates include a component that is based on the reporting unit s cost of capital.

Based on the results of our annual impairment testing, the fair values of our reporting units at April 1, 2011 significantly exceeded their carrying values. No triggering events or changes in circumstances occurred during the period April 1, 2011 (our testing date) through September 30, 2011 that would warrant re-testing for goodwill impairment.

LIQUIDITY AND CAPITAL RESOURCES

Net working capital was negative $905 million as of September 30, 2011, which included short-term borrowings and commercial paper totaling $949 million and current maturities of long-term debt of $64 million. We will rely primarily upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, to fund our liquidity and capital requirements for the next 12 months.

In October 2011, we executed a new five-year $1.5 billion credit facility at Spectra Capital and a new five-year $700 million credit facility at Spectra Energy Partners. The new facilities replaced our existing $1.5 billion Spectra Capital and $500 million Spectra Energy Partners credit facilities which were both due to expire in 2012. With the new credit facilities, we have access to four revolving credit facilities, with total combined capital commitments of approximately $3.0 billion. Including the increased capacity at Spectra Energy Partners for the new credit facility, approximately $2.0 billion of the facilities were available at September 30, 2011. These facilities are used principally as back-stops for commercial paper programs or for the issuance of letters of credit. At Union Gas, we primarily use commercial paper to support our short-term working capital fluctuations. At Spectra Capital, Spectra Energy Partners and Westcoast, we primarily use commercial paper for temporary funding of our capital expenditures. We also utilize commercial paper, other variable-rate debt and interest rate swaps to achieve our desired mix of fixed and variable-rate debt. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and Financing Cash Flows and Liquidity for a discussion of effective shelf registrations.

Total debt balances since year-end 2010 have remained fairly flat at about $11.2 billion. Financing activities in 2011 included an increase in commercial paper balances and refinanced long-term debt at very favorable rates. Our debt-to-total-capitalization ratio was 56% at September 30, 2011.

Operating Cash Flows

Net cash provided by operating activities increased $680 million to $1,687 million for the nine months ended September 30, 2011 compared to the same period in 2010, driven mainly by:

lower refunds to Union Gas customers in the first half of 2011 for gas purchase costs collected in 2010 compared to refunds in 2010 for collections in 2009,

lower net tax payments in 2011 primarily as a result of the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which deferred a significant amount of tax payments to future periods, and

higher earnings across all segments in 2011.

Investing Cash Flows

Net cash flows used in investing activities increased $125 million to $1,546 million in the first nine months of 2011 compared to the same period in 2010. This change was driven primarily by higher capital and investment expenditures in 2011 from capital expansion projects in western Canada and the northeastern United States, partially offset by net proceeds from sales of Spectra Energy Partners AFS securities in 2011 that were previously pledged as collateral against its term debt that was repaid.

	Nine Months Ended September 30, 2011	2010
	(in millions)	
Capital and Investment Expenditures (a)		
U.S. Transmission	$ 534	$ 478
Distribution	200	126
Western Canada Transmission & Processing	515	260
Other	56	23
Total	$ 1,305	$ 887

(a) Excludes the acquisitions of Big Sandy in 2011 and the Bobcat assets and development project in 2010.

Capital and investment expenditures for the nine months ended September 30, 2011 consisted of $802 million for expansion projects and $503 million for maintenance and other projects.

Excluding the acquisition of Big Sandy discussed below, we project 2011 capital and investment expenditures of approximately $2.0 billion, consisting of approximately $0.8 billion for U.S. Transmission, $0.3 billion for Distribution and $0.9 billion for Western Canada Transmission & Processing. Total projected 2011 capital and investment expenditures include approximately $1.2 billion of expansion capital expenditures and $0.8 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. We continue to assess short and long-term market requirements and will adjust our capital plans as required.

On July 1, 2011, Spectra Energy Partners completed the acquisition of Big Sandy for approximately $390 million in cash. See Note 2 of Notes to Condensed Consolidated Financial Statements for further discussion.

Financing Cash Flows and Liquidity

Net cash used in financing activities totaled $188 million in the first nine months of 2011 compared to $406 million provided by financing activities in the first nine months of 2010. This change was driven mainly by:

a $147 million increase in short-term borrowings and commercial paper outstanding in 2011 compared to an $821 million increase in 2010, and

$23 million of net debt issuances in the 2011 period, including net revolving credit facility borrowings, compared to $123 million of net issuances in 2010, partially offset by

proceeds of $213 million in 2011 from the issuance of Spectra Energy Partners common units.

On June 9, 2011, Spectra Energy Partners issued $500 million aggregate principal amount of unsecured senior notes, including $250 million of 2.95% senior notes due in 2016 and $250 million of 4.60% senior notes

46

due in 2021. Net proceeds from the offering were used to repay all of the outstanding borrowings under Spectra Energy Partners term loan and a significant portion of the funds borrowed under its credit facility. The remaining balance of the proceeds was used for general corporate purposes.

On June 14, 2011, Spectra Energy Partners issued 7.2 million common units to the public, representing limited partner interests, and 0.1 million general partner units to Spectra Energy. Total net proceeds to Spectra Energy Partners were $218 million (net proceeds to Spectra Energy were $213 million), used to fund a portion of the acquisition of Big Sandy.

On June 21, 2011, Union Gas issued 300 million Canadian dollars (approximately $309 million as of the issuance date) of 4.88% notes due in 2041. Net proceeds from the offering were used for general corporate purposes, including refinancing of prior maturities of debt.

Available Credit Facilities and Restrictive Debt Covenants. In May 2011, Westcoast entered into a new 300 million Canadian dollar credit facility that expires in 2015, which replaced its 200 million Canadian dollar credit facility that was scheduled to expire in June 2011. In October 2011, Spectra Capital entered into a new $1.5 billion credit facility which replaced its $1.5 billion facility and Spectra Energy Partners entered into a new $700 million credit facility which replaced its $500 million credit facility. The new Spectra Capital and Spectra Energy Partners credit facilities expire in 2016 and replace facilities that were scheduled to expire in 2012. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of available credit facilities and related financial and other covenants.

The terms of our new Spectra Capital credit agreement require our consolidated debt-to-total-capitalization ratio, as defined in the agreement, to be 65% or lower. Per the terms of the new agreement, collateralized debt and Spectra Energy Partners debt and capitalization are excluded from the financial covenant. As of September 30, 2011, this ratio was 59%. Our equity and, as a result, this ratio, are sensitive to significant movements of the Canadian dollar relative to the U.S. dollar due to the significance of our Canadian operations. Based on the strength of our total capitalization as of September 30, 2011, it is unlikely that a material adverse effect would occur as a result of a weakened Canadian dollar.

Credit Ratings

	Standard and Poor s	Moody s Investor Service	Fitch Ratings	DBRS
As of September 30, 2011				
Spectra Capital (a)	BBB	Baa2	BBB	n/a
Texas Eastern Transmission, LP (a)	BBB+	Baa1	BBB+	n/a
Westcoast (a)	BBB+	n/a	n/a	A (low)
Union Gas (a)	BBB+	n/a	n/a	A
Maritimes & Northeast Pipeline, L.L.C. (a)	BBB	Baa3	n/a	n/a
M&N LP (b)	A	A2/A3	n/a	A
Spectra Energy Partners (a)	BBB	Baa3	BBB	n/a

(a) Represents senior unsecured credit rating.
(b) Represents senior secured credit rating. The A2 rating applies to M&N LP s 6.9% notes due 2019 and the A3 rating applies to its 4.34% notes due 2019.
n/a Indicates not applicable.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

Dividends. We continue to anticipate our dividend payout ratio over time to be consistent with our targeted payout ratio, which is up to 65% of estimated annual net income from controlling interests per share of common

47

stock. The actual payout ratio, however, may vary from year to year depending on earnings levels. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors. A dividend of $0.28 per common share was declared on October 25, 2011 and will be paid on December 12, 2011.

Other Financing Matters. On October 28, 2011, Westcoast issued 150 million Canadian dollars (approximately $151 million as of the issuance date) aggregate principal amount of 3.883% notes due in 2021 and 150 million Canadian dollars (approximately $151 million as of the issuance date) aggregate principal amount of 4.791% notes due in 2041. Net proceeds from the offering will be used for general corporate purposes.

Spectra Energy Corp and Spectra Capital have an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities, respectively. Spectra Energy Partners also has an effective shelf registration statement on file with the SEC to register the issuance of unspecified amounts of limited partner common units and various debt securities. In addition, as of the date of this report, certain of our subsidiaries in Canada had 1.2 billion Canadian dollars (approximately $1.2 billion) in the aggregate available for issuance in the Canadian market under debt shelf prospectuses.

OTHER ISSUES

New Accounting Pronouncements. See Note 21 of Notes to Condensed Consolidated Financial Statements for discussion.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Our exposure to market risk is described in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010. We believe our exposure to market risk has not changed materially since then.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported within the time periods specified by the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2011, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended September 30, 2011 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.
We have no material pending legal proceedings that are required to be disclosed hereunder. For information regarding other legal proceedings, including regulatory and environmental matters, see Notes 4 and 16 of Notes to Condensed Consolidated Financial Statements, which information is incorporated by reference into this Part II.

Item 1A. Risk Factors.
In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, which could materially affect our financial condition or future results. Other than the risk factor below, there have been no material changes to those risk factors.

We are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate pipeline operations are subject to pipeline safety regulation administered by the PHMSA of the U.S. Department of Transportation. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

In 2010, serious pipeline incidents on systems unrelated to ours focused the attention of Congress and the public on pipeline safety. Legislative proposals have been introduced in Congress that would strengthen the PHMSA s enforcement and penalty authority, and expand the scope of its oversight. In August 2011, the PHMSA initiated an Advance Notice of Proposed Rulemaking announcing its consideration of substantial revisions in its regulations to increase pipeline safety. The PHMSA also has issued guidance that states it will focus near-term enforcement efforts on recordkeeping and integrity management, following urgent National Transportation Safety Board recommendations related to pipeline pressure and recordkeeping. Because it is uncertain what legislation or regulatory changes will be enacted, we cannot determine the impact that such legislation or regulatory changes may have on our operations or financial condition at this time. Pipeline failures or failure to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by the PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have a material adverse effect on our operations, earnings, financial condition and cash flows.

Item 6. Exhibits.
Any agreements included as exhibits to this Form 10-Q may contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

were not intended to be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;

may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement;

may apply contract standards of materiality that are different from materiality under the applicable securities laws; and

were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement.

We acknowledge that, notwithstanding the inclusion of the foregoing cautionary statements, we are responsible for considering whether additional specific disclosures of material information regarding material contractual provisions are required to make the statements in this Form 10-Q not misleading.

(a) Exhibits

Exhibit Number	
10.1	Acknowledgement and Waiver Agreement, dated as of September 6, 2011, by and among ConocoPhillips, ConocoPhillips Gas Company, Spectra Energy Corp, Spectra Energy DEFS Holding, LLC and Spectra Energy DEFS Holding Corp (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on September 12, 2011)
10.2	Credit Agreement, dated as of October 18, 2011, among Spectra Energy Capital, LLC, as Borrower, Spectra Energy Corp, as Parent, the Initial Lenders named therein and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit No. 10.1 to Form 8-K of Spectra Energy Corp on October 20, 2011)
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase.
*101.LAB	XBRL Taxonomy Extension Label Linkbase.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

SIGNATURES

Pursuant to the requirements 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.

SPECTRA ENERGY CORP

Date: November 8, 2011

/s/ GREGORY L. EBEL
Gregory L. Ebel
President and Chief Executive Officer

Date: November 8, 2011

/s/ J. PATRICK REDDY
J. Patrick Reddy
Chief Financial Officer

50