Ellyn Lynne
Form 4
November 24, 2010

FORM 4

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

OMB APPROVAL

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STATEMENT OF CHANGES IN 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 *
Ellyn Lynne

(Last) (First) (Middle)

ONE ENERGY PLAZA

(Street)

DETROIT, MI 48226

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
DTE ENERGY CO [DTE]

3. Date of Earliest Transaction (Month/Day/Year)
11/23/2010

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

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Senior Vice President and CIO

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 Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	11/23/2010		M		10,000	A	$ 44.72	21,756	D	
Common Stock	11/23/2010		M		10,000	A	$ 43.42	31,756	D	
Common Stock	11/23/2010		S		20,000	D	$ 45.1624 (1)	11,756	D	
Common Stock								7,167.207 (2)	I	401k

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

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

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8 D S (I
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Stock Option (right to buy)	$ 44.72	11/23/2010		M			10,000	(3)	02/15/2015	Common Stock	10,000	
Stock Option (right to buy)	$ 43.42	11/23/2010		M			10,000	(4)	02/28/2016	Common Stock	10,000	

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Ellyn Lynne ONE ENERGY PLAZA DETROIT, MI 48226			Senior Vice President and CIO	

Signatures

/s/ Lisa A. Muschong Attorney-in-Fact	11/24/2010
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(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).

(1) Price shown is weighted average sale price. The sale transactions reported on this line ranged in price from $45.13 to $45.20. The reporting person hereby undertakes to provide upon request by the Commission staff, DTE Energy Company, or a security holder of DTE Energy Company, full information regarding the number of shares sold at each separate price.

(2)

Includes shares of DTE common stock acquired under the DTE Energy Company Savings and Stock Ownership Plan (the "Plan") as of a Plan statement dated as of November 23, 2010.

(3) The option vested in three equal annual installments beginning on February 15, 2006.

(4) The option vested in three equal annual installments beginning on February 28, 2007.

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. one;">2017

Weighted-average shares - basic

451,055

464,768

455,361

465,057

Dilution effect of stock appreciation rights and stock awards at end of period

2,059

1,977

1,781

1,695

Weighted-average shares - diluted

453,114

466,745

457,142

466,752

The following is a calculation of weighted-average shares excluded from diluted EPS due to the anti-dilutive effect:

	Three Months Ended	Six Months Ended

(In thousands)	June 30, 2018	2017	June 30, 2018	2017
Weighted-average stock appreciation rights and stock awards excluded from diluted EPS due to the anti-dilutive effect calculated using the treasury stock method	—	—	956	774

12. Income Taxes

On December 22, 2017, the U.S. enacted tax legislation referred to as the Tax Cuts and Jobs Act (the Tax Act) which significantly changes U.S. corporate income tax laws beginning, generally, in 2018. These changes include, among others, (i) a permanent reduction of the U.S. corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, (ii) elimination of the corporate alternative minimum tax, (iii) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (iv) limitation on the tax deduction for interest expense to 30% of adjusted taxable income, (v) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, and (vi) elimination of many business deductions and credits, including the domestic production activities deduction, the deduction for entertainment expenditures, and the deduction for certain executive compensation in excess of $1 million. The Company included the impacts of the Tax Act in the fourth quarter 2017 consolidated financial statements, and no changes were made to those provisional amounts during the first half of 2018. The Company will continue to examine the impact of this legislation and future regulations. Additional impacts from the enactment of the Tax Act will be recorded as they are identified during the measurement period as provided for in SAB No. 118, which extends up to one year from the enactment date. The 2018 tax provision reflects the law changes noted above, including the new corporate tax rate of 21%.

Income tax expense for the first six months of 2018 decreased $27.0 million compared to the first six months of 2017 due to a lower effective tax rate, partially offset by higher pre-tax income. The effective tax rates for the first six months of 2018 and 2017 were 24.5% and 38.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Act law changes that were effective January 1, 2018, partially offset by an increase in the blended state statutory tax rate as a result of changes in the Company's state apportionment factors due to the Eagle Ford Shale asset divestiture in February 2018.

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During the second quarter of 2018, the Company recorded an $18.4 million net reserve for unrecognized tax benefits related to alternative minimum tax (AMT) associated with uncertain tax positions and a $5.5 million liability for accrued interest associated with the uncertain tax positions. Any additional AMT payments could be utilized as credits against future regular tax liabilities and would be fully refunded from 2018 through 2021 under the new Tax Act. Accordingly, the uncertain tax positions identified would not have a material impact on the Company's effective tax rate.

13. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	June 30, 2018	December 31, 2017
Accounts receivable, net		
Trade accounts	$175,384	$ 215,511
Joint interest accounts	1,551	467
Other accounts	4,896	1,312
	181,831	217,290
Allowance for doubtful accounts	(1,286)	(1,286)
	$180,545	$ 216,004
Other assets		
Deferred compensation plan	$16,050	$ 14,966
Debt issuance costs	6,281	7,990
Income taxes receivable	3,047	—
Other accounts	202	56
	$25,580	$ 23,012
Accounts payable		
Trade accounts	$33,900	$ 7,815
Natural gas purchases	27,852	4,299
Royalty and other owners	28,743	39,207
Accrued transportation	40,031	51,433
Accrued capital costs	24,854	31,130
Taxes other than income	9,426	16,801
Deposits received for asset sales	5,000	81,500
Other accounts	66,172	5,860
	$235,978	$ 238,045
Accrued liabilities		
Employee benefits	$11,113	$ 20,645
Taxes other than income	1,562	550
Asset retirement obligations	1,000	4,952
Other accounts	142	1,294
	$13,817	$ 27,441
Other liabilities		
Deferred compensation plan	$27,849	$ 29,145
Other accounts	32,699	10,578
	$60,548	$ 39,723

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ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following review of operations for the three and six month periods ended June 30, 2018 and 2017 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management's Discussion and Analysis included in the Cabot Oil & Gas Corporation Annual Report on Form 10-K/A for the year ended December 31, 2017 (Form 10-K/A).

OVERVIEW

Financial and Operating Overview

Financial and operating results for the six months ended June 30, 2018 compared to the six months ended June 30, 2017 are as follows:

- Natural gas production increased 7.0 Bcf, or 2.1%, from 330.0 Bcf in 2017 to 337.0 Bcf in 2018, as a result of drilling and completion activities in Pennsylvania.
- Crude oil/condensate/NGL production decreased 1.4 Mmbbls, or 62%, from 2.2 Mmbbls in 2017 to 0.8 Mmbbls in 2018, as result of the sale of our Eagle Ford Shale assets in February 2018.
- Equivalent production decreased 1.1 Bcfe, or 0.3%, from 343.1 Bcfe, or 1,895.8 Mmcfe per day, in 2017 to 342.0 Bcfe, or 1,889.5 Mmcfe per day, in 2018. The decrease is primarily due to the sale of our Eagle Ford Shale assets in south Texas.
- Average realized natural gas price was $2.29 per Mcf, 9% lower than the $2.51 per Mcf realized in the comparable period of the prior year.
- Average realized crude oil price was $63.68 per Bbl, 39% higher than the $45.80 per Bbl realized in the comparable period of the prior year.
- Total capital expenditures were $329.9 million compared to $407.3 million in the comparable period of the prior year.
- Drilled 39 gross wells (39.0 net) with a success rate of 87.2% compared to 48 gross wells (42.1 net) with a success rate of 97.9% for the comparable period of the prior year.
- Completed 34 gross wells (34.0 net) in 2018 compared to 51 gross wells (48.0 net) in 2017.
- Average rig count during 2018 was approximately 3.0 rigs in the Marcellus Shale and approximately 1.0 rig in other areas, compared to an average rig count in the Marcellus Shale of approximately 2.0 rigs and approximately 1.0 rig in the Eagle Ford Shale during 2017.
- Received net proceeds of $646.9 million primarily related to the divestiture of our Eagle Ford Shale assets in south Texas in February 2018.
- Repurchased 20.0 million shares of our common stock for $481.5 million in 2018.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly commodity prices and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by pipeline capacity constraints, inventory storage levels, basis differentials, weather conditions and other factors. In addition, our realized prices are further impacted by our hedging activities. As a result, we cannot accurately predict future commodity prices and, therefore, cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues. We expect commodity prices to remain volatile. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. For information about the impact of realized commodity prices on our revenues, refer to "Results of Operations" below.

We account for our derivative instruments on a mark-to-market basis with changes in fair value recognized in operating revenues in the Condensed Consolidated Statement of Operations. As a result of these mark-to-market adjustments, we will likely experience volatility in our earnings due to commodity price volatility. Refer to "Impact of Derivative Instruments on Operating Revenues" below and Note 5 of the Notes to the Condensed Consolidated Financial Statements for more information.

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Commodity prices have remained volatile but have improved during 2018 compared to the fourth quarter of 2017. In the event that commodity prices significantly decline, management would test the recoverability of the carrying value of its oil and gas properties and, if necessary, record an impairment charge.

We believe that we are well-positioned to manage the challenges presented in a depressed commodity pricing environment, and that we can endure the continued volatility in current and future commodity prices by:

- Continuing to exercise discipline in our capital program with the expectation of funding our capital expenditures with cash on hand, operating cash flows, and if required, borrowings under our revolving credit facility.
- Continuing to optimize our drilling, completion and operational efficiencies, resulting in lower operating costs per unit of production.
- Continuing to manage our balance sheet, which we believe provides sufficient availability under our revolving credit facility and existing cash balances to meet our capital requirements and maintain compliance with our debt covenants.
- Continuing to manage price risk by strategically hedging our natural gas and crude oil production.

Outlook

Our full year 2018 capital spending program, the majority of which is allocated to the Marcellus Shale, includes approximately $890.0 million in capital expenditures related to our drilling and completion program, leasehold acquisitions and contributions of approximately $70.0 million to our equity method investments. All such expenditures are expected to be funded by existing cash, operating cash flow and if required, borrowings under our revolving credit facility.

In 2017, we drilled 91 gross wells (82.5 net) and completed 105 gross wells (94.2 net), of which 50 gross wells (44.3 net) were drilled but uncompleted in prior years. For the full year of 2018, we plan to drill approximately 85 gross wells (85.0 net) and complete 95 gross wells (95.0 net). We will continue to assess the natural gas environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the six months ended June 30, 2018 were from the sale of natural gas and crude oil production and proceeds from the sale of assets. These cash flows were primarily used to fund our capital expenditures, contributions to our equity method investments, interest payments on debt, repurchase of shares of our common stock and payment of dividends. See below for additional discussion and analysis of cash flow.

The borrowing base under the terms of our revolving credit facility is redetermined annually in April. In addition, either we or the banks may request an interim redetermination twice a year or in connection with certain acquisitions or divestitures of oil and gas properties. Effective April 18, 2018, the borrowing base and available commitments were reaffirmed at $3.2 billion and $1.7 billion, respectively. There were no borrowings outstanding under our revolving credit facility as of June 30, 2018.

On July 2, 2018, we closed on the sale of our oil and gas properties in the Haynesville Shale for $30.0 million. We do not expect this divestiture to have an impact on our borrowing base or available commitments.

A decline in commodity prices could result in the future reduction of our borrowing base and related commitments under the revolving credit facility. Unless commodity prices decline significantly from current levels, we do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. We believe that, with the existing cash on hand, operating cash flow and availability under our revolving credit facility, we have the capacity to fund our spending plans.

At June 30, 2018, we were in compliance with all restrictive financial covenants for both the revolving credit facility and senior notes. See our Form 10-K/A for further discussion of our restrictive financial covenants.

In July 2018, we repaid $237.0 million of maturities associated with our 6.51% weighted-average senior notes.

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Cash Flows

Our cash flows from operating activities, investing activities and financing activities are as follows:

	Six Months Ended June 30,	
(In thousands)	2018	2017
Cash flows provided by operating activities	$546,660	$529,946
Cash flows provided by (used in) investing activities	196,692	(405,484)
Cash flows used in financing activities	(482,405)	(106,470)
Net increase in cash and cash equivalents	$260,947	$17,992

Operating Activities. Operating cash flow fluctuations are substantially driven by commodity prices, changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been volatile, primarily as a result of supply and demand for natural gas and crude oil, pipeline infrastructure constraints, basis differentials, inventory storage levels and seasonal influences. In addition, fluctuations in cash flow may result in an increase or decrease in our capital expenditures. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities.

Our working capital is substantially influenced by the variables discussed above and fluctuates based on the timing and amount of borrowings and repayments under our revolving credit facility, repayments of debt, the timing of cash collections and payments on our trade accounts receivable and payable, respectively, repurchases of our securities and changes in the fair value of our commodity derivative activity. From time to time, our working capital will reflect a deficit, while at other times it will reflect a surplus. This fluctuation is not unusual. At June 30, 2018 and December 31, 2017, we had a working capital surplus of $396.7 million and $134.9 million, respectively.

Net cash provided by operating activities in the first six months of 2018 increased by $16.7 million compared to the first six months of 2017. This increase was primarily due to favorable changes in working capital and other assets and liabilities and lower cash operating expenses, partially offset by lower operating revenues and cash payments on derivative settlements. The decrease in operating revenues was primarily due to a decrease in realized natural gas prices and lower equivalent production, partially offset by higher crude oil prices. Average realized natural gas prices decreased by 9% and crude oil prices increased 39%, respectively, for the first six months of 2018 compared to the first six months of 2017. Equivalent production was flat for the first six months of 2018 compared to the first six months of 2017 due to higher natural gas production in the Marcellus Shale, offset by lower crude oil production due to the Eagle Ford Shale divestiture in February 2018.

See "Results of Operations" for additional information relative to commodity price, production and operating expense fluctuations.

Investing Activities. Cash flows provided by investing activities increased by $602.2 million for the first six months of 2018 compared to the first six months of 2017. The increase was due to $645.4 million higher proceeds from the sale of assets primarily due to the divestiture of our Eagle Ford Shale assets in February 2018 and $6.1 million lower capital expenditures. These increases were partially offset by $49.3 million higher capital contributions associated with our equity method investments.

Financing Activities. Cash flows used in financing activities increased by $375.9 million for the first six months of 2018 compared to the first six months of 2017. This increase was primarily due to $419.7 million of repurchases of our common stock in 2018 as compared to $68.3 million in 2017 and $22.1 million of higher dividend payments related to an increase in our dividend rate from $0.07 per share for the first six months of 2017 to $0.12 per share in the first six months of 2018.

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Capitalization

Information about our capitalization is as follows:

(In thousands)	June 30, 2018	December 31, 2017
Debt [(1)]	$1,522,572	$1,521,891
Stockholders' equity	2,154,174	2,523,905
Total capitalization	$3,676,746	$4,045,796
Debt to total capitalization	41 %	38 %
Cash and cash equivalents	$740,994	$480,047

(1) Includes $304.0 million of current portion of long-term debt at June 30, 2018 and December 31, 2017, respectively.

During the first six months of 2018, we repurchased 20.0 million shares of our common stock for $481.5 million.

During the first six months of 2018 and 2017, we paid dividends of $54.7 million ($0.12 per share) and $32.6 million ($0.07 per share), respectively, on our common stock.

In January 2018, the Board of Directors approved an increase in the quarterly dividend on our common stock from $0.05 per share to $0.06 per share.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital expenditures, excluding any significant property acquisitions, with cash generated from operations, and if required, borrowings under our revolving credit facility. We budget these expenditures based on our projected cash flows for the year.

The following table presents major components of our capital and exploration expenditures:

	Six Months Ended June 30,	
(In thousands)	2018	2017
Capital expenditures		
Drilling and facilities	$313,900	$310,308
Leasehold acquisitions	11,344	91,497
Pipeline and gathering	—	462
Other	4,667	5,022
	329,911	407,289
Exploration expenditures[(1)]	58,117	10,157
Total	$388,028	$417,446

(1) Exploration expenditures include $51.1 million and $2.8 million of exploratory dry hole expenditures for the first six months of 2018 and 2017, respectively.

For the full year of 2018, we plan to drill approximately 85 gross wells (85.0 net) and complete 95 gross wells (95.0 net). In 2018, our drilling program includes approximately $890.0 million in total capital expenditures compared to $757.2 million in 2017. See “Outlook” for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. There have been no material changes to our contractual obligations described under “Transportation and Gathering Agreements” and “Lease Commitments” as disclosed in Note 9 of the Notes to the Consolidated Financial Statements and the obligations described under “Contractual

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Obligations" in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Form 10-K/A.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our Condensed Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Form 10-K/A for further discussion of our critical accounting policies.

Recently Adopted and Recently Issued Accounting Pronouncements

Refer to Note 1 of the Notes to the Condensed Consolidated Financial Statements, "Financial Statement Presentation," for a discussion of new accounting pronouncements that affect us.

Results of Operations

Second Quarters of 2018 and 2017 Compared

We reported net income in the second quarter of 2018 of $42.4 million, or $0.09 per share, compared to net income of $21.5 million, or $0.05 per share, in the second quarter of 2017. The increase in net income was primarily due to lower operating expenses, partially offset by lower operating revenues.

Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Three Months Ended June 30,		Variance	
Revenue Variances (In thousands)	2018	2017	Amount	Percent
Natural gas	$364,660	$395,328	$(30,668)	(8)%
Crude oil and condensate	—	44,625	(44,625)	(100)%
Gain (loss) on derivative instruments	(3,668)	13,805	(17,473)	(127)%
Brokered natural gas	92,576	4,037	88,539	2,193 %
Other	(121)	2,662	(2,783)	(105)%
	$453,447	$460,457	$(7,010)	(2)%

	Three Months Ended June 30,		Variance		Increase (Decrease) (In thousands)
	2018	2017	Amount	Percent	
Price Variances					
Natural gas	$2.11	$2.38	$(0.27)	(11)%	$ (45,424)
Volume Variances					
Natural gas (Bcf)	172.4	166.2	6.2	4 %	$ 14,756
Total					$ (30,668)

Natural Gas Revenues

The decrease in natural gas revenues of $30.7 million was due to lower natural gas prices partially offset by higher production. The increase in production was a result of an increase in our drilling and completion activities in Pennsylvania.

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Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $44.6 million was due to lower crude oil production as a result of the sale of our Eagle Ford Shale assets in February 2018.

Impact of Derivative Instruments on Operating Revenues

	Three Months Ended June 30,	
(In thousands)	2018	2017
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$5,819	$1,204
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	(9,487)	12,601
	$(3,668)	$13,805

Brokered Natural Gas

	Three Months Ended June 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Brokered natural gas sales	$92,576	$4,037		
Brokered natural gas purchases	80,082	3,419		
Brokered natural gas margin	$12,494	$618	$11,876	1,922%

The $11.9 million increase in brokered natural gas margin is a result of an increase in brokered activity. This increase was due to higher volumes associated with natural gas purchases that were required to satisfy certain sales obligations.

Operating and Other Expenses

	Three Months Ended June 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Operating and Other Expenses				
Direct operations	$15,657	$27,262	$(11,605)	(43)%
Transportation and gathering	114,189	120,544	(6,355)	(5)%
Brokered natural gas	80,082	3,419	76,663	2,242 %
Taxes other than income	5,392	8,310	(2,918)	(35)%
Exploration	54,500	3,959	50,541	1,277 %
Depreciation, depletion and amortization	84,910	144,322	(59,412)	(41)%
Impairment of oil and gas properties and other assets	—	68,555	(68,555)	(100)%
General and administrative	21,228	23,957	(2,729)	(11)%
	$375,958	$400,328	$(24,370)	(6)%
Loss on equity method investments	$(4)	$(1,286)	$(1,282)	(100)%
Gain (loss) on sale of assets	544	(1,403)	(1,947)	(139)%
Interest expense, net	23,328	20,619	2,709	13 %
Other (income) expense	118	(315)	433	(137)%
Income tax expense	12,152	15,609	(3,457)	(22)%

Total costs and expenses from operations decreased by $24.4 million, or 6%, in the second quarter of 2018 compared to the same period of 2017. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $11.6 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018.

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- Transportation and gathering decreased $6.4 million due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018.
- Brokered natural gas increased $76.7 million. See the preceding table titled “Brokered Natural Gas” for further analysis.
- Taxes other than income decreased $2.9 million primarily due to $2.8 million lower production taxes and $1.8 million lower ad valorem taxes both resulting from the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018. These decreases were partially offset by a $1.4 million increase in drilling impact fees as a result of an increase in drilling activity in Pennsylvania.
- Exploration increased $50.5 million due to an increase in exploratory dry hole costs of $51.1 million. The exploratory dry hole costs in 2018 relate to our activities in one of our exploratory areas and our decision to cease further activity in that area based on the results of those activities.
- Depreciation, depletion and amortization decreased $59.4 million, primarily due to lower DD&A of $52.2 million, lower amortization of unproved properties of $6.0 million and lower accretion of $1.2 million in the second quarter of 2018. DD&A decreased $49.9 million due to a lower DD&A rate of $0.45 per Mcfe for the second quarter of 2018 compared to $0.73 per Mcfe for the second quarter of 2017, primarily due to the sale of higher rate fields in Eagle Ford Shale and West Virginia and positive reserve revisions related to our year end reserve estimation process.
- Impairment of oil and gas properties decreased $68.6 million due to the impairment of oil and gas properties and related pipeline assets in West Virginia, Virginia and Ohio associated with the proposed sale of these properties in the second quarter of 2017.
- General and administrative decreased $2.7 million due to $4.4 million of lower stock-based compensation expense associated with certain of our market-based performance awards. The remaining changes in other general and administrative expenses were not individually significant.

Interest Expense, net

Interest expense, net increased $2.7 million due to $5.5 million higher interest expense related to uncertain tax positions partially offset by $2.2 million higher interest income.

Income Tax Expense

Income tax expense decreased $3.5 million due to a lower effective tax rate, partially offset by higher pre-tax income. The effective tax rates for the second quarter of 2018 and 2017 were 22.3% and 42.0%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Cuts and Jobs Act law changes that were effective January 1, 2018, as well as the impact of non-recurring discrete items recorded during the second quarter of 2018 as compared to the second quarter of 2017.

First Six Months of 2018 and 2017 Compared

We reported net income in the first six months of 2018 of $159.7 million, or $0.35 per share, compared to net income of $127.2 million, or $0.27 per share, in the first six months of 2017. The increase in net income was primarily due to lower operating expenses and income tax expense, partially offset by lower operating revenues and higher loss on sale of assets.

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Revenue, Price and Volume Variances

Our revenues vary from year to year as a result of changes in commodity prices and production volumes. Below is a discussion of revenue, price and volume variances.

	Six Months Ended June 30,		Variance	
Revenue Variances (In thousands)	2018	2017	Amount	Percent
Natural gas	$776,768	$828,770	$(52,002)	(6)%
Crude oil and condensate	48,722	87,616	(38,894)	(44)%
Gain (loss) on derivative instruments	1,909	47,190	(45,281)	(96)%
Brokered natural gas	97,526	8,732	88,794	1,017 %
Other	1,749	5,994	(4,245)	(71)%
	$926,674	$978,302	$(51,628)	(5)%

	Six Months Ended June 30,		Variance		Increase (Decrease)
	2018	2017	Amount	Percent	(In thousands)
Price Variances					
Natural gas	$2.30	$2.51	$(0.21)	(8)%	$ (69,572)
Crude oil and condensate	$64.68	$45.29	$19.39	43 %	14,593
Total					$ (54,979)
Volume Variances					
Natural gas (Bcf)	337.0	330.0	7.0	2 %	$ 17,570
Crude oil and condensate (Mbbl)	754	1,935	(1,181)	(61)%	(53,487)
Total					$ (35,917)

Natural Gas Revenues

The decrease in natural gas revenues of $52.0 million was due to lower natural gas prices partially offset by an increase in production. The increase in production was a result of an increase in our drilling and completion activities in Pennsylvania.

Crude Oil and Condensate Revenues

The decrease in crude oil and condensate revenues of $38.9 million was primarily due to lower production partially offset by higher crude oil prices. The decrease in production was the result of the sale of our Eagle Ford Shale assets in February 2018.

Impact of Derivative Instruments on Operating Revenues

	Six Months Ended June 30,	
(In thousands)	2018	2017
Cash received (paid) on settlement of derivative instruments		
Gain (loss) on derivative instruments	$(20,312)	$(319)
Non-cash gain (loss) on derivative instruments		
Gain (loss) on derivative instruments	22,221	47,509
	$1,909	$47,190

Brokered Natural Gas

	Six Months Ended June 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Brokered natural gas sales	$97,526	$8,732		
Brokered natural gas purchases	$85,032	$7,465		
Brokered natural gas margin	$12,494	$1,267	$11,227	886 %

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The $11.2 million increase in brokered natural gas margin is a result of an increase in brokered activity. This increase was due to higher volumes associated with natural gas purchases that were required to satisfy certain sales obligations.

Operating and Other Expenses

	Six Months Ended June 30,		Variance	
(In thousands)	2018	2017	Amount	Percent
Operating and Other Expenses				
Direct operations	$35,727	$51,903	$(16,176)	(31)%
Transportation and gathering	226,314	244,018	(17,704)	(7)%
Brokered natural gas	85,032	7,465	77,567	1,039 %
Taxes other than income	12,582	17,368	(4,786)	(28)%
Exploration	58,117	10,157	47,960	472 %
Depreciation, depletion and amortization	167,038	279,422	(112,384)	(40)%
Impairment of oil and gas properties and other assets	—	68,555	(68,555)	100 %
General and administrative	45,288	47,659	(2,371)	(5)%
	$630,098	$726,547	$(96,449)	(13)%
Loss on equity method investments	$(998)	$(2,569)	$(1,571)	(61)%
Gain (loss) on sale of assets	(40,505)	(1,626)	38,879	2,391 %
Interest expense, net	43,386	41,390	1,996	5 %
Other (income) expense	232	109	123	113 %
Income tax expense	51,793	78,814	(27,021)	(34)%

Total costs and expenses from operations decreased by $96.4 million, or 13%, in the first six months of 2018 compared to the same period of 2017. The primary reasons for this fluctuation are as follows:

- Direct operations decreased $16.2 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and the Eagle Ford Shale assets in the first quarter of 2018.
- Transportation and gathering decreased $17.7 million largely due to the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and the Eagle Ford Shale assets in the first quarter of 2018.
- Brokered natural gas increased $77.6 million. See the preceding table titled “Brokered Natural Gas” for further analysis.
- Taxes other than income decreased $4.8 million primarily due to $2.8 million lower production taxes and $4.4 million lower ad valorem taxes both resulting from the sale of our oil and gas properties in West Virginia in the third quarter of 2017 and Eagle Ford Shale assets in the first quarter of 2018. These decreases were partially offset by a $2.2 million increase in drilling impact fees as a result of an increase in drilling activity in Pennsylvania.
- Exploration increased $48.0 million due to an increase in exploratory dry hole costs of $51.1 million. The exploratory dry hole costs in 2018 relate to our activities in one of our exploratory areas and our decision to cease further activity in that area based on the results of those activities.
- Depreciation, depletion and amortization decreased $112.4 million primarily due to lower DD&A of $101.3 million, lower amortization of unproved properties of $8.7 million and lower accretion of $2.4 million. The decrease in DD&A was primarily due to a decrease of $98.0 million related to a lower DD&A rate of $0.44 per Mcfe for the first six months of 2018 compared to $0.73 per Mcfe for the first six months of 2017. The lower DD&A rate was due to the cessation of DD&A related to the sale of our higher rate Eagle Ford Shale assets that were classified as held for sale in the fourth quarter of 2017 and positive reserve revisions related to our year end reserve estimation process.
- Impairment of oil and gas properties decreased $68.6 million due to the impairment of oil and gas properties and related pipeline assets in West Virginia, Virginia and Ohio associated with the proposed sale of these properties in the second quarter of 2017.

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Explanation of Responses:

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- General and administrative decreased $2.4 million primarily due to lower stock-based compensation cost of $7.2 million associated with certain of our market-based performance awards offset by $3.0 million higher employee costs and professional services. The remaining differences were not individually significant.

Loss on Sale of Assets

Loss on sale of assets increased $38.9 million due to the sale of our Eagle Ford Shale assets in the first quarter of 2018.

Interest Expense, net

Interest expense, net increased $2.0 million due to $5.5 million higher interest expense related to uncertain tax positions partially offset by $3.1 million higher interest income.

Income Tax Expense

Income tax expense decreased $27.0 million due to a lower effective tax rate, partially offset by slightly higher pre-tax income. The effective tax rates for the first six months of 2018 and 2017 were 24.5% and 38.2%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Cuts and Jobs Act law changes that were effective January 1, 2018, partially offset by an increase in the blended state statutory tax rate as a result of changes in our state apportionment factors due to the Eagle Ford Shale asset divestiture in February 2018.

Forward-Looking Information

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging and risk management activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words “expect,” “project,” “estimate,” “believe,” “anticipate,” “intend,” “budge “plan,” “forecast,” “target,” “predict,” “may,” “should,” “could,” “will” and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and crude oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See “Risk Factors” in Item 1A of the Form 10-K/A for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Market Risk

Our primary market risk is exposure to natural gas and crude oil prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Risk Management Activities

Our risk management strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets through the use of commodity derivatives. A committee that consists of members of senior management oversees our risk management activities. Our commodity derivatives generally cover a portion of our production and provide only partial price protection by limiting the benefit to us of increases in prices, while protecting us in the event of price declines. Further, if any of our counterparties defaulted, this protection might be limited as we might not receive the full benefit of our commodity derivatives. Please read the discussion below as well as Note 6 of the Notes to the Consolidated Financial Statements in our Form 10-K/A for a more detailed discussion of our derivative and risk management activities.

Periodically, we enter into commodity derivatives including collar, swap and basis swap agreements, to protect against exposure to price declines related to our natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity derivatives other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the

NYMEX gas and crude oil futures.

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As of June 30, 2018, we had the following outstanding financial commodity derivatives:

Type of Contract	Volume	Contract Period	Swaps Weighted-Average	Basis Swaps Weighted-Average	Estimated Fair Value Asset (Liability) (In thousands)
Natural gas (Leidy)	17.9 Bcf	Jul. 2018 - Dec. 2018		$ (0.69)	$ (408)
Natural gas (Transco)	16.0 Bcf	Jul. 2018 - Dec. 2019		$ 0.42	3,904
Natural gas (NYMEX)	46.5 Bcf	Jul. 2018 - Dec. 2018	$ 2.93		(5,365)
Natural gas (NYMEX)	6.0 Bcf	Jul. 2018 - Oct. 2018	$ 3.10		496
					$ (1,373)

As of June 30, 2018, we had the following outstanding physical commodity derivatives:

Type of Contract	Volume	Contract Period	Weighted-Average Fixed Price	Estimated Fair Value Asset (Liability) (In thousands)
Natural gas purchase	6.0 Bcf	Jul. 2018 - Oct. 2018	$ 3.67	$ (4,827)
				$ (4,827)

In the above tables, natural gas prices are stated per Mcf.

The amounts set forth in the tables above represent our total unrealized derivative position at June 30, 2018 and exclude the impact of non-performance risk. Non-performance risk is considered in the fair value of our derivative instruments that are recorded in our Condensed Consolidated Financial Statements and is primarily evaluated by reviewing credit default swap spreads for the various financial institutions with which we have derivative contracts, while our non-performance risk is evaluated using a market credit spread provided by one of our banks.

During the first six months of 2018, natural gas basis swaps covered 21.4 Bcf, or 6%, of natural gas production at an average price of $2.56 per Mcf. Natural gas swaps covered 45.2 Bcf, or 13%, of natural gas production at an average price of $2.95 per Mcf. Crude oil collars with floor prices of $55.00 per Bbl and ceiling prices ranging from $63.35 to $63.80 per Bbl covered 0.2 Mmbbl, or 33%, of crude oil production at an average price of $63.62 per Bbl.

In January 2018, as a result of the pending sale of our Eagle Ford Shale assets, we terminated all of our outstanding crude oil financial derivatives for $0.3 million.

We are exposed to market risk on commodity derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. Our counterparties are primarily commercial banks and financial service institutions that management believes present minimal credit risk and our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses related to non-performance risk of our counterparties and we do not anticipate any material impact on our financial results due to non-performance by third parties. However, we cannot be certain that we will not experience such losses in the future.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future commodity prices. See “Forward-Looking Information” for further details.

Fair Value of Other Financial Instruments

The estimated fair value of other financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amount reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents approximates fair value due to the short-term maturities of these instruments.

We use available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or

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discount) is determined by comparing our senior notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all senior notes and the revolving credit facility is based on interest rates currently available to us.

The carrying amount and fair value of debt is as follows:

	June 30, 2018		December 31, 2017	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$1,522,572	$1,486,210	$1,521,891	$1,527,624
Current maturities	(304,000)	(305,966)	(304,000)	(312,055)
Long-term debt, excluding current maturities	$1,218,572	$1,180,244	$1,217,891	$1,215,569

ITEM 4. Controls and Procedures

As of June 30, 2018, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the “Exchange Act”). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission’s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

On January 1, 2018, the Company implemented a new Enterprise Resource Planning (ERP) system designed to upgrade our technology and improve our financial and operational information. The Company has modified its existing internal controls related to the ERP system implementation. While the Company believes that this new system and related changes to internal controls will ultimately strengthen its internal control over financial reporting, there are inherent risks in implementing a new ERP system and the Company will continue to evaluate and test these control changes in order to provide certification as of its fiscal year ending December 31, 2018 on the effectiveness, in all material respects, of its internal control over financial reporting.

With the exception of the ERP implementation described above, there were no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2018 that have materially affected, or are reasonably likely to materially effect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

Legal Matters

The information set forth under the heading “Legal Matters” in Note 8 of the Notes to Condensed Consolidated Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

Environmental Matters

From time to time we receive notices of violation from governmental and regulatory authorities in areas in which we operate relating to alleged violations of environmental statutes or the rules and regulations promulgated thereunder. While we cannot predict with certainty whether these notices of violation will result in fines and/or penalties, if fines and/or penalties are imposed, they may result in monetary sanctions, individually or in the aggregate, in excess of $100,000.

ITEM 1A. Risk Factors

For additional information about the risk factors that affect us, see Item 1A of Part I of our Annual Report on Form 10-K/A for the year ended December 31, 2017.

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ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. In February 2018, the Board of Directors authorized an increase of 25.0 million shares to our share repurchase program. There is no expiration date associated with the authorization. The shares included in the table below were purchased on the open market and were held as treasury stock as of June 30, 2018.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
April 2018 (1)	1,645,998	$ 23.40	1,645,998	20,080,295
May 2018	—	—	—	20,080,295
June 2018 (2)	10,000,000	$ 23.56	10,000,000	10,080,295
Total	11,645,998		11,645,998	

(1) Shares were repurchased under a Rule 10b5-1 Plan that was in effect from April 1, 2018 to April 26, 2018.

(2) Includes 2.6 million shares that were repurchased prior to June 30, 2018 and settled in July 2018.

ITEM 6. Exhibits

Exhibit Number	Description
31.1	302 Certification — Chairman, President and Chief Executive Officer.
31.2	302 Certification — Executive Vice President and Chief Financial Officer.
32.1	906 Certification.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

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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.

CABOT OIL & GAS CORPORATION
(Registrant)

July 27, 2018	By:	/s/ DAN O. DINGES
		Dan O. Dinges
		Chairman, President and Chief Executive Officer
		(Principal Executive Officer)
July 27, 2018	By:	/s/ SCOTT C. SCHROEDER
		Scott C. Schroeder
		Executive Vice President and Chief Financial Officer
		(Principal Financial Officer)
July 27, 2018	By:	/s/ TODD M. ROEMER
		Todd M. Roemer
		Vice President and Controller
		(Principal Accounting Officer)

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