National Storage Affiliates Trust
Form SC 13G/A
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TEXT

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
SCHEDULE 13G
Under the Securities Exchange Act of 1934

Amendment # 2

Name of Issuer: National Storage Affiliates Trust

Title of Class
of Securities: Common Stock

CUSIP Number: 637870106

1) NAME AND I.R.S. IDENTIFICATION NO. OF REPORTING PERSON

Prudential Financial, Inc. 22-3703799

2.) MEMBER OF A GROUP: (a) N/A
(b) N/A

3) SEC USE ONLY:

4) PLACE OF ORGANIZATION: New Jersey

NUMBER OF SHARES BENEFICIALLY OWNED BY REPORTING PERSON WITH:

5) Sole Voting Power: 23,012 See Exhibit A
6) Shared Voting Power: 1,791,935 See Exhibit A
7) Sole Dispositive Power: 23,012 See Exhibit A
8) Shared Dispositive Power: 1,791,935 See Exhibit A

9) AGGREGATE AMOUNT BENEFICIALLY OWNED: 1,814,947 See Exhibit A

10) AGGREGATE AMOUNT IN ROW (9) EXCLUDES SHARES: Not Applicable

11) PERCENT OF CLASS REPRESENTED BY AMOUNT IN ROW (9): 3.6 See Exhibit A

12) TYPE OF REPORTING PERSON: HC

ITEM 1(a). NAME OF ISSUER:

National Storage Affiliates Trust

ITEM 1(b). ADDRESS OF ISSUER'S EXECUTIVE OFFICES:

5200 DTC PARKWAY
SUITE 200
GREENWOOD VILLAGE, CO 80111

ITEM 2(a). NAME OF PERSON FILING:

Prudential Financial, Inc.

ITEM 2(b). ADDRESS OF PRINCIPAL BUSINESS OFFICE:

751 Broad Street
Newark, New Jersey 07102-3777

ITEM 2(c). CITIZENSHIP:

New Jersey

ITEM 2(d). TITLE OF CLASS OF SECURITIES:

Common Stock

ITEM 2(e). CUSIP NUMBER:

637870106

ITEM 3. The Person filing this statement is a Parent Holding Company as defined in Section 240.13d-1(b)(1)(ii)(G) of the Securities Exchange Act of 1934.

ITEM 4. OWNERSHIP:

(a) Number of Shares
Beneficially Owned: 1,814,947
See Exhibit A

(b) Percent of Class: 3.6

(c) Powers	No. Of Shares
Sole power to vote or to direct the vote	23,012 See Exhibit A
Shared power to vote or	1,791,935 See Exhibit A

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to direct the vote

Sole power to dispose or  23,012 See Exhibit A
to direct disposition

Shared power to dispose   1,791,935  See Exhibit A
or to direct disposition
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ITEM 5. OWNERSHIP OF 5% OR LESS OF A CLASS:

Prudential Financial, Inc. through its beneficial ownership of the Item 7 listed entities has ceased to be deemed the beneficial owner of more than 5% of the outstanding Common Stock of this issuer.

ITEM 6. OWNERSHIP OF MORE THAN 5% ON BEHALF OF ANOTHER PERSON:

Not Applicable

ITEM 7. IDENTIFICATION AND CLASSIFICATION OF THE SUBSIDIARY WHICH ACQUIRED THE SECURITY BEING REPORTED ON BY THE ULTIMATE PARENT COMPANY:

See Exhibit A

ITEM 8. IDENTIFICATION AND CLASSIFICATION OF MEMBERS OF THE GROUP:

Not Applicable

ITEM 9. NOTICE OF DISSOLUTION OF GROUP:

Not Applicable

ITEM 10. CERTIFICATION:

By signing below, Prudential Financial, Inc. certifies that, to the best of its knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect.

The filing of this statement should not be construed as an admission that Prudential Financial, Inc. is, for purposes of Sections 13 or 16 of the Securities Exchange Act of 1934, the beneficial owner of such shares.

SIGNATURE

After reasonable inquiry and to the best of its knowledge and belief,
Prudential Financial, Inc. certifies that the information set forth in this
statement is true, complete and correct.

PRUDENTIAL FINANCIAL, INC.

By: Richard Baker
Second Vice President

Date: 02/01/2018
As of: 12/31/2017

Exhibit A

ITEM 4. OWNERSHIP:

Through its parent/subsidiary relationship, Prudential Financial, Inc. may be deemed the beneficial owner of the same securities as the Item 7 listed subsidiaries and may have direct or indirect voting and/or investment discretion over 1,814,947 shares.

These shares were acquired in the ordinary course of business, and not with the purpose or effect of changing or influencing control of the Issuer. The filing of this statement should not be construed as an admission that Prudential Financial, Inc. is, for the purposes of Sections 13 or 16 of the Securities Exchange Act of 1934, the beneficial owner of these shares.

ITEM 7. IDENTIFICATION/CLASSIFICATION:

Prudential Financial, Inc. is a Parent Holding Company and the indirect parent of the following subsidiaries, who are the beneficial owners of the number and percentage of securities which are the subject of this filing as set forth next to their names:

Subsidiaries		Number of Shares	Percentage
The Prudential Insurance Company of America	IC	0	0
Prudential Retirement Insurance and Annuity Company	IC	0	0
Jennison Associates LLC	IA	1,734,717	3.45

PGIM, Inc.	IA	0	0
Quantitative Management Associates LLC	IA	80,230	0.16

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Oil (Bbl)

$
61.86

$
47.82

$
14.04

29
%
Natural gas (Mcf)

3.76

3.77

(0.01
)

—
%
Total (BOE)

52.63

42.40

10.23

24
%
Average realized sales price
(including impact of cash settled derivatives)

Oil (Bbl)

$
57.42

$
46.88

$
10.54

22
%
Natural gas (Mcf)

3.85

3.78

0.07

2
%
Total (BOE)

49.36

41.68

7.68

18
%
Oil and natural gas revenues
(in thousands)

Oil revenue

$
237,898

$
144,893

$
93,005

64
%
Natural gas revenue

26,617

18,754

7,863

42
%
Total

$
264,515

$
163,647

$
100,868

62
%
Additional per BOE data

Sales price [a]

$
52.63

$
42.40

$
10.23

24
%
Lease operating expense [b]

5.21

6.06

(0.85
)

(14
)%
Gathering and treating expense [c]

—

0.44

(0.44
)

(100
)%
Production taxes

3.18

2.78

0.40

14
%
Operating margin

$
44.24

$
33.12

$
11.12

34
%

(a) Excludes the impact of cash settled derivatives.
(b) Excludes gathering and treating expense.
(c) On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the six months ended June 30, 2018 were accounted for as a reduction to revenue. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

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Revenues

The following tables reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended June 30, 2017	$72,885	$9,398	$82,283
Volume increase	18,222	4,756	22,978
Price increase	31,506	308	31,814
Net increase	49,728	5,064	54,792
Revenues for the three months ended June 30, 2018	$122,613	$14,462	$137,075

(in thousands)	Oil	Natural Gas	Total
Revenues for the six months ended June 30, 2017	$144,893	$18,754	$163,647
Volume increase	39,021	7,909	46,930
Price increase (decrease)	53,984	(46)	53,938
Net increase	93,005	7,863	100,868
Revenues for the six months ended June 30, 2018	$237,898	$26,617	$264,515

Commodity prices

The prices for oil and natural gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and actions by the Organization of Petroleum Exporting Countries and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and cost of the capital;
- the amount we are allowed to borrow under our Credit Facility; and
- the value of our oil and natural gas properties.

For the three and six months ended June 30, 2018, the average NYMEX price for a barrel of oil was $67.91 and $65.43 per Bbl compared to $48.15 and $49.95 per Bbl for the same period of 2017. The NYMEX price for a barrel of oil for the three and six months ended June 30, 2018 ranged from a low of $62.06 per Bbl to a high of $74.15 per Bbl and a low of $59.19 per Bbl to a high of $74.15 per Bbl, respectively.

For the three and six months ended June 30, 2018, the average NYMEX price for natural gas was $2.83 and $2.84 per MMBtu compared to $3.14 and $3.10 per MMBtu for the same periods of 2017. The NYMEX price for natural gas for the three and six months ended June 30, 2018 ranged from a low of $2.66 per MMBtu to a high of $3.02 per MMBtu and a low of $2.55 per MMBtu to a high of $3.63 per MMBtu, respectively.

Oil revenue

For the three months ended June 30, 2018, oil revenues of $122.6 million increased $49.7 million, or 68%, compared to revenues of $72.9 million for the same period of 2017. The increase in oil revenue was primarily attributable to a 25% increase in production and a 35% increase in the average realized sales price, which rose to $61.46 per Bbl from $45.67 per Bbl. The increase in production was comprised of 1,045 MBbls attributable to wells placed on production as a result of our horizontal drilling program and 33 MBbls from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

For the six months ended June 30, 2018, oil revenues of $237.9 million increased $93.0 million, or 64%, compared to revenues of $144.9 million for the same period of 2017. The increase in oil revenue was primarily attributable to a 27% increase in production and a 29% increase in the average realized sales price, which rose to $61.86 per Bbl from $47.82 per Bbl. The increase in production was comprised of 1,903 MBbls attributable to wells placed on production as a result of our horizontal drilling program and 43 MBbls from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

See Note 3 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions.

Natural gas revenue (including NGLs)

For the three months ended June 30, 2018, natural gas revenues of $14.5 million increased $5.1 million, or 54%, compared to $9.4 million for the same period of 2017. The increase primarily relates to a 51% increase in natural gas volumes and a 2% increase in the average realized sales price, which rose to $3.77 per Mcf from $3.69 per Mcf, reflecting both natural gas and natural gas liquids prices. The increase in production was comprised of 241 MMcf attributable to wells placed on production as a result of our horizontal drilling program and 68 MMcf from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells. Natural gas revenues for the three months ended June 30, 2018, include a reduction of $2.0 million of gathering and treating expense.

For the six months ended June 30, 2018, natural gas revenues of $26.6 million increased $7.9 million, or 42%, compared to $18.8 million for the same period of 2017. The increase primarily relates to a 42% increase in natural gas volumes. The increase in production was comprised of 395 MMcf attributable to wells placed on production as a result of our horizontal drilling program and 93 MMcf from producing wells added from our acquired properties. The average realized sales price of $3.76 per Mcf, reflecting both natural gas and natural gas liquids prices, was consistent with prices for the same period of 2017. Offsetting these increases were normal and expected declines from our existing wells. Natural gas revenues for the six months ended June 30, 2018, include a reduction of $3.2 million of gathering and treating expense.

See Notes 1, 2 and 3 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense and the Company’s acquisitions, respectively.

Operating Expenses

(in thousands, except per unit amounts)	Three Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
	2018	BOE	2017	BOE	$	%	$	%
Lease operating expenses [a]	$13,141	$4.99	$12,145	$6.01	$996	8 %	$(1.02)	(17)%
Production taxes	7,539	2.86	4,820	2.38	2,719	56 %	0.48	20 %
Depreciation, depletion and amortization	38,733	14.70	26,213	12.97	12,520	48 %	1.73	13 %
General and administrative	8,289	3.15	6,430	3.18	1,859	29 %	(0.03)	(1)%
Settled share-based awards	—	—	6,351	3.14	(6,351)	(100)%	(3.14)	(100)%
Accretion expense	206	0.08	208	0.10	(2)	(1)%	(0.02)	(20)%
Acquisition expense	1,767	0.67	2,373	1.17	(606)	(26)%	(0.50)	(43)%

	Six Months Ended June 30,							
		Per		Per	Total Change		BOE Change	
(in thousands, except per unit amounts)	2018	BOE	2017	BOE	$	%	$	%
Lease operating expenses [a]	$26,179	$5.21	$25,084	$6.50	$1,095	4 %	$(1.29)	(20)%
Production taxes	16,002	3.18	10,723	2.78	5,279	49 %	0.40	14 %
Depreciation, depletion and amortization	74,151	14.75	50,646	13.12	23,505	46 %	1.63	12 %
General and administrative	17,057	3.39	11,636	3.01	5,421	47 %	0.38	13 %
Settled share-based awards	—	—	6,351	1.65	(6,351)	(100)%	(1.65)	(100)%
Accretion expense	424	0.08	392	0.10	32	8 %	(0.02)	(20)%
Acquisition expense	2,315	0.46	2,822	0.73	(507)	(18)%	(0.27)	(37)%

(a)

On January 1, 2018, the Company adopted the revenue recognition accounting standard. Consequently, natural gas gathering and treating expenses for the three and six months ended June 30, 2018 were accounted for as a reduction to revenue. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

Lease operating expenses (“LOE”). These are daily costs incurred to extract oil and natural gas and maintain our producing properties. Such costs also include maintenance, repairs, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

For the three months ended June 30, 2018, LOE increased by 8% to $13.1 million compared to $12.1 million for the same period of 2017. For the three months ended June 30, 2018, LOE per BOE decreased to $4.99 per BOE, excluding gathering and treating expense, compared to $6.01 per BOE, including $0.45 per BOE of gathering and treating expense, for the same period of 2017, which was primarily attributable to higher production volumes from an increased number of producing wells from our horizontal drilling program and acquisitions as discussed above. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

For the six months ended June 30, 2018, LOE increased by 4% to $26.2 million compared to $25.1 million for the same period of 2017. For the six months ended June 30, 2018, LOE per BOE decreased to $5.21 per BOE, excluding gathering and treating expense, compared to $6.50 per BOE, including $0.44 per BOE of gathering and treating expense, for the same period of 2017, which was primarily attributable to higher production volumes from an increased number of producing wells from our horizontal drilling program and acquisitions as discussed above. See Notes 1 and 2 in the Footnotes to the Financial Statements for additional information regarding revenue recognition and the treatment of gathering and treating expense.

Production taxes. Production taxes include severance and ad valorem taxes. In general, production taxes are directly related to commodity price changes; however, severance taxes are based upon current year commodity prices, whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

Production taxes for the three months ended June 30, 2018 increased by 56% to $7.5 million compared to $4.8 million for the same period of 2017. The increase was primarily due to an increase in severance taxes, which was attributable to the increase in revenue. On a per BOE basis, production taxes for the three months ended June 30, 2018 increased by 20% compared to the same period of 2017.

Production taxes for the six months ended June 30, 2018 increased by 49% to $16.0 million compared to $10.7 million for the same period of 2017. The increase was primarily due to an increase in severance taxes, which was attributable to the increase in revenue. Also contributing to the increase was an increase in ad valorem taxes, which was attributable to an increase in the valuation of our oil and gas properties by taxing jurisdictions as a result of an increased number of producing wells from our horizontal drilling program, and acquisitions as discussed above. On a per BOE basis, production taxes for the six months ended June 30, 2018 increased by 14% compared to the same period of 2017.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unevaluated properties, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

For the three months ended June 30, 2018, DD&A increased 48% to $38.7 million compared to $26.2 million for the same period of 2017. The increase is primarily attributable to a 30% increase in production and a 13% increase in our per BOE DD&A rate. For the three months ended June 30, 2018, DD&A on a per unit basis increased to $14.70 per BOE compared to $12.97 per BOE for the same period of 2017. The increase is attributable to greater increases in our depreciable base and assumed future development costs to undeveloped proved reserves relative to the increase in our estimated proved reserve base. The increases in our depreciable base, assumed future development costs and estimated proved reserve base are a result of additions made through our horizontal drilling efforts and acquisitions.

For the six months ended June 30, 2018, DD&A increased 46% to $74.2 million compared to $50.6 million for the same period of 2017. The increase is primarily attributable to a 30% increase in production and a 12% increase in our per BOE DD&A rate. For the six months ended June 30, 2018, DD&A on a per unit basis increased to $14.75 per BOE compared to $13.12 per BOE for the same period of 2017. The increase is attributable to greater increases in our depreciable base and assumed future development costs to undeveloped proved reserves relative to the increase in our estimated proved reserve base. The increases in our depreciable base, assumed future development costs and estimated proved reserve base are a result of additions made through our horizontal drilling efforts and acquisitions.

General and administrative, net of amounts capitalized (“G&A”). These are costs incurred for overhead, including payroll and benefits for our corporate staff, severance and early retirement expenses, costs of maintaining offices, managing our production and development operations, franchise taxes, depreciation of corporate level assets, public company costs, vesting of equity and liability awards under share-based compensation plans and related mark-to-market valuation adjustments over time, fees for audit and other professional services, and legal compliance.

G&A for the three months ended June 30, 2018 increased to $8.3 million compared to $6.4 million for the same period of 2017. The increase is primarily attributable to non-cash compensation and the corresponding rise in personnel costs due to the growth in our operating activities. G&A expenses for the periods indicated include the following (in thousands):

	Three Months Ended June 30,			
	2018	2017	$ Change	% Change
Recurring expenses				
G&A	$7,186	$5,506	$1,680	31 %
Share-based compensation	1,587	966	621	64 %
Fair value adjustments of cash-settled RSU awards	(484)	(567)	83	(15)%
Non-recurring expenses				
Early retirement expenses	—	444	(444)	(100)%
Early retirement expenses related to share-based compensation	—	81	(81)	(100)%
Total G&A expenses	$8,289	$6,430	$1,859	29 %

G&A for the six months ended June 30, 2018 increased to $17.1 million compared to $11.6 million for the same period of 2017. The increase is primarily attributable to non-cash compensation and the corresponding rise in personnel costs due to the growth in our operating activities. G&A expenses for the periods indicated include the following (in thousands):

	Six Months Ended June 30,			
	2018	2017	$ Change	% Change
Recurring expenses				
G&A	$13,858	$10,098	$3,760	37 %
Share-based compensation	2,692	1,887	805	43 %
Fair value adjustments of cash-settled RSU awards	507	(874)	1,381	(158)%
Non-recurring expenses				
Early retirement expenses	—	444	(444)	(100)%
Early retirement expenses related to share-based compensation	—	81	(81)	(100)%
Total G&A expenses	$17,057	$11,636	$5,421	47 %

Settled share-based awards. In June 2017, the Company settled the outstanding share-based award agreements of its former Chief Executive Officer, resulting in $6.4 million recorded on the Consolidated Statements of Operations as Settled share-based awards.

Accretion expense. The Company is required to record the estimated fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated ARO costs. Interest is accreted on the present value of the ARO and reported as accretion expense within operating expenses in the consolidated statements of operations.

Accretion expense related to our ARO for the three months ended June 30, 2018, was consistent with the same period of 2017. Accretion expense related to our ARO for the six months ended June 30, 2018, increased 8% compared to the same period of 2017. Accretion expense generally correlates with the Company's ARO, which was $10.1 million at June 30, 2018 as compared to $6.8 million at June 30, 2017. See Note 9 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Acquisition expense. Acquisition expense decreased $0.6 million and $0.5 million for the three and six months ended June 30, 2018, compared to the same periods of 2017. Acquisition expense for all periods was related to costs with respect to our acquisition efforts in the Permian Basin. See Note 3 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions.

Other Income and Expenses and Preferred Stock Dividends

(in thousands)	Three Months Ended June 30,			
	2018	2017	$ Change	% Change
Interest expense, net of capitalized amounts	$594	$589	$ 5	1 %
(Gain) loss on derivative contracts	16,554	(10,494)	27,048	(258)%
Other income	(703)	(64)	(639)	998 %
Total other (income) expense	$16,445	$(9,969)		
Income tax expense	$481	$322	$ 159	49 %
Preferred stock dividends	(1,824)	(1,824)	—	— %

	Six Months Ended June 30,			
(in thousands)	2018	2017	$ Change	% Change
Interest expense, net of capitalized amounts	$1,053	$1,254	$(201)	(16)%
(Gain) loss on derivative contracts	21,036	(25,797)	46,833	(182)%
Other income	(914)	(772)	(142)	18 %
Total other (income) expense	$21,175	$(25,315)		
Income tax expense	$976	$789	$ 187	24 %
Preferred stock dividends	(3,647)	(3,647)	—	— %

Interest expense, net of capitalized amounts. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Interest expense, net of capitalized amounts, of $0.6 million incurred during the three months ended June 30, 2018 was consistent with the same period of 2017. Interest expense, net of capitalized amounts, incurred during the six months ended June 30, 2018 decreased $0.2 million compared to the same period of 2017. This decrease was primarily due to an increase in the premium amortization of $0.5 million attributable to the 6.125% Senior Notes. Offsetting the decrease was a $0.3 million increase in deferred financing costs primarily resulting from the issuance of $400 million of 6.375% Senior Notes. See Note 5 in the Footnotes to the Financial Statements for additional information on our debt obligations.

Gain (loss) on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. This amount represents the (i) gain (loss) related to fair value adjustments on our open derivative contracts and (ii) gains (losses) on settlements of derivative contracts for positions that have settled within the period.

For the three months ended June 30, 2018, the net loss on derivative contracts was $16.6 million compared to a $10.5 million net gain for the same period of 2017. The net gain (loss) on derivative instruments for the periods indicated includes the following (in thousands):

Three Months Ended June 30,	
2018	2017

Oil derivatives		
Net loss on settlements	$(8,131)	$(315)
Net gain (loss) on fair value adjustments	(8,311)	10,128
Total gain (loss) on oil derivatives	$(16,442)	$9,813
Natural gas derivatives		
Net gain on settlements	$151	$48
Net gain (loss) on fair value adjustments	(263)	633
Total gain (loss) on natural gas derivatives	$(112)	$681
Total gain (loss) on oil & natural gas derivatives	$(16,554)	$10,494

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For the six months ended June 30, 2018, the net loss on derivative contracts was $21.0 million compared to a $25.8 million net gain for the same period of 2017. The net gain (loss) on derivative instruments for the periods indicated includes the following (in thousands):

	Six Months Ended June 30,	
	2018	2017
Oil derivatives		
Net loss on settlements	$(17,049)	$(2,840)
Net gain (loss) on fair value adjustments	(4,243)	27,394
Total gain (loss) on oil derivatives	$(21,292)	$24,554
Natural gas derivatives		
Net gain on settlements	$607	$82
Net gain (loss) on fair value adjustments	(351)	1,161
Total gain on natural gas derivatives	$256	$1,243
Total gain (loss) on oil & natural gas derivatives	$(21,036)	$25,797

See Notes 6 and 7 in the Footnotes to the Financial Statements for additional information on the Company's derivative contracts and disclosures related to derivative instruments.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate, based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

The Company had income tax expense of $0.5 million and $1.0 million for the three and six months ended June 30, 2018, compared to income tax expense of $0.3 million and $0.8 million for the same periods of 2017. The change in income tax expense is primarily related to deferred state of Texas gross margin tax. The Company had a valuation allowance of $38.6 million as of June 30, 2018. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends of $1.8 million and $3.6 million for the three and six months ended June 30, 2018 were consistent with dividends for the same periods of 2017. Dividends reflect a 10% dividend rate. See Note 10 in the Footnotes to the Financial Statements for additional information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We mitigate these risks through a program of risk management including the use of derivative instruments.

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, demand, regional market conditions, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes which we hedge through use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 40% to 60% of our anticipated internally forecast production, subject to market conditions, for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices, in addition to modification of our capital spending plans related to operational activities and acquisitions.

The Company's hedging portfolio, linked to NYMEX benchmark pricing, covers approximately 3,588,000 Bbls and 3,864,000 MMBtu of our expected oil and natural gas production, respectively, for the remainder of 2018. We also have commodity hedging contracts linked to Midland WTI basis differentials relative to Cushing and Waha basis differentials covering approximately 2,208,000 Bbls and 1,104,000 MMBtu of our expected oil and natural gas production, respectively, for the remainder of 2018. See Note 6 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at June 30, 2018, and derivative contracts established subsequent to that date.

The Company may utilize fixed price swaps, which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales.

The Company may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counterparty receives the difference from the Company. Additionally, the Company may sell put (or call) options at a price lower than the floor price (or higher than the ceiling price) in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices. In a three-way collar, to the extent that realized prices are below the floor price of the sold put option (or above the ceiling price of the sold call option), the Company's net realized benefit from the three-way collar will be reduced on a dollar-for-dollar basis.

The Company may purchase put and call options, which reduce the Company's exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to the Company.

The Company enters into these various agreements to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company's derivative positions are designated as hedges for accounting purposes.

Interest rate risk

The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. As of June 30, 2018, the Company had no principal outstanding under the Credit Facility with a weighted average interest rate of 3.97%. Based on a notional amount of $10 million outstanding under the facility, an increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $0.1 million. See Note 5 in the Footnotes to the Financial Statements for more information on the Company's interest rates on its Credit Facility.

Counterparty and customer credit risk

The Company's principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

The Company markets its oil and natural gas production to energy marketing companies. We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At June 30, 2018 our total receivables from the sale of our oil and natural gas production were approximately $73.4 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At June 30, 2018 our joint interest receivables were approximately $35.7 million.

Our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Most of the counterparties on our derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional derivative instruments with these or other lenders under our Credit Facility, representing institutions with investment grade ratings. We have existing International Swap Dealers Association Master Agreements (“ISDA Agreements”) with our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of offset upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may offset all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

Item 4. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is accumulated and communicated to the issuer’s management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2018.

Changes in internal control over financial reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our financial position or results of operations.

Item 1A. Risk Factors

In addition to the information set forth in this Quarterly Report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2017. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2017, and in this Quarterly Report are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

The purchase agreement for the Cimarex Acquisition contains conditions to closing, some of which are beyond our control, and we may be unable to consummate the Cimarex Acquisition. The purchase agreement for the Cimarex Acquisition contains closing conditions, including limitations on purchase price adjustments (including with respect to adjustments for title and environmental defects) and customary closing conditions. It is possible that one or more of the conditions in the purchase agreement will not be satisfied, and we may be unable or unwilling to consummate the Cimarex Acquisition. If the Cimarex Acquisition is not closed on account of a material breach of the purchase agreement on our part that is not subsequently cured, we may be required to forfeit our earnest money deposit as liquidated damages. If we are unable to close the Cimarex Acquisition, our common stock price could be materially adversely affected.

Our analysis of the properties subject to the Cimarex Acquisition was based in part on information provided to us by the seller and the limited representations, warranties and indemnifications of the seller contained in the purchase agreement, which may prove to be incorrect, resulting in our not realizing the expected benefits of this transaction and the value of the transaction is largely associated with undeveloped acreage that may not materialize. Our analysis of the properties subject to the Cimarex Acquisition, including our estimates of the associated proved reserves, is based in part on information provided to us by the seller, including historical production data. Our independent reserve engineers have not provided a report regarding the estimates of reserves with respect to the properties subject to this transaction. As a result, the assumptions on which our internal estimates of proved reserves and horizontal drilling locations have been based may prove to be incorrect in a number of material ways, resulting in our not realizing our expected benefits of this transaction. In addition, the representations, warranties and indemnities of the seller contained in the purchase agreement are limited, and we may not have recourse against the seller in the event that the acreage does not perform as expected.

Furthermore, a large portion of the acreage we are acquiring is undeveloped, and our plans, development schedule and production schedule associated with the acreage may fail to materialize. As a result, our investment in these areas may not be as economic as we anticipate, and we could incur material write-downs of unevaluated properties.

The Cimarex Acquisition involves risks associated with acquisitions and integrating acquired properties, including the potential exposure to significant liabilities, and the intended benefits of the Cimarex Acquisition may not be realized. The Cimarex Acquisition involves risks associated with acquisitions and integrating acquired properties into existing operations, including that:

- our senior management’s attention may be diverted from the management of daily operations to the integration of the assets acquired in the Cimarex Acquisition and our recent acquisitions;
- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;
- the properties acquired in the Cimarex Acquisition may not perform as well as we anticipate;
-

unexpected costs, delays and challenges may arise in integrating the assets acquired in the Cimarex Acquisition into our existing operations; and

- we may need to hire additional staff and devote additional resources to integrate the properties acquired in the Cimarex Acquisition.

Even if we successfully integrate the properties acquired in the Cimarex Acquisition into our operations, it may not be possible to realize the full benefits we anticipate or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits we anticipate from the Cimarex Acquisition, our business, results of operations and financial condition may be materially adversely affected.

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

None.

Item 3. Defaults Upon Senior Securities

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None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

The following exhibits are filed as part of this Form 10-Q.

Exhibit Number	Description
2.	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession
2.1	Purchase and Sale Agreement, dated May 23, 2018, between Cimarex Energy Co, Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. and Callon Petroleum Operating Company (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed on May 24, 2018)
3.	Articles of Incorporation and By-Laws
3.1	Certificate of Incorporation of the Company, as amended through May 12, 2016 (incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q, filed on November 3, 2016)
3.2	Certificate of Designation of Rights and Preferences of 10.00% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Form 8-A, filed on May 23, 2013)
3.3	Bylaws of the Company (incorporated by reference to Exhibit 3.3 of the Company's Form 10-K, filed on February 28, 2018)
4.	Instruments defining the rights of security holders, including indentures
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Form 10-K, filed on February 28, 2018)
4.2	Certificate for the Company's 10.00% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company's Form 8-A, filed on May 23, 2013)
4.3	Registration Rights Agreement, dated May 26, 2016, among Callon Petroleum Company and each of the Persons set forth on Schedule A therein (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on May 31, 2016)
4.4	Indenture of 6.125% Senior Notes Due 2024, dated as of October 3, 2016, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on October 4, 2016)
4.5	Indenture of 6.375% Senior Notes Due 2026, dated as of June 7, 2018, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on June 7, 2018)
4.6	Registration Rights Agreement of 6.375% Senior Notes Due 2026, dated June 7, 2018, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed on June 7, 2018)
10.	Material contracts
10.1	Amendment No. 1 to the Sixth Amended and Restated Credit Agreement, dated April 5, 2018, among Callon Petroleum Company, JPMorgan Chase Bank, National Association, as administrative agent and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on April 6, 2018)
10.2	Purchase Agreement of 6.375% Senior Notes Due 2026, dated as of May 31, 2018, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchases named in Schedule 1 thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on June 1, 2018)
10.3 (d)	Callon Petroleum Company 2018 Omnibus Incentive Plan (incorporated by reference to Appendix A of the Company's definitive proxy statement on Schedule 14A, filed on March 23, 2018)
10.4 (a)(d)	Form of Callon Petroleum Company Director Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan

10.5	(a)(d)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan
10.6	(a)(d)	Form of Callon Petroleum Company Employee Cash-Settleable Performance Share Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan
10.7	(a)(d)	Form of Callon Petroleum Company Employee Stock-Settleable Performance Share Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan
31.		Section 13a-14 Certifications
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)
32.	(b)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)
101.	(c)	Interactive Data Files

(a) Filed herewith.

(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this report and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

(c) Pursuant to Rule 406T of Regulation S-T, these interactive data files are being furnished herewith and are not deemed filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

(d) Indicates management compensatory plan, contract, or arrangement.

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.

Callon Petroleum Company

Signature	Title	Date
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	President and Chief Executive Officer	August 6, 2018
/s/ James P. Ulm, II James P. Ulm, II	Senior Vice President and Chief Financial Officer	August 6, 2018