Independence Contract Drilling, Inc.
Form 10-Q
April 26, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-36590
Independence Contract Drilling, Inc.
(Exact name of registrant as specified in its charter)

Delaware	37-1653648
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
11601 North Galayda Street Houston, Texas	77086
(Address of principal executive offices)	(Zip code)

(281) 598-1230
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer x
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨
	Emerging growth company x

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. x
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
38,252,765 shares of the registrant’s Common Stock were outstanding as of April 23, 2018.

INDEPENDENCE CONTRACT DRILLING, INC.
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Part I. FINANCIAL INFORMATION

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Quarterly Report on Form 10-Q, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, may constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future revenues, income and capital spending. Our forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “plan,” “goal,” “will” or other words that convey the uncerta future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. These risks, contingencies and uncertainties include, but are not limited to, the following:

- a decline in or substantial volatility of crude oil and natural gas commodity prices;
- a sustained decrease in domestic spending by the oil and natural gas exploration and production industry;
- our inability to implement our business and growth strategy;
- fluctuation of our operating results and volatility of our industry;
- inability to maintain or increase pricing of our contract drilling services, or early termination of any term contract for which early termination compensation is not paid;
- our backlog of term contracts declining rapidly;
- the loss of any of our customers, financial distress or management changes of potential customers or failure to obtain contract renewals and additional customer contracts for our drilling services;
- overcapacity and competition in our industry;
- an increase in interest rates and deterioration in the credit markets;
- our inability to comply with the financial and other covenants in debt agreements that we may enter into as a result of reduced revenues and financial performance;
- a substantial reduction in borrowing base under our credit facility as a result of a decline in the appraised value of our drilling rigs or reduction in the number of rigs operating;
- unanticipated costs, delays and other difficulties in executing our long-term growth strategy;
- the loss of key management personnel;
- new technology that may cause our drilling methods or equipment to become less competitive;
- labor costs or shortages of skilled workers;
- the loss of or interruption in operations of one or more key vendors;
- the effect of operating hazards and severe weather on our rigs, facilities, business, operations and financial results, and limitations on our insurance coverage;
- increased regulation of drilling in unconventional formations;
- the incurrence of significant costs and liabilities in the future resulting from our failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment; and
- the potential failure by us to establish and maintain effective internal control over financial reporting.

All forward-looking statements are necessarily only estimates of future results, and there can be no assurance that actual results will not differ materially from expectations, and, therefore, you are cautioned not to place undue reliance on such statements. Any forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this Form 10-Q and Part I, “Item 1A. Risk Factors” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017. Further, any forward-looking statement speaks only as of the date on which it is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events.

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PART I — FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
Independence Contract Drilling, Inc.
Balance Sheets
(Unaudited)
(in thousands, except par value and share amounts)

	March 31, 2018	December 31, 2017
Assets		
Cash and cash equivalents	$2,503	$ 2,533
Accounts receivable, net	16,244	18,056
Inventories	2,795	2,710
Assets held for sale	1,920	1,920
Prepaid expenses and other current assets	3,381	2,957
Total current assets	26,843	28,176
Property, plant and equipment, net	274,046	275,105
Other long-term assets, net	1,236	1,364
Total assets	$302,125	$ 304,645
Liabilities and Stockholders' Equity		
Liabilities		
Current portion of long-term debt	$511	$ 533
Accounts payable	10,500	11,627
Accrued liabilities	5,018	6,969
Total current liabilities	16,029	19,129
Long-term debt	53,886	49,278
Deferred income taxes, net	634	683
Other long-term liabilities	41	73
Total liabilities	70,590	69,163
Commitments and contingencies (Note 11)		
Stockholders' equity		
Common stock, $0.01 par value, 100,000,000 shares authorized; 38,597,447 and 38,246,919 shares issued, respectively; and 38,252,765 and 37,985,225 shares outstanding, respectively	383	380
Additional paid-in capital	327,162	326,616
Accumulated deficit	(93,791)	(89,645)
Treasury stock, at cost, 344,682 and 261,694 shares, respectively	(2,219)	(1,869)
Total stockholders' equity	231,535	235,482
Total liabilities and stockholders' equity	$302,125	$ 304,645

The accompanying notes are an integral part of these financial statements.

Independence Contract Drilling, Inc.
Statements of Operations
(Unaudited)
(in thousands, except per share amounts)

	Three Months Ended March 31,	
	2018	2017
Revenues	$25,627	$20,236
Costs and expenses		
Operating costs	18,926	14,898
Selling, general and administrative	3,479	3,718
Depreciation and amortization	6,591	6,256
Asset impairment, net	(35)	129
(Gain) loss on disposition of assets, net	(82)	828
Total costs and expenses	28,879	25,829
Operating loss	(3,252)	(5,593)
Interest expense	(943)	(630)
Loss before income taxes	(4,195)	(6,223)
Income tax (benefit) expense	(49)	46
Net loss	$(4,146)	$(6,269)
Loss per share:		
Basic and diluted	$(0.11)	$(0.17)
Weighted average number of common shares outstanding:		
Basic and diluted	38,124	37,546

The accompanying notes are an integral part of these financial statements.

Independence Contract Drilling, Inc.
Statement of Stockholders' Equity
(Unaudited)
(in thousands, except share amounts)

	Common Stock					
	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Total Stockholders' Equity
Balances at December 31, 2017	37,985,225	$ 380	$ 326,616	$ (89,645)	$ (1,869)	$ 235,482
RSUs vested, net of shares withheld for taxes	350,528	3	(98)	—	—	(95)
Purchase of treasury stock	(82,988)	—	—	—	(350)	(350)
Stock-based compensation	—	—	644	—	—	644
Net loss	—	—	—	(4,146)	—	(4,146)
Balances at March 31, 2018	38,252,765	$ 383	$ 327,162	$ (93,791)	$ (2,219)	$ 231,535

The accompanying notes are an integral part of these financial statements.

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Independence Contract Drilling, Inc.
Statements of Cash Flows
(Unaudited)
(in thousands)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Cash flows from operating activities		
Net loss	$(4,146)	$(6,269)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities		
Depreciation and amortization	6,591	6,256
Asset impairment, net	(35)	129
Stock-based compensation	644	1,012
(Gain) loss on disposition of assets, net	(82)	828
Deferred income taxes	(49)	46
Amortization of deferred financing costs	90	125
Bad debt expense	22	—
Changes in operating assets and liabilities		
Accounts receivable	1,790	(807)
Inventories	(56)	(75)
Prepaid expenses and other assets	(386)	(885)
Accounts payable and accrued liabilities	(2,371)	(1,780)
Net cash provided by (used in) operating activities	2,012	(1,420)
Cash flows from investing activities		
Purchases of property, plant and equipment	(6,259)	(8,645)
Proceeds from the sale of assets	146	13
Net cash used in investing activities	(6,113)	(8,632)
Cash flows from financing activities		
Borrowings under Credit Facility	13,779	13,457
Repayments under Credit Facility	(9,100)	(2,600)
Purchase of treasury stock	(350)	(24)
RSUs withheld for taxes	(95)	(455)
Payments for capital lease obligations	(163)	(109)
Net cash provided by financing activities	4,071	10,269
Net (decrease) increase in cash and cash equivalents	(30)	217
Cash and cash equivalents		
Beginning of period	2,533	7,071
End of period	$2,503	$7,288
Supplemental disclosure of cash flow information		
Cash paid during the period for interest	$848	$510
Supplemental disclosure of non-cash investing and financing activities		
Change in property, plant and equipment purchases in accounts payable	$(739)	$(263)
Additions to property, plant and equipment through capital leases	$70	$327
Transfer of assets from held for sale to held and used	$2,717	$—

The accompanying notes are an integral part of these financial statements.

INDEPENDENCE CONTRACT DRILLING, INC.
Notes to Financial Statements
(Unaudited)

1. Nature of Operations and Recent Events

Except as expressly stated or the context otherwise requires, the terms "we," "us," "our," "ICD," and the "Company" refer to Independence Contract Drilling, Inc.

We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a rig fleet comprised entirely of custom designed ShaleDriller® rigs.

Our standardized rig fleet consists of 14 premium 200 Series ShaleDriller rigs, all of which are equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. Every rig in our fleet is a 1500-hp, AC programmable rig designed to be fast-moving between drilling sites and is equipped with 7500 psi mud systems, top drives, automated tubular handling systems and blowout preventer handling systems. All of our rigs are equipped with bi-fuel capabilities that enable the rig to operate on either diesel or a natural gas-diesel blend.

Our first rig commenced drilling in May 2012. We currently focus our operations on unconventional resource plays located in geographic regions that we can efficiently support from our Houston, Texas facilities in order to maximize economies of scale. Currently, our rigs are operating in the Permian Basin, Eagle Ford Shale and the Haynesville Shale, however, our rigs have previously operated in the Mid-Continent and Eaglebine regions as well.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Oil and Natural Gas Prices and Drilling Activity

Both oil and natural gas prices began to decline in the second half of 2014, declined further during 2015 and remained low in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015, and reached a low of $26.19 on February 11, 2016 (West Texas Intermediate - Cushing, Oklahoma (“WTI”) spot price as reported by the United States Energy Information Administration (the “EIA”)). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015 and to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

In November 2016, Organization of Petroleum Exporting Countries (“OPEC”) members formally agreed to reduce their production quotas, starting January 1, 2017. These production cuts significantly reduced the overhang of global oil supplies. OPEC members met in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in June 2018 to review market conditions and the impact of their freeze on global supplies. In addition to OPEC members, certain non-OPEC producers such as Russia have agreed to production cuts, which has also supported crude oil and related energy commodity prices.

As a result of these supply cuts and positive demand trends, crude oil prices have recovered with WTI oil prices reaching a three-year high of $67.35 on April 13, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.04 per MMBtu in 2018 as of April 16, 2018. However, there are no indications at this time that oil prices and rig counts will recover, in the near term, to their previous highs experienced in 2014.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At March 31, 2018, all of our rigs were under contract and operating. In addition to improving utilization, contract tenors improved with customers signing term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels, with the potential to move higher if market conditions continue to improve.

However, if oil prices were to fall for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property. In the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million, as a result of water-related damage sustained during the heavy rainfall that occurred during Hurricane Harvey in August 2017. During the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 balance sheet and recognized a recovery of asset impairment expense of approximately $208 thousand in our statement of operations for the three months ended March 31, 2018. Additionally, our December 31, 2017 balance sheet was adjusted to reflect a reduction in assets held for sale of $2.7 million and an increase in property, plant and equipment of $2.7 million.

In conjunction with the decision to hold and use a portion of the Galayda Facility in the first quarter of 2018, management concluded that four dilapidated buildings on the property would likely be torn down. As such, we impaired the carrying value of these buildings to zero, reducing property, plant and equipment $173 thousand and recognizing asset impairment expense of $173 thousand.

2. Interim Financial Information

These unaudited financial statements include the accounts of ICD, and have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”). These financial statements should be read along with our audited financial statements for the year ended December 31, 2017, included in our Annual Report on Form 10-K for the year ended December 31, 2017. In management’s opinion, these financial statements contain all adjustments necessary to fairly present our financial position, results of operations, cash flows and changes in stockholders' equity for all periods presented.

As we had no items of other comprehensive income in any period presented, no other components of comprehensive income is presented.

Interim results for the three months ended March 31, 2018 may not be indicative of results that will be realized for the full year ending December 31, 2018.

Revenue and Cost Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). We adopted ASU 2014-09 and its related amendments (collectively known as ASC 606) effective on January 1, 2018 using the modified retrospective method. While ASC 606 requires additional disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, its adoption did not have a material impact on the measurement or recognition of our revenues. We may recognize demobilization fee revenue earlier in the contract term than we have historically, but demobilization fee revenues are earned very infrequently under our contracts.

See Note 3 "Revenue from Contracts with Customers" for the required disclosures related to the impact of adopting this standard and a discussion of our updated policies related to revenue recognition and accounting for costs to obtain and fulfill a customer contract.

Segment and Geographical Information

Our operations consist of one reportable segment because all of our drilling operations are located in the United States and have similar economic characteristics. Corporate management administers all properties as a whole rather than as discrete operating segments. Operational data is tracked by rig; however, financial performance is measured as a single

enterprise and not on a rig-by-rig basis. Further, the allocation of capital resources is employed on a project-by-project basis across our entire asset base to maximize profitability without regard to individual geographic areas.

Other Matters

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. This guidance is effective for public companies for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities. We are currently evaluating the impact this guidance will have on our financial statements and have engaged a third party consultant to assist us in this evaluation process.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for public companies for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

3. Revenue from Contracts with Customers

Effective January 1, 2018, we adopted Accounting Standards Codification (“ASC”) Revenue from Contracts with Customers (“ASC 606”), using the modified retrospective method. This standard applies to all contracts with customers, except for contracts that are within the scope of other standards, such as leases, insurance, collaborative arrangements and financial instruments. Under ASC 606, an entity recognizes revenue when it transfers control of the promised goods or services to its customer, in an amount that reflects the consideration which the entity expects to receive in exchange for those goods or services. If control transfers to the customer over time, an entity selects a method to measure progress that is consistent with the objective of depicting its performance.

In determining the appropriate amount of revenue to be recognized as we fulfill our obligations under the agreement, the following steps must be performed at contract inception: (i) identification of the promised goods or services in the contract; (ii) determination of whether the promised goods or services are performance obligations, including whether they are distinct in the context of the contract; (iii) measurement of the transaction price, including the constraint on variable consideration; (iv) allocation of the transaction price to the performance obligations; and (v) recognition of revenue when (or as) we satisfy each performance obligation.

Drilling Services

Our revenues are principally derived from contract drilling services and the activities in our drilling contracts, for which revenues may be earned, include: (i) providing a drilling rig and the crews and supplies necessary to operate the rig; (ii) mobilizing and demobilizing the rig to and from the initial and final drill site, respectively; (iii) certain reimbursable activities; (iv) performing rig modification activities required for the contract; and (v) early termination revenues. We account for these integrated services provided under our drilling contracts as a single performance obligation, satisfied over time, that is comprised of a series of distinct time increments. Consideration for activities that are not distinct within the context of our contracts, and that do not correspond to a distinct time increment within the contract term, are allocated across the single performance obligation and recognized ratably in proportion to the actual services performed over the initial term of the contract. If taxes are required to be collected from customers relating to our drilling services, they are excluded from revenue.

Dayrate Drilling Revenue. Our drilling contracts provide that revenue is earned based on a specified rate per day for the activity performed. The majority of revenue earned under daywork contracts is variable, and depends on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term. Such rates generally include the full operating rate, moving rate, standby rate, and force majeure rate and determination of the rate per time increment is made based on the actual circumstances as they occur. Other variable consideration under these contracts could include reduced revenue related to downtime, delays or moving caps.

Mobilization/Demobilization Revenue. We may receive fees (on either a fixed lump-sum or variable dayrate basis) for the mobilization and demobilization of our rigs. These activities are not considered to be distinct within the context of the contract and therefore, the associated revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract. We record a contract liability for mobilization fees received, which is amortized ratably to revenue as services are rendered over the initial term of the related drilling contract. Demobilization fee revenue expected to be received upon contract completion is estimated as part of the overall transaction price at contract inception and recognized in earnings ratably over the initial term of the contract with an offset to an accretive contract asset.

In our contracts, there is generally significant uncertainty as to the amount of demobilization fee revenue that may ultimately be collected due to contractual provisions which stipulate that certain conditions be present at contract completion for such revenue to be received. For example, the amount collectible may be reduced to zero if the rig has been contracted with a new customer upon contract completion. Accordingly, the estimate for such revenue may be constrained depending on the facts and circumstances pertaining to the specific contract. We assess the likelihood of receiving such revenue based on past experience and knowledge of the market conditions.

Reimbursable Revenues. We receive reimbursements from our customers for the purchase of supplies, equipment and other services provided at their request in accordance with a drilling contract or other agreement. Such reimbursable revenue is variable and subject to uncertainty, as the amounts received and timing thereof is highly dependent on factors outside of our influence. Accordingly, reimbursable revenue is fully constrained and not included in the total transaction price until the uncertainty is resolved, which typically occurs when the related costs are incurred on behalf of a customer. We are generally considered a principal in such transactions and record the associated revenue at the gross amount billed to the customer.

Capital Modification Revenue. From time to time, we may receive fees (on either a fixed lump-sum or variable dayrate basis) from our customers for capital improvements to our rigs to meet their requirements. Such revenue is allocated to the overall performance obligation and recognized ratably over the initial term of the related drilling contract, as these activities are not considered to be distinct within the context of our contracts. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract.

Early Termination Revenue. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied.

Disaggregation of Revenue

The following table summarizes revenues from our contracts disaggregated by revenue generating activity contained therein for the three months ended March 31, 2018 and March 31, 2017:

(in thousands)	Three Months Ended March 31, 2018	March 31, 2017
Dayrate drilling	$23,777	$19,146
Mobilization	459	541
Reimbursables	1,231	541
Capital modification	160	—

Other	—	8
	$25,627	$20,236

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Contract Balances

Accounts receivable are recognized when the right to consideration becomes unconditional based upon contractual billing schedules. Payment terms on invoiced amounts are typically 30 days. Contract asset balances could consist of demobilization fee revenue that we expect to receive that is recognized ratably throughout the contract term, but invoiced upon completion of the demobilization activities. Once the demobilization fee revenue is invoiced the corresponding contract asset is transferred to accounts receivable. Contract liabilities include payments received for mobilization fees as well as upgrade activities, which are allocated to the overall performance obligation and recognized ratably over the initial term of the contract.

The following table provides information about receivables, contract assets and contract liabilities related to contracts with customers:

(in thousands)	March 31, 2018	December 31, 2017
Receivables, which are included in "Accounts receivable, net"	$ 16,193	$ 18,028
Contract assets	$ —	$ —
Contract liabilities	$ (377)	$ (836)

Significant changes in contract assets and contract liabilities balances during the period are as follows:

(in thousands)	March 31, 2018 Contract Assets	March 31, 2018 Contract Liabilities
Revenue recognized that was included in contract liabilities at beginning of period	$ —	$ 459
Increase in contract liabilities due to cash received, excluding amounts recognized as revenue	$ —	$ —
Transferred to receivables from contract assets at beginning of period	$ —	$ —

Transaction Price Allocated to the Remaining Performance Obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) as of March 31, 2018. The estimated revenue does not include amounts of variable consideration that are constrained.

	Year Ending			
(in thousands)	2018	2019	2020	Total
Revenue	$ 304	$ 73	$ —	$ 377

The amounts presented in the table above consist only of fixed consideration related to fees for rig mobilizations and demobilizations, if applicable, which are allocated to the drilling services performance obligation as such performance obligation is satisfied. We have elected the exemption from disclosure of remaining performance obligations for variable consideration. Therefore, dayrate revenue to be earned on a rate scale associated with drilling conditions and level of service provided for each fractional-hour time increment over the contract term and other variable consideration such as penalties and reimbursable revenues, have been excluded from the disclosure.

Contract Costs

We capitalize costs incurred to fulfill our contracts that (i) relate directly to the contract, (ii) are expected to generate resources that will be used to satisfy our performance obligations under the contract and (iii) are expected to be recovered through revenue generated under the contract. These costs, which principally relate to rig mobilization costs at the commencement of a new contract, are deferred as a current or noncurrent asset (depending on the length of the contract term), and amortized ratably to contract drilling expense as services are rendered over the initial term of the related drilling contract. Such contract costs amounted to $0.3 million and $0.1 million, and were recorded as “Prepaid expenses and other current assets” and “Other long-term assets, net,” respectively, on our balance sheet at March 31, 2018. We amortized $0.4 million of contract costs during the three months ended March 31, 2018.

Costs incurred for the demobilization of rigs at contract completion are recognized as incurred during the demobilization process. Costs incurred for rig modifications or upgrades required for a contract, which are considered to be capital improvements, are capitalized as drilling and other property and equipment and depreciated over the estimated useful life of the improvement.

Impact of ASC 606 on Financial Statement Line Items

The timing of our revenue recognition under ASC 606 is similar to revenue recognition under the previous guidance, except for the recognition of demobilization fee revenue, which we earn infrequently. Such revenue, which was recognized upon completion of a contract under the previous guidance, will now be estimated at contract inception and recognized as contract drilling revenue as the drilling services performance obligation is satisfied, subject to constraint, with an offset to a contract asset. As we had no existing contracts as of January 1, 2018, where we expect to receive a demobilization fee from our customers, there was no cumulative effect of a change in accounting principle required to adjust our January 1, 2018 retained earnings.

4. Financial Instruments and Fair Value

Fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, there exists a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1	Unadjusted quoted market prices for identical assets or liabilities in an active market;
Level 2	Quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets or liabilities; and
Level 3	Unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date.

This hierarchy requires us to use observable market data, when available, and to minimize the use of unobservable inputs when determining fair value.

The carrying value of certain of our financial instruments, consisting primarily of cash and cash equivalents, accounts receivable and accounts payable, approximates their fair value due to the short-term nature of such instruments.

The fair value of our Credit Facility debt is determined by Level 3 measurements based on the amount of future cash flows associated with the debt, discounted using our current borrowing rate for comparable debt instruments (the Income Method). Based on our evaluation of the risk free rate, the market yield and credit spreads on comparable company publicly traded debt issues, we used an annualized discount rate, including a credit valuation allowance, of 6.2%. The fair value of our capital lease obligations is determined using Level 3 measurements using our current incremental borrowing rate. The estimated fair value of our long-term debt, including our capital lease obligations, totaled $54.9 million and $50.6 million as of March 31, 2018 and December 31, 2017, respectively, compared to a carrying amount of $53.9 million and $49.3 million as of March 31, 2018 and December 31, 2017, respectively. The fair value of our assets held for sale is determined using Level 3 measurements.

Fair value measurements are applied with respect to our non-financial assets and liabilities measured on a non-recurring basis, which would consist of measurements primarily of long-lived assets.

5. Inventories

All of our inventory as of March 31, 2018 and December 31, 2017 consisted of supplies held for use in our drilling operations.

6. Accrued Liabilities

Accrued liabilities consisted of the following:

(in thousands)	March 31, 2018	December 31, 2017
Accrued salaries and other compensation	$ 1,583	$ 2,646
Insurance	1,605	507
Deferred revenues (contract liabilities)	335	762
Property, sales and other taxes	1,262	2,693
Other	233	361
	$ 5,018	$ 6,969

7. Long-term Debt

Our Long-term Debt consisted of the following:

(in thousands)	March 31, 2018	December 31, 2017
Credit Facility due November 5, 2020	$ 53,220	48,541
Capital lease obligations	1,177	1,270
	54,397	49,811
Less: current portion	(511)	(533)
Long-term debt	$ 53,886	$ 49,278

Credit Facility

In November 2014, we entered into our Credit Facility with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $155.0 million Credit Facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. In 2015, we amended the Credit Facility to provide for a springing lock-box arrangement and, in light of market conditions and our reduced capital plans, reduce aggregate commitments to $125.0 million and modify certain maintenance covenants. In 2016, we amended the Credit Facility to reduce aggregate commitments to $85.0 million and further modify certain maintenance covenants. In connection with this amendment, we expensed certain previously deferred debt issuance costs totaling $0.5 million reflecting the reduction in borrowing capacity.

In 2017, we amended the Credit Facility to extend the maturity date by two years to November 5, 2020 and to provide for an additional uncommitted $65.0 million accordion feature that allows for future increases in facility commitments. Interest under the Credit Facility remained unchanged. The amendment also contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

The obligations under the Credit Facility are secured by all of our assets and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the “advance rate”, of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of March 31, 2018, the advance rate was 72.5%. The advance rate declines 1.25% each quarter through June 2019. Thereafter, through the maturity date, the advance rate remains at 65%. Rigs that remain idle for 90 consecutive days or longer are removed from the borrowing base until they are contracted. In addition, rigs are appraised two times a year and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig.

At our election, interest under the Credit Facility is determined by reference, at our option, to either (i) the London Interbank Offered Rate (“LIBOR”), plus 4.5% or (ii) a “base rate” equal to the higher of the prime rate published by JP Morgan Chase Bank or three-month LIBOR plus 1%, plus in each case, 3.5%, the federal funds effective rate plus 0.05%. We

also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of March 31, 2018, the weighted average interest rate on our borrowings was 6.35%.

The Credit Facility contains various financial covenants including a leverage covenant, fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger, consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment. As of March 31, 2018, we are in compliance with these covenants.

Under the Credit Agreement, as amended, for purposes of calculating EBITDA, non-cash stock-based compensation is added back to EBITDA, as well as up to $2.0 million per year of previously capitalized construction costs that were incurred in 2017. In April 2018, in connection with the construction of our 15th ShaleDriller rig, we amended the Credit Facility as follows: (i) permit capital expenditures up to a maximum of $13 million associated with the new rig to be excluded from the calculation of our fixed charge coverage ratio covenant, (ii) calculate EBITDA during the second quarter of 2018 on an annualized quarterly basis, (iii) calculate EBITDA during the third quarter of 2018 on an annualized six-month basis and (iv) calculate EBITDA during the fourth quarter of 2018 on an annualized nine-month basis.

The Credit Facility provides that an event of default may occur if a material adverse change to ICD occurs, which is considered a subjective acceleration clause under applicable accounting rules. In accordance with ASC 470-10-45, because of the existence of this clause, borrowings under the Credit Facility will be required to be classified as current in the event the springing lock-box event occurs, regardless of the actual maturity of the borrowings. The requirement for a mandatory lock-box trigger occurs when availability under the Credit Facility is $10.0 million or less.

We had $53.2 million in outstanding borrowings under the Credit Facility at March 31, 2018. Remaining availability of our $85.0 million commitment under the Credit Facility was $31.8 million at March 31, 2018.

Capital Lease Obligations

During the first quarter of 2016, our vehicle lease agreements were amended, which resulted in a change in the classification of certain leases from operating leases to capital leases. On the amendment date we recorded $0.8 million in capital lease obligations, representing the lesser of fair market value or the present value of future minimum lease payments on the conversion date. These leases generally have initial terms of 36 months and are paid monthly.

8. Stock-Based Compensation

In March 2012, we adopted the 2012 Omnibus Long-Term Incentive Plan (the “2012 Plan”) providing for common stock-based awards to employees and non-employee directors. The 2012 Plan was subsequently amended in August 2014 and June 2016. The 2012 Plan, as amended, permits the granting of various types of awards, including stock options, restricted stock and restricted stock unit awards, and up to 4,754,000 shares were authorized for issuance. Restricted stock and restricted stock units may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options expire ten years after the grant date. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. As of March 31, 2018, approximately 1,016,855 shares were available for future awards.

In the first quarter of 2017, we adopted ASU 2016-09, Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting. The FASB issued this accounting standard in an effort to simplify the accounting for employee share-based payments and improve the usefulness of the information provided to users of financial statements. Our policy is to account for forfeitures of share-based compensation awards as they occur.

A summary of compensation cost recognized for stock-based payment arrangements is as follows:

(in thousands)	Three Months Ended March 31,	
	2018	2017
Compensation cost recognized:		
Stock options	$—	$—
Restricted stock and restricted stock units	644	1,012
Total stock-based compensation	$644	$1,012

No stock-based compensation was capitalized in connection with rig construction activity during the three months ended March 31, 2018 or the three months ended March 31, 2017.

Stock Options

We use the Black-Scholes option pricing model to estimate the fair value of stock options granted to employees and non-employee directors. The fair value of the options is amortized to compensation expense on a straight-line basis over the requisite service periods of the stock awards, which are generally the vesting periods.

There were no stock options granted during the three months ended March 31, 2018 or the three months ended March 31, 2017.

A summary of stock option activity and related information for the three months ended March 31, 2018 is as follows:

	Three Months Ended March 31, 2018	
	Options	Weighted Average Exercise Price
Outstanding at January 1, 2018	682,950	$ 12.74
Granted	—	—
Exercised	—	—
Forfeited/expired	—	—
Outstanding at March 31, 2018	682,950	$ 12.74
Exercisable at March 31, 2018	682,950	$ 12.74

The number of options vested at March 31, 2018 was 682,950 with a weighted average remaining contractual life of 4.1 years and a weighted average exercise price of $12.74 per share. There were no unvested options or unrecognized compensation cost related to outstanding stock options at March 31, 2018.

Restricted Stock

Restricted stock awards consist of grants of our common stock that vest ratably over three to four years. We recognize compensation expense on a straight-line basis over the vesting period. The fair value of restricted stock awards is determined based on the estimated fair market value of our shares on the grant date. As of March 31, 2018, there was no unrecognized compensation cost related to unvested restricted stock awards and all previously issued restricted stock awards had vested.

Restricted Stock Units

We have granted restricted stock units ("RSUs") to key employees under the 2012 Plan. We have granted three-year time vested RSUs, as well as performance-based and market-based RSUs, where each unit represents the right to receive, at the end of a vesting period, up to two shares of ICD common stock with no exercise price. Exercisability of the market-based RSUs is based on our three-year total shareholder return ("TSR") as measured against the TSR of a defined peer group and vesting of the performance-based RSUs is based on our cumulative EBITDA, safety or uptime performance statistics, as defined in the restricted stock unit agreement, over a three-year period. We used a Monte Carlo simulation model to value the TSR market-based RSUs. The fair value of the performance-based RSUs is based on the market price of our common stock on the date of grant. During the restriction period, the RSUs may not be transferred or encumbered, and the recipient does not receive dividend equivalents or have voting rights until the units vest. As of March 31, 2018, there was $5.2 million of total unrecognized compensation cost related to unvested RSUs. This cost is expected to be recognized over a weighted average

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period of 1.1 years.

A summary of the status of our RSUs as of March 31, 2018, and of changes in RSUs outstanding during the three months ended March 31, 2018, is as follows:

	Three Months Ended March 31, 2018	
	RSUs	Weighted Average Grant-Date Fair Value Per Share
Outstanding at January 1, 2018	993,320	$ 5.11
Granted	641,041	4.55
Vested and converted	(350,528)	5.03
Forfeited	(22,589)	4.75
Outstanding at March 31, 2018	1,261,244	$ 4.86

9. Stockholders' Equity and Earnings (Loss) per Share

As of March 31, 2018, we had a total of 38,252,765 shares of common stock, $0.01 par value, outstanding. We also had 344,682 shares held as treasury stock. Total authorized common stock is 100,000,000 shares.

Basic earnings (loss) per common share ("EPS") are computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock. A reconciliation of the numerators and denominators of the basic and diluted losses per share computations is as follows:

	Three Months Ended March 31,	
(in thousands, except per share data)	2018	2017
Net loss (numerator):	$(4,146)	$(6,269)
Loss per share:		
Basic and diluted	$(0.11)	$(0.17)
Shares (denominator):		
Weighted average common shares outstanding - basic	38,124	37,546
Net effect of dilutive stock options, warrants and restricted stock units	—	—
Weighted average common shares outstanding - diluted	38,124	37,546

For all periods presented, the computation of diluted loss per share excludes the effect of certain outstanding stock options and RSUs because their inclusion would be anti-dilutive. The number of options that were excluded from diluted loss per share were 682,950 during the three months ended March 31, 2018 and 920,020 during the three months ended March 31, 2017. RSUs, which are not participating securities and are excluded from our basic and diluted loss per share because they are anti-dilutive, were 1,261,244 for the three months ended March 31, 2018 and 1,367,823 for the three months ended March 31, 2017.

10. Income Taxes

Our effective tax rate was 1.2% for the three months ended March 31, 2018, and (0.7)% for the three months ended March 31, 2017. Taxes in the current year period relate to Louisiana state income tax and Texas margin tax. Taxes in the prior year period relate to Texas margin tax. For federal income tax purposes, we have applied a valuation allowance against any potential deferred tax asset which would have ordinarily resulted.

11. Commitments and Contingencies

Purchase Commitments

As of March 31, 2018, we had outstanding purchase commitments to a number of suppliers totaling $12.1 million, net of deposits previously made, related primarily to the construction of drilling rigs. Of these commitments, $11.9 million relates to equipment currently scheduled for delivery in 2018.

Lease Commitments

We lease certain equipment and vehicles under non-cancelable operating and capital leases. Future minimum lease payments under operating and capital lease commitments, with lease terms in excess of one year subsequent to March 31, 2018, were as follows:

(in thousands)	
2018	$584
2019	689
2020	345
2021	8
	$1,626

As of March 31, 2018, property, plant and equipment on our balance sheet included $1.2 million of equipment under capital lease, which is net of $0.5 million of accumulated amortization. As of December 31, 2017, property, plant and equipment in our balance sheet included $1.3 million of equipment under capital lease, net of $0.5 million of accumulated amortization. This equipment consists entirely of vehicles used in our operations.

Contingencies

We may be the subject of lawsuits and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such lawsuits and claims. While lawsuits and claims are asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that the outcome of any of these known legal proceedings or claims will have a material adverse effect on our financial position or results of operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations together with the financial statements and related notes that are included elsewhere in this Quarterly Report on Form 10-Q and with our audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2017, filed with the Securities and Exchange Commission on February 26, 2018 (the "Form 10-K"). This discussion contains forward-looking statements based upon current expectations that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including those described in the section titled "Cautionary Statement Regarding Forward-Looking Statements" and those set forth under Part 1"Item 1A. Risk Factors" or in other parts of the Form 10-K.

Management Overview

We were incorporated in Delaware on November 4, 2011. We provide land-based contract drilling services for oil and natural gas producers targeting unconventional resource plays in the United States. We construct, own and operate a premium land rig fleet comprised entirely of technologically advanced, custom designed 200 Series ShaleDriller rigs that are specifically engineered and designed to optimize the development of our customers' most technically demanding oil and natural gas properties. Our first rig began drilling in May 2012.

Our standardized fleet consists of 14 premium 200 Series ShaleDriller rigs, all of which are equipped with our integrated omni-directional walking system that is specifically designed to optimize pad drilling for our customers. During the first quarter of 2018, we also recommenced construction of our 15th ShaleDriller rig which is expected to be completed by mid-third quarter 2018. Every rig in our fleet is a 1500-hp, AC programmable rig ("AC rig") designed to be fast-moving between drilling sites and is equipped with 7500 psi mud systems, top drives, automated tubular handling systems and blowout preventer ("BOP") handling systems. All of our rigs are equipped with bi-fuel capabilities that enable the rig to operate on either diesel or a natural gas-diesel blend.

Our business depends on the level of exploration and production activity by oil and natural gas companies operating in the United States, and in particular, the regions where we actively market our contract drilling services. The oil and natural gas exploration and production industry is a historically cyclical industry characterized by significant changes in the levels of exploration and development activities. Oil and natural gas prices and market expectations of potential changes in those prices significantly affect the levels of those activities. Worldwide political, regulatory, economic, and military events, as well as natural disasters have contributed to oil and natural gas price volatility historically, and are likely to continue to do so in the future. Any prolonged reduction in the overall level of exploration and development activities in the United States and the regions where we market our contract drilling services, whether resulting from changes in oil and natural gas prices or otherwise, could materially and adversely affect our business.

Both oil and natural gas prices began to decline in the second half of 2014, declined further during 2015 and remained low in 2016. The closing price of oil was as high as $106.06 per barrel during the third quarter of 2014, was $37.13 per barrel on December 31, 2015 and reached a low of $26.19 on February 11, 2016 (West Texas Intermediate - Cushing, Oklahoma ("WTI") spot price as reported by the United States Energy Information Administration (the "EIA")). Similarly, natural gas prices (as measured at Henry Hub) declined from an average of $4.37 per MMBtu in 2014, to $2.62 per MMBtu in 2015 and to $2.52 per MMBtu in 2016. As a result, our industry experienced an exceptional downturn and market conditions have only begun to stabilize and slowly recover.

In November 2016, Organization of Petroleum Exporting Countries ("OPEC") members formally agreed to reduce their production quotas, starting January 1, 2017. These production cuts significantly reduced the overhang of global oil supplies. OPEC members met in December 2017 and agreed to extend the freeze into 2018, and are expected to meet again in June 2018 to review market conditions and the impact of their freeze on global supplies. In addition to OPEC members, certain non-OPEC producers such as Russia have agreed to production cuts, which has also supported crude oil and related energy commodity prices.

As a result of these supply cuts and positive demand trends, crude oil prices have recovered with WTI oil prices reaching a three-year high of $67.35 on April 13, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.04 per MMBtu in 2018 as of April 16, 2018. However, there are no indications at this time that oil and natural gas prices and rig counts will recover, in the near term, to their previous highs experienced in 2014.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At March 31, 2018, all 14 of our rigs were under contract and operating. In addition to improving utilization, contract tenors are improving with customers willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels, with the potential to move higher if market conditions continue to improve. However, the pace and duration of the current recovery is unknown, and if oil prices were to fall for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Emerging Growth Company

We are an emerging growth company ("EGC") as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the “JOBS Act”. We will remain an EGC for up to five years from the date of the completion of our initial public offering (the “IPO”) on August 13, 2014, or until the earlier of (1) the last day of the fiscal year in which our total annual gross revenues exceed $1.07 billion, (2) the date that we become a “large accelerated filer” as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which would occur if the market value of our common equity that is held by non-affiliates is $700 million or more as of the last business day of our most recently completed second fiscal quarter or (3) the date on which we have issued more than $1.0 billion in non-convertible debt during the preceding three-year period.

As an EGC, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not EGCs including, but not limited to:

- not being required to comply with the auditor attestation requirements related to our internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;
- reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements; and
- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

In addition, Section 107 of the JOBS Act provides that an EGC can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards. Under this provision, an EGC can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies.

We have not elected to avail ourselves of the extended transition period available to EGCs as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Significant Developments

Change in Plan of Sale of Assets

During the second quarter of 2017, our management committed to a plan to sell our corporate headquarters and rig assembly yard complex located at 11601 North Galayda Street, Houston, Texas (the "Galayda Facility"). As a result, we reclassified an aggregate $4.0 million of land, buildings and equipment from property, plant and equipment to assets held for sale on our balance sheet and recognized a $0.5 million asset impairment charge representing the difference between the carrying value and the fair value, less the costs to sell the related property. In the third quarter of 2017, we recorded an additional impairment on this group of assets totaling $0.6 million, as a result of water-related damage sustained during the heavy rainfall that occurred during Hurricane Harvey in August 2017.

During the first quarter of 2018, management changed its plan to sell all of the Galayda Facility assets and decided to improve and utilize a portion of the land and buildings on the property. Based on this decision, which was previously considered unlikely, certain land and buildings at the Galayda Facility were reclassified to assets held and used as of March 31, 2018. Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 balance sheet and recognized a recovery of asset impairment expense of approximately $208 thousand in our statement of operations for the three months ended March 31, 2018. Additionally, our December 31, 2017 balance sheet was adjusted to reflect a reduction in assets held for sale of $2.7 million and an increase in property, plant and equipment of $2.7 million.

In conjunction with the decision to hold and use a portion of the Galayda Facility in the first quarter of 2018, management concluded that four dilapidated buildings on the property would likely be torn down. As such, we impaired the carrying value of these buildings to zero, reducing property, plant and equipment $173 thousand and recognizing asset impairment expense of $173 thousand.

Our Revenues

We earn contract drilling revenues pursuant to drilling contracts entered into with our customers. We perform drilling services on a “daywork” basis, under which we charge a specified rate per day, or “dayrate.” The dayrate associated with each of our contracts is a negotiated price determined by the capabilities of the rig, location, depth and complexity of the wells to be drilled, operating conditions, duration of the contract and market conditions. The term of land drilling contracts may be for a defined number of wells or for a fixed time period. We generally receive lump-sum payments for the mobilization of rigs and other drilling equipment at the commencement of a new drilling contract. Revenue and costs associated with the initial mobilization are deferred and recognized ratably over the term of the related drilling contract once the rig spuds. Costs incurred to relocate rigs and other equipment to an area in which a contract has not been secured are expensed as incurred. Our contracts provide for early termination fees in the event our customers choose to cancel the contract prior to the specified contract term. We record a contract liability for such fees received up front, and recognize them ratably as contract drilling revenue over the initial term of the related drilling contract or until such time that all performance obligations are satisfied. While under contract, our rigs generally earn a reduced rate while the rig is moving between wells or drilling locations, or on standby waiting for the customer. Reimbursements for the purchase of supplies, equipment, trucking and other services that are provided at the request of our customers are recorded as revenue when incurred. The related costs are recorded as operating expenses when incurred. Revenue is presented net of any sales tax charged to the customer that we are required to remit to local or state governmental taxing authorities.

Our Operating Costs

Our operating costs include all expenses associated with operating and maintaining our drilling rigs. Operating costs include all “rig level” expenses such as labor and related payroll costs, repair and maintenance expenses, supplies, workers' compensation and other insurance, ad valorem taxes and equipment rental costs. Also included in our operating costs are certain costs that are not incurred at the rig level. These costs include expenses directly associated with our operations management team as well as our safety and maintenance personnel who are not directly assigned to our rigs but are responsible for the oversight and support of our operations and safety and maintenance programs across our fleet.

Our operating costs also include costs and expenses associated with construction activities at our Galayda yard location to the extent that construction activities cease or are not continuous. As a result of the significant downturn in industry conditions, we substantially reduced our rig construction activities during the fourth quarter of 2015 and throughout 2016 and 2017. As a result, we began expensing a portion of our Galayda yard construction costs during the fourth quarter of 2015 and expect to continue expensing such costs until we resume continuous rig construction activities.

During the first quarter of 2017, our operating costs also included approximately $0.7 million of costs associated with the reactivation of two idle and standby rigs. These costs included costs associated with recommissioning the rig, the hiring and training of new crews and the purchase of supplies and other consumables required for the operation of the rigs.

How We Evaluate our Operations

We regularly use a number of financial and operational measures to analyze and evaluate the performance of our business and compensate our employees, including the following:

- Safety Performance. Maintaining a strong safety record is a critical component of our business strategy. We believe we are one of the few land drillers that utilizes a safety management system that complies with the Bureau of Safety and Environmental Enforcement’s SEMS II workplace safety rules. We measure safety by tracking the total recordable incident rate for our operations. In addition, we closely monitor and measure compliance with our safety policies and procedures, including “near miss” reports and job safety analysis compliance.
- Utilization. Rig utilization measures the percentage of time that our rigs are earning revenue under a contract during a particular period. We measure utilization by dividing the total number of Operating Days (defined below) for a rig by the total number of days the rig is available for operation in the applicable calendar period. A rig is available for operation commencing on the earlier of the date it spuds its initial well following construction or when it has been completed and is actively marketed. “Operating Days” represent the total number of days a rig is earning revenue under a contract, beginning when the rig spuds its initial well under the contract and ending with the completion of the rig’s

demobilization.

- Revenue Per Day. Revenue per day measures the amount of revenue that an operating rig earns on a daily basis during a particular period. We calculate revenue per day by dividing total contract drilling revenue earned during the applicable period by the number of Operating Days in the period. Revenues attributable to costs reimbursed by customers are excluded from this measure.

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- Operating Cost Per Day. Operating cost per day measures the operating costs incurred on a daily basis during a particular period. We calculate operating cost per day by dividing total operating costs during the applicable period by the number of Operating Days in the period. Operating costs attributable to costs reimbursed by customers are excluded from this measure.
- Operating Efficiency and Uptime. Maintaining our rigs' operational efficiency is a critical component of our business strategy. We measure our operating efficiency by tracking each drilling rig's unscheduled downtime on a daily, monthly, quarterly and annual basis.

Results of Operations

The following summarizes our financial and operating data for the three months ended March 31, 2018 and 2017:

(In thousands, except per share data)	Three Months Ended March 31, 2018	March 31, 2017
Revenues	$25,627	$20,236
Costs and expenses		
Operating costs	18,926	14,898
Selling, general and administrative	3,479	3,718
Depreciation and amortization	6,591	6,256
Asset impairment, net	(35)	129
(Gain) loss on disposition of assets, net	(82)	828
Total cost and expenses	28,879	25,829
Operating loss	(3,252)	(5,593)
Interest expense	(943)	(630)
Loss before income taxes	(4,195)	(6,223)
Income tax (benefit) expense	(49)	46
Net loss	$(4,146)	$(6,269)
Other financial and operating data		
Number of completed rigs (end of period)	14	14
Rig operating days (1)	1,259.4	1,072.9
Average number of operating rigs (2)	14.0	11.9
Rig utilization (3)	100.0 %	91.7 %
Average revenue per operating day (4)	$19,055	$17,949
Average cost per operating day (5)	$13,414	$11,930
Average rig margin per operating day	$5,641	$6,019

(1) Rig operating days represent the number of days our rigs are earning revenue under a contract during the period, including days that standby revenues are earned. During the three months ended March 31, 2018, we did not earn any revenue on a standby basis. During the three months ended March 31, 2017, there were 77.9 operating days in which we earned revenue on a standby basis, including 69.0 standby-without-crew days.

(2) Average number of operating rigs is calculated by dividing the total number of rig operating days in the period by the total number of calendar days in the period.

(3) Rig utilization is calculated as rig operating days divided by the total number of days our drilling rigs are available during the applicable period.

(4) Average revenue per operating day represents total contract drilling revenues earned during the period divided by rig operating days in the period. Excluded in calculating average revenue per operating day are revenues associated with the reimbursement of out-of-pocket costs paid by customers of $1.6 million and $1.0 million during the three months ended March 31, 2018 and 2017, respectively.

(5) Average cost per operating day represents operating costs incurred during the period divided by rig operating days in the period. The following costs are excluded in calculating average cost per operating day: (i) out-of-pocket costs reimbursed by customers of $1.6 million and $1.0 million during the three months ended March 31, 2018 and 2017, respectively, (ii) new crew training costs of $25.0 thousand and $60.0 thousand during the three months ended March 31, 2018 and 2017, respectively, (iii) construction overhead costs expensed due to reduced rig construction activity of $0.4 million and $0.2 million during the three months ended March 31, 2018 and 2017, respectively, (iv) rig reactivation costs associated with the redeployment of previously stacked rigs, excluding new crew training costs (included in (ii) above), of $0.7 million during the three months ended March 31, 2017 and (v) out-of-pocket expenses of $0.1 million, net of insurance recoveries, incurred as a result of damage to one of our rig's mast during the three months ended March 31, 2017.

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues

Revenues for the three months ended March 31, 2018 were $25.6 million, representing a 26.6% increase as compared to revenues of $20.2 million for the three months ended March 31, 2017. This increase was attributable to an increase in operating days to 1,259 days as compared to 1,073 days in the prior year period. Additionally, 69 days in the prior year period represented standby-without-crew days at lower dayrates. On a revenue per operating day basis, our revenue per day increased by 6.2% to $19,055 during the three months ended March 31, 2018, as compared to revenue per day of $17,949 for the three months ended March 31, 2017. This increase in revenue per day was primarily the result of a decrease in rigs earning revenue on a standby-without-crew basis during the current period.

Operating Costs

Operating costs for the three months ended March 31, 2018 were $18.9 million, representing an 27.0% increase as compared to operating costs of $14.9 million for the three months ended March 31, 2017. This increase was attributable to an increase in operating days to 1,259 days as compared to 1,073 days in the prior year period. Additionally, 69 days in the prior year period represented standby-without-crew days. Rigs on standby-without-crew incur minimal operating costs. On a cost per operating day basis, our cost increased to $13,414 per day during the three months ended March 31, 2018, representing a 12.4% increase compared to cost per operating day of $11,930 for the three months ended March 31, 2017. This increase in cost per operating day was primarily the result of a decrease in rigs earning revenue on a standby-without-crew basis during the current period, as well as an increase in repair and maintenance costs during the current period.

Selling, General and Administrative

Selling, general and administrative expenses for the three months ended March 31, 2018 were $3.5 million, representing a 6.4% decrease as compared to selling, general and administrative expense of $3.7 million for the three months ended March 31, 2017. This decrease as compared to the prior year quarter primarily relates to decreased stock-based compensation, partially offset by higher training costs in the current quarter.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended March 31, 2018 was $6.6 million, representing a 5.4% increase compared to depreciation and amortization expense of $6.3 million for the three months ended March 31, 2017. This increase relates primarily to upgrades and additions to certain rigs in 2017.

Asset Impairment, net

During the first quarter of 2018, management decided to hold and use a portion of the Galayda Facility which was previously classified as held for sale (see “Significant Developments - Change in Plan of Sale of Assets” in Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations). Accordingly, we reduced assets held for sale by $2.7 million and increased property, plant and equipment by $2.9 million on our March 31, 2018 balance sheet and recognized a recovery of asset impairment expense of approximately $208 thousand in our statement of operations for the three months ended March 31, 2018.

In conjunction with the decision to hold and use a portion of the Galayda Facility in the first quarter of 2018, management concluded that four dilapidated buildings on the property would likely be torn down. As such, we impaired the carrying value of these buildings to zero, reducing property, plant and equipment $173 thousand and recognizing asset impairment expense of $173 thousand.

(Gain) Loss on Disposition of Assets, net

A gain on the disposition of assets totaling $82.0 thousand was recorded for the three months ended March 31, 2018 compared to a loss on the disposition of assets totaling $0.8 million in the prior year comparable period. In the current year period, the gain primarily relates to the sale or disposition of miscellaneous drilling equipment. In the prior year period, the loss related primarily to the disposal of certain rig components associated with the upgrade of two of our rigs to a 7,500 psi mud system during the first quarter of 2017.

Interest Expense

Interest expense for the three months ended March 31, 2018 was $0.9 million, as compared to $0.6 million for the three months ended March 31, 2017. The increase as compared to the prior year comparable period was primarily the result of increased average borrowings, as well as an increase in the 30 day LIBOR rate, which drives our borrowing rate of interest, between March 31, 2017 and March 31, 2018. Our interest expense is derived from borrowings under our Credit Facility, which are primarily used to fund our rig construction and rig upgrade activity and general corporate purposes.

Income Tax (Benefit) Expense

The income tax benefit recorded for the three months ended March 31, 2018 amounted to $49.0 thousand compared to an income tax expense of $46.0 thousand for the three months ended March 31, 2017. Our effective tax rates for the three months ended March 31, 2018 and 2017 were 1.2% and (0.7)%, respectively. Taxes in the current year period relate to Louisiana state income tax and to Texas margin tax. Taxes in the prior year period relate to Texas margin tax.

Liquidity and Capital Resources

Our liquidity as of March 31, 2018 included approximately $31.8 million of our $85.0 million commitment availability under our Credit Facility, $2.5 million of cash and $8.3 million of other net working capital.

Our principal use of capital has been the construction of drilling rigs and associated equipment and working capital and inventories to support our drilling operations. Our first drilling rig was completed and began operating in May 2012. As of March 31, 2018, we had 14 200 Series rigs. Our primary sources of capital to date have been funds received from our initial private placement, our IPO, our April 2016 public offering of common stock, and cash flows from operations and our Credit Facility.

Net Cash Provided By (Used In) Operating Activities

Cash provided by operating activities was $2.0 million for the three months ended March 31, 2018 compared to cash used in operating activities of $1.4 million during the same period in 2017. Factors affecting changes in operating cash flows are similar to those that impact net earnings, with the exception of non-cash items such as depreciation and amortization, impairments, gains or losses on disposals of assets, stock-based compensation, deferred taxes and amortization of deferred financing costs. Additionally, changes in working capital items such as accounts receivable, inventory, prepaid expense and accounts payable can significantly affect operating cash flows. Cash flows from operating activities during the first three months of 2018 were higher as a result of a decrease in net loss of $2.1 million, adjusted for non-cash items, of $7.2 million for the three months ended March 31, 2018 compared to $8.4 million during the same period in 2017. Working capital changes decreased cash flows from operating activities by $1.0 million for the three months ended March 31, 2018 compared to decreased cash flows of $3.5 million during the same period in 2017.

Net Cash Used In Investing Activities

Cash used in investing activities was $6.1 million for the three months ended March 31, 2018 compared to cash used in investing activities of $8.6 million during the same period in 2017. During the first three months of 2018, cash payments of $6.3 million for capital expenditures were offset by proceeds from the sale of property, plant and equipment of $0.1 million. During the 2017 period, cash payments of $8.6 million for capital expenditures were offset by de minimis proceeds from the sale of property, plant and equipment.

Net Cash Provided by Financing Activities

Cash provided by financing activities was $4.1 million for the three months ended March 31, 2018 compared to cash provided by financing activities of $10.3 million during the same period in 2017. During the first three months of 2018, we made borrowings under our Credit Facility of $13.8 million. These proceeds were offset by repayments under our Credit Facility of $9.1 million, the purchase of treasury stock of $0.4 million, restricted stock unit's withheld for taxes paid of $0.1 million and payments for capital lease obligations of $0.2 million. During the first three months of 2017 we made borrowings under our Credit Facility of $13.5 million. These proceeds were offset by repayments under our Credit Facility of $2.6 million, the purchase of treasury stock of $24.0 thousand, restricted stock unit's withheld for taxes paid of $0.5 million and payments for capital lease obligations of $0.1 million.

Future Liquidity Requirements

We expect our future capital and liquidity needs to be related to funding capital expenditures for our next new build rig, capital spare inventory, operating expenses, maintenance capital expenditures, working capital and general corporate purposes. We believe that our cash and cash equivalents, cash flows from operating activities and borrowings under our Credit Facility will adequately finance all of our purchase commitments, capital expenditures and other cash requirements over the next twelve months.

Long-term Debt

In November 2014, we entered into our Credit Facility with a syndicate of financial institutions led by CIT Finance, LLC, that provided for a committed $155.0 million Credit Facility and an additional uncommitted $25.0 million accordion feature that allowed for future increases in the facility. In 2015, we amended the Credit Facility to provide for a springing lock-box arrangement and, in light of market conditions and our reduced capital plans, reduce aggregate commitments to
$125.0 million and modify certain maintenance covenants. In 2016, we amended the Credit Facility to reduce aggregate commitments to $85.0 million and further modify certain maintenance covenants. In connection with this amendment, we expensed certain previously deferred debt issuance costs totaling $0.5 million reflecting the reduction in borrowing capacity.

In 2017, we amended the Credit Facility to extend the maturity date by two years to November 5, 2020 and to provide for an additional uncommitted $65.0 million accordion feature that allows for future increases in facility commitments. Interest under the Credit Facility remained unchanged. The amendment also contained various changes to the financial and other covenants to accommodate the extension in term, including changes to the leverage ratio covenant, fixed charge coverage ratio covenant and rig utilization ratio covenant.

The obligations under the Credit Facility are secured by all of our assets and are unconditionally guaranteed by all of our current and future direct and indirect subsidiaries.

Borrowings under the Credit Facility are subject to a borrowing base formula that allows for borrowings of up to 85% of eligible trade accounts receivable not more than 90 days outstanding, plus up to a certain percentage, the “advance rate”, of the appraised forced liquidation value of our eligible, completed and owned drilling rigs. As of March 31, 2018, the advance rate was 72.5%. The advance rate declines 1.25% each quarter through June 2019. Thereafter, through the maturity date, the advance rate remains at 65%. Rigs that remain idle for 90 consecutive days or longer are removed from the borrowing base until they are contracted. In addition, rigs are appraised two times a year and are subject to upward or downward revisions as a result of market conditions as well as the age of the rig.

At our election, interest under the Credit Facility is determined by reference, at our option, to either (i) the London Interbank Offered Rate (“LIBOR”), plus 4.5% or (ii) a “base rate” equal to the higher of the prime rate published by JP Morgan Chase Bank or three-month LIBOR plus 1%, plus in each case, 3.5%, the federal funds effective rate plus 0.05%. We also pay, on a quarterly basis, a commitment fee of 0.50% per annum on the unused portion of the Credit Facility commitment. As of March 31, 2018, the weighted average interest rate on our borrowings was 6.35%.

The Credit Facility contains various financial covenants including a leverage covenant, fixed charge coverage ratio and rig utilization ratio. Additionally, there are restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness or issue disqualified capital stock; transfer or sell assets; pay dividends or distributions; redeem subordinated indebtedness; make certain types of investments or make other restricted payments; create or incur liens; consummate a merger, consolidation or sale of all or substantially all assets; and engage in business other than a business that is the same or similar to the current business and reasonably related businesses. The Credit Facility does, however, permit us to incur up to $20.0 million of additional indebtedness for the purchase of additional rigs or rig equipment. As of March 31, 2018, we are in compliance with these covenants.

Under the Credit Agreement, as amended, for purposes of calculating EBITDA, non-cash stock-based compensation is added back to EBITDA, as well as up to $2.0 million per year of previously capitalized construction costs that were incurred in 2017. In April 2018, in connection with the construction of our 15th ShaleDriller rig, we amended the Credit Facility as follows: (i) permit capital expenditures up to a maximum of $13 million associated with the new rig to be excluded from the calculation of our fixed charge coverage ratio covenant, (ii) calculate EBITDA during the second quarter of 2018 on an annualized quarterly basis, (iii) calculate EBITDA during the third quarter of 2018 on an annualized six-month basis and (iv) calculate EBITDA during the fourth quarter of 2018 on an annualized nine-month basis.

The Credit Facility provides that an event of default may occur if a material adverse change to ICD occurs, which is considered a subjective acceleration clause under applicable accounting rules. In accordance with ASC 470-10-45, because of the existence of this clause, borrowings under the Credit Facility will be required to be classified as current in the event the springing lock-box event occurs, regardless of the actual maturity of the borrowings. The requirement for a mandatory lock-box trigger occurs when availability under the Credit Facility is $10.0 million or less.

We had $53.2 million in outstanding borrowings under the Credit Facility at March 31, 2018. Remaining availability of our $85.0 million commitment under the Credit Facility was $31.8 million at March 31, 2018.

Additionally, included in our long-term debt are capital leases. These leases generally have initial terms of 36 months and are paid monthly. See Note 7 in Part 1 "Item 1. Financial Statements" for additional information.

Other Matters

Off-Balance Sheet Arrangements

We are party to certain arrangements defined as “off-balance sheet arrangements” that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. These arrangements relate to non-cancelable operating leases and unconditional purchase obligations not fully reflected on our balance sheets (see Note 11 - “Commitments and Contingencies”, in Part 1, Item 1. Notes to Financial Statements, for additional information).

Emerging Growth Company

We have not elected to avail ourselves of the extended transition period available to emerging growth companies ("EGCs") as provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, for complying with new or revised accounting standards, therefore, we will be subject to new or revised accounting standards at the same time as other public companies that are not EGCs.

Recent Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases, to establish the principles that lessees and lessors shall apply to report useful information to users of financial statements about the amount, timing, and uncertainty of cash flows arising from a lease. Under the new guidance, lessees will be required to recognize (with the exception of short-term leases) at the commencement date, a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. This guidance is effective for public companies for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities. We are currently evaluating the impact this guidance will have on our financial statements and have engaged a third party consultant to assist us in this evaluation process.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, as additional guidance on the measurement of credit losses on financial instruments. The new guidance requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable supportable forecasts. In addition, the guidance amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The new guidance is effective for public companies for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. We are in the initial stages of evaluating the impact this guidance will have on our accounts receivable.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks including risks related to potential adverse changes in interest rates and commodity prices. We actively monitor exposure to market risk and continue to develop and utilize appropriate risk management techniques. We do not use derivative financial instruments for trading or to speculate on changes in commodity prices.

Interest Rate Risk

Total long-term debt at March 31, 2018 included $53.2 million of floating-rate debt attributed to borrowings at an average interest rate of 6.35%. As a result, our annual interest cost in 2018 will fluctuate based on short-term interest rates.

The impact on annual cash flow of a 10% change in the floating-rate (approximately 0.64%) would be approximately $0.3 million annually based on the floating-rate debt and other obligations outstanding at March 31, 2018; however, there are no assurances that possible rate changes would be limited to such amounts.

Commodity Price Risk

The demand for contract drilling services is a result of E&P companies spending money to explore and develop drilling prospects in search of oil and natural gas. This customer spending is driven by their cash flow and financial strength, which is affected by trends in crude oil and natural gas commodity prices. Crude oil prices are determined by a number of factors including supply and demand, worldwide economic conditions and geopolitical factors. Crude oil and natural gas prices have historically been volatile and very difficult to predict. This volatility can lead many E&P companies to base their capital spending on much more conservative estimates of commodity prices. As a result, demand for contract drilling services is not always purely a function of the movement of current commodity prices. Following the November 2016 decision by OPEC to reduce production quotas, oil prices have recovered, reaching a three year high of $67.35 on April 13, 2018. Similarly, natural gas prices at Henry Hub averaged $2.99 per MMBtu in 2017, and have averaged $3.04 per MMBtu in 2018 as of April 16, 2018. While this continued recovery in pricing is promising, there are no indications at this time that oil and natural gas prices and rig counts will recover to their previous highs experienced in 2014.

Due to this deterioration and stabilization of commodity prices well below previous highs, our customers are principally focused on their most economic wells, and driving cost and production efficiencies that deliver the most economic wells with the lowest capital costs. As a result of this drive towards production and cost efficiencies, operators are focusing more of their capital spending on horizontal drilling programs compared to vertical drilling, and are more focused on utilizing drilling equipment and techniques that optimize costs and efficiency. Thus, we believe the rapid market deterioration and stabilization of oil prices well below historical highs has significantly accelerated the pace of the ongoing land rig replacement cycle and continued shift to horizontal drilling from multi-well pads utilizing “pad optimal” rig technology.

As market conditions have improved from trough levels in 2016 and begun to stabilize higher, demand for our ShaleDriller rigs has improved. At March 31, 2018, all of our rigs were under contract and operating. In addition to improving utilization, contract tenors are improving with customers being willing to sign term contracts of six to twelve months or longer, and at higher dayrates compared to trough levels. However, the pace and duration of the current recovery is unknown, and if commodity prices were to fall for any sustained period of time, market conditions and demand for our products and services could deteriorate.

Credit and Capital Market Risk

Our customers may finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as currently being experienced, can make it difficult for our customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices, or a reduction of available financing may result in a reduction in customer spending and the demand for our drilling services. This reduction in spending could have a material adverse effect on our business, financial condition and results of operations.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and

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15d-15(e)) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures were effective as of March 31, 2018 at the reasonable assurance level.

Changes in Internal Control Over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are the subject of certain legal proceedings and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such legal proceedings and claims. While the legal proceedings and claims may be asserted for amounts that may be material should an unfavorable outcome be the result, management does not currently expect that the resolution of these matters will have a material adverse effect on our financial position or results of operations. In addition, management monitors our legal proceedings and claims on a quarterly basis and establishes and adjusts any reserves as appropriate to reflect our assessment of the then-current status of such matters.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risks discussed in Part 1, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017. There has been no material change in our risk factors from those described in the Annual Report. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

During the first quarter of 2018, we withheld shares of our common stock to satisfy minimum tax withholding obligations in connection with the vesting of certain restricted stock awards. These shares are deemed to be “issuer purchases” of shares that are required to be disclosed pursuant to this Item but were not purchased as part of a publicly announced program to purchase common shares. The following table provides information relating to our repurchase of shares of common stock during the three months ended March 31, 2018 (dollars in thousands, except average price paid per share):

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares That May Yet be Purchased Under the Program (1)
January 1 - January 31	—	$ —	—	$ —
February 1 - February 28	82,988	$ 4.22	—	$ —
March 1 - March 31	—	$ —	—	$ —
Total	82,988	$ 4.22	—	$ —

(1) We do not have a current share repurchase program authorized by the board of directors.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of Independence Contract Drilling, Inc. (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed August 13, 2014, Exhibit 3.1)
3.2	Amended and Restated Bylaws of Independence Contract Drilling, Inc. (Incorporated by reference to the Company's Registration Statement on Form S-1 (File No. 333-196914) filed July 18, 2014, Exhibit 3.3)
10.1	Second Amended and Restated Credit Facility, dated July 14, 2017 (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed July 17, 2017, Exhibit 10.1)
10.2*	Second Amendment to Second Amended and Restated Credit Facility, dated April 23, 2018
10.3	Form of Director RSU - Partial Cash Settlement Option Agreement (Incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36590) filed February 14, 2018, Exhibit 10.1)
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.INS*	XBRL Instance Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.SCH*	XBRL Schema Document

*Filed with this report

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.

INDEPENDENCE CONTRACT DRILLING, INC.

By: /s/ Byron A. Dunn
Name: Byron A. Dunn
Title: President and Chief Executive Officer (Principal Executive Officer)

By: /s/ Philip A. Choyce
Name: Philip A. Choyce
Title: Executive Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer)

By: /s/ Michael J. Harwell
Name: Michael J. Harwell
Title: Vice President - Finance and Chief Accounting Officer (Principal Accounting Officer)

Date: April 26, 2018